Installation and Operation of Pilot Controlled Gas-Lift Valves in Multiple Completion Wells

By BOB WALTON
Odex Engineering Co.

INTRODUCTION

Artificial lift methods for multiple completion wells are increasingly important as these type wells become deeper and tubing sizes become smaller.

During the past two years, the number of wells completed as duals, triples, or quadruples has increased in greater proportion to total wells drilled than during any other period in the history of the oil industry.

Gas lift is one of the several artificial lift methods being used to produce oil and/or water from wells. The application of this system to multiple zones producing from a single casing well bore has, naturally, presented problems.

PURPOSE

The purpose of this paper is to show how the design and operation of pilot-controlled gas-lift valves have overcome many of the inherent problems of multiple completions.

Within the production tubing string, multiple completed wells are no different than single completions. From a gas-lift standpoint, the main difference is that several wells producing from a common casing, have a common casing annulus gas supply as shown in Figure 1. This fact eliminates the use of pressure in the annulus as the sole means for actuating the gas-lift valves.

PROBLEM

The problem to be solved is to produce two or more wells that have different production characteristics with a common gas supply source. To accomplish this production, it is necessary that the gas-lift valves be opened by a signal from within the production tubing string and then pass a predetermined quantity of gas from the annulus into the tubing and then close. Many times, it is impossible to predict the exact operating level, i.e. gas injection point, and this fact must be considered in the over-all gas-lift design.

The inability to predict the exact operating level in the wells being considered makes it advisable, in most instances, to set all valves in all production strings at the same surface closing pressure.

The foregoing introduction, purpose, and problem outline the general conditions of multiple completion wells.

At this stage, it is necessary to describe the operation of a pilot-controlled flow valve in order to show later how it can be embodied into a design to successfully produce multiple completed wells.

GAS-LIFT VALVE DESCRIPTION

The pilot-controlled gas-lift valve is, as the name implies, a main valve section controlled by a pilot valve. This valve mechanism is actually two separate valves operating for one purpose.

The pilot valve consists of a hermetically sealed bellows unit at atmospheric pressure, a valve and seat, and a spring to elongate the bellows and hold the valve on the seat.

The main valve section has two main parts: a large-ported inlet valve and a moveable piston directly connected to the inlet valve. The piston is arranged so its upper side is exposed to the discharge of the pilot valve, and the lower side is subject to the tubing pressure. A bleed port is drilled through the piston and is sized to pass less gas than is the pilot valve.

This complete valve is shown in Figure 2. When in operation and when the valve is in a closed position, the bellows and the upper side of the valve and seat are exposed to casing pressure; the lower side of the valve and seat are exposed to tubing pressure. When this condition exists, the casing pressure is acting on the total bellows area, less the valve seat area, to overcome the predetermined spring load. In reverse, the tubing pressure is acting on the valve seat area in an attempt to open the valve. After the valve is open and gas is passing into the upper portion of the piston chamber, the pressure is equalized across the valve and seat. In this position, the casing pressure is acting on the total bellows area to overcome the spring load and keep the valve open until the pressure in the casing drops to a predetermined level. In analyzing the above factors, it can be determined that, when the tubing pressure at the valve level is lower than is the casing pressure the opening pressure of the valve is always higher than is the closing pressure and the closing pressure is constant regardless of tubing pressure. Therefore, by increasing the area of the pilot valve and seat, the effect of the tubing pressure (fluid load) on the opening pressure of the valve is increased but the closing pressure remains constant and is unaffected by tubing pressure regardless of the pilot valve and seat area. The area of the bellows is constant in all valves of the same type. For simplicity in design calculations, the different pilot valve and seat sizes in relation to the bellows area are expressed in a percentage factor of the closing pressure of the valve and noted as "per cent spread". This per cent spread multiplied by the differential across the valve (differential between casing pressure and tubing pressure) gives the increase in psi above closing pressure required to open the valve under these conditions.

In this section of the paper, an attempt will be made to show the necessary reasoning and calculations required to evaluate well data and design a workable gas-lift installation.

The chart, identified as Figure 3, gives well data of three wells completed to produce through individual tubing strings but with one common casing annulus. The three zones are separated by packers. This arrangement is shown in Figure 1.

From Figure 3 it will be noted that Zone "C" has a high bottom hole pressure and productivity index, that the oil gravity is high, and that little decline in bottom hold pressure is indicated. This well will have a long flowing life and artificial lift is not required.

Zone "A" has a relatively high bottom hole pressure but a low productivity index. The static gradient is high enough that the bottom hole pressure is not great enough to overcome the static load; and the well will not flow.

SAMPLE CALCULATIONS

The following calculations using the known well data (Figure 3) positions the valves in the wells in such

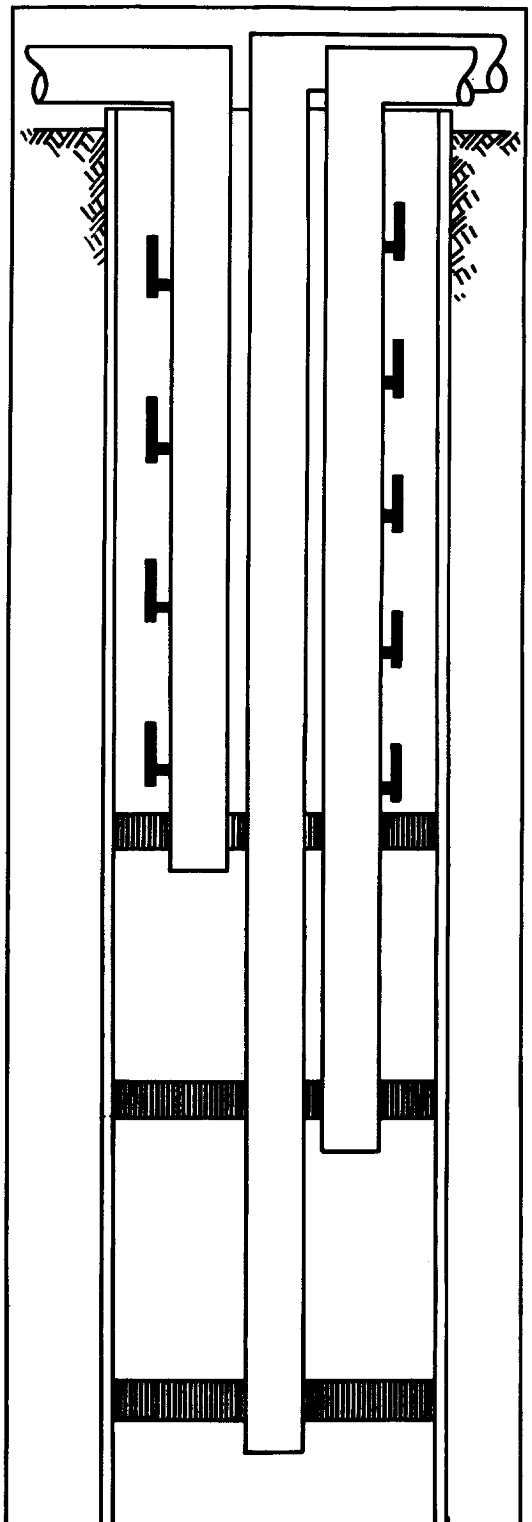

FIG. 1

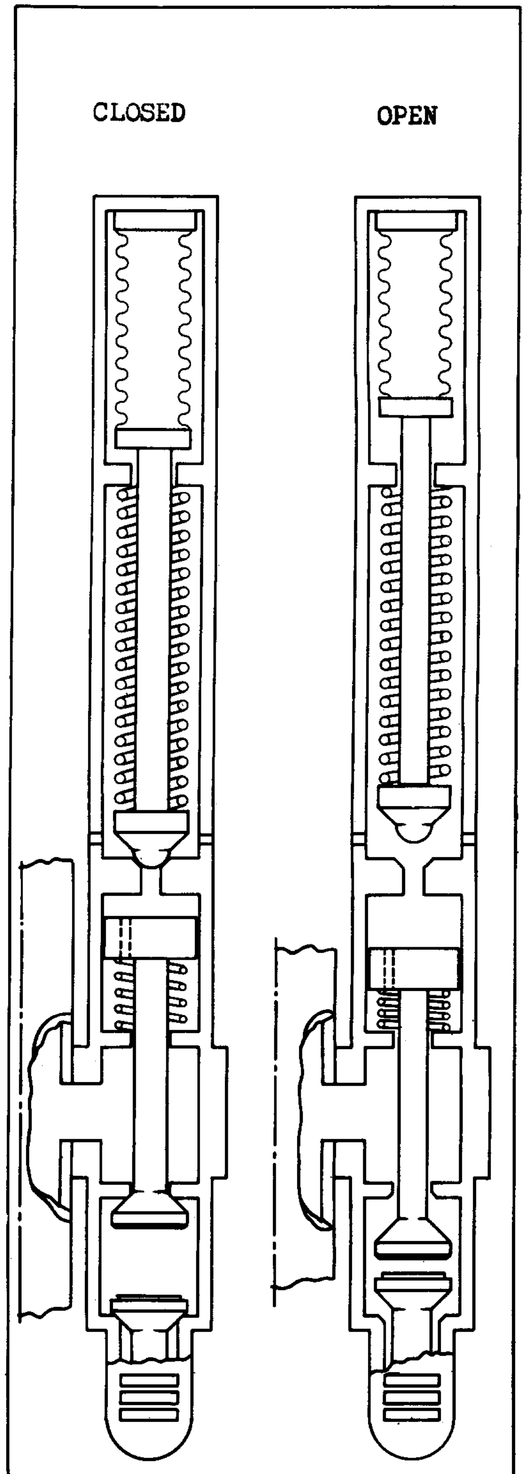

FIG. 2

WELL DATA

	ZONE A	ZONE B	ZONE C
DEPTH OF PERFS	10,500'	8800	12,500
BPH @ PERFS	3200 PSI	1800 PSI	5025 PSI
PRODUCTIVITY INDEX	0.10	0.15	6.00
OIL GRAVITY° API	40°	42°	50°
WATER CUT, %	10%	0% increase to 90%	TRACE Increase to 60%
STATIC FLUID LEVEL FT. FROM SURFACE	1660	3650	FLOWING
STATIC FLUID GRADIENT	0.362	0.349	FLOWING
TYPE RESERVOIR	GAS CAP	GAS CAP(ON WATER FLOOD)	WATER DRIVE
ANTICIPATED DROP IN BHP (PSI/YEAR)	150 PSI	0 PSI TO 100 PSI	100 PSI
TUBING SIZE	2" OD BUTTRESS	2" OD BUTTRESS	2 3/8" EUE 8 RT
TOP FIELD ALLOWABLE (BOPD)	190	150	250
CALENDAR DAY ALLOWABLE (BOPCD) BASED ON 10 DAY ALLOWABLE	63.3	50	83.3
GAS PRESSURE AVAILABLE FOR POWER	650 PSI		

FIG. 3

manner that the pressure available and operating pressure of the valves will always unload the wells to the desired producing level.

All symbols used are described in one column. All formula are identified by numerals in parenthesis i.e. (1).

SAMPLE CALCULATIONS ZONE "B"

I THROUGH III

I. To locate the top valve:

$$F_t = \frac{Pa-Pd}{G_s} = \frac{650-50}{0.349} = 1720' \qquad (1)$$

But the static fluid level is 3650 ft from surface; therefore locate the top valve at the static fluid level. With a desirable surface closing pressure of 550 psi and the valve set at 3650 ft from surface, the top valve will be set with P_c = 601 psi (see Fig. 4) $P_c = P_{cs} + G_w$ (2)

II. To position next valve:

$$S = \frac{P_c - P_t}{G_s} - F_b - F_i \qquad (3)$$

(values are determined from valve above)

$$S = \frac{601-50}{0.349} - 380 - 0 = 1297'$$

$$D = F_t + S_1 + S_2 = 3650 + 1297 = 4947'$$

For this valve: $P_c = P_{cs} + G_w$

$P_c = 550 + 71 = 621$ psi (see Fig. 4)

III. To position succeeding valves:

$$S = \frac{P_c - P_t}{G_s} - F_b - F_i \qquad (3)$$

$$S = \frac{621-50}{0.349} - 380' - 225^* = 1031'$$

Then $D = F_t + S_1 + S_2 + \ldots\ldots = 3650 + 1297 + 1031$

$D = 5978'$

and for this valve: $P_c = P_{cs} + G_w$

$P_c = 550 + 86 = 636$ psi

NOTE: F_i is determined from two charts using G_s, the PI of the well, and the surmergence of the valve above. The surmergence of the valve above is determined from the following formula:

$$M = D - F_L - \frac{P_t}{G_s} \qquad (4)$$

$$M = 497 - 3650 - \frac{50}{0.349} = 1154$$

From Figure 1 one finds:

PI = 0.15 $\quad G_s = 0.349$

Then, from the two feed in factor charts one finds F_i = 225'.

This procedure is repeated until S becomes less than 500 ft. The valves are then spaced 500 ft apart until the desired depth is reached.

The completed installation showing valve depths and pressures for both zone "A" and "B" are shown in Figure 4. It should be noted that all valves in both wells have the same surface closing pressures.

The above calculations and valve spacing shown in Figure 4 will not satisfactorily produce these wells. The method of operation coupled with the per cent spread selection of the gas-lift valves are the unique features of the design.

It is advisabe, as a later description of the operation will show, that ample gas volume to lift a complete load of fluid from the well will be stored in the casing annulus before the operating valve opens. To do this the size of the fluid load must be known and the gas volume necessary to deliver the load to the surface must be calculated. From past experience, it has been determined that the most efficient fluid load, in pounds per square inch, is 70% of the downwell closing pressure of the flow valve. This 70% load factor will be used in the following calculations.

IV. To determine desirable spread: First calculate the volume of gas needed to deliver a head of fluid to the surface:

VALVE SPACINGS AND PRESSURE SETTINGS

ZONE A

VALVE NO.	DEPTH	SURFACE CLOSING PRESSURE (PSI)	GAS COLUMN WEIGHT (PSI)	DOWNWELL CLOSING PRESSURE (PSI)
10	1660	550	23	573
9	2980	550	41	591
8	4094	550	58	608
7	5014	550	72	622
6	5795	550	84	634
5	6437	550	93	643
4	6972	550	100	650
3	7472	550	109	659
2	7972	550	118	668
1	8472	550	125	675

ZONE B

VALVE NO.	DEPTH	SURFACE CLOSING PRESSURE (PSI)	GAS COLUMN WEIGHT (PSI)	DOWNWELL CLOSING PRESSURE (PSI)
7	3650	550	51	601
6	4947	550	71	621
5	5978	550	86	636
4	6784	550	99	649
3	7406	550	109	659
2	7906	550	117	667
1	8406	550	124	674

FIG. 4

$$V_h = \frac{(P_{ci})(0.70)(V_t)(d_1)}{(14.6)} \quad (5)$$

$$V_h = \frac{(674)(0.70)(1.52)(84.06)}{14.6} = 3730 \text{ SCF}$$

Now, we want to store enough gas in the casing to deliver a head of fluid to the surface; therefore:

$$V_h = V_c = \frac{(S_o)(V_a)(d_1)}{14.6} \quad (6)$$

$$3730 = \frac{(S_o)(14.06)(84.06)}{(14.6)}$$

$$S_o = \frac{(3730)(14.6)}{(14.06)(84.06)}$$

$$S_o = 46 \text{ psi}$$

$$\%S_v = \frac{S_o(100)}{P_{ci}(0.30)}$$

$$\%S_v = \frac{(46)(100)}{(674)(p.30)} = 22.8\%$$

Definition of symbols used:

F_t = depth of top valve, ft
P_a = maximum available surface pressure, psi
P_d = differential across top valve for unloading, psi
G_s = static fluid gradient, psi/ft
P_c = downwell closing pressure of valve, psi
G_w = pressure exerted by gas in casing, psi
P_{cs} = surface closing pressure of valve, psi
S = spacing between valves, ft
P_t = surface tubing pressure, psi
F_b = fall back factor, ft
F_i = fill in factor, ft
D = depth of valves, ft
M = valve submergence, ft
F_L = static fluid level, ft
V_h = vol. of gas per head, SCF
P_{ci} = downwell closing pressure of bottom valve, psi
V_t = tubing capacity, ft^3 /100 ft of tbg
d_1 = depth of bottom valve, in 100 ft
V_c = gas capacity of annulus, SCF
S_o = operating speed of casing pressure, psi
V_a = annular capacity, ft^3/100 ft of annulus
S_v = spread of valve, %

The following graphs published by the Merla Tool Corp. were used:

Graph #1077 - Weight of Gas column
Graph #1093 - Fall back Factor vs Valve Depth
Graph #1092 - Feed in Factor Curve A
Graph #1091 - Feed in Factor Curve B

OPERATION

From the above calculations, a 22.8% spread is needed in the operating valves to give the desired spread of 46 psi in the casing annulus pressure. This means that a valve set to close at 674 psi will open at 674+46 = 720 psi when the tubing load at the valve is .70 x 674 = 471.8 psi. If the fluid load in the tubing is less than 471.8 psi, the opening pressure of the valve will be greater than 720 psi. As was stated earlier, all valves have a surface closing pressure of 550 psi, even though the downwell pressures are higher. If 46 psi is added to the surface closing pressure of 550 psi, the desired surface opening pressure is 596 psi.

After the tubing and valves are installed in the well, the gas supply line is connected to the casing annulus with a combination pressure and volume control unit to control admission of gas. This unit consists of an adjustable choke in series with a pilot controlled motor value. The pilot control is made in two separate units, one unit to control casing pressure and the other to overide the casing pressure control and close the motor valve when the fluid head reaches the surface, thus eliminating wasted gas injection while a fluid head is being delivered from either tubing string.

For this well, the adjustable choke would be set initially for the equivalent passage of a 12/64 in. port. The casing pressure control would be set for a maximum pressure of 596 PSI and the tubing control unit set to close off the gas supply when the tubing pressure increased twenty PSI above dormant pressure. With these settings, the lowest valve in either tubing string exposed to gas would open when the tubing load at the valve reached 70% of the downwell closing pressure. All the pilot controlled valves have a 1/2 in. delivery port; it therefore follows that the open valve would pass more gas than the surface choke could deliver. This action will drop the casing pressure as the fluid load is being delivered to the surface. When the fluid head reaches the surface, a pressure increase will occur at the tubing head and the gas supply valve will close. The casing pressure will continue to drop until the closing pressure of the valve is reached. After the fluid load and resultant tail gas have been dissipated from the tubing, the pressure at the tubing head will decrease, and the surface gas supply valve will open and again build the casing pressure to the desired level for another cycle.

CONCLUSION

The above described installation is extremely flexible so that manipulation of the volume and pressures at the surface on a trial-and-error basis will produce a maximum volume of fluid with a minimum amount of gas.