Flow Valve Selection for Gas Lifting Duals

By *H. W. WINKLER*
Camco, Inc.

ABSTRACT

Increased drilling and operating costs have resulted in a greater number of dually completed wells. Most operators prefer two parallel tubing strings over concentric installations, since the development of detachable two-string packers and split wellhead equipment for parallel strings. This paper discusses in detail the flow valve selection for gas lifting both zones of a dual with a common injection gas source. The material is presented in a manner which permits an operator to choose the proper valve design for a dual without a previous thorough knowledge of gas lift principles. The design considerations using fluid operated, intermittent and continuous flow gas lift valves for dual installations are discussed. An efficient installation is based on the combination of producing characteristics of the two zones. Proposed valve installations are outlined for the following combinations:

1. Both zones continuous flow.
2. One zone continuous flow and the other zone intermittent flow.
3. Both zones intermittent flow.
4. Producing characteristics of either or both zones unknown.

Considerations for equipment, running and operation are offered. Miscellaneous illustrations and field data are included to illustrate valve design techniques.

INTRODUCTION

No one type of gas lift installation will meet the producing requirements of every dual well to be artificially lifted. The producing characteristics of each zone must be considered individually. The casing size limits the combination of tubing sizes which can be employed.

Most dual gas lift installations were of the concentric type, prior to the development of detachable two-string packers, parallel flow tubes, and split hanger wellhead equipment for parallel strings.[1] Combination concentric and parallel type installations, for gas lifting two zones of dually completed wells with separate injection gas sources, have been run in West Texas.[2] A concentric installation generally requires at least one small tubing string. If one zone must be gas lifted intermittently through a small tubing string and will not flow between gas injections, the maximum daily production is limited. The improbability of intermitting a high producing rate through 1" tubing is illustrated in the following example.

Problem Example 1

Well data: 1" Non-Upset J-55 Tubing in 2" Upset Tubing
Depth of Operating Valve = 6000'
Surface Opening Pressure of Valve = 500 psig
Wellhead Tubing Back Pressure = 100 psig
Static Fluid Gradient = 0.4 psi per ft.
Capacity of 1" Tubing = 1.07 Bbls. per 1000'

Maximum Fluid Head Build-Up Opposite Valve:

$$\frac{500 - 100}{0.4} = 1000', \text{ (Considering gas weight provides differential across valve)}$$

If a 0.5 barrel slug were produced every 30 minutes (which represents approximately 50 per cent fall-back), the daily production would be only 24 barrels of fluid per day.

Parallel String Installations

The present trend is away from the concentric type installation and toward parallel string installations, which will permit the separate running and pulling of the short string without unseating the long string. The two parallel strings, as shown in Fig. 1 offer additional

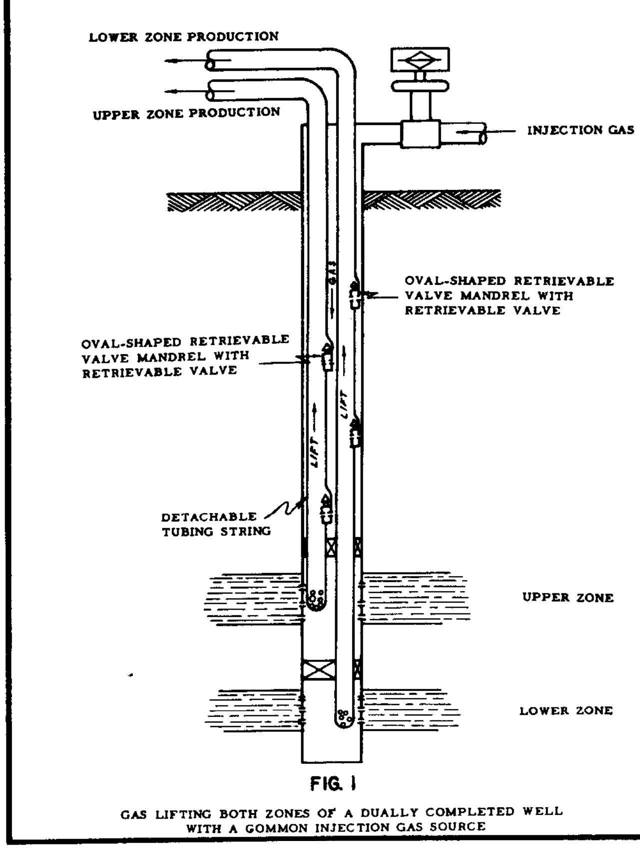


FIG. 1
GAS LIFTING BOTH ZONES OF A DUALLY COMPLETED WELL WITH A COMMON INJECTION GAS SOURCE

capacity over most concentric type installations. These parallel tubing strings provide all the advantages of full open tubing, such as paraffin cutting, the running of bottom hole pressure surveys, and permanent type well completion operations. Dual tubing wellhead equipment provides parallel centerlines through the mastergate valves.

The use of a retrievable production tube between packers permits the workover of either zone by wire line without pipe-handling equipment. In addition, the retrievable production tube allows gas lifting the upper or lower zone through either string of tubing.[3] For example, assume only one string of flow valves has been run in a dual well in which the initial well data is in error. The valves are on the string through which the good zone is producing. Changing the retrievable production tube by wire line methods prevents having to pull both tubing strings. The retrievable production tube can eliminate changing retrievable flow valves, or pulling tubing with conventional valves, if the valve installations require switching for more efficient operation.

FLUID OPERATED VALVE DESIGN

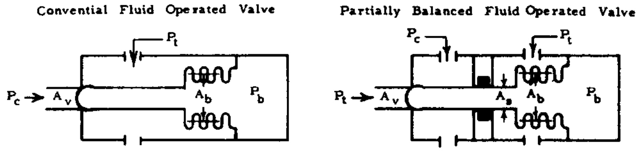
Operation And Advantages:

Fluid operated valves are ideally suited to many dual gas lift operations because the valves are opened automatically by a tubing pressure build-up opposite the valves. No time cycle surface control of the injection gas is required. The pressure in the tubing is applied opposite the bellows, as shown in Fig. 2. A minimum pressure differential of 150 to 200 psi be-

FORCES ACTING ON FLUID OPERATED VALVES

VALVE CLOSED --- READY TO OPEN

Convential Fluid Operated Valve | Partially Balanced Fluid Operated Valve



Opening Force = Closing Force

$P_t(A_b - A_v) + P_c(A_v) = P_b(A_b)$

Opening Force = Closing Force

$P_t(A_v + A_b - A_s) + P_c(A_s - A_v)^* = P_b(A_b)$

* As A_s approaches A_v the casing effect approaches zero.

Where: A_b - Effective Bellows Area; A_s - Area of Stem; A_v - Area of Port; P_b - Bellows Charge Pressure; P_c - Injection Pressure; P_t - Tubing Pressure

FIG. 2

tween the injection pressure opposity the valve and the tubing trigger pressure is recommended for fluid operated design. Since fluid operated valves are opened by tubing pressure, it is not necessary to drop valve opening pressures with depth. Partially or completely balanced fluid operated valves, schematically illustrated in Fig. 2, are recommended because of their greater sensitivity to tubing pressure.

Since the injection pressure has little or no effect on the opening pressure of the valve, interference between flow valves on both strings opening at the same time, or one string of valves using all the injection gas, is minimized. The point of gas injection is dependent upon the producing bottom hole pressure and will automatically be deeper for lower bottom hole pressure wells. Figs. 3 and 4 illustrate the versatility of fluid operated valves lifting from 9 to 190 barrels of fluid per day with efficient gas-fluid ratios. An adjustable choke is the only surface equipment required to control the injection gas. Fluid operated valve design has limitations, which should be considered prior to its installation.

Limitations:

The primary limiting considerations are as follows:

1. High Capacity Production - If the required point of gas injection for extremely high rates of production is below the second proposed valve, fluid operated valves should not be used. Fig. 5 illustrates why the maximum injection pressure cannot be utilized without inefficient multipoint injection when the point of gas injection is at a lower fluid operated valve. Fluid operated valve action is a slugging type of gas lift unless the point of gas injection is near the surface and the valve remains open. Although nearly 200 barrels of fluid per day are being lifted through 1-1/2" tubing from the upper zone, Fig. 3, heading action can be noted from the tubing pressure recording. As the fluid slug passes the upper fluid operated valves, these valves open. Choke selection is important to assure that the valves will close immediately after the fluid slug surfaces.

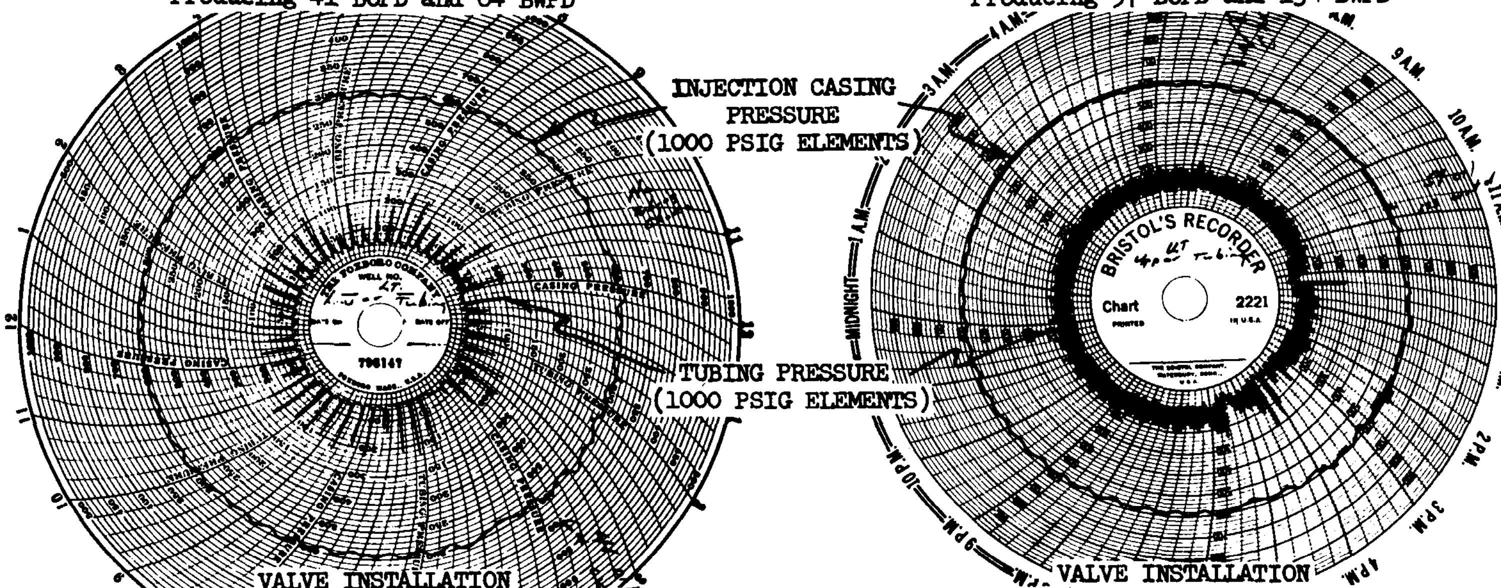
2. Low Bottom Hole Pressure - The fluid operated valves cannot be used for wells with extremely low flowing bottom hole pressures that will not support the fluid head required to trigger the bottom fluid operated valve.

3. High Tubing Back Pressure - Wellhead tubing back pressure should be minimized for efficient operation. Excessive tubing pressure prevents the fluid operated valves from closing until the injection casing pressure has decreased to the tubing trigger pressure of the valves. The high tubing pressure, following the surfacing of the fluid head, must be reduced rapidly to assure closing of the fluid operated valves. Long and/or small flow lines and flow line restrictions, such as surface chokes, will prevent fluid operated valves from closing after the fluid slug has surfaced.

4. Higher Equipment Cost - The number of valves required for a fluid operated installation will generally exceed those required for an intermitting valve installation for the same well. If the point of gas injection is known to be several thousand feet below the surface, pressure operated intermitting valves can be run for unloading. This reduces the initial cost by decreasing the number of flow valves required and prevents excessive gas passage through upper valves as the slug surfaces. Pressure recording charts for this type installation are illustrated in Fig. 3.

LOWER ZONE
Producing 41 BOPD and 64 BWPD

UPPER ZONE
Producing 57 BOPD and 133 BWPD



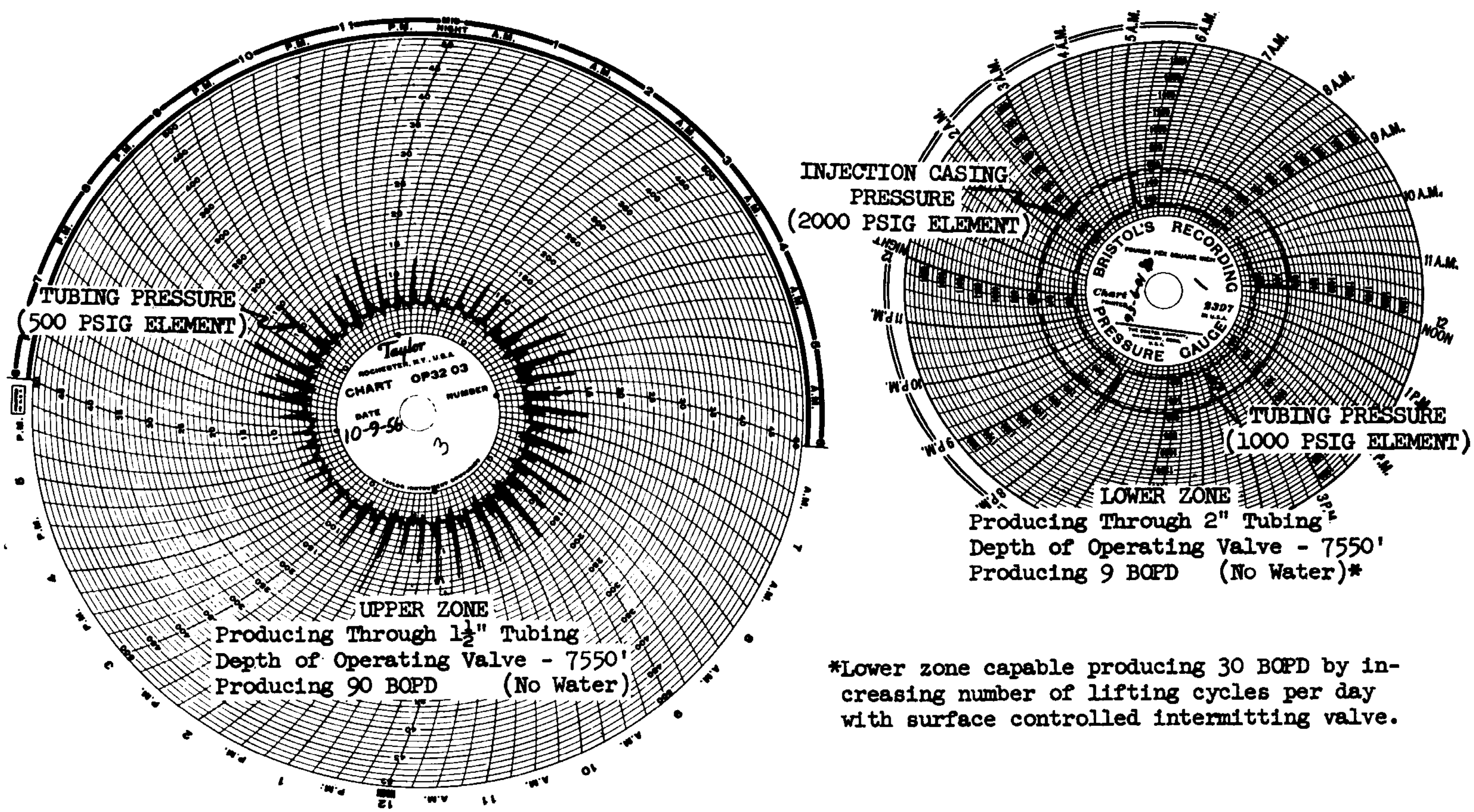
VALVE INSTALLATION (Lower Zone)

Type Valve	Opening Press.	Depth
Intermitting	670 psig	1472'
Intermitting	650 psig	2483'
Fluid-Operated	430 psig	3037'
Fluid-Operated	420 psig	3585'
Fluid-Operated	410 psig	4133'
Fluid-Operated	400 psig	4697'
Fluid-Operated	390 psig	5251'
Fluid-Operated	380 psig	5809'

VALVE INSTALLATION (Upper Zone)

Type Valve	Opening Press.	Depth
Intermitting	670 psig	1452'
Intermitting	650 psig	2440'
Fluid-Operated	430 psig	2965'
Fluid-Operated	420 psig	3497'
Fluid-Operated	410 psig	4024'
Fluid-Operated	400 psig	4550'
Fluid-Operated	390 psig	5074'
Fluid-Operated	380 psig	5596'

FIG. 3: Charts from Dual Gas Lift Installation with Both Zones Fluid Operated Through Two 1-1/2" Tubing Strings. Charts Recorded Simultaneously.



*Lower zone capable producing 30 BOPD by increasing number of lifting cycles per day with surface controlled intermitting valve.

FIG. 4: Charts from Dual Gas Lift Installation with Both Zones Fluid-Operated. Charts Recorded Simultaneously.

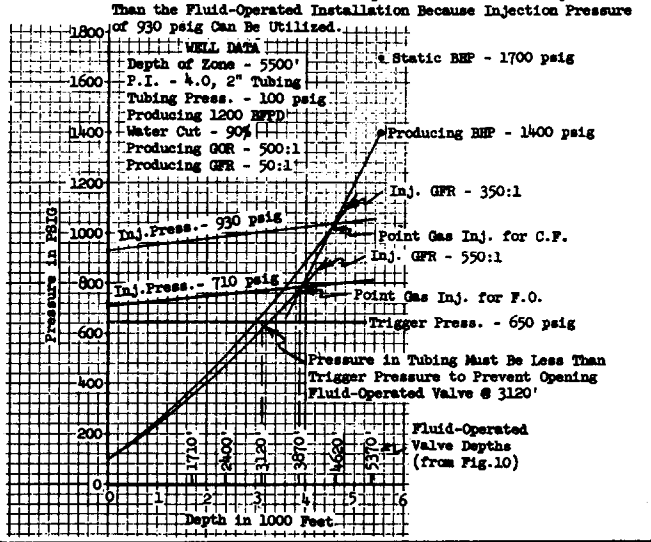
5. Lack of Surface Control - Many low productivity wells are not suited for fluid operated valve design due to their fluid feed-in and pressure build-up characteristics. The lower zone, Fig. 4, is capable of producing over three times as much oil per day with the increased number of injection cycles possible with surface control. A weak well can take longer to build up the last barrel required to trigger a fluid operated valve than it did for the first two or three barrels to feed in. This two or three barrels can be lifted by opening a pressure controlled valve with an intermitter at the surface.

FIG.5: CONTINUOUS FLOW VERSUS FLUID OPERATED VALVE DESIGN FOR EXTREMELY HIGH PRODUCING RATES

FLUID-OPERATED VALVE DESIGN
Surface Inj. Press. - 710 psig
Trigger Pressure - 650 psig
Point of Gas Inj. - 3870'
Producing GFR - 600:1
Injection GFR - 550:1
Inj Gas Requirements - 660 MCFD

CONTINUOUS FLOW VALVE DESIGN
Surface Inj. Press. - 930 psig
(Actual Press. Available at Well)
Point of Gas Inj. - 4500'
Producing GFR - 400:1
Injection GFR - 350:1
Inj. Gas Requirement - 420 MCFD

COMPARISON: Continuous Flow Installation Requires 240 MCFD Less Injection Gas Than the Fluid-Operated Installation Because Injection Pressure of 930 psig Can Be Utilized.



6. Small Tubing Sizes - When a small I.D. tubing is used in combination with a larger I.D. tubing, the sizes of the tubing should be considered when using fluid operated valves. A given fluid feed-in represents a greater head in small tubing sizes; therefore, the number of injection cycles per day will increase as the tubing size decreases. It is possible that the small string can use most of the injection gas, thus starving the valves on the larger size tubing. More oil could have been produced from the lower zone, Fig. 4, with fluid operated valves, if this zone had been produced through 1-1/2" instead of the 2" tubing.

INTERMITTING PRESSURE OPERATED VALVE DESIGN

Operating Pressure

The surface closing pressure of the operating intermitting valve for one zone of a dual must be greater than the surface injection pressure required, to efficiently gas lift the other zone by continuous flow or with fluid operated valves. The injection pressure for lifting this other zone must be less, to assure closing the operating intermitting valve between injection cycles. The maximum injection pressure build-up for each cycle should be constant, to efficiently lift the intermitting zone. The casing pressure must be the same when the intermitter opens, to have the same injection pressure build-up for a constant injection period. A by-pass around the time cycle operated intermitter is required, to maintain a constant casing pressure between gas injections.

Injection Gas By-Pass

A by-pass with a pressure regulator, regulator and choke, adjustable metering valve, or choke, supplies the injection gas to lift the continuous flow or fluid operated zone between gas injections for the intermitting zone. A sketch of a by-pass and adjustable metering valve is shown in Fig. 6.

CONTINUOUS FLOW VALVE DESIGN

For Single Completion

The design of a single zone continuous flow installation must be understood before considering a dual with both zones being lifted by a common injection gas source. The flow valve orifice sizing for a single completion continuous flow well is not critical for a properly designed installation. The differential across the operating valve can be controlled from the surface by regulating the injection gas pressure, provided the

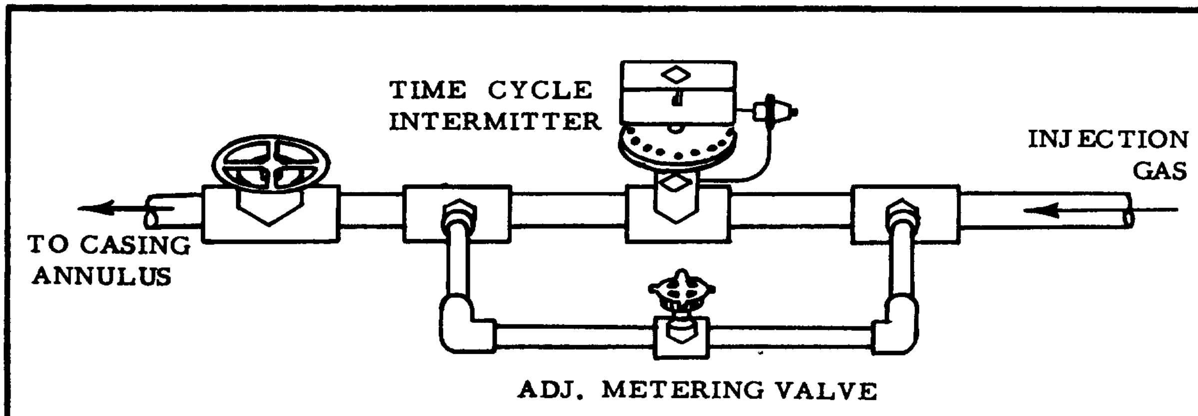


FIG.6: Injection Gas By-Pass with Adjustable Metering Valve

closing pressure of the valve is equal to, or less than, the flowing tubing pressure opposite the valve. It is common practice to design the closing pressure of the operating valve less than the flowing tubing pressure opposite the valve, in order that a differential of near zero can be attained across the valve without the valve closing. This permits efficient gas lift operation with a large orifice size.

For Dual Completion

In a dual where both zones are lifted by a common source of injection gas, the valve orifice sizing becomes very important. Control should be maintained at an operating valve on one string rather than at the surface. The gas volume control should be incorporated in the valve by proper orifice sizing, because a change in surface injection pressure affects both zones.

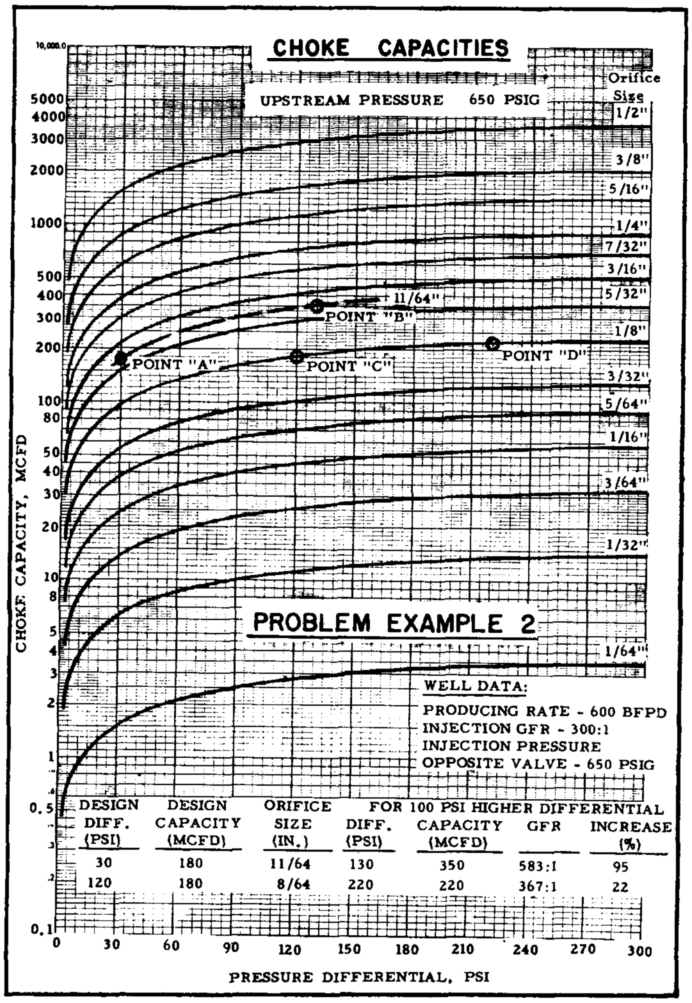
An orifice size should be selected for one zone that cannot pass a volume of gas appreciably greater than the quantity of gas required to lift that zone. The calculated required point of gas injection may be in error, or the tubing pressure opposite the valve could change, thus resulting in a differential that could easily vary 100 psi from the design conditions. If the differential is greater, the valve would pass more gas, which would result in a further reduction of tubing pressure opposite the valve and an additional increase in differential.

Problem Example 2

Problem Example 2 shows the relationship of volume versus pressure differential for a given orifice size. A pressure traverse is obtained for the continuous flow zone of a dual by a bomb survey or by calculations, as outlined in The Power of Gas, by C. V. Kirkpatrick. This establishes the point of gas injection for the required producing rate. A 600 BFPD producing rate with an injection pressure opposite the valve of 650 psig is used in the example.

The first orifice selection is based on a 30 psi differential between the 620 psig flowing pressure inside the tubing opposite the valve and the 650 psig injection pressure at valve depth. If the actual differential is 100 psi higher or 130 psi instead of the 30 psi, the valve will pass 350 MCFD of gas instead of the required 180 MCFD. This is shown by points A and B with point B representing nearly twice as much gas as is needed. The injection casing pressure could have been reduced for a single completion well until the injection gas-fluid ratio approached the 300 cubic feet per barrel required to lift the well. Since both zones are being lifted with a common injection gas source, any change in injection pressure affects the producing rate of the other zone. If the orifice size had been selected for a differential of 120 psi, a decrease in flowing tubing pressure opposite the valve of 100 psi below the design valve would have increased the volume of injection gas only 22 per cent, as shown by points C and D.

Problem Example 2 illustrates the importance of metering the injection gas at the operating valve for one zone, and locating this operating valve at a depth which will permit sufficient differential across the orifice for a relatively constant gas passage, with fluctuating tubing and injection pressures opposite the valve. The operator should select an orifice size capable of passing approximately 25 per cent more gas than the estimated requirements, with a 120 psi differential for duals to allow pressure adjustments for producing the other zone.



DESIGN DIFF. (PSI)	DESIGN CAPACITY (MCFD)	ORIFICE SIZE (IN.)	FOR 100 PSI HIGHER DIFFERENTIAL DIFF. (PSI)	CAPACITY (MCFD)	GFR	INCREASE (%)
30	180	11/64	130	350	583:1	95
120	180	8/64	220	220	367:1	22

VALVE SELECTION FOR DUALS WITH COMMON INJECTION GAS SOURCE

When only one zone requires gas lifting, or both zones are to be lifted with separate injection gas sources, the flow valve design for each zone is treated as a single completion. The flow valve design for both zones of a dual with a common injection gas source must be based on the producing characteristics of the individual zones. Proposed valve installations are outlined for dual wells, with the following combinations of producing characteristics:

1. Both zones continuous flow.
2. One zone continuous flow and the other zone intermittent flow.
3. Both zones intermittent flow.
4. Producing characteristics of either or both zones unknown.

BOTH ZONES CONTINUOUS FLOW

Both Valve Strings Pressure Operated

The operating valve for one zone must be choked as discussed in Problem Example 2. An optimum injection pressure for one zone would probably be wrong for the other zone, particularly if large orifices were selected for both operating valves.

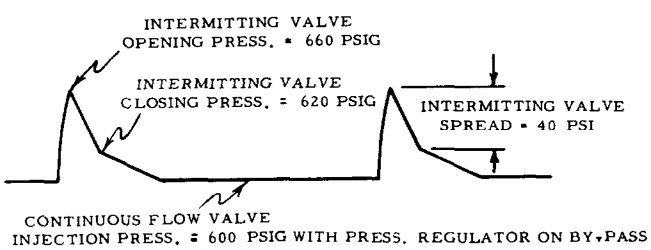
The operating valve for the other zone need not be choked, and should have a closing pressure less than the flowing pressure in the tubing opposite the valve. The surface injection pressure can be adjusted for maximum efficiency, similar to a single completion, without appreciably affecting the zone with the fixed orifice. This presents fewer calculations and permits greater flexibility, since the gas requirements must be estimated for only one zone instead of two.

ONE ZONE CONTINUOUS FLOW AND THE OTHER ZONE INTERMITTENT FLOW

Both Valve Strings Pressure Operated

The flow valve selection would be similar to that for lifting both zones by continuous flow, except for valve operating pressures. The higher capacity zone should be lifted with a pressure operated valve that is properly choked and located as previously outlined. The low capacity zone should be lifted with a pressure operated intermitting valve which has a closing pressure higher than the injection pressure required, to continuously flow the other zone.

The proper valve design for both zones would result in an injection pressure recording similar to that shown in Fig. 7. The variation of injection gas pressure for intermitting will not appreciably affect the gas volumes through the operating continuous flow valve because its orifice selection is based on at least 100 to 120 psi difference between tubing and injection pressures opposite the valve. A by-pass with a pressure regulator and choke, as shown in Fig. 8, is required for this operation.



Same Well Data as Given in Problem Example 2:
Orifice Size in Operating Valve - 8/64"
Inj. Press. Opposite Valve - 650 psig (600 psig Surface)
Inj. Press. Opposite Valve - 715 psig (660 psig Surface)
Max. Diff. Across Valve - 185 psi (660 psig Surface)
Orifice Capacity - 210 MCFD with 185 psi Differential
(Less Than 17% in Excess of Required 180 MCFD)

FIG. 7: Schematic Casing Injection Pressure Recording for Dual With One Zone Continuous Flow and the Other Zone Intermittent Lift

One Valve String Pressure Operated, The Other Fluid Operated

The pressure operated valve for lifting the higher capacity zone would be choked as previously discussed. The choke size selection is based on the available operating injection pressure. The tubing trigger pressures for the fluid-operated valve should be selected to have adequate pressure differential for efficient operation with the injection pressure required to lift the continuous flow zone. A pressure regulator,

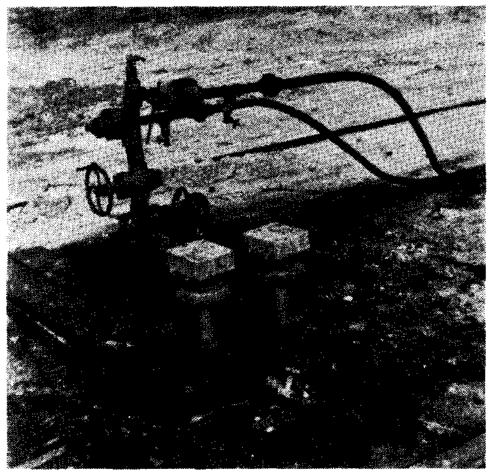


Fig. 8 BY-PASS WITH PRESSURE REGULATOR AND ADJUSTABLE CHOKE FOR DUAL GAS LIFT INSTALLATION

regulator and choke, metering valve, or choke can be used to control the injection gas volume.

BOTH ZONES INTERMITTENT FLOW

One Valve String Pressure Operated, The Other Fluid Operated

The intermitting valve installation should be used to lift the higher capacity zone because of surface control. An exception would be a well in which the weaker zone did not have adequate bottom hole pressure to trigger the lowest fluid operated valve. A by-pass should be used to prevent fluctuating, intermitting valve action. A three pen pressure recording of a dual installation, in which one zone is intermitted and the other fluid operated without an injection gas by-pass, is shown in Fig. 9. Each time the fluid operated zone produced a fluid head, the injection pressure decreased and the intermitting zone failed to operate for the next two injections.

Both Valve Strings Fluid Operated

Both zones of many dual gas lift installations are being lifted efficiently with fluid operated valves. Only a surface choke is required to control the injection gas volumes. However, the limitations of fluid operated valve designs should be considered carefully for each zone before installing valves. All the fluid operated valves in the installations noted in Figs. 3, 4, and 9 are partially or completely balanced wire line, retrievable fluid operated valves.

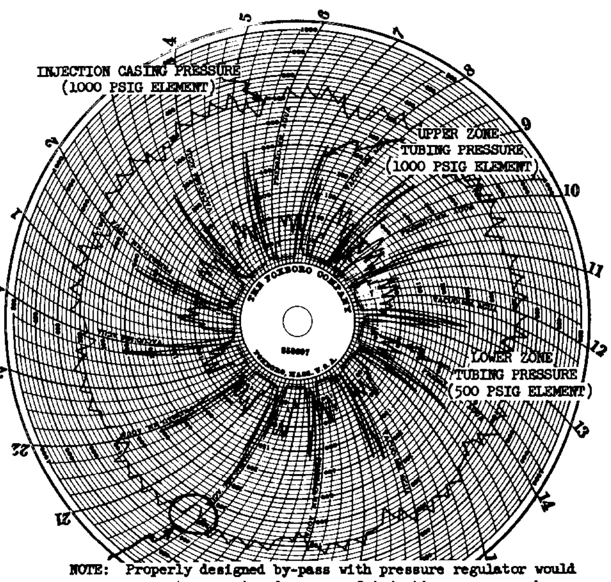
Both Zones Lifted With Same Valve String

If the monthly allowable for each zone can be produced in two weeks or less, both zones can be gas lifted through a single tubing string, using a crossover. Each zone is produced the last two weeks of a month and the first two weeks of the following month, while the other zone is blanked off. The zones are then switched and the other zone is produced for the following four weeks. This procedure requires crossing-over only once each month. This type of installation has been used in West Texas.

PRODUCING CHARACTERISTICS OF EITHER OR BOTH ZONES UNKNOWN

Both Valve Strings Fluid Operated

Fluid operated valve design is recommended when



NOTE: Properly designed by-pass with pressure regulator would prevent excessive decrease of injection pressure when fluid-operated valves open. Intermitting operating valve could lift simultaneously with fluid-operated valves.

LOWER ZONE	UPPER ZONE
Producing 60 BOPD (2" Tubing)	Producing 27 BOPD (2" Tubing)
Intermitting Pressure Operated Valves	Balance Fluid-Operated Valves
Depth of Operating Valve - 5725'	Trigger Pressure - 600 psig
Valve Opening Pressure - 750 psig	

FIG.9: Three-Pen Pressure Recorder Chart from Dual Gas Lift Installation with One String Intermitting Pressure Operated Valves and the Other String Fluid Operated Valves.

the production of both zones will not exceed the limits of a slugging type of lift, and there is no production data available. The point of gas injection cannot be estimated without reasonably accurate pressure and productivity data. Since the fluid operated valves are actuated by the fluid head build-up in the tubing, both zones can be lifted efficiently with the point of gas injection near the packer of one zone, and near the surface for the other.

Generally, the operator will know from drill stem tests, off-set wells, previous producing tests, etc. whether or not a zone will have an extremely high productivity and water cut. Continuous flow design should be considered for high capacity wells, as previously mentioned.

CONSIDERATIONS FOR EQUIPMENT, RUNNING AND OPERATION

1. Retrievable Equipment - Retrievable valve mandrels permit rapid and economical replacement of wire line retrievable flow valves, to assure efficient gas lift operations with changing well conditions. These mandrels, used in conjunction with other wire line equipment for permanent type well completion workovers, can eliminate pipe handling equipment.[3] One major oil company replaced valves by wire line in sixteen deep single completion wells for a total estimated savings of $71,000 as compared to conventional workover methods.[4] The economic advantage would have been greatly increased for dual wells. Retrievable dummy valves can be installed until flow valves are needed, or dummies can be used above or below operating valves for further savings and increased lifting efficiency.

2. Wellhead Equipment - The selection of wellhead equipment is important for dual gas lift wells. If non-concentric valve mandrels are to be run on the detachable string of a parallel type installation, a tubing hanger must be used that will permit passage of these mandrels on the second string. Wellhead manufacturers have standardized on the distance between the centerlines of the tubing strings in their dual trees. This distance is 3-35/64" for two strings of 2" tubing in 7" O.D. casing and is 2-25/32" for two strings of 1-1/2" tubing in 5-1/2" O.D. casing.

3. Pressure Recorders - Flow valve performance and gas lift operation are reflected by the tubing and casing pressures. Three pen recorders should be installed on all dual wells being gas lifted, to record both tubing pressures and injection pressure. The recorder gives the operator a daily permanent record of his gas lift installation. If operational difficulties occur, the operator knows it immediately and can remedy the situation before having an appreciable loss in production or high pressure gas.

4. Turned Down and Beveled Couplings - The couplings on upset tubing can be turned down to increase the clearance. Two-inch upset couplings can be turned down to 2.910" O.D. and 1-1/2" upset couplings to 2-3/8" O.D., without reducing the tensile strength of either size tubing string. To assure passage of the second string, the couplings must be beveled on one string if neither string has a streamlined joint, such as CS Hydril.

5. Non-Rotating Hold-Down - A latching device, which requires rotation to release the short tubing string from the upper packer, cannot be used with non-concentric gas lift mandrels.

6. Casing Scraper - If the condition of the casing is doubtful, a scraper should be run before running tubing in a dual. This will assure easy passage of the mandrels into the well and prevent damage to the packers.

7. Single Valve String for Unloading - If both zones have low bottom hole pressures, the casing annulus can be unloaded through one string of valves. Only one tubing string must be valved from the surface. The top valve on the other string can be located at the static fluid level of the zone to be lifted. The bottom wire line retrievable flow valve is left out of the mandrel, in the string not valved to the surface. When the annulus is unloaded, the fluid level will drop in both strings and the retrievable flow valve is installed. If retrievable equipment is not used, the string not valved to the surface can be unloaded by swabbing.

8. Mandrel Spacing - When both strings have non-concentric valve mandrels, the spacing between mandrels is important. While running, no two mandrels on the detachable string should pass two mandrels on the long string at the same time. Fig. 10 illustrates one

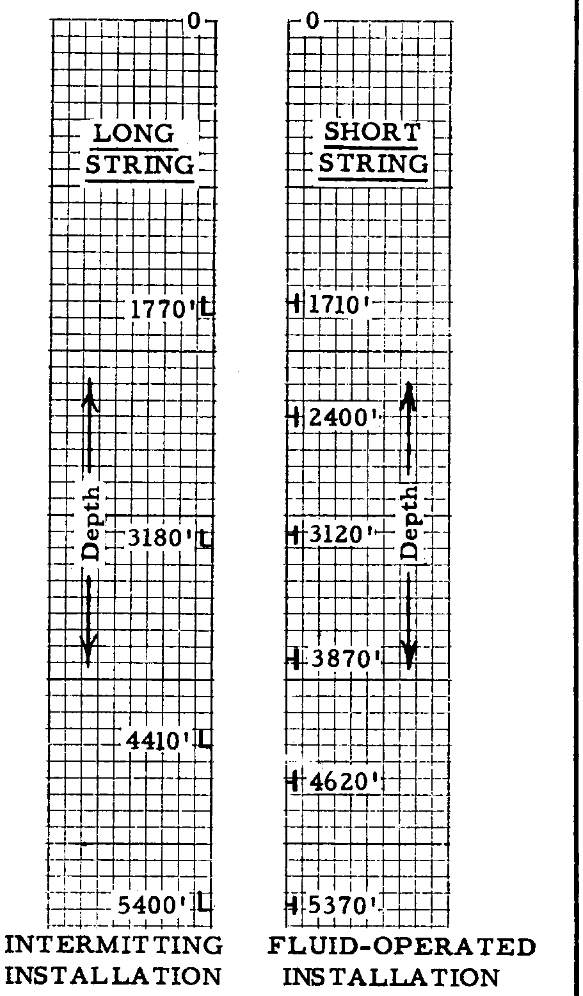


FIG. 10: Plot of Valve Depths for Dual Gas Lift Installation to Check Mandrel Spacing for Interference While Running

method used to check valve spacing. These valve depths were calculated for a well in which production through the long string would be intermitted, and the other zone fluid operated. The depths are plotted on rectangular coordinate paper. The plot of the short string is moved past the plot of the long string to sinulate running of the second string. A visual check is made to be certain that only one mandrel is passing another at any time while running the second string. By switching the valve spacing in Fig. 10, assuming the short string to be the long string, possible mandrel interference could occur twice during running operations.

9. Improving Valve Design - An operator seldom has sufficiently accurate well data for a perfect initial design. If the flow valve design does not operate properly, both tubing and injection casing pressures should be recorded with both zones lifting simultaneously. Then each zone should be tested independently with the other zone shut-in. Operating pressures and gas requirements for each zone can be determined for the desired rate of production. A test is being conducted on the dual gas lift well shown in Fig. 11, using a three pen pressure recorder. With this information, the valve installation can be redesigned for more efficient lifting of both zones with a common injection gas source. As previously discussed, retrievable flow valves facilitate a rapid and inexpensive valve design change.

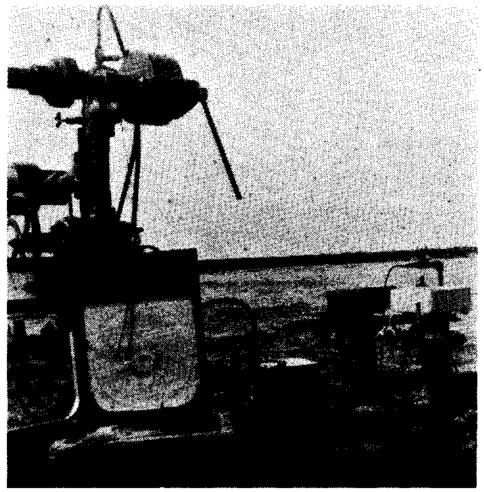


Fig. 11 THREE-PEN PRESSURE RECORDER RECORDING BOTH TUBING AND INJECTION CASING PRESSURES OF DUAL GAS LIFT INSTALLATION ON TEST.

CONCLUSIONS

The types of dual valve installations which should be employed for wells with varying producing characteristics have been recommended. Specific valve design for a particular well was not included, because the valve spacing for gas lifting each zone must be based on actual well data and available injection pressure. No "pat" valve spacing or flow valve operating pressures can be given for fluid operated, intermittent or continuous flow gas lift design that is applicable to all wells. Since reservoir conditions generally do not remain constant, wire line retrievable gas lift valves are desirable to assure satisfactory operation for the depletion of both zones of a dual.

REFERENCES

1. H. W. Winkler: "Good Installation Design Vital in Gas Lifting Dual Zone Wells", World Oil, July, 1955.

2. E. G. Thurman: "Dual Gas Lift Systems Compared", World Oil, February, 1954.

3. G. H. Tausch and J. W. Kenneday: "Permanent-Type Dual Completions", API Spring Meeting, San Antonio, 1956.

4. F. G. Courtney: "Permanent Completions Pay Off for Gulf in South Louisiana", Petroleum Engineer, December, 1955.