Intermittent Gas Lift Design Utilizing Multipoint Gas Injection

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Introduction

The multipoint installation design technique has the advantage of supplementing injection gas at several depths in the tubing to reduce injection gas breakthrough and liquid fallback, and still retain casing pressure control of the gas lift valves' opening and closing pressures. This type of installation has the following applications: (1) for capacity production from an intermittent installation; (2) for deep lift and/or lifting through large tubing; (3) for unknown depth of lift or unknown point of gas injection changing due to a changing flowing bottom hole pressure; (4) for low injection gas pressure relative to depth of lift; (5) for dual gas lift installations; and (6) for borderline wells.

Many wells can be classified as borderline in regard to gas lift installation design because the type of installation, continuous flow or intermittent lift, best suited for the well, is not readily apparent from the well data. When there is doubt about the most suitable type of installation, an intermittent multipoint design is generally recommended. An understanding of basic gas lift valve mechanics is essential for understanding the operating principle of multipoint design.

Valve Mechanics

An unbalanced casing pressure operated gas lift valve in a well is illustrated in Fig. 1. This valve is called unbalanced because the casing opening pressure at valve depth (P_o @ L) is exerted over the effective area of the bellows (A_b) less the area of the valve port (A_v) and not over the entire effective bellows area. The tubing pressure at valve depth (P_o @ L) is exerted over the valve port area as an opening force: the larger the port, the greater the tubing pressure will affect the valve opening pressure and the less the casing pressure will affect this opening pressure. An opening force balance equation for the valve in a well at the instant the valve opens is as follows:

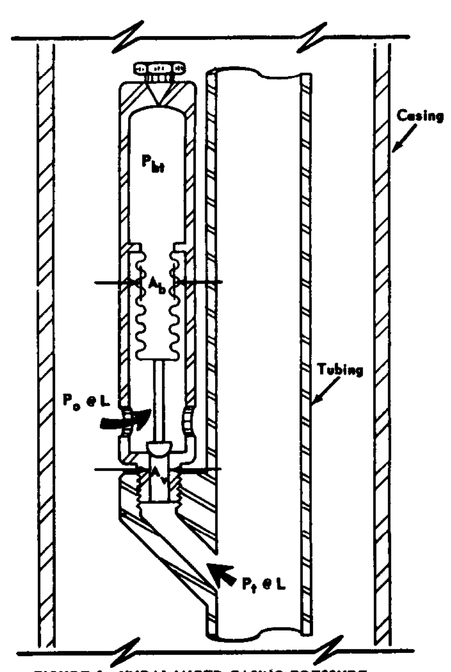


FIGURE 1: UNBALANCED CASING PRESSURE OPERATED GAS LIFT VALVE IN A WELL – VALVE CLOSED, READY TO OPEN.

Forces Opening Valve = Force Closing Valve

$$\underbrace{\begin{array}{c}\text{Po@ L}\\ \text{Casing}\\ \text{Opening}\\ \text{Press.}\\ \text{at Valve}\\ \text{Depth}\\ \text{(psig)}\end{array}\left[\begin{array}{c}\text{Ab}\\ \text{Effec-}\\ \text{tive}\\ \text{Area}\\ \text{of}\\ \text{Bellows}\\ \text{(sq in.)}\end{array} - \begin{array}{c}\text{Av}\\ \text{Area}\\ \text{of}\\ \text{Valve}\\ \text{Port}\\ \text{(sq}\\ \text{in.)}\end{array}\right]}_{\text{Opening Force on Bellows}} + \underbrace{\begin{array}{c}P_t\text{ @ L}\\ \text{Tubing}\\ \text{Press.}\\ \text{at}\\ \text{Valve}\\ \text{Depth}\\ \text{(psig)}\end{array}\left[\begin{array}{c}A_v\\ \text{Area}\\ \text{of}\\ \text{Valve}\\ \text{Port}\\ \text{(sq}\\ \text{in.)}\end{array}\right]}_{\text{Opening Force on Port}}$$

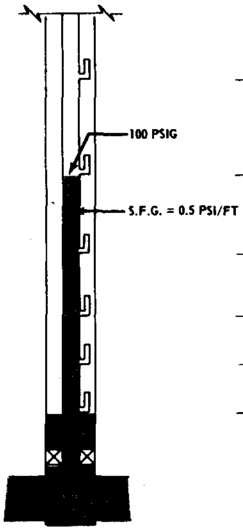
$$= \underbrace{\begin{array}{c}\text{Pbt}\\ \text{Bellows}\\ \text{Charge}\\ \text{Press.}\\ \text{at Well}\\ \text{Temp}\\ \text{(psig)}\end{array}\left[\begin{array}{c}A_b\\ \text{Effec-}\\ \text{tive}\\ \text{Area}\\ \text{of}\\ \text{Bellows}\\ \text{(sq in.)}\end{array}\right]}_{\text{Closing Force on Bellows}}$$

The psi decrease in valve opening pressure per psi increase in tubing pressure at valve depth is called the tubing effect factor (TEF) for the valve, and this factor is a constant based on the areas of the bellows and valve port. The larger the port is for the same size bellows, the greater is the tubing effect factor for an unbalanced valve.

The tubing effect (TE) for an unbalanced valve is equal to the tubing pressure at valve depth multiplied by the tubing effect factor for the valve. The tubing effect is the difference between the valve opening pressure if the tubing pressure were zero; and the actual opening pressure in the well where the tubing pressure at valve depth exerted over the port area is greater than zero. As the tubing pressure at valve depth increases, the valve opening pressure decreases. The larger the valve port the greater is the decrease in opening pressure for the same tubing pressure at valve depth.

Theory of Operation of Multipoint Intermittent Installation Design

The principle of operation is based on a combination of casing and tubing pressure control. Lowering of the valve opening pressure by the tubing pressure at valve



L Depth of Valve (ft.)	P_{vc} Surface Closing Pressure of Valve (psig)	P_{vc} @ L Valve Closing Pressure at Valve Depth (psig)	P_{vo} @ T_v Valve Opening Pressure When Tbg. Press. Is Zero at Operating Temperature (psig)	P_t @ L Tubing Press. at Valve Depth at Instant Deepest Operating Valve Opens (psig)	T.E. Tubing Effect (psi)	P_o @ L Actual Valve Opening Press. at Valve Depth (psig)	Remarks
4900	600	665	792	88	17	775	Valve Closed
5500	600	673	801	100	19	782	Valve Closed
6000	600	679	808	350	67	741	Valve Closed
6450	600	685	815	575	109	706	Deepest Operating Valve At Instant Valve Opens
6850	600	690	821	775	147	674	Valve Open
7200	600	695	827	950	180	647	Valve Open

*WELL DATA:

Tubing Pressure at 5500 Feet = 100 psig
Static Fluid Gradient = 0.5 psi/ft.
Type Valves: Camco Type C with 3/8 inch Port (T.E.F. = .19)

FIGURE 2: ILLUSTRATES PRINCIPLE OF OPERATION OF INTERMITTENT INSTALLATION DESIGNED FOR MULTIPOINT GAS INJECTION.

depth is utilized in the design of an installation. Unbalanced valves with a large port (high tubing effect factor) are required for this design technique. The principle of operation is illustrated in Fig. 2. All valves have a 3/8 in. port and a tubing effect factor of 0.19. To simplify the illustration, all valves in this installation have the same surface closing pressure and the static fluid gradient is assumed to be 0.5 psi/ft. In this example, the valve at 6450 ft is the operating valve, since the tubing pressure exceeds the casing pressure at the depth of the next lower valves at 6850 and 7200 ft at the instant the operating valve opens.

The valve at 6450 ft opens when the casing pressure reaches 706 psig. At this instant the casing pressure would have to be 741 psig before the valve at 6000 ft would open. After the valve at 6450 ft opens, the tubing pressure at this depth approaches the casing pressure which is increasing during gas injection. As soon as the slug passes the valve at 6000 ft, the high injection gas pressure behind the slug lowers the opening pressure of this valve and it opens. Then available at this depth is full casing pressure which eliminates the slight decrease in pressure that occurs in the 450 ft of tubing between the two valves. Depending on the distance between valves and the maximum casing pressure during a period of gas injection, this operation continues until several valves are open.

When the flowing bottom hole pressure in this installation decreases, the point of gas injection will automatically be deeper. The deepest valve with a tubing pressure less than the casing pressure at its depth is the first valve to open after the controller opens and the casing pressure begins to increase.

Comparison of Continuous Flow with Multipoint Intermittent Gas Lift Installation in Same Well

A two-pen pressure recorder chart from a continuous flow installation in West Texas which was capable of producing a maximum of 100 BPD of liquid, regardless of the injection gas volume, is shown in Fig. 3. During

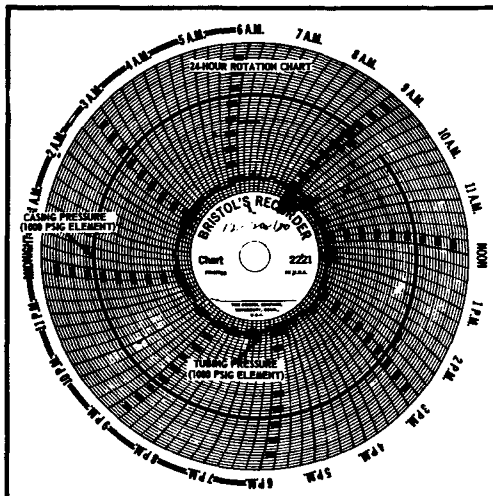


FIGURE 3: TWO-PEN PRESSURE RECORDER CHART OBTAINED FROM A WELL WITH A CONTINUOUS FLOW INSTALLATION PRODUCING LESS THAN 100 BARRELS PER DAY.

the 24-hr period covered by this chart, the well produced approximately 65 bbl. of liquid (13 bbl. of oil). The well had 2-in. nominal tubing and a short 3-in. flowline; therefore, wellhead tubing pressure was no problem. The static fluid level in the well after a 24-hr shut-in was 3000 ft and approximately 200 BPD of liquid (90 per cent water) could be produced by swabbing, with the resulting working fluid level at 4500 ft. The fluid level in the casing was located with an acoustical well sounder and a pressure survey was conducted immediately after the well was shut in. These surveys were conducted to locate the operating gas lift valve. The acoustical survey indicated the fluid level in the casing to be at a depth of 5535 ft. There were gas lift valves at 5100 ft and 5610 ft. Based on the fluid level, swabbing tests and pressure survey, the operating valve was determined to be the valve at 5100 ft.

It was apparent that the maximum producing rate by gas lift could not be attained by continuous flow because the depth to the point of gas injection necessary to obtain the desired drawdown could not be reached by continuous flow operation. A flowing pressure gradient exists above the point of gas injection during continuous flow. The minimum possible flowing bottom hole pressure (maximum pressure drawdown across the formation) depends on the minimum flowing pressure gradient which can be established above the point of gas injection. In this well, it was impossible to attain a flowing gradient low enough to establish the flowing bottom hole pressure for the desired producing rate.

The following multipoint intermittent installation was designed and run in this well:

Approximate Surface Valve Closing Pressure (psig)	Depth of Valve (ft)	Valve Opening Pressure at 60 F. in Tester (psig)
700	3510	835
690	4465	830
680	5135	825
670	5650	815
660	6035	805
650	6355	795
640	6675	785
630	7000	775

All valves in this installation had a 3/8-in. port and a tubing effect factor of 0.19 (19 psi decrease in valve opening pressure per 100 psi increase in tubing pressure at valve depth).

A two-pen pressure recorder chart from this installation is shown in Fig. 4. During the 24-hr period covered

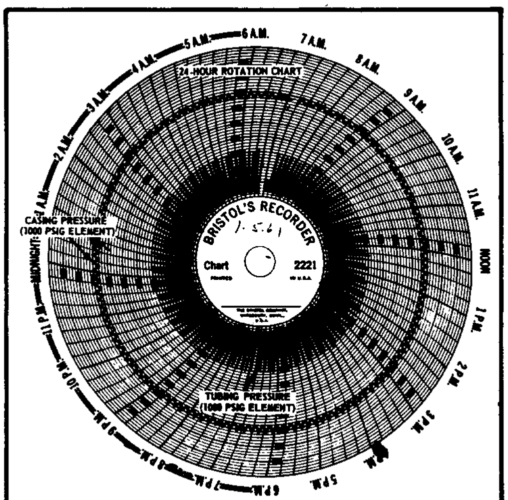


FIGURE 4: TWO-PEN PRESSURE RECORDER CHART OBTAINED FROM A WELL WITH A MULTIPOINT INTERMITTENT INSTALLATION PRODUCING APPROXIMATELY 500 BARRELS PER DAY.

by this chart, the well produced 494 bbl. of liquid (44 bbl. of oil) through 2-in. nominal tubing from a depth below 6000 ft.

The maximum producing rate by multipoint intermittent lift is based on the maximum number of injection cycles per day and the liquid production per cycle. The primary factors which affect the maximum cycle frequency are the (1) depth of lift, (2) tubing size, (3) injection gas pressure, (4) injection gas volume, (5) injection gas breakthrough and liquid fallback, (6) gas throughput capacity of operating valve, or valves, (7) bottom hole pressure buildup characteristics of well, (8) wellhead tubing back pressure, and (9) unusual well conditions, such as emulsions, etc. In this installation, the injection gas line pressure was 780 psig and the gas volume could be considered unlimited since the source was a gasoline plant and the well was near a large trunk line. The surface closing pressure of the deepest operating valve is 660 psig which is 120 psi less than line pressure. Consequently, the casing pressure increased rapidly after the time cycle controller on the injection gas line opened; the increase resulted in good valve action. As each liquid slug passed upper valves, these valves opened because of the increase in tubing pressure from the injection gas under the slug. And supplementing of the injection gas through the large ported valves reduced the injection gas breakthrough and liquid fallback. One of the most important factors contributing to the high producing rate was the maximum cycle frequency possible with this installation. The wellhead tubing pressure decreased to separator pressure immediately after the slug surfaced because of the short, large flowline. Had the time required for the tubing pressure to decrease after a slug surfaced been excessive, the maximum injection gas cycle frequency would have been reduced, a reduction which would have decreased the maximum producing capacity of the installation.

Conclusions

In this paper, one of the most flexible types of gas lift installations is described. Although a high capacity installation is offered to illustrate the advantages of multipoint intermittent design, the same design technique can be used in lower capacity wells and for unloading valves in a chamber of plunger installation. This type of installation design should be considered when the injection gas pressure is low and/or the point of gas injection is unknown. Installations can be designed with no decrease in operating injection gas pressure, regardless of the depth of lift.

Bibliography

Portions of this paper were extracted from Camco's Gas Lift Manual, copyright 1962.

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