Increase Production By Gas Lift With Chambers

By H. W. WINKLER
GEORGE F. CAMP
Camco, Incorporated,
Houston, Texas

ABSTRACT

The accumulation chamber is an efficient method of oil production by gas lift. The fundamental purpose of the chamber is to provide additional storage space in the well bore during intermitting gas lift operation. Various formulae are offered for the calculation of chamber design. It is shown by theoretical analysis, supported by field data, that the use of the gas lift chamber principle improves production.

INTRODUCTION

The use of the accumulation chamber in high productivity, low bottom hole pressure and low productivity, low bottom hole pressure wells has been employed for many years. This paper deals with specific application of gas lift chamber design as applied to those wells. In addition, low productivity, high bottom hole pressure wells are considered. Actual field data are included to support the advantages of chamber design. This material is presented in the following sequence:

1. Application and Advantages of Chambers.
2. Types of Chambers and Their Design.
3. Chamber Design Considerations.
4. Actual Field Data.
5. Conclusions.
6. Definitions of Symbols.

APPLICATIONS AND ADVANTAGES OF CHAMBERS

The accumulation chamber provides an inexpensive, trouble-free type of lift which will enable operator to produce low bottom hole pressure stripper type wells to depletion. In shallow wells, the gas lift equipment for a chamber installation with one conventional valve will not exceed five hundred dollars, ($500.00), including the surface controller. If the operator has a few joints of three or four inch diameter line pipe and a hookwall packer on hand, the additional costs to install the gas lift equipment will be primarily pulling unit charges. The equipment cost can run into several thousand dollars, depending on the number of flow valves required, retrievable or non-retrievable equipment, special packers, and crossovers. However, the initial investment and operating costs for gas lifting generally are far less than for any other form of artificial lift equipment for stripper wells.

A chamber is generally applied to high productivity, low bottom hole pressure and low productivity, low bottom hole pressure wells. In either type well the producing bottom hole pressure is not sufficient to support a column of fluid that can be efficiently intermitted as a solid slug by the conventional intermittent installation. The chamber provides increased slug volume per linear foot of head above the formation. This means more fluid per cycle and is particularly advantageous in wells which must be operated at maximum cycle rates.

For a well with 5½" O.D.—17 lb. casing and 2" tubing, the ratio of the annular volume between the chamber and dip tube to the tubing above the chamber, as shown in Figure 1 is 4.6 to one. In other words, one foot of fluid in the chamber annulus is equal in volume to 4.6 feet of fluid in the tubing. A 200' fluid head build-up in the dip tube and chamber annulus would represent 920' plus 200' or 1120' of fluid head in the dip tube and tubing with the chamber annulus displaced by gas. The 200' represents the fluid already in the dip tube before the chamber is emptied.

A chamber provides a method of dropping the point of gas injection near total depth in wells with several hundred feet of perforations or open hole. The lower point of gas injection creates a greater drawdown, thus resulting in a lower producing bottom hole pressure. This will increase the production in most wells. For a given head of fluid against the formation, the chamber permits a much greater fluid recovery per injection cycle than does any other gas lift method. The actual point of gas injection is at the lower end of the dip tube. Since the end of the dip tube is usually only inches above the bottom of the chamber, the bottom of the chamber is generally considered the point of gas injection for most chamber length calculations.

Injection gas enters the chamber on top of the fluid in all installations discussed in this paper. Before the gas can enter the tubing, all fluid must be displaced from the chamber. The fluid is moving at an optimum velocity before the injection gas enters the tubing; therefore, break through of the lift gas is held to a minimum. The chamber design offers the efficiency of a plunger with the advantage of being able to produce considerably more fluids per day from a high productivity, low bottom hole pressure well. A greater number of gas injection cycles per day are possible with a chamber than with a plunger because of the time required for the plunger to fall back to its bottom hole stop.

A chamber should be used if the injection gas pressure is greater than the producing bottom hole pressure. The only limitation to the chamber capacity is the resultant injection pressure in the chamber less the back pressure. The large fluid recovery per cycle results in a low injected gas-fluid ratio. For example: a conventional intermittent installation is producing 0.5 barrel of fluid per cycle with a 300' fluid head build-up opposite the valve. The operating valve passes 2000 cubic feet of gas per cycle between its opening and closing pressures; therefore, the injection gas-fluid ratio is 4000:1. If a chamber were installed in this well whereby two barrels of fluid were recovered per cycle for the same volume of injection gas, the injected gas-fluid ratio would be reduced to 1000:1 by increasing the fluid recovery per cycle and reducing the gas break-through.

The lifting efficiency of many present intermittent gas lift installations with low productivity indices and high bottom hole pressures can be improved with up-hole chambers. A solid fluid slug with minimum fall-back is assured by chamber because the injection gas does not enter the tubing until the fluid is rapidly moving toward the wellhead. A chamber will increase the daily production by permitting an overall lower average producing bottom hole pressure. The chamber provides maximum slug volume for minimum head against the formation. A plot of formation pressure build-up versus time reveals that a well has a maximum rate of pressure build-up immediately after shut-in. The increase in bottom hole pressure after shut-in is a function of reservoir fluid feed-in. By properly locating an up-hole chamber, the well can be produced in the rapid build-up portion of the curve, thus increasing the production by increasing the feed-in. These up-hole chambers are ideally suited to low productivity, high bottom hole pressure wells which must be gas lifted against high wellhead tubing back pressures.

A problem example comparing chamber versus conventional gas lift design illustrates the theoretical chamber advantages in terms of drawdown and barrels of fluid per day. A complete list of all the symbols and abbreviations with their definitions and units are included at the end of this paper.

WELL DATA:

Total depth = 10,000'.
5 1/2" O.D. - 17 lb casing 2" tubing.
Productivity index = 0.05 bbls/day /psi.
Static fluid gradient = 0.4 psi/ft.
Tubing back pressure at wellhead = 200 psig.
Shut-in bottom hole pressure = 1757 psig.
Assumed intermitting rate = 1 cycle/ hour.

SOLUTION:

Step 1: Determine maximum possible production in barrels per hour.

(a) Minimum bottom hole pressure would be tubing back pressure plus the gas column weight.

$$P_m = P_w + dP$$

$$P_m = 200 \text{ psig} + 50\text{psi} = 250 \text{ psig}$$

(b) Maximum possible production per day

$$Q_o = \text{P.I.}(P_s - P_m)$$

$$Q_o = 0.05\ (1757-250) = 75.35 \text{ BOPD}$$

Therefore, maximum hourly production

$$Q_o\ /24 = 3.14 \text{ BOPH}$$

Step 2: Determine average flowing bottom hole pressure with conventional gas lift design.

(a) V_t = 3.87 bbls/1000' (for 2" tubing)

(b) Hourly feed-in 2" tubing $= \frac{3.14 \text{ BOPH}}{V_t} = 811$ ft./ hr.

(c) Effective pressure build-up per cycle

$(P_f - P_m) = 811$ ft./hr.(S.G.) = 324 psi

(d) Average flowing bottom hole pressure =

$$P_m + \frac{P_f - P_m}{2} = 250 + \frac{324}{2}$$

=412 psig

Step 3: Determine average flowing bottom hole pressure with chamber.

(a) Determine chamber length assuming chamber full with 3.14 bbls. feed-in for a two-packer chamber with 2" dip tube.

V_{c-a}(C.L.) + V_{d-t}(C.L.)=3.14 bbls.

17.8 bbls/1000'(C.L.) + 3.87 bbls/1000'(C.L.) = 3.14 bbls.

C. L. = 3.14 bbls divided by 21.67 bbls/1000' = 145 ft.

(b) Effective hourly pressure build-up = C. L. (S. G.) = 145 ft. (0.4psi/ft.) = 58 psi = $P_f - P_m$

(c) Average flowing bottom hole pressure $= P_m + \frac{P_f - P_m}{2} = 250 + \frac{58}{2} = 279$ psig.

Step 4: Subtract Step 3 from Step 2 to compute chamber advantage in terms of drawdown.

Additional drawdown with chamber = 412 psig — 279 psig = 133 psi

Step 5: Determine chamber advantage in terms of barrels of oil per day.

Q_o = Drawdown (P.I.)

Q_o = 133(0.05) = 6.65 BOPD advantage

In the above example, the P.I. curve is assumed to be a straight line function. Although the well's P.I. is actually reduced as bottom hole pressure declines, the problem does illustrate that lower operating bottom hole pressures can be attained with a chamber. This means more production.

TYPES OF CHAMBERS AND THEIR DESIGN

A chamber design is an adaptation of the closed intermittent installation. For successful operation, all chamber installations must have an operating valve, standing valve, and bleed port which function properly. It is therefore advisable to use wire line retrievable equipment to economically correct malfunctions with a minimum loss of production. There are two basic types of chambers: the insert or bottle type and the two-packer type. The insert chamber generally employs only one packer. Either of these basic types can be modified in many ways for application to individual well conditions. These modifications depend primarily on the length, size, and condition of the open hole or perforated interval; condition of the casing; injection pressure; producing bottom hole pressure; producing gas-fluid ratio; and any unusual well conditions such as sand, salting, etc. The chamber designs are divided into the following classifications:

1. Conventional chamber installation.
2. Insert chamber installation with packer several hundred feet above chamber.
3. Two-packer chamber installation with upper packer in casing and lower packer in liner.
4. Chamber installation with dip tube larger than tubing.

Chamber lengths are calculated and checked for each classification. These simplified volume calculations based on maximum head for checking the proposed chamber length are recommended to assure a chamber design that will not stymie. The symbols and abbreviations and units are included at the end of this paper.

CONVENTIONAL CHAMBER INSTALLATION

This installation can be either an insert or two-packer type. Variations of conventional chamber installations are show in Figures 1 through 6. If the working fluid level does not exceed the top of the chamber and the dip tube and chamber lengths are the same, the generally accepted chamber formula can be used as shown in Example 1.

EXAMPLE 1:

Two-packer chamber installation assuming the working fluid level does not exceed the top of the chamber.

WELL DATA:

Total depth = 6400'.

Perforated interval from 6200' to 6400'.

5½" O.D. - 17 lb. casing set at 6400'.

2" tubing and dip tube.

Injection gas pressure = 600 psig.

Static fluid gradient = 0.4 psi/ ft.

Wellhead tubing pressure = 40 psig

$$\frac{P_i - P_w}{\text{S. G.}} = \text{C.L.} + R(\text{C.L.})$$

$$\text{C.L.} = \frac{P_i - P_w}{\text{S.G.}(R+1)} \quad \text{(Equation 1)}$$

$$\text{C.L.} = \frac{600 - 40}{0.4\ (5.6)} = 250' \text{ chamber}$$

Where R =

$$\frac{V_{c-a}}{V_t} = \frac{17.8 \text{ bbls/1000'}}{3.87 \text{ bbls/1000'}} = 4.6$$

Check: Maximum head of fluid that the injection pressure will support.

$$H = \frac{P_i - P_w}{\text{S. G.}} = \frac{600 - 40}{0.4}$$

= 1400' Maximum Head

H = C.L. + R(C.L.)

1400' = 250' + 4.6(250') = 1400'

Equqation 1 is the conventional chamber formula applicable either to a two-packer or insert chamber. The chamber and dip tube are assumed to fill only to the top of the chamber in this equation. The tubing above the chamber is assumed to remain empty. The bottom packer is placed as near the top of the perforations as possible and the top packer 250 feet above it. In the case of an insert chamber, the bottom of the chamber can be set near total depth. Therefore, the chamber length should be calculated by Equation 3, unless the working fluid level does not exceed the top of the chamber.

When the producing fluid level exceeds the top of the chamber, the conventional formula must be revised. Examples 2 and 3 illustrate a two-packer and an insert type chamber in which the fluid level exceeds the top of the packer.

EXAMPLE 2:

Two-packer chamber installation for the same well data as in Example 1, except the maximum flowing bottom hole pressure between injections is 300 psig, and the bottom packer is set at 6150'.

Maximum Working Fluid Height =

$$\frac{P_f - P_w}{\text{S.G.}} = \frac{300 - 40}{0.4} = 650'$$

Maximum Working Fluid Level Above Bottom Packer, F.L.B.

F.L.B. = 6150' — (6400' — 650') = 400'.

$$\text{C.L.} = \frac{P_i - P_w}{\text{S.G.}(R)} - \frac{\text{F.L.B.}}{R} \quad \text{Equation 2}$$

$$\text{C.L.} = \frac{600 - 40}{0.4\ (4.6)} - \frac{400}{4.6}$$

= 217' chamber

Check: H = F.L.B. + R(C.L.)

1400' = 400' + 4.6(217') = 400'

In Equation 2, the maximum working fluid level is above the top of the chamber and the bottom packer is set 50' above the top of the perforations.

EXAMPLE 3:

Insert chamber installation for the same well data as in Example 1 and 2, except 3½" nominal (4" O.D.) line pipe is used for the chamber, and the bottom of the chamber is near total depth.

$$\text{C. L.} = \frac{P_i - P_f}{\text{S.G.}(R)} \quad \text{(Equation 3)}$$

$$\text{C. L.} = \frac{600 - 300}{0.4(1.73)} = 433' \text{ chamber}$$

Where: R =

TWO-PACKER CHAMBER INSTALLATIONS

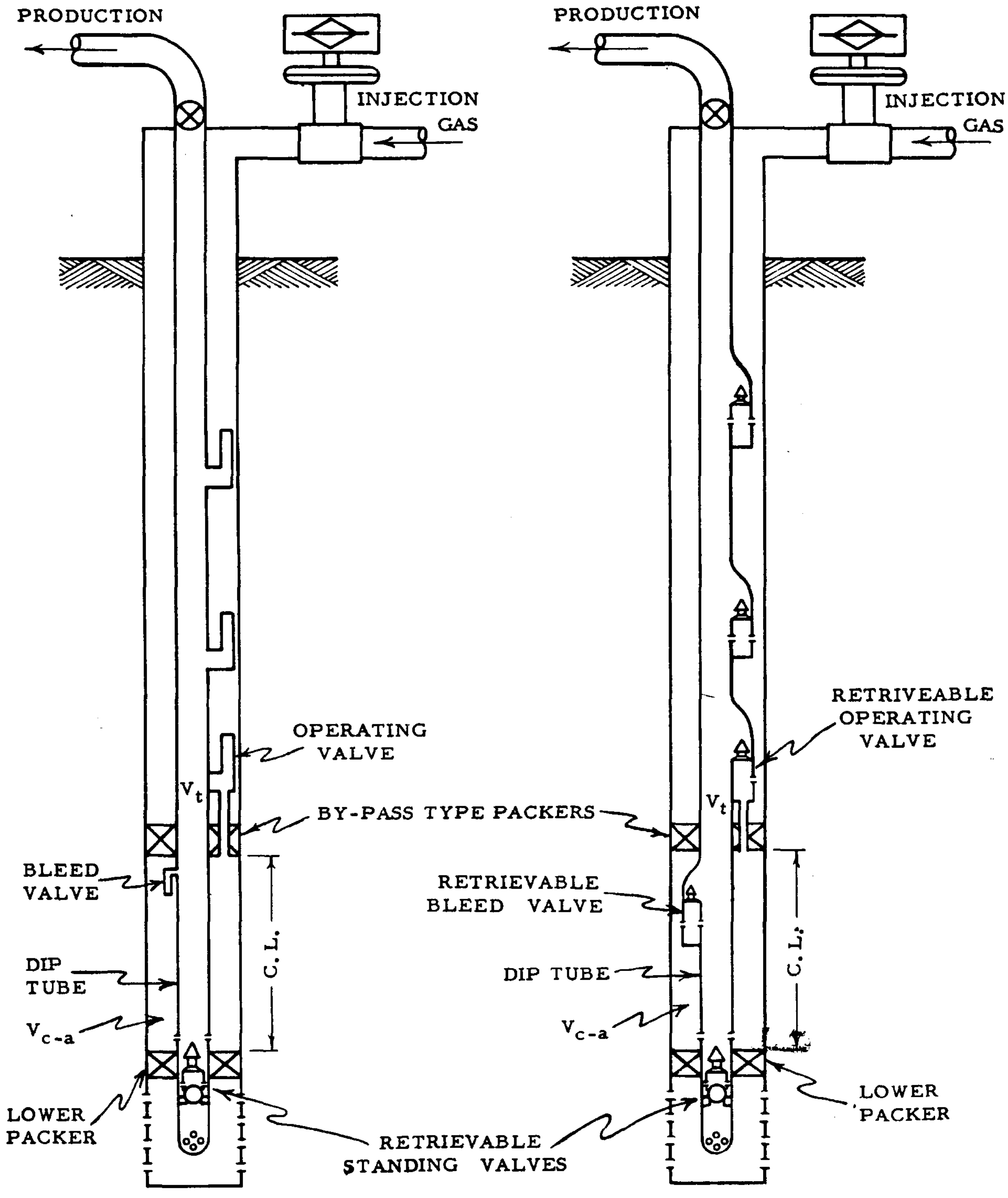


FIG. 1

Two-packer chamber installation with conventional flow valves and retrievable standing valve.

FIG. 2

Two-packer chamber installation with retrievable flow valves, bleed valve, and standing valve. All operating equipment wire line retrievable without pulling tubing.

INSERT CHAMBER INSTALLATIONS

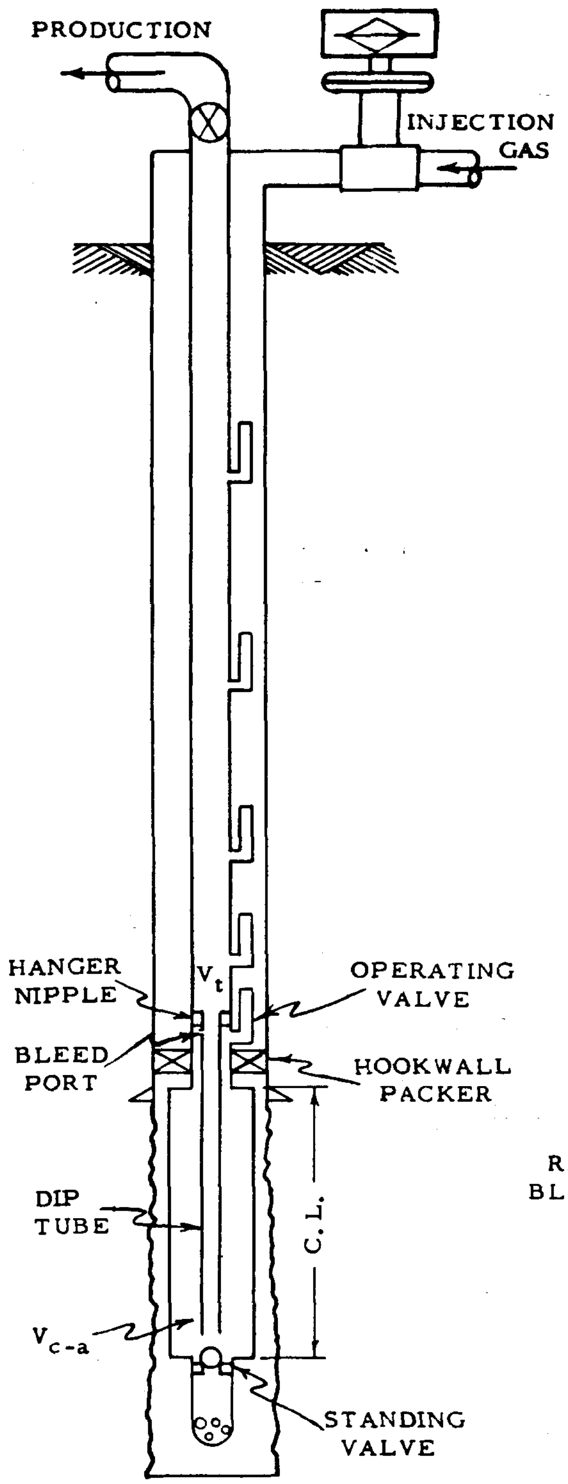


FIG. 3

Insert chamber installation with conventional valves using hanger nipple and hookwall packer. Especially applicable for depletion of shallow wells in which very little expenditure can be justified.

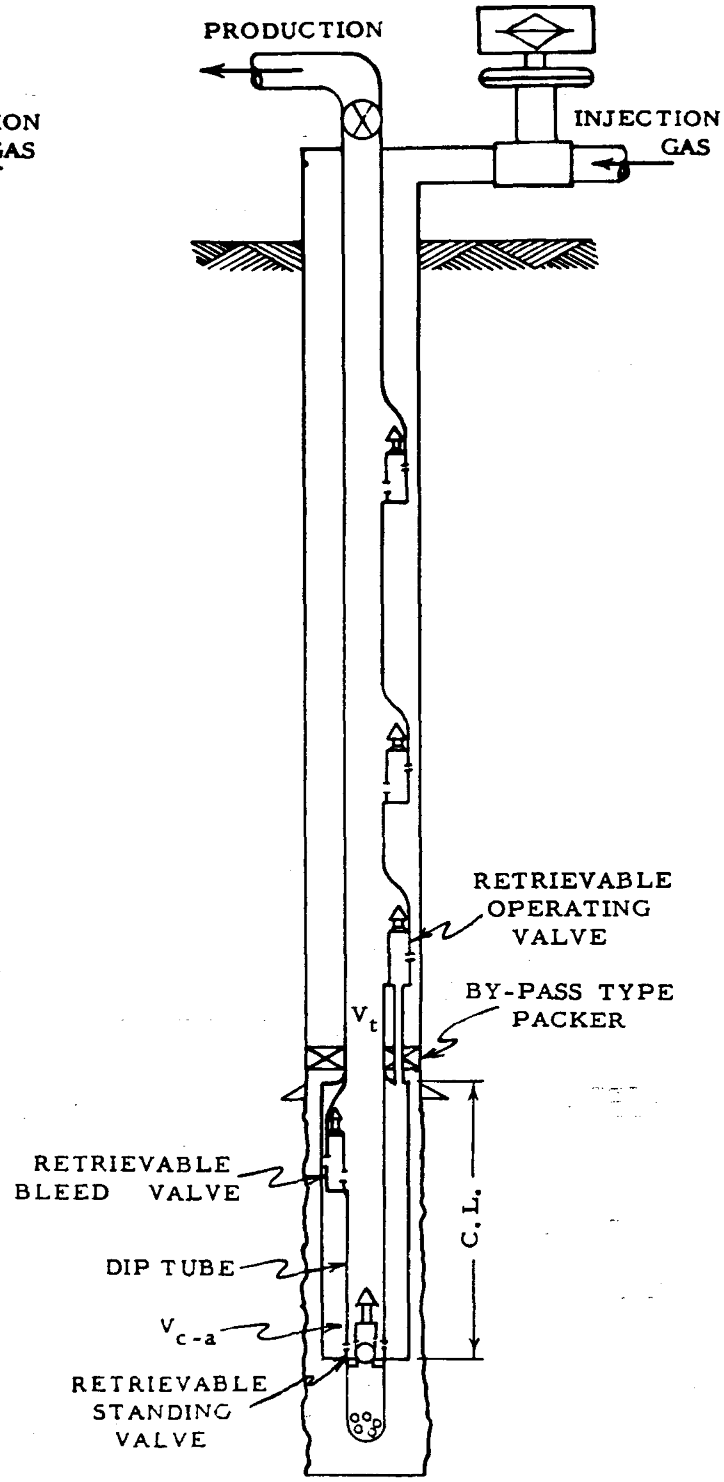


FIG. 4

Insert chamber installation with retrievable flow valves, bleed valve, and standing valve. By-pass packer and parallel injection gas line eliminates disadvantage of small dip tube.

CHAMBER INSTALLATIONS USING CROSS-OVER MANDRELS

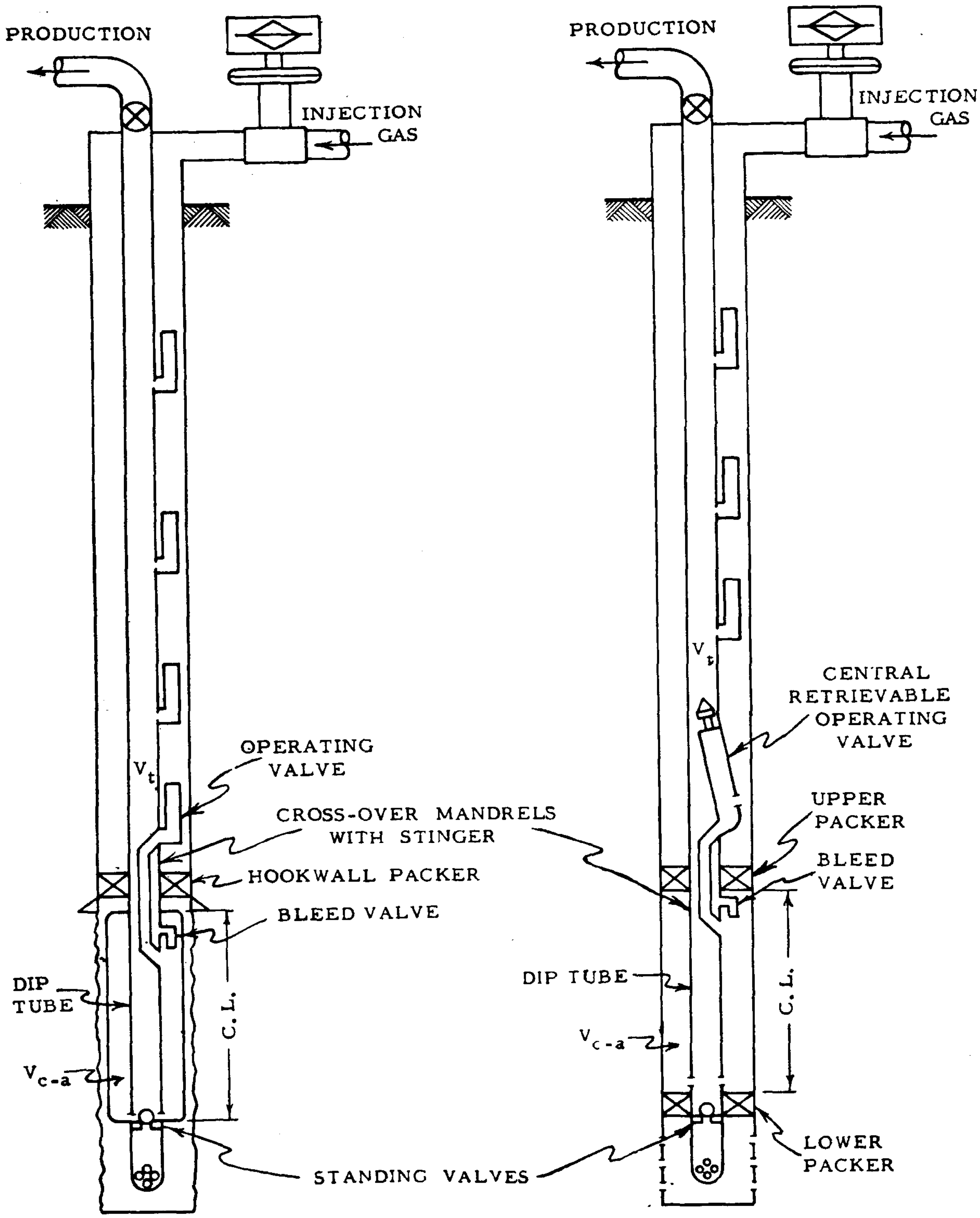


FIG. 5 **FIG. 6**

Chamber installations with crossover mandrel replacing by-pass type packer. Central retrievable operating valve offers maximum flexibility with minimum investment.

$$\frac{V_{c\text{-}a}}{V_t} = \frac{6.7 \text{ bbls}/1000'}{3.87 \text{ bbls}/1000'} = 1.73$$

Check: $H = F.L.B. + R(C.L.)$
$1400' = 650' + 1.73(433') = 1400'$

In Equation 3, it is assumed that the bottom of the chamber is at total depth; therefore, the maximum working fluid height in the well between gas injections is equal to the maximum working fluid level above the bottom of the chamber, F.L.B.

INSERT CHAMBER INSTALLATION WITH PACKER SEVERAL HUNDRED FEET ABOVE CHAMBER

When a well has several hundred feet of perforations or open hole and a low producing bottom hole pressure, the packer must be set several hundred feet above the top of the chamber, as illustrated in Figures 7 and 8. The chamber is set near total depth to obtain the desired drawdown. If a parallel injection gas line is used, the design calculations are the same as noted in Examples 1 through 3. The formula to be used depends upon the maximum working bottom hole pressure and the depth of the chamber. When a small dip tube and hanger nipple are used, the calculations must include two annular volume to tubing ratios if the working fluid level exceeds the top of the chamber.

EXAMPLE 4:

Insert chamber installation, as shown in Figure 1, with the top of the chamber located several hundred feet below the packer and the maximum working fluid level not exceeding the top of the dip tube (hanger nipple):

WELL DATA:

4¾" I.D. open hole from 6000' to 6450'.
5½" O.D. - 17lb. casing and 2" tubing.
1" Dip tube 500' long.
Chamber of 3½" Nom. (4" O.D.) pipe.
Depth of packer = 5950'.
Static fluid gradient = 0.45 psi/ft.
Injection gas pressure = 650 psig.
Wellhead tubing pressure = 50 psig

C.L. = (Equation 4)

$$C.L. = \frac{(P_i - P_w) - D.T.L.(1 + R_{t-a})S.G.}{S.G.(R - R_{t-a})}$$

$$C.L. = \frac{(650 - 50) - 500(1 + 0.57)0.45}{0.45(2.6 - 0.57)}$$

= 270' chamber

Where: R =

$$\frac{V_{c-a}}{V_t} = \frac{10.1 \text{ bbls}/1000'}{3.87 \text{ bbls}/1000'} = 2.6$$

$$R_{t-a} = \frac{V_{t-a}}{V_t} = \frac{2.19 \text{ bbls}/1000'}{3.87 \text{ bbls}/1000'}$$

= 0.57

Check: H =

$$\frac{P_i - P_w}{S.G.} = \frac{650 - 50}{0.45}$$

= 1333' Maximum Head

$H = D.T.L. + C.L.(R) + (D.T.L. - C.L.)R_{t-a}$

$1333' = 500' + 270'(2.6) + 230'(0.57) = 1333'$

In Equation 4, it is assumed that the dip tube, chamber, and tubing annulus fill to the top of the dip tube. If the well has an extremely low producing bottom hole pressure and the maximum working fluid level does not reach the top of the chamber as calculated from Equation 4, the chamber length can be designed with the top of the chamber located at the maximum working fluid level. Equation 4 should be used when the working fluid level is between the top of the chamber and the packer because the volume between the tubing and the dip tube is small and very little feed-in represents considerable head.

EXAMPLE 5:

Insert chamber installation for the same well data as in Example 4, except the maximum working fluid level is 800' above total depth (F.L.B. = 800' with the chamber located as near total depth as possible):

C.L. = (Equation 5)

$$C.L. = \frac{(P_i - P_w) - [F.L.B. + R_{t-a}(D.T.L.)]S.G.}{S.G.(R - R_{t-a})}$$

$$C.L. = \frac{(650 - 50) - [800 + 0.57(500)]0.45}{0.45(2.6 - 0.57)}$$

= 122' chamber

Check: $H = F.L.B. + C.L.(R) + (D.T.L. - C.L.)R_{t-a}$

$1333' = 800' + 122'(2.6) + (500' - 122')0.57 = 1333'$

In Equation 5, fluid head build-up above the packer is considered.

TWO-PACKER CHAMBER INSTALLATION WITH UPPER PACKER IN CASING AND LOWER PACKER IN LINER

The operator is faced with two annular volume to tubing ratios in the design of this chamber. It differs from the previous classification in that the upper volume is greater than the lower volume. A combination casing-liner annulus chamber is particularly applicable in low fluid level wells with several hundred feet of shot hole. An insert chamber should not be used because of the hazard of pulling operations in such an open hole. A schematic of this installation is shown in Figure 9. The upper packer in the casing eliminates the injection gas pressure against the liner pack-off except during gas injection cycles. The depth of the liner seat and the proposed depth of the upper packer must be known before designing this chamber installation.

EXAMPLE 6:

Two-packer chamber installation in which the upper packer is in the casing an the lower packer must be located in the liner with the maximum working fluid level not exceeding the top of the chamber:

WELL DATA:

Total depth = 6400'.
7" O.D. - 23 lb casing set at 5900'.
5½ O.D. - 14 lb. liner from 5840' to 6350'.
2½" tubing and dip tube.
Set top packer at 5800'(O.S.L. = 40').
Injection gas pressure = 800 psig.
Static fluid gradient = 0.35 psi/ft. (All oil).
Wellhead tubing pressure = 40psig.

C.L. = (Equation 6)

$$C.L. = \frac{(P_i - P_w) - O.S.L.(R - R_L)S.G.}{S.G.(R_L + 1)}$$

$$C.L. = \frac{(800 - 40) - 40(5.43 - 2.84)0.35}{0.35(2.84 + 1)}$$

= 538' chamber

Where: R =

$$\frac{V_{c\text{-}a}}{V_t} = \frac{31.4 \text{ bbls}/1000'}{5.79 \text{ bbls}/1000'} = 5.43$$

$$R_L = \frac{V_{L\text{-}a}}{V_t} = \frac{16.4 \text{ bbls}/1000'}{5.79 \text{ bbls}/1000'}$$

= 2.84

Check: H =

$$\frac{P_i - P_w}{S.G.} = \frac{800 - 40}{0.35}$$

=2170' Maximum Head

$H = O.S.L.(R) + (C.L. - O.S.L.)R_L + C.L.$

$2170' = 40'(5.43) + (538' - 40')2.84 + 538' \doteq 2170'$

Equation 6 is based on the assumption that the maximum working fluid level between gas injection builds up only to the level of the top packer.

EXAMPLE 7:

Two-packer chamber installation using the same well data as in Example 6 with the upper packer in the casing, the lower packer in the liner and a maximum producing bottom hole pressure of 600 psig.

Maximum Working Fluid Height =

$$\frac{P_f - P_w}{S.G.} = \frac{600 - 40}{0.35} = 1600'$$

Maximum Working Fluid Level Above The Upper Packer, F.L.T.

$F.L.T. = 5800' - (6400' - 1600')$
$= 1000'$

(Equation 7)

$$C.L. = \frac{(P_i - P_w)}{S.G.(R_L + 1)} - \frac{O.S.L.(R - R_L) + F.L.T.}{(R_L + 1)}$$

$$C.L. = \frac{(800 - 40)}{0.35(2.84 + 1)} - \frac{40(5.43 - 284) + 1000}{(2.84 + 1)}$$

= 278' chamber

INSERT CHAMBER INSTALLATIONS WITH PACKER SEVERAL HUNDRED FEET ABOVE CHAMBER

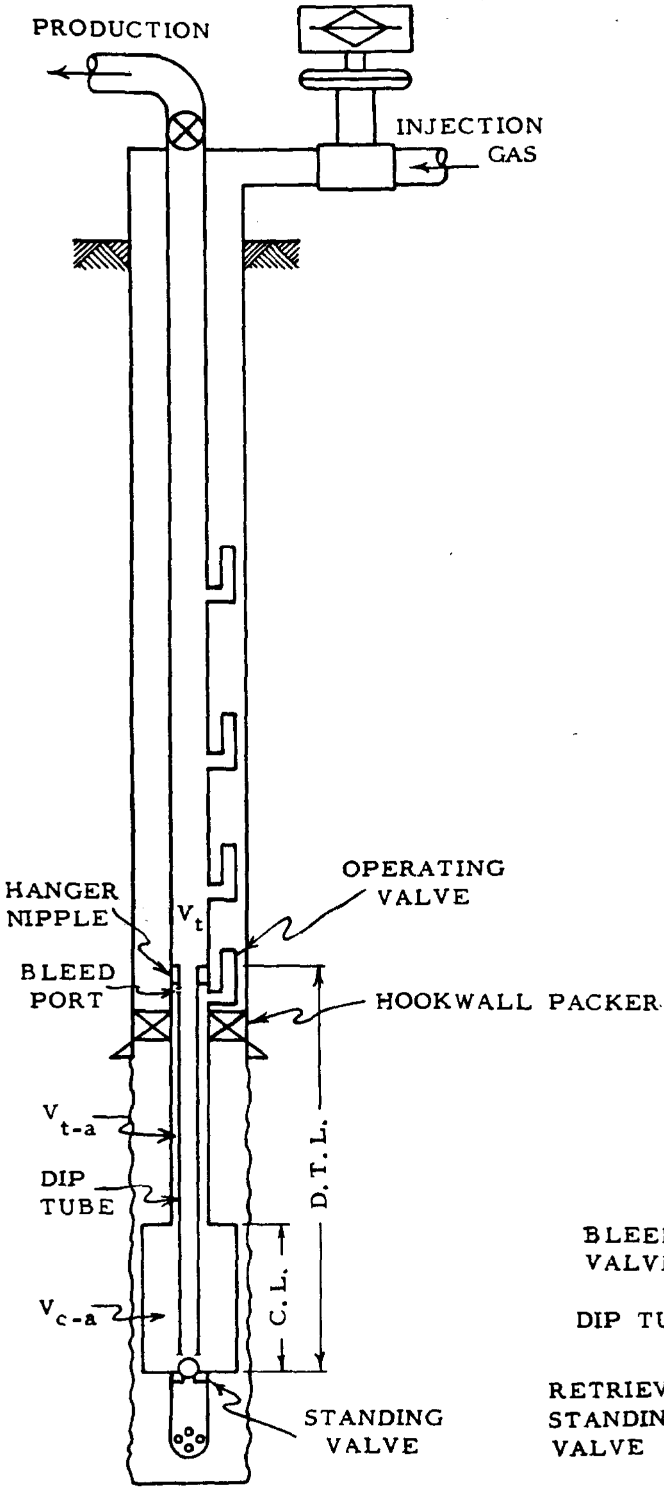


FIG. 7

Insert chamber installation with conventional valves and hanger nipple. Large dip tube permits a retrievable standing valve and pressure bomb surveys.

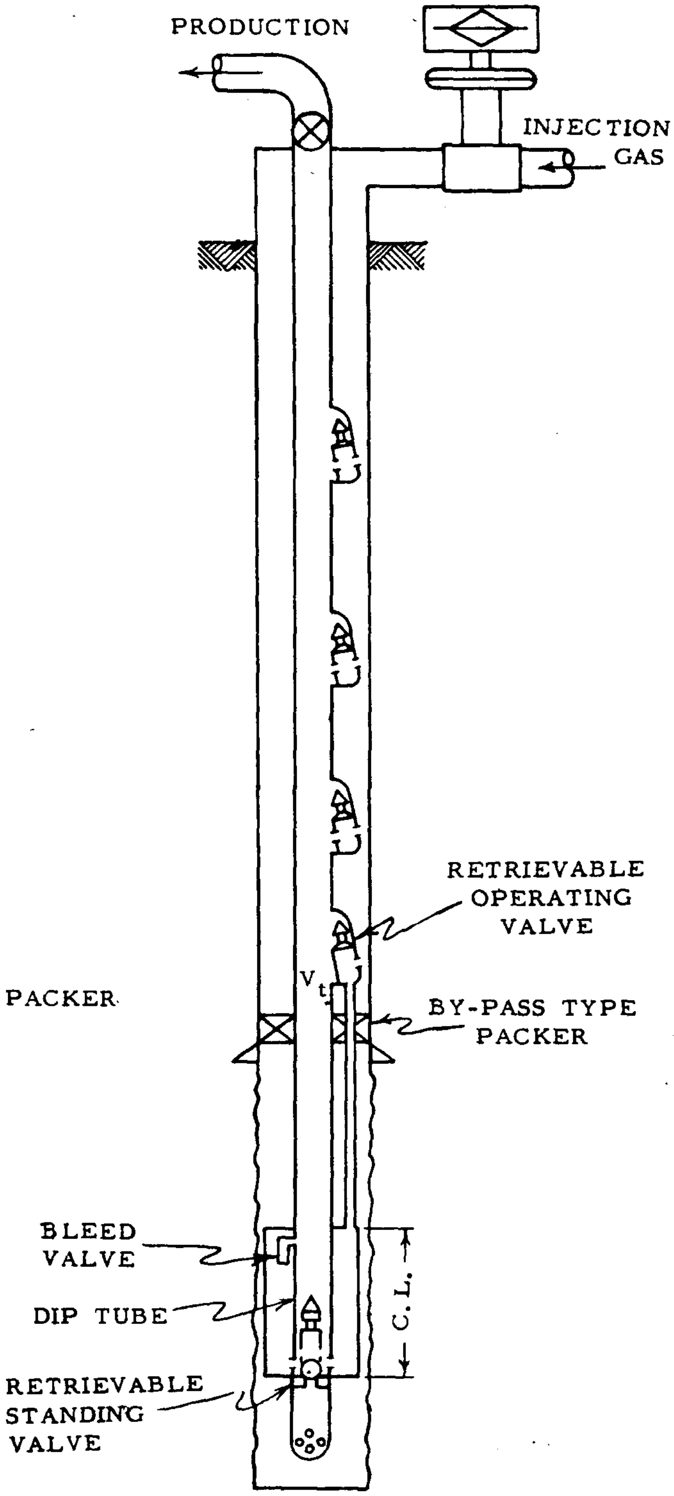


FIG. 8

Insert chamber with retrievable flow valves and standing valve. Parallel injection gas line permits maximum slug volume for minimum head build-up.

CASING-LINER CHAMBER INSTALLATION

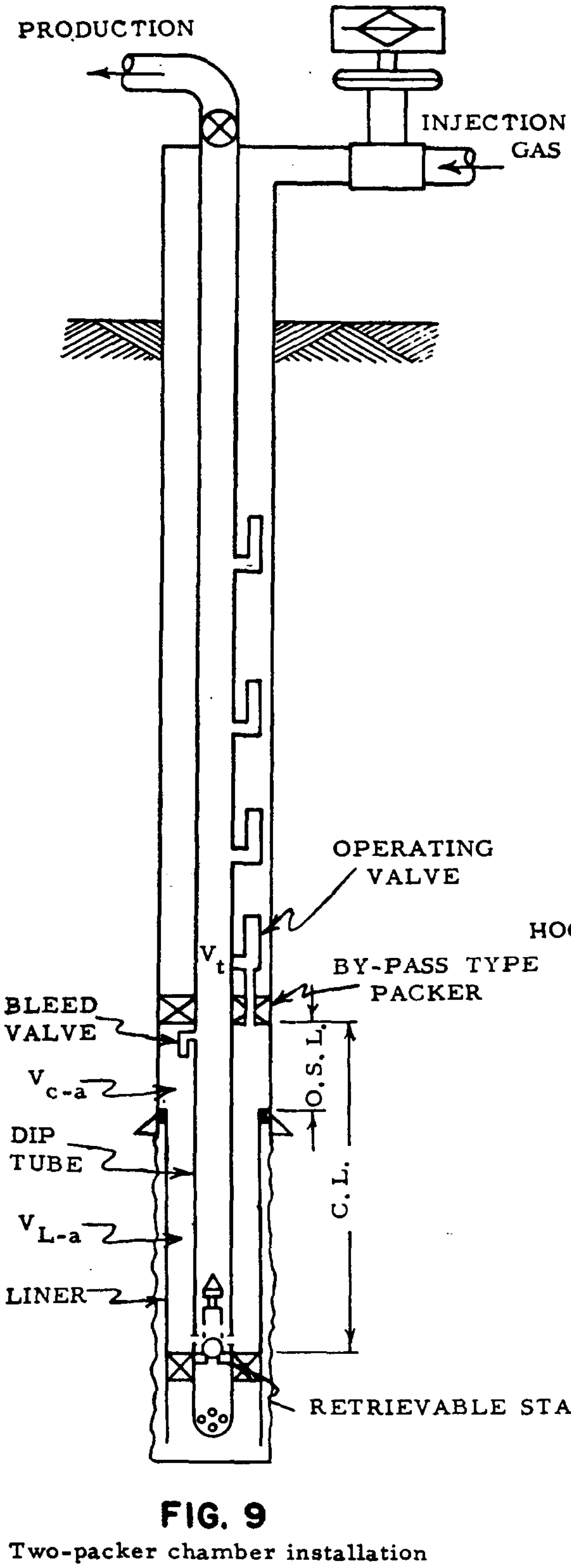


FIG. 9

Two-packer chamber installation using both casing annulus and liner annulus as the chamber. Either retrievable or non-retrievable equipment can be employed.

RETRIEVABLE DIP TUBE INSTALLATION USING TUBING AS CHAMBER

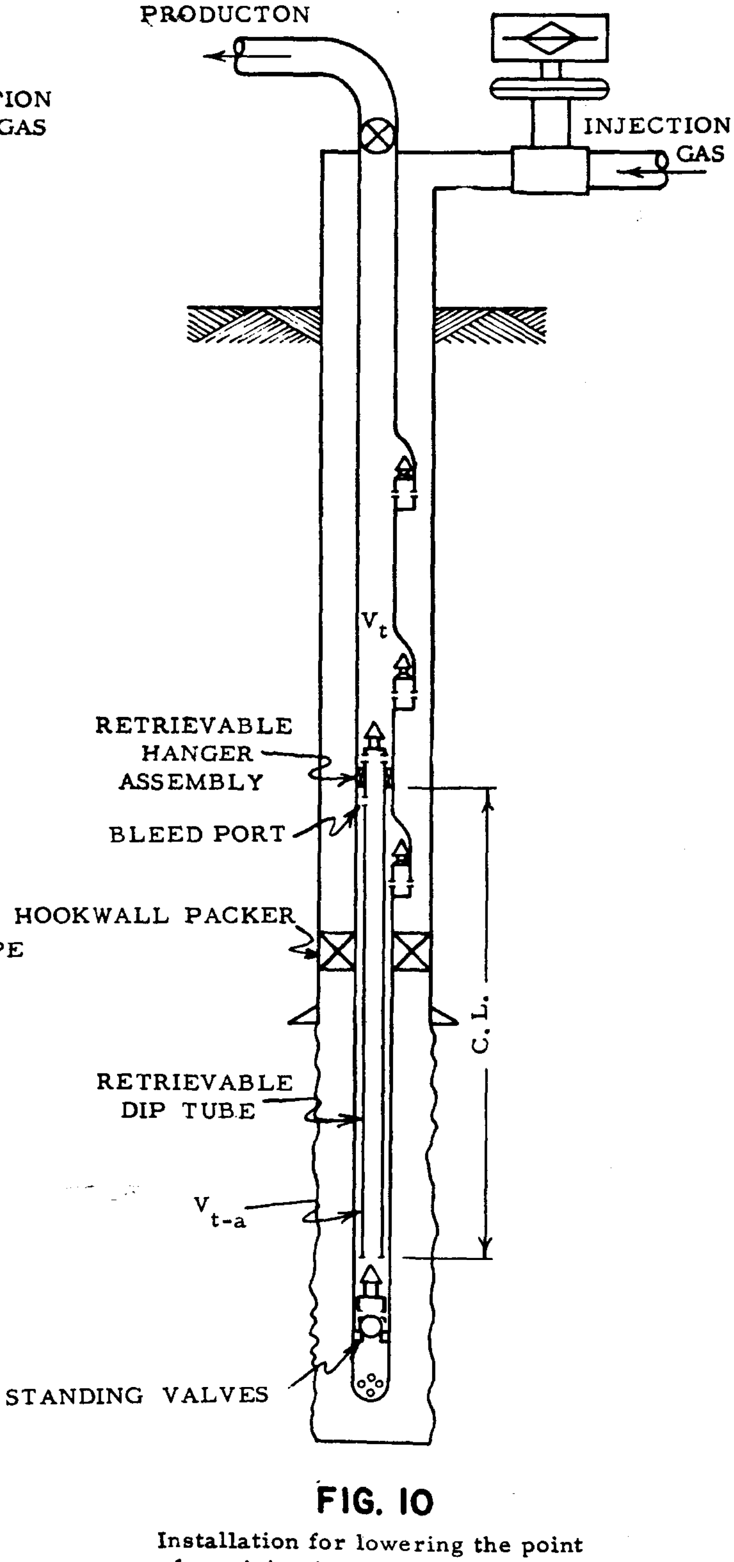


FIG. 10

Installation for lowering the point of gas injection without pulling the tubing. Retrievable dip tube and tubing form a chamber.

INSERT CHAMBER INSTALLATIONS FOR A LONG, PERFORATED INTERVAL AND BAD CASING

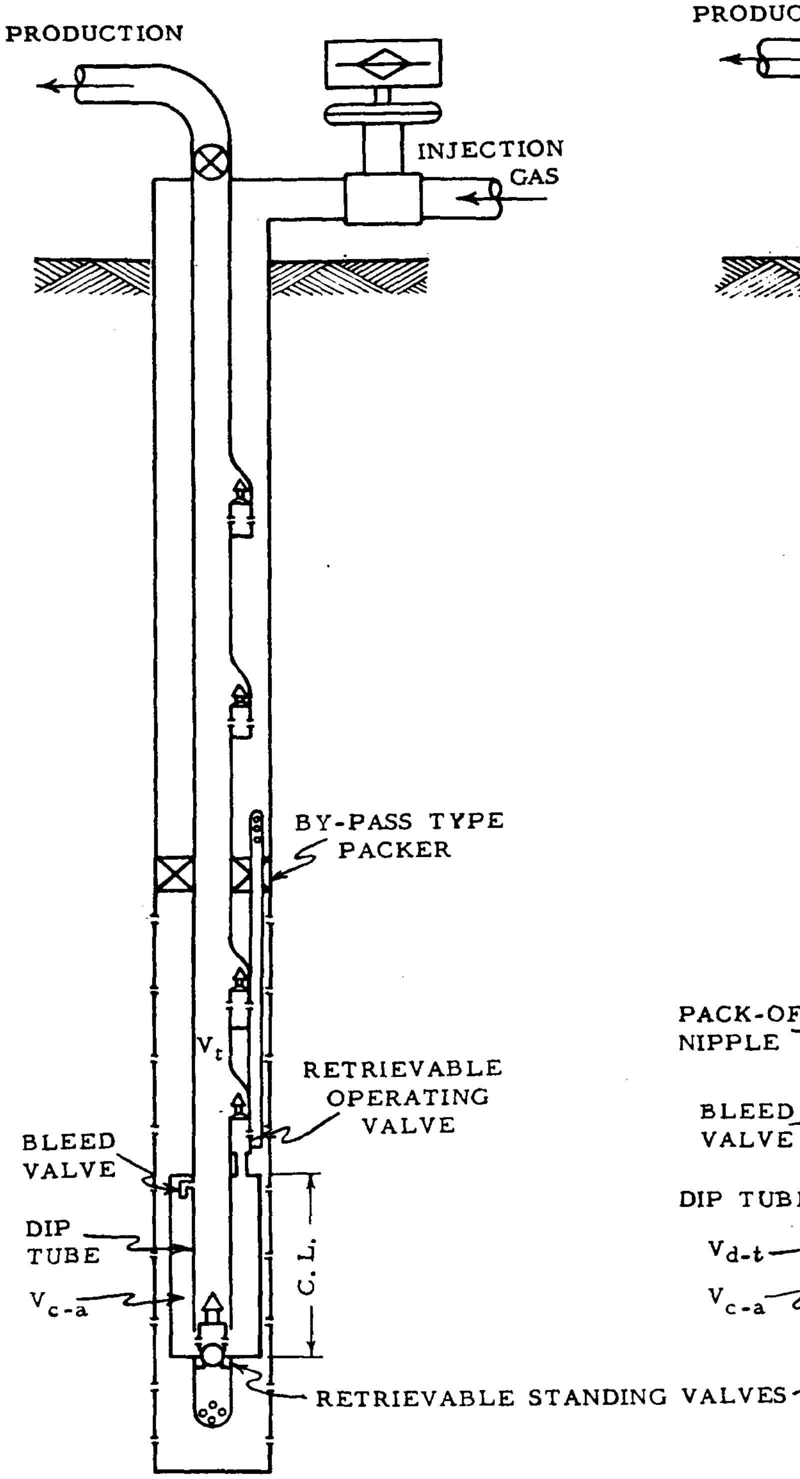


FIG. 11

Insert chamber installation permitting point of gas injection near total depth in well with several thousand feet of perforations. Open-hole retrievable valve mandrels are run below packer.

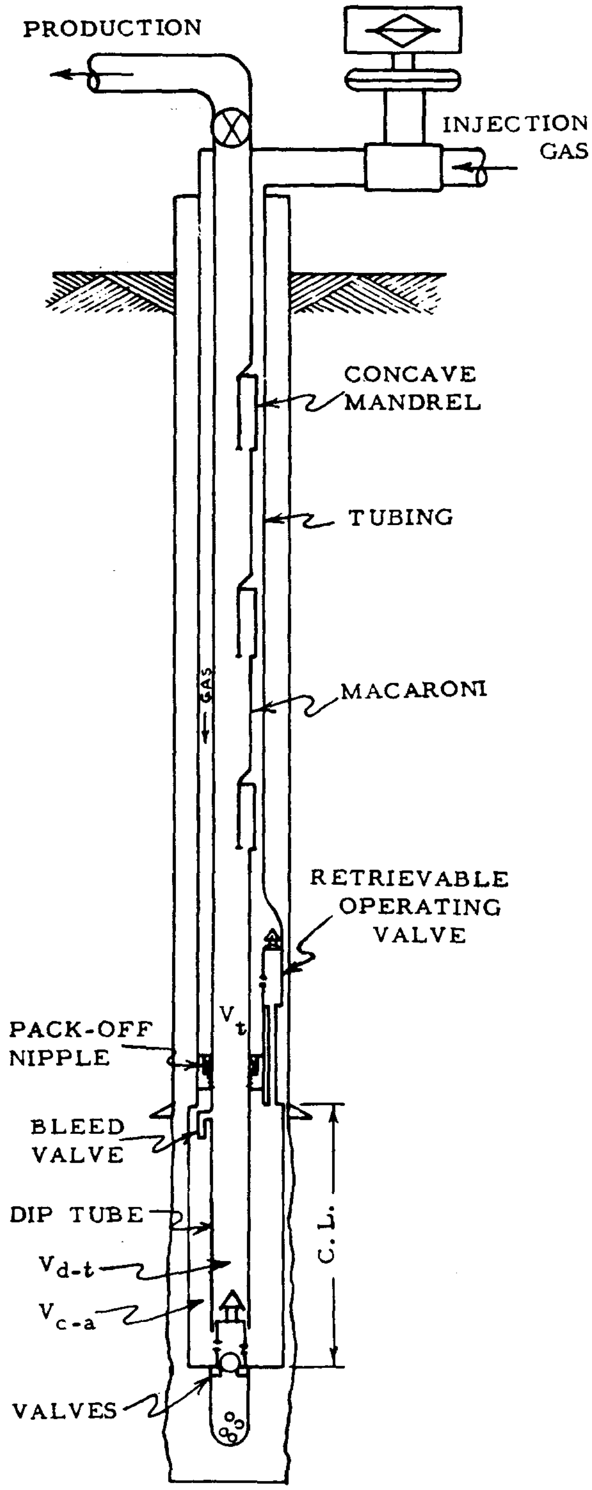


FIG. 12

Insert chamber installation for a well with bad casing. All valves removable without pulling the tubing. Operating valve can be retrieved by wire line after pulling macaroni.

Check: $H = O.S.L.(R) + (C.L. - O.S.L.)\,R_L + (C.L. + F.L.T.)$

$2170' = 40'(5.43) + (278' - 40')\,2.84 + 278' + 1000' = 2170'$

A maximum operating fluid level above the upper packer is considered in Equation 7. The distance between the packers for this type of chamber is critical as can be seen from a comparison of Example 6 with Example 7. This is the result of the high chamber to tubing volume ratios. It is better to make the chamber a little small rather than too large. These designs are for a well producing all oil. If the wells should begin producing water without the fluid level changing appreciably, the injection pressure would not be adequate to lift from the chamber.

CHAMBER INSTALLATION WITH DIP TUBE LARGER THAN TUBING

If the dip tube is larger than the tubing string, the maximum head occurs at the instant the fluid leaves the dip tube and the gas enters the

TWO-PACKER CHAMBER INSTALLATION

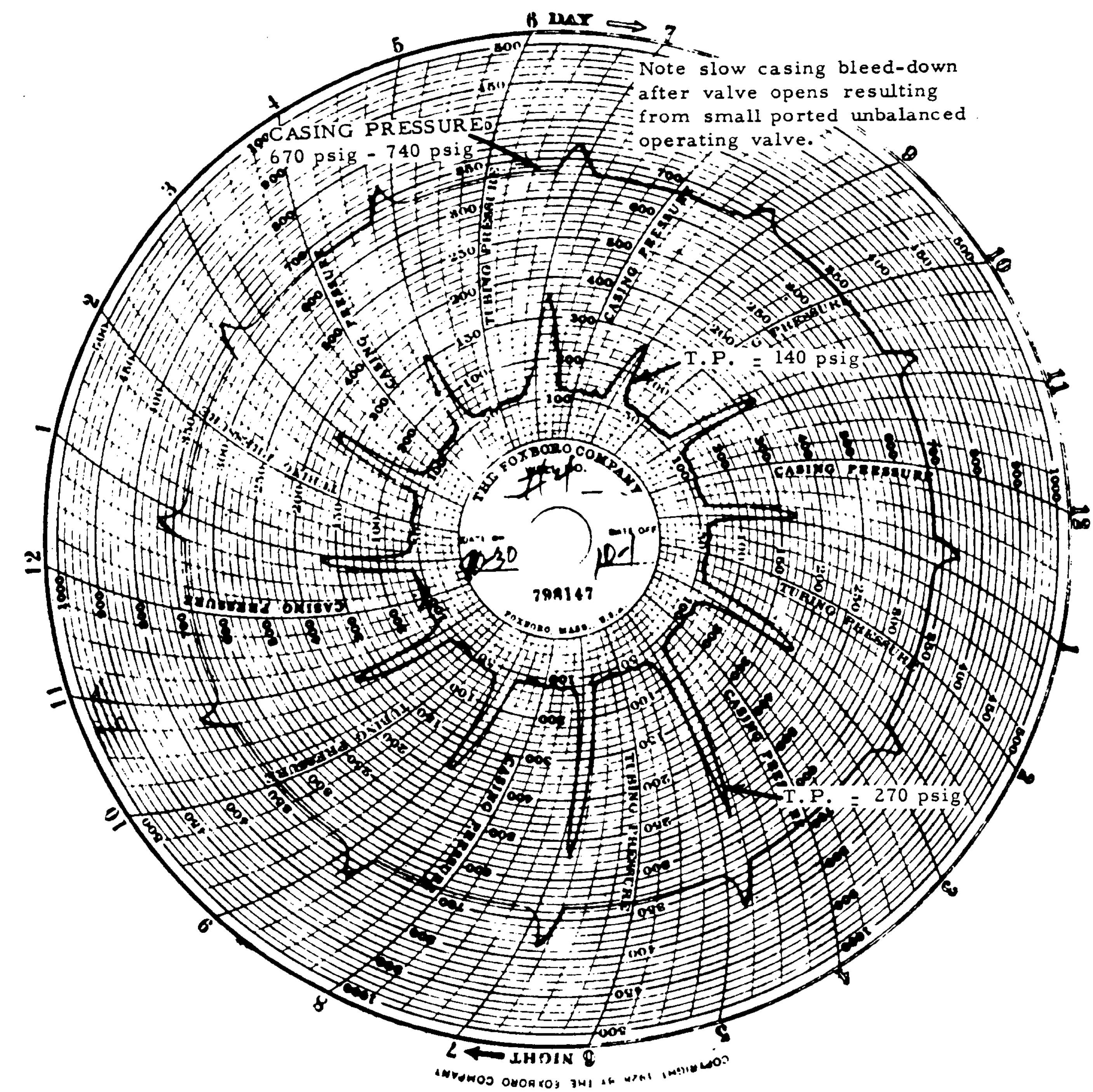


FIG. 13

Well Data: Bottom of 251' chamber at 10,260'.
2-1/2" Tubing in 7" O.D. Casing.
Producing 53 BFPD - 4.4 BO per cycle.

tubing. The total volume of the chamber and dip tube must be calculated, and this volume converted into feet of head in the small tubing string. The insert chamber for bad casing in Figure 12, is an example in which the dip tube could be larger than the macaroni string.

EXAMPLE 8:

Insert chamber installation for the same well data as in Example 4, except a 2" dip tube and 1" macaroni string are used with the equipment run as shown in Figure 12.

(Equation 8)

$$C.L. = \frac{(P_i - P_w)V_t}{S.G.(V_{d\text{-}t} + V_{c\text{-}a})}$$

$$C.L. = \frac{(650 - 50)1.07}{0.45(3.87 + 6.7)}$$

$$= 135' \text{ chamber}$$

Where:

$V_t = 1.07$ bbls/1000'

$V_{c\text{-}a} = 6.7$ bbls/1000'

$V_{d\text{-}t} = 3.87$ bbls/1000'

WELL "A" TWO-PEN SURFACE PRESSURE RECORDING CHART

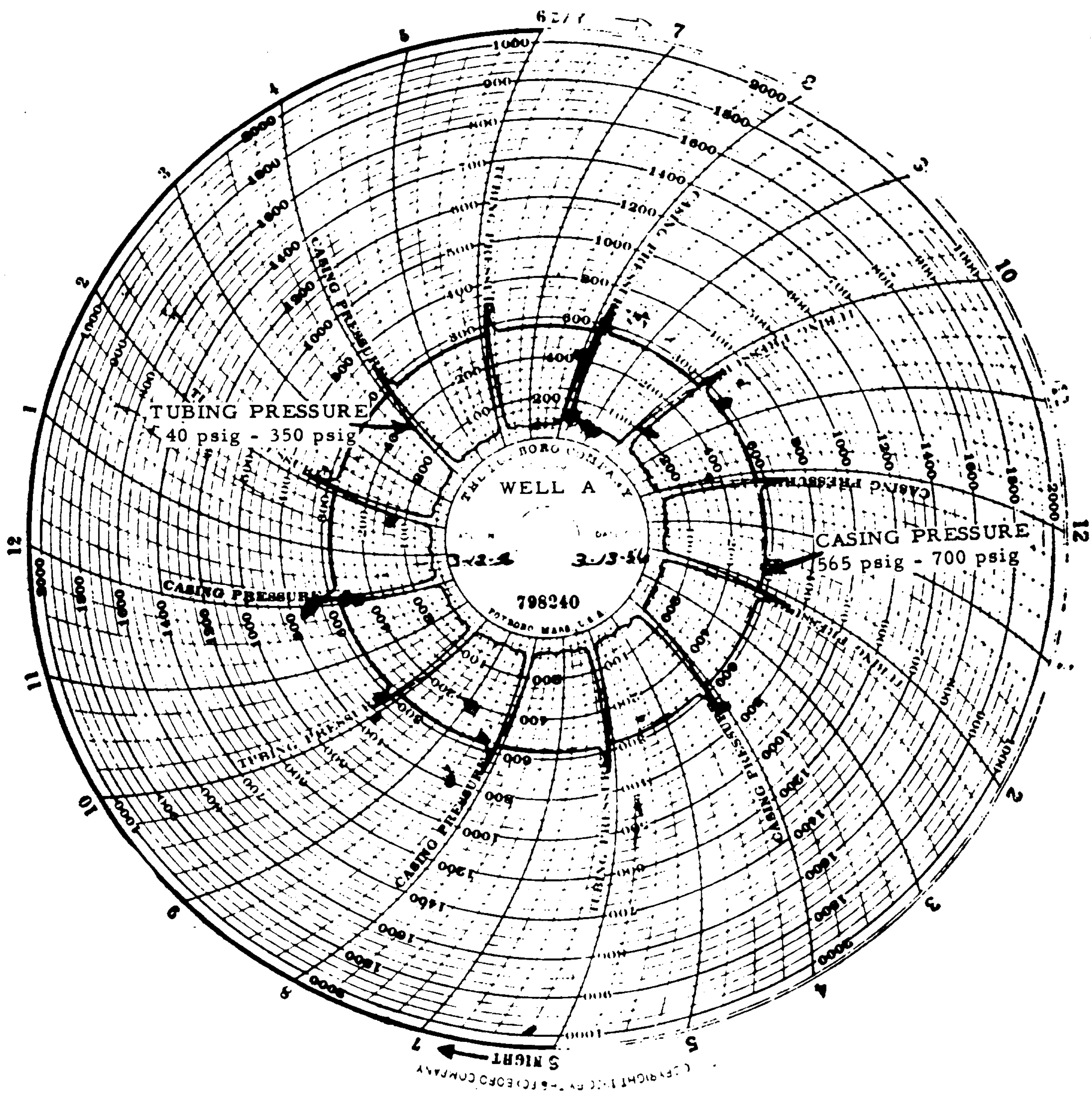


FIG. 14

Well Data: Total Depth - 6750' 2" Tubing 5-1/2" O.D. Casing.
Two-packer chamber 343' long.
Producing 42 BOPD - 3.5 BO per cycle.

Check:

$$H(V_t) = C.L.(V_{d-t}) + C.L.(V_{c-a})$$

$$1333' = \frac{135'(3.87) + 135'(6.7)}{1.07}$$

$$= 1333'$$

Equation 8 is based on the assumption that the working level does not exceed the top of the chamber. A limited reservoir feed-in represents a sizable fluid head build-up in small tubing; therefore, the maximum possible working fluid level must be considered in this type of chamber.

EXAMPLE 9:

Insert chamber installation for the same well data as in Example 8, except the maximum producing fluid level is 500' above the top of the chamber (F.L.T. = 500').

$$C.L. = \frac{[(P_i - P_w) - F.L.T.(S.G.)]V_t}{S.G.(V_{d-t}) + V_{c-a}} \qquad \text{(Equation 9)}$$

$$C.L. = \frac{[(650 - 50) - 500(0.45)]1.07}{0.45(3.87 + 6.7)}$$

$$= 84' \text{ chamber}$$

Check: $H(V_t) =$

$$C.L.(V_{d-t}) + C.L.V_{c-a}) + F.L.T.(V_t)$$

$$1333' =$$

$$\frac{84'(3.87) + 84'(6.7)}{1.07} + 500' = 1333'$$

CHAMBER DESIGN CONSIDERATIONS

A chamber should always be designed to permit gas injection through the operating valve only. The point of gas injection of the operating valve is at the bottom of the dip tube and not the point at which the valve is actually located on the tubing string. The unloading valve immediately above the operating valve may in some instances be run only a joint above the operating valve. This unloading valve is located near the operating valve to assure unloading the chamber. It is advisable for the closing pressure of the operating valve to be at least 50 psi lower than the closing pressure of the above unloading valve. This prevents opening of the unloading valve while lifting from the chamber.

The dip tube and chamber fill to the same level if the bleed port is adequate. The dip tube is full when the injection gas first enters the chamber and is still full at the instant gas enters the tubing string through the dip tube. The back pressure from the head of fluid, regardless of the size dip tube, is only a function of its length and not its volume. The dip tube should be as near the tubing I.D. as possible to provide a maximum slug volume per foot of head and to reduce turbulence and gas break-through when the fluid slug passes from a small dip tube to the larger tubing. In addition, a large dip tube permits using a retrievable standing valve and running pressure bomb surveys.

To compensate for the pressure loss through the operating valve, by-pass packer, crossover, etc., the design injection gas pressure available inside the chamber should be consedered equal to or less than the surface closing pressure of the unloading valve immediately above the operating valve. The gas weight in the casing annulus and the difference between the opening and closing pressure of the unloading valve will offset the pressure loss in most instances.

The size of bleed port near the top of the chamber is not a problem in wells producing little formation gas. The function of this bleed port is to remove the formation gas to permit the chamber to fill with liquid rather than gas. A 25 psi differential valve with small orifices or a 3/32" hole is generally used in low gas producing wells. The advantage of the differential valve is that it will close when the operating valve opens, thus preventing a gas cut slug. A high gas-fluid ratio well must have the bleed port properly sized. This port should be adequate to pass the formation gas during the fill-in time between cycles.

The difference between the opening and closing pressures of a pressure operated flow valve, commonly referred to as valve "spread", is important in chamber design. The opening pressure of a pressure operated valve is reduced by back pressure in the tubing opposite the valve, but the closing pressure remains constant. The higher the tubing pressure opposite the valve, the lower the valve spread. In most chamber installations, the pressure in the tubing opposite the operating valve is the wellhead tubing pressure plus a few pounds of gas weight. The valve spread can be prohibitive if a partially balanced type valve is not used. The balancing mechanism built into the valve reduces its spread characteristics, but retains a large port size. The operator can select the valve spread to meet his gas requirements. The spread required decreases as the size of the casing annulus increases.

The top of the chamber should not be located above the maximum working fluid level of the well. An excessive chamber length will result in excessive injection gas-fluid ratios, if it does not completely fill. The chamber must be completely filled with high pressure injection gas before the gas enters the tubing and lifts the slug to the surface. The injection gas bleed down time for a chamber that is too long reduces the number of injection gas cycles per day; therefore, the producing capacity of a high productivity, extremely low bottom hole pressure well is reduced. In many wells the daily production has been increased by lowering the opening pressure of

WELL "A" BOTTOM HOLE PRESSURE BOMB SURVEY

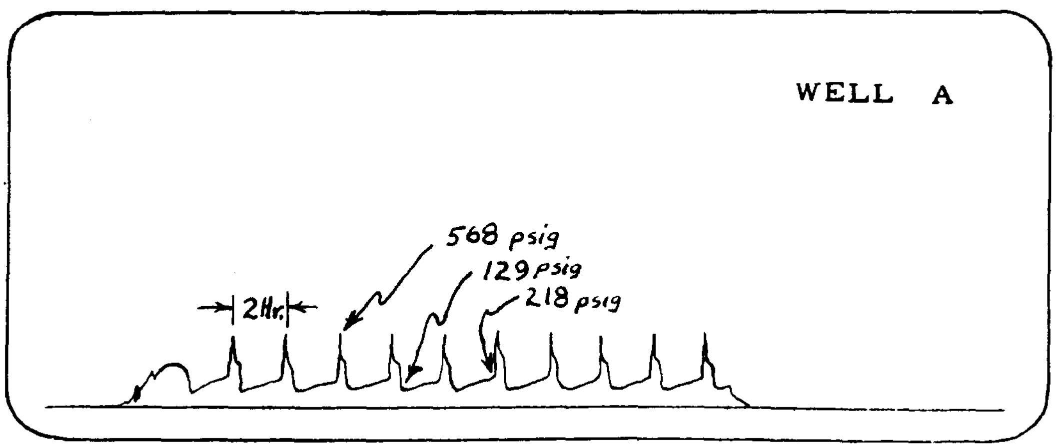


FIG. 15

BHP versus TIME with bomb inside chamber.
12 injection gas cycles per day.
Producing 3.5 BO per cycle.

the operating valve when the chamber is not filling.

When a two-packer chamber installation is contemplated, a hookwall or production type packer can be used on bottom with a pin or cup type packer on top. If a hookwall packer is used as the upper packer, a cup type packer is generally employed as the lower packer. The casing should always be scraped prior to running a cup packer. Cup packers set at great depths are frequently damaged during running operations. When the cup packer is to be set in a liner, centralizers can be used to prevent the cups from dragging against the casing walls while being run in the hole.

Retrievable gas lift equipment offers the operator maximum efficiency with minimum loss of production. Wells in a closed type reservoir will have low producing bottom hole pressures at time of abandonment. A chamber can be run initially in these wells to permit depletion without pulling the tubing. The retrievable valves can be reset to efficiently produce the wells during the changing conditions of the flush, twilight, and depletions

WELL "B" TWO-PEN SURFACE PRESSURE RECORDING CHART

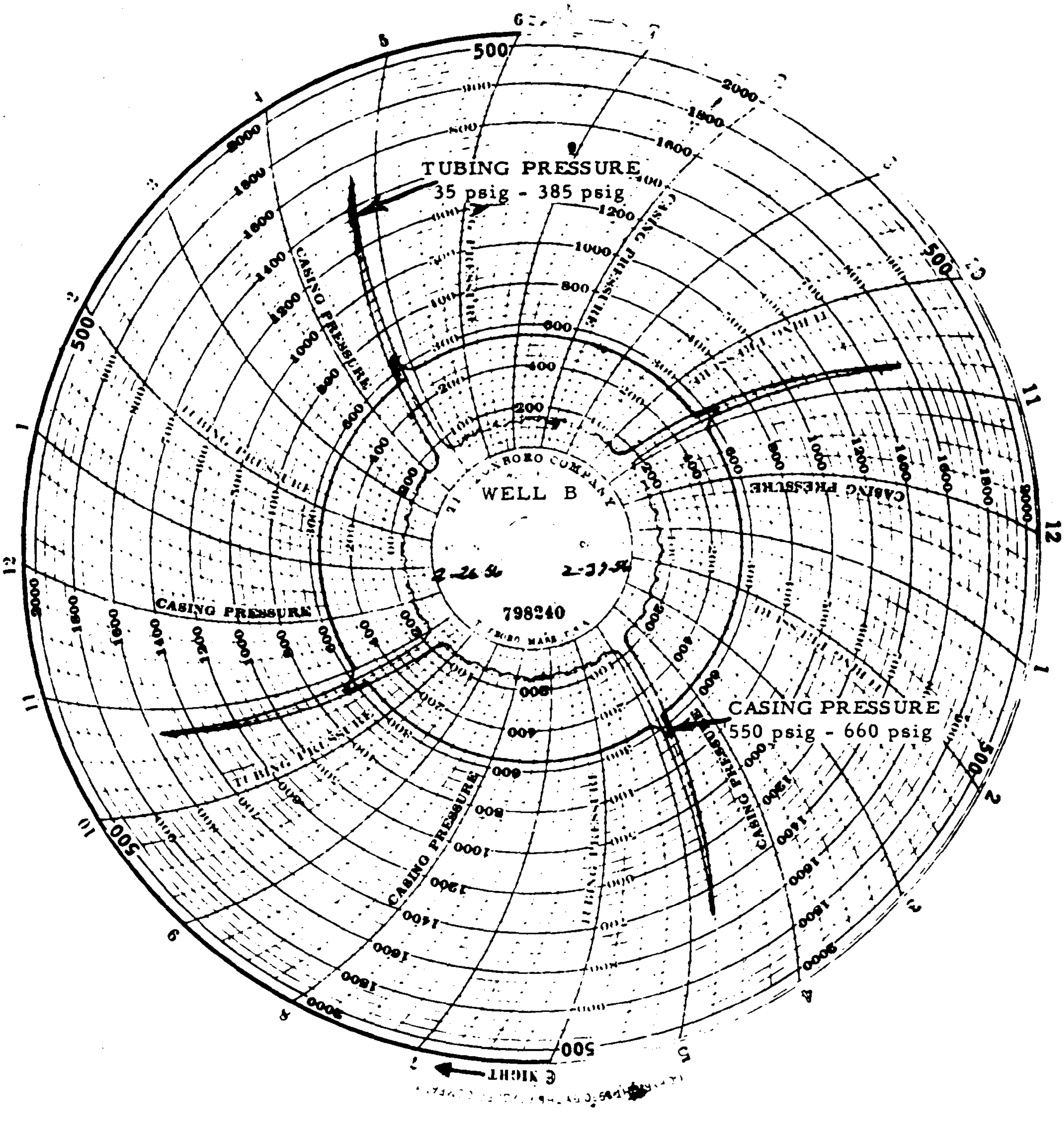


FIG. 16

Well Data: Total Depth - 6700' 2-1/2" Tubing 7" O. D. Casing.
Two-packer chamber 233' long.
Producing 24 BOPD - 6 BO per cycle.

stages. Large savings are realized by eliminating costly tubing jobs and packer repairs.

ACTUAL FIELD DATA

Two thousand foot wells with bottom hole pressures of only 20 psig are being depleted by gas lift with chambers in Peru. These wells, which date back to World War I, are producing more fluid by gas lift than by the previous producing methods, and the number of operating personnel has been drastically reduced with installation of gas lift equipment. Deep wells in Califarnia with low bottom hole pressures are being sucessfully produced by gas lift using chambers. These wells range in depth from 8,000 feet to 10,500 feet with producing bottom hole pressures as low as 300 psig. The wells have a gross producing rate equal to or greater than before the chambers were installed, with a reduction in lifting costs of 40 to 60 per cent.

Chamber installations are currently being run in Oklahoma in wells ranging in depth from 6,000 to 10,200 feet. Their successful operation has resulted in the replacement of other methods or artificial lift with chamber installations. Many gas lift wells are being converted to chamber installations with resulting increase in production and efficiency. A 10,620 foot low bottom hole pressure well in Louisiana in which a chamber was run illustrates the advantages of a chamber over conventional gas lift. The well was producing 36 barrels of fluid per day for five months prior to the chamber. The well has produced 53 barrels of fluid per day for the four months following the chamber installation, with a very noted reduction in gas-fluid ratios. Figure 13 is a two-pen surface pressure recorder chart of this well.

The following group of tests emphasize the flexibility of chamber design and illustrates the gas lift chamber advantages versus positive displacement pumps and natural flow.

Example I. Depletion Production—

Well A Data: Total Depth = 6750', 2" Tubing, 5½" O.D. Casing:

Equipment	Date of Test	Production (BOPD)	Gas-Oil Raatio (cu. ft./bbl.)
Positive displacement pump	2-1-56	34	1954-producing
Gas lift chamber	2-27-56	42	1257-injection

Figures 14 and 15 are the two-pen surface pressure recorder and actual bottom hole pressure charts of a typical test run on the above well.

Well B Data: Total Depth = 6700', 2½" Tubing, 7" O.D. Casing.

This Chamber installation is producing 24 BOPD with a minimum producing bottom hole pressure of 66 psig. Figure 16 is a two-pen surface recorder chart, and Figure 17 is an actual bottom hole pressure chart of this depletion type well.

Example II. Intermediate Production.

Well C Data: Total Depth = 6750', 2" Tubing, 5½" O.D. Casing:

Equipment	Date of Test	Production Oil (BPD)	Water (BPD)	Total (BPD)	Injection Gas-Oil Ratio (cu.ft./bbl.)
Positive displacement pump	1-29-56	61	40	101	——
Gas lift chamber	2-29-56	86	39	125	1179

NOTE: During positive displacement pump test the well was equipped with 2½" tubing.

Example III. Chamber versus Natural Flow.

Well D Data: Total Depth = 6750', 2½" Tubing, 7" O.D. Casing:

Equipment	Date of Test	Production (BOPD)	Injection Gas-Oil Ratio (cu. ft./bbl.)
Natural flow	4-15-55	149	——
Gas lift chamber	11-15-55	185	1909

Well E Data: Total Depth = 6750', 2" Tubing 5½" O.D. Casing:

Equipment	Date of Test	Production (BOPD)	Injection Gas-Oil Ratio (cu. ft./bbl.)
Natural flow	8-20-55	126	——
Gas lift chamber	12-26-55	164	2537

Figure 18 is a two-pen surface pressure recorder chart of Example Well E.

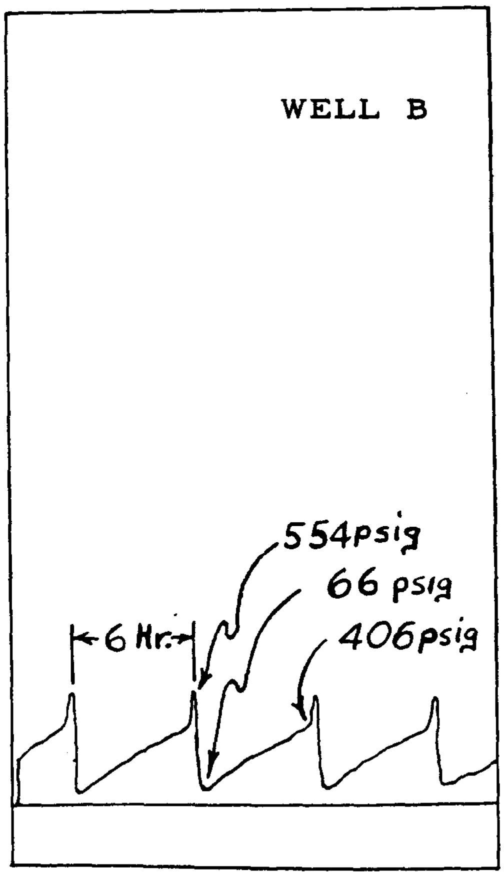
All the above production data represent as nearly as possible stabilized well conditions.

CONCLUSIONS

Advantages of a properly designed chamber can be summarized as follows:

1. The equipment and operating costs for gas lifting stripper wells are low.
2. Ultimate depletion of low bottom hole pressure wells is possible.
3. The point of gas injection can be located near total depth in wells with several hundred feet of perforations or open hole.
4. Minimum gas greak-through is assured.

WELL "B" BOTTOM HOLE PRESSURE BOMB SURVEY



BHP versus TIME with
bomb inside chamber.
4 injection gas cycle per day.
Producing 6 BO per cycle.

FIG. 17

5. Maximum fluid recovery is obtained with a minimum fluid head build-up against the formation.

6. Daily production can be increased

7. The required injection gas-fluid ratio is reduced.

8. A lower average producing bottom hole pressure is assured.

Information required to calculate chamber length is:

1. The effective injection gas pressure available inside the chamber and the wellhead tubing back pressure are required.

2. The ratio of the volume of the chamber annulus to the volume of the tubing above the chamber must be determined.

3. The maximum static fluid gradient at depletion should be used.

4. The maximum working fluid level between gas injections must be known.

5. The location of the packer in relation to the top of an insert chamber is important if a small dip tube is employed.

6. The volume of the dip tube must be considered of the dip tube is larger than the tubing.

Additional chamber design considerations which affect the overall operational efficiency are as follows:

WELL "E" TWO-PEN SURFACE PRESSURE RECORDING CHART

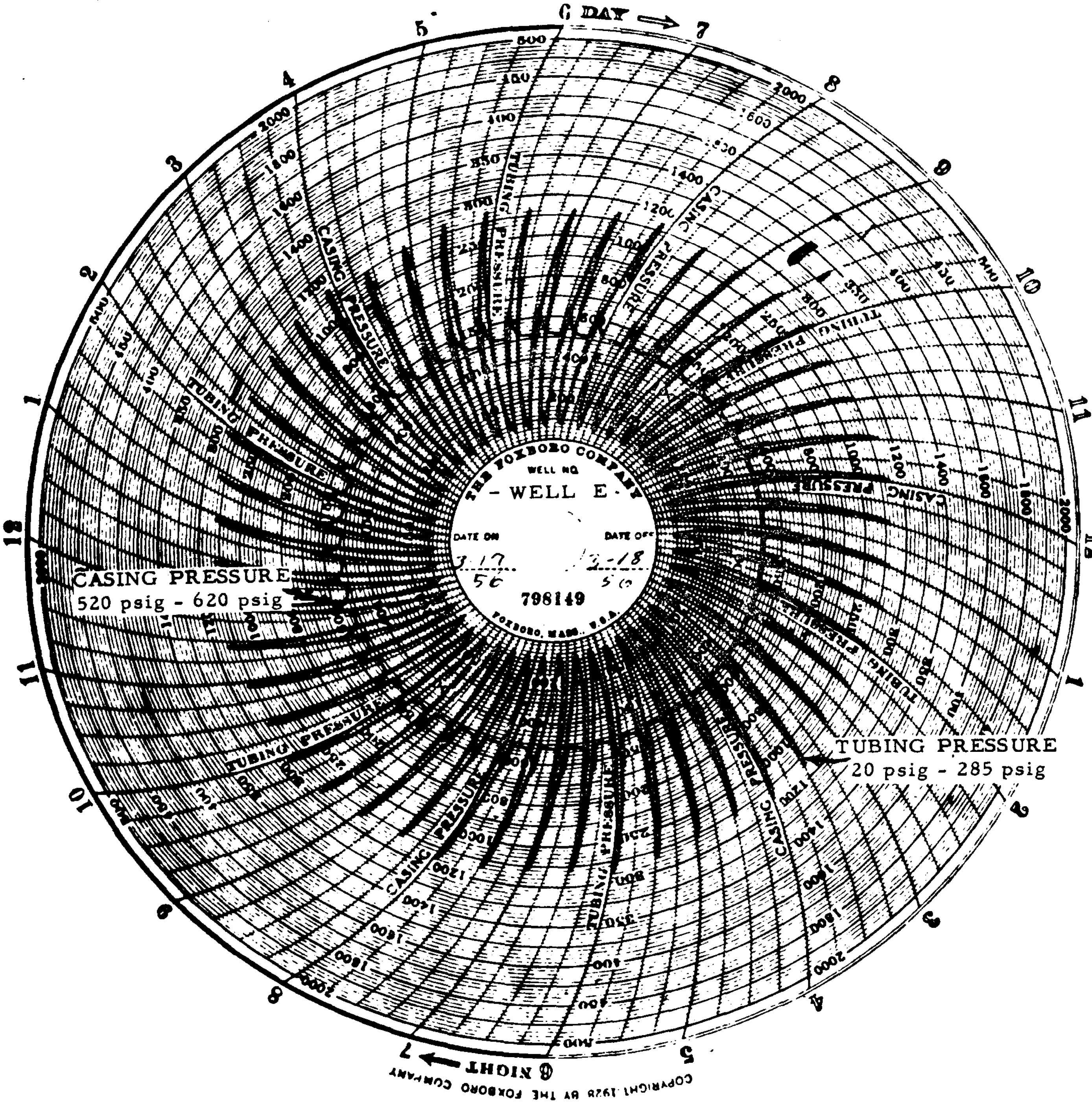


FIG. 18

Well Data: Total Depth - 6750' 2" Tubing 5-1/2" O.D. Casing.
Two-packer chamber 343' long.
Producing 164 BOPD - 3.4 BO per cycle.

1. The unloading valve immediately above the operating valve must be properly located.

2. The bleed port should be correctly sized to pass the formation gas.

3. A partially balanced flow valve is necessary for most chamber installations to reduce the spread of the operating valve.

4. The packer combination for a two-packer installation will depend on the individual well conditions and desired expenditure.

5. Retrievable equipment will provide maximum efficiency and eliminate pulling tubing for valve replacement.

Actual field data show that a properly designed chamber installation will perform as follows:

1. Wells with bottom hole pressures as low as 20 psig can be sucessfully depleted.

2. The lifting costs of low volume, deep wells can be drastically reduced.

3. The overall efficiency of low productivity index conventional intermittent installations is improved by chambers.

4. Production can be increased over that of positive desplacement pumping methods and natural flow.

DEFINITION OF SYMBOLS

C.L.—Chamber length, feet.

dP—Gas column weight, psi.

D.T.L.—Dip tube length, feet.

F.L.B.— Maximum producing fluid level above bottom of chamber, feet.

F.L.T.—Maximum producing fluid level above top of chamber, feet.

H—Maximum head $= (P_i - P_w)/$ S.G., feet.

O.S.L.—Length of oil string used for chamber, feet.

P_f—Maximum producing bottom hole pressure build-up between gas injection, psig.

P_i—Injection gas pressure available inside chamber, psig.

P_m—Minimum producing bottom hole pressure between gas injections, psig.

P_s—Shut-in bottom hole pressure, psig.

P_w—Wellhead tubing pressure, psig.

P.I.—Productivity Index, bbls/day/psi.

Q_o—Daily oil production, bbls/day.

R—Ratio of annular volume of chamber to volume of tubing V_{c-a}/V_t, no units.

R_L—Ratio of annulur volume of liner to volume of tubing V_{L-a}/V_t, no units.

R_{t-a}—Ratio of annulur volume of tubing to volume of tubing V_{t-a}/V_t, no units.

S.G.—Static gradient of produced fluid, psi/ft.

V_{c-a}—Annular volume between dip tube and chamber, bbls/1000'.

V_{d-t}—Volume of dip tube, bbls/1000'.

V_{L-a}—Annulur volume between dip tube and liner, bbls/100'.

V_t—Volume of tubing above chamber, bbls/1000'.

V_{t-a}—Annulur volume between dip tube and tubing, bbls/1000'.