Deep Chamber Lift

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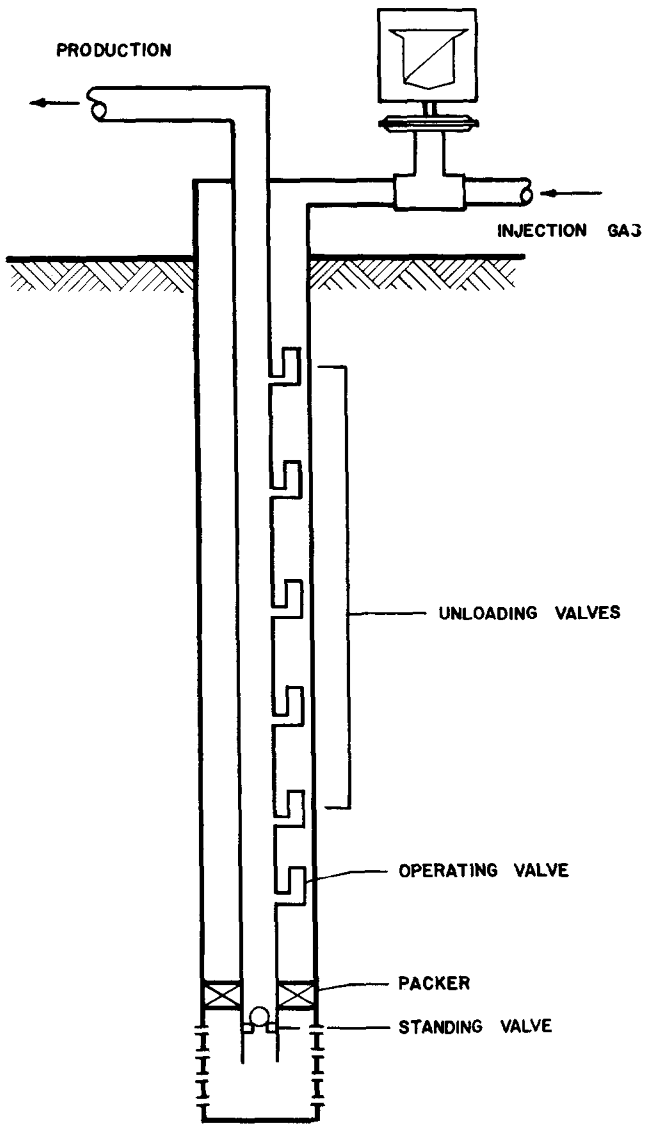
INTRODUCTION

The purpose of this paper is to discuss the principle of oil production from deep reservoirs by the gas lift chamber method.

This paper will be divided into five principle parts: (1) a section explaining the purpose of the chamber, (2) a discussion of chamber operation and arrangement, (3) a section concerning chamber design, (4) a discussion of results obtained by utilizing chambers for deep life operations, and (5) a summary.



TYPICAL GAS LIFT INSTALLATION

FIG. I

PURPOSE OF CHAMBER

The present trend in drilling and production is toward deeper and deeper operations. As production from these greater depths must eventually be artificially lifted, an efficient and effective method must be used to produce the fluid from these deep reservoirs. For purpose of discussion in this paper, 7000 ft or more will be considered as "deep". The problems encountered with a low pressure reservoir, whether the productivity index be high or low, are particularly troublesome in this case. A solution to the problem of producing fluid from these deep, low reservoir pressure formations is to employ a down hole accumulation chamber in conjunction with intermittent gas lift operations. The various types of chamber installations are illustrated in Figs. 2 through 4 and will be discussed later in the paper.

The volume of liquid produced per unit of time by the intermittent gas lift method — of which a chamber installation is a form — from a given depth is dependent upon the fluid volume that can be lifted per individual slug and the time required to complete a slug cycle, i.e., the time required for the individual slug volume to be produced into the well bore from the reservoir plus the time required to lift this slug to the surface. By utilizing an accumulation chamber at depth, one can realize two advantages over the standard gas lift installation. These are that (1) a greater fluid volume is accumulated per linear foot of fluid build-up and that (2) by producing larger slugs per cycle, more effective use of lift gas can be realized. The net result is more production per day at a lower injected gas fluid ratio. In considering these two advantages, one should assume the following well conditions:

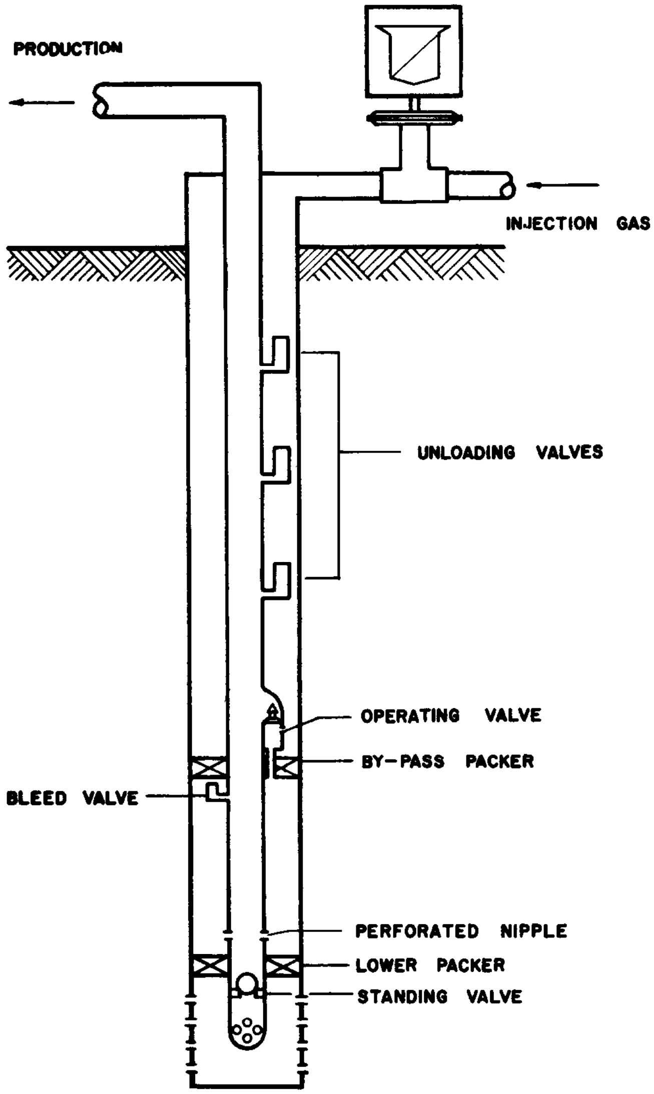
TD - 10,000 ft
Casing - 5 1/2 in., 20 lb per ft at depth
Tubing - 2 3/8 in. OD, 4.7 lb per ft
Production for purpose of installation comparison - [illegible] bbls per slug
Gradient of fluid - 0.35 psi per ft
Separator back pressure and effect of gas weight in the tubing is the same for each installation and is neglected in calculations.
Depth of lift - bottom depth
Efficiency - Assumed 100 per cent

Fluid Volume Accumulated per Linear Foot of Build-up

Considered first is the fluid build-up in a two packer chamber installation, Figs. 2 and 2a, required to accumulate a four barrel slug volume. The casing annulus and the tubing are used for this purpose. This height of fluid build-up, HT, above the lower packer is:

$$HT = \frac{Vs}{(BPFT + (BPFA)}$$

Where: Vs = Slug Volume = 4 bbl
BPFT = Bbl per linear ft of tubing = .00387



TWO PACKER CHAMBER INSTALLATION
FIG. 2

$$HT = \frac{(4\ \text{Bbl})}{(.00387 + .0167)}$$

BPFA = Bbl per linear ft of annulus = .0167

$= 195$ ft

The point of gas entry into the tubing is through the perforated nipple located immediately above the lower packer. The pressure exerted by the 195 ft of fluid build-up above this point is

$$PF = (HT)\,(GF)$$

$$= (195\ \text{ft})(0.35\ \text{psi per ft})$$

$$= 68\ \text{psi}$$

Where: GF = Fluid Gradient = 0.35 psi per ft

For purpose of comparison one considers now the requirements necessary for a standard intermittent gas lift installation to produce four Bbl per slug. In this installation, Fig. 1, the point of gas entry into the tubing is through the lowest valve. The height, HT, above this point required for a 4 Bbl accumulation would be:

$$HT = \frac{(Vs)}{(BPFT)}$$

$$= \frac{(4\ \text{bbl})}{(.00387)}$$

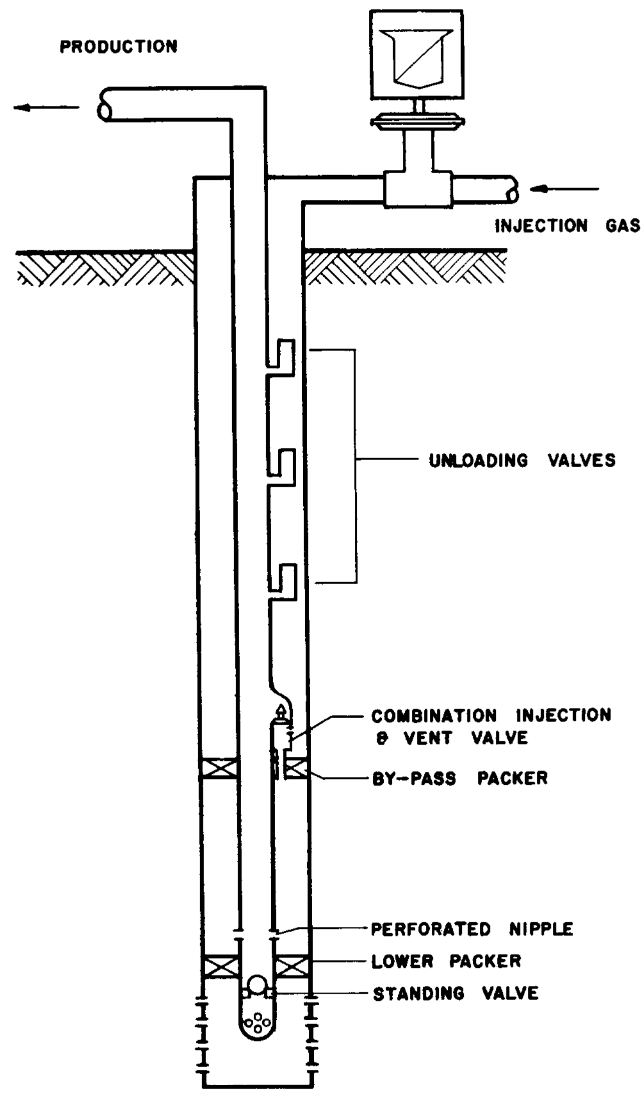
$$= 1034\ \text{ft}$$

The pressure exerted by this 1034 ft of fluid build-up is:

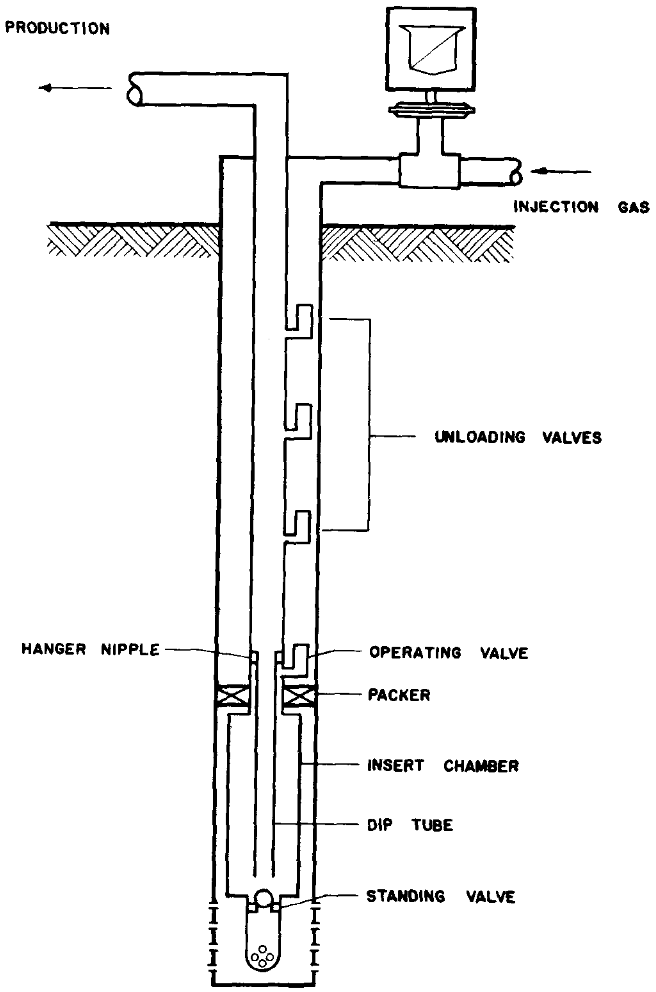
$$PF = (1034\ \text{ft})(0.35\ \text{psi per ft})$$

$$= 362\ \text{psi}$$

By the use of a chamber, the pressure effect per slug



TWO PACKER CHAMBER INSTALLATION
WITH COMBINATION INJECTION-VENT VALVE
FIG. 2a



INSERT CHAMBER INSTALLATION

FIG. 3

build-up has been reduced from 362 psi to 68 psi, or approximately 81 per cent.

One may now state the above conversely by saying that for a given producing reservoir pressure build-up between slugs, an increase in fluid volume of approximately 5.3 to 1 can be realized with the use of a chamber installation. This increase is accomplished by the additional use of the annular volume rather than by the use of the tubing volume alone. An even greater advantage is realized as the annular volume becomes larger with the use of larger casing. The end result is a higher producing rate when a chamber is utilized.

More Effective Use of High Pressure Gas

To effectively lift fluid from deep reservoirs, the installation must produce, at high velocities (800 ft per min), large slugs, which are accumulated by the use of a chamber installation. High velocities are obtained because the lift gas does not enter the tubing until the fluid in the chamber annulus has been displaced. This process will be discussed further in the operations portion of the paper.

CHAMBER OPERATION AND ARRANGEMENT

Basic Equipment

As shown in Figs. 2, 3 and 4 there are three basic types of chamber installations: (1) the two packer, (2) the insert, and (3) one packer chamber. However, in each case is required the same basic equipment:

Unloading Valves
Operating Valve
Bypass packer and lower packer if required
Bleed Valve -
Perforated Nipple
Standing Valve
Surface Controls

During unloading operations the unloading valves are used to lower the producing fluid level to the point where the chamber may be utilized.

The operating valve should have an opening pressure lower than the closing pressure of the bottom unloading valve. This difference insures that no interference will occur between these two valves. The operating valve should be the only valve opening to inject gas after the operation of the chamber begins.

The lower packer, which is only required in the two-packer installation, may be a standard permanent or hook wall. The upper or bypass packer is a standard pin-type packer which is used to allow the passage of lift gas from the casing annulus into the chamber.

To be effective, the chamber must fill with fluid between each injection; therefore, a bleed valve or vent port must be installed in the top of the chamber. This vent must be large enough to allow trapped and produced gas to escape from the chamber into the tubing at low differential pressure. If this escape is not accomplished, the chamber is of little or no value, and the performance would again approach that of a standard intermittent installation. A properly designed and operating vent valve is perhaps the most important portion of the complete installation.

A tubing perforated nipple is installed immediately above the bottom packer to furnish a passage for reservoir fluid to enter and be displaced from the chamber.

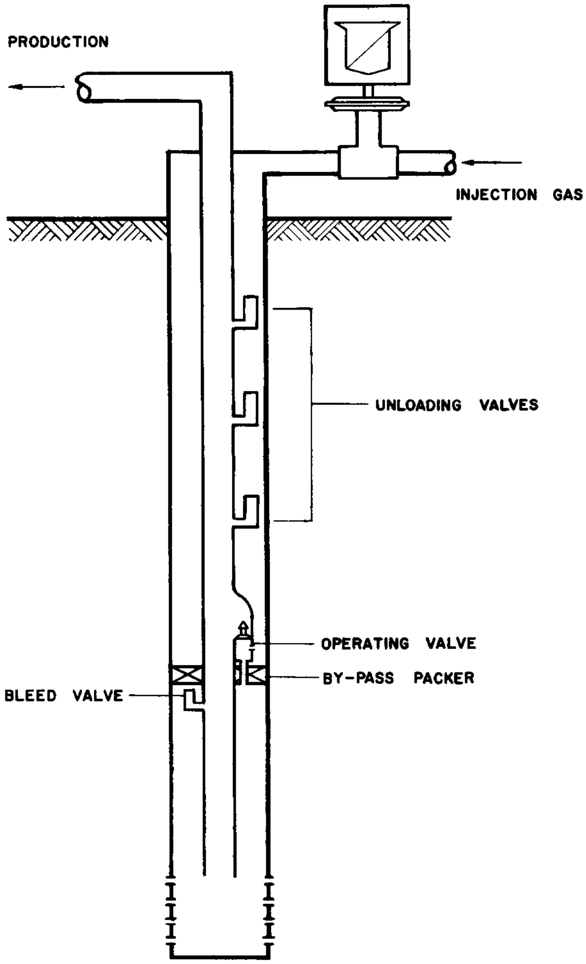
The purpose of a standing valve, which is installed below the chamber, is to prevent injection gas pressure from being exerted upon the producing formation and forcing bluid back into the reservoir.

Surface control of the injection gas may be by choke or intermitter.

Operation

Regardless of the type of chamber installation, the operation is quite similar and is as follows (cf. Figs. 2 through 4):

1. The well is unloaded by use of the upper valves: gas flow is established through the operating valve: the chamber is unloaded; and the valve closes.
2. Fluid flows from the reservoir into the well bore, through the standing valve, and into the chamber. Gas must be vented effectively for the fluid to flow into the chamber annulus.
3. After the chamber is filled, the operating valve is opened by an increase in casing gas pressure. As discussed earlier in the paper, this casing pressure may



ONE PACKER CHAMBER INSTALLATION

FIG. 4

be controlled by surface choke or intermitter.

4. Gas is now injected through the operating valve; it bypasses the packer tube and packer and moves on into the top of the chamber annulus. This injection in turn closes the bleed or vent valve and standing valve, and the gas pressure on top of the fluid in the chamber forces the fluid to move down into the chamber annulus, through the perforated nipple, and up the tubing. The fluid is moving at a fast rate at the time when the gas reaches the perforated nipple and enters the tubing. This movement results in high slug velocities minimizing gas break-through and fluid fall-back. In contrast, a straight intermitting lift has, at the instant gas enters the tubing, a relatively static load above the operating valve.

5. As the fluid is forced up the tubing by gas expansion, the casing pressure drops to the valve closing pressure. The fluid is displaced from the tubing, followed by tail gas. The tubing pressure returns to separator pressure, and the cycle is repeated.

Two Packer Installation

As shown in Figs. 2 and 2a, the volume of the tubing and casing annulus between the two packers is utilized as the accumulation chamber. The bottom packer is a standard hook wall or permanent packer, while the top packer is a standard bypass shear pin-type packer. The bottom packer is set; then the pin in the upper packer is sheared by tubing weight, and this packer is set. The advantage of this type installation is that it is relatively inexpensive, simple, and easy to run.

Insert Installation

This type of installation (Fig. 3) is normally used in open hole completions or in wells with several hundred feet of perforation. A two packer chamber would have to be set above the perforations and would result in higher operating bottom hole pressure. One packer only is required for this installation, and the insert chamber is used below the packer in conjunction with a standard full tubing ID or smaller than tubing ID dip tube. By using this type of installation, the point of gas injection into the tubing or dip tube is near the total depth even though the bypass packer may be several hundred feet up the hole.

One Packer Installation

The use of this type installation (Fig. 4) is limited to use with tight formations. A single bypass packer is used, and the casing annulus below the packer is used as the chamber. This chamber can be installed with a minimum investment. However, except in unusual cases, it is recommended that one of the other two types of installations be installed.

CHAMBER DESIGN

Conventional intermittent design methods are used to determine the spacing for the unloading valves. The design of the chamber is limited either by the available lift gas pressure at the chamber or the ability of the reservoir to produce. After the chamber annulus fluid has been displaced into the tubing, the pressure at the lower end of the tubing must not exceed the available lift pressure at the valve. This is normally the limiting design factor, therefore, the design would proceed as follows:

1. One should determine the available gas pressure at depth and subtract 100 psi to allow for pressure drop across the valve and separator pressure.
2. The chamber length is then calculated by the following:

$$\text{Chamber Length} = \frac{(\text{Pressure Available}) - (100\text{ psi})}{(\text{Specify Gravity Fluid})(\text{Ratio} + 1)}$$

Given: Well conditions as given in Part One of paper.

Pressure available - 800 psi

Specific gravity of fluid = 0.35 psi/ft

$$\text{Ratio} = \frac{(\text{Volume per ft in casing annulus})}{(\text{Volume per ft in tubing})}$$

$$\frac{.0167}{.00387} = 4.3$$

$$\text{Chamber Length} = \frac{(800)-(100)}{(0.35)(4.3+1)}$$

$$= 378\text{ ft}$$

To effectively use the available supply pressure, a

TABLE I

ACTUAL RESULTS OBTAINED WITH CHAMBERS

WELL NO	GROSS PROD. RATE (B/D)	CUT (%)	TUBING SIZE	DEPTH CHAMBER	CYCLES / DAY	BBLS./ CYCLE	OPER. VALVE PRESS. (P.S.I.)	INJ. GAS MCF/CYCLE	AVG. PRESS. BTM. CHAMBER (P.S.I.)	INJ. G.F.R. FT.³/ BBL.
1	68	15	2 1/2	10,500	13	5.2	950	16.8	444	3,300
2	95	10	2 1/2	10,950	12	7.9	950	18.3	422	2,320
3	65	20	2 1/2	10,170	22	3.0	950	15.2	326	5,010
4	45	25	2 1/2	10,455	13.5	3.3	950	19.6	269	5,900
5	21	12	2 1/2	10,300	6	3.5	1000	14.1	218	4,000
6	8	5	2 1/2	8,990	3	2.7	950	18.4	204	6,800
7	17	4	2 1/2	8,400	3	5.7	950	13.8	210	2,420
8	90	10	2 1/2	8,295	12	7.5	800	11.1	360	1,470
9	38	12	2 1/2	7,985	14	2.7	950	12.6	239	4,670
10	49	8	2 1/2	8,155	12	4.1	950	11.5	330	2,800
11	63	14	2 1/2	7,990	12	5.2	950	13.8	343	2,650
12	60	5	2 1/2	9,340	20.6	2.9	950	13.4	290	4,650

NOTE: CHAMBER PRESSURE CORRECTED TO 100 P.S.I. T.P.

chamber with a length of 378 ft should be used.

RESULTS OBTAINED WITH CHAMBERS

Twelve examples are listed in Table I. These twelve wells produced an average of 51.5 BOPD from 9300 ft. The average producing reservoir pressure, including a back pressure at the surface of 100 psi, was found to be 295 psi. The average injection gas-fluid ratio in this instance was 3820 to 1.

SUMMARY

The chamber lift method of producing wells is finding wider use every year. Many wells in Oklahoma, California, New Mexico, West Texas and the Texas Gulf Coast are already producing by this method.

By the use of modern chamber design, large ported gas lift valves and efficient venting of produced gas from the chamber, these wells will be produced to economic depletion. But by the more efficient use of high pressure gas the operating cost during the last stage of the producing life will be held to a minimum.