Gas Lift in Multiple Completed Wells

By D. A. LAMBIE

Shell Oil Company

And BOB WALTON

Merla, Inc.

INTRODUCTION

Shell Oil Company recently surveyed the dual intermittent gas lift performance in the South Andrews and TXL Fields. The survey covered a diversity of methods of dual intermittent gas lift and revealed that not only are the methods varied but the characteristics of the wells cover most of the categories of intermittent gas lift. It was then decided to prepare this ten-year history of the development of the gas lift production practices in these two fields. This history concerns only those dual wells both sides of which are on intermittent gas lift. There are sixty-eight wells in this category which furnish adequate data for this study. Particular attention will be given to installation designs in an attempt to evaluate their technique advantages and strict limitations for particular well conditions.

There is a tendency to standardize on a once successful method. Any failures tend to be blamed on equipment or personalities, but misapplication is the culprit in more instances than one might expect. Where the operator has not even had that one successful method he may falsely accuse the art of gas lift in general. These are natural reactions but not always the most profitable ones for the operator.

DUAL WELL EQUIPMENT

The decision was made early to use side-pocket mandrels and retrievable gas lift valves on the long string of the duals. Conventional mandrels and valves were used on the short string because it could be pulled from the well at a relatively low cost and the expense of side-pocket mandrels could not be justified.

The mechanical hook-ups are varied but generally the wells completed with 7-in. casing have two parallel strings of 2-3/8 in. tubing. The wells with 5-1/2 in. casing have one string of 2-1/16 in. tubing in parallel with one string of 1-1/2 in. tubing. The available injection gas operating pressures are from 700 to 800 psi in the TXL Field and 900 to 1000 psi in the South Andrews Field. Motor valves operated by time-cycle controllers are used for gas injection control due to the inherent freezing problems encountered with choke controlled injection.

PRODUCING CHARACTERISTICS

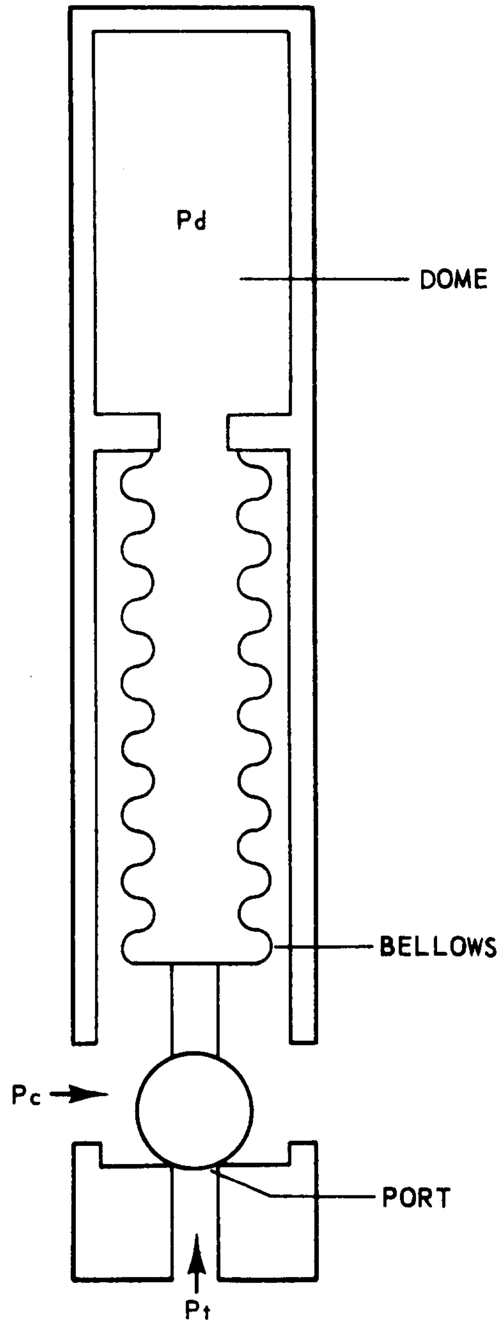
The well's characteristics, in general, are typical of intermittent gas lift wells. The static bottom-hole pressures have declined in the solution gas-drive reservoirs from 2800 to 4500 to about 500 or 1000 psi, and producing bottom-hole pressures of 150 to 300 psi are necessary to adequately produce the wells. Well depths vary from 4500 ft to 10,000 ft. The production rate varies from 10 to 100 BFPD with productivity indices of 0.05 to 0.15 bbl per square inch of pressure drawdown at the perforations. The zones are separated by 500 to 700 ft in most cases but 1500 to 2000 ft in others.

INITIAL INSTALLATIONS

Dual intermittent gas lift was initiated in the late 1950's, and the initial installations used single element, nitrogen-charged, casing pressure operated gas lift valves, Fig. 1, set for decreasing operating pressures. The top valve had the highest pressure, and the bottom valve had the lowest pressure, Fig. 2. This meant that the operating casing pressure was limited to the set pressure of the lowest operating valve.

Since these valves functioned in the same manner as pressure relief valves, it was apparent that valves in both strings of tubing would not operate together unless the pressures at their respective operating depths were the same. If one operating value had a lower set pressure, it would thief gas from the higher pressure operating valve on the other side. This resulted in single, not dual, operation. At best this interference resulted in very poor dual operation. One tubin string was equipped with wireline retrievable valves which facilitated the attempts to change pressures on some of the valves to make the operating pressure of the two zones more compatible. While this proved to be a help, changing well conditions would again cause the pressure in the two valve strings to be incompatible.

The last resort was to install motor valves on each flowline. These motor valves were controlled by a time-cycle controller which shut one flowline in so that each zone could be produced independently of the other for certain alternate time periods. This operation proved relatively successful but was, in effect, about the same as producing two single installations on alternate days. Also, the drawdown was limited in many cases because a valve in the shut-in string would open and the tubing would become pressured with injection gas. The need to produce both zones 100 per cent of the time resulted in trials of different gas lift methods even though some alternate-day systems are still being used.



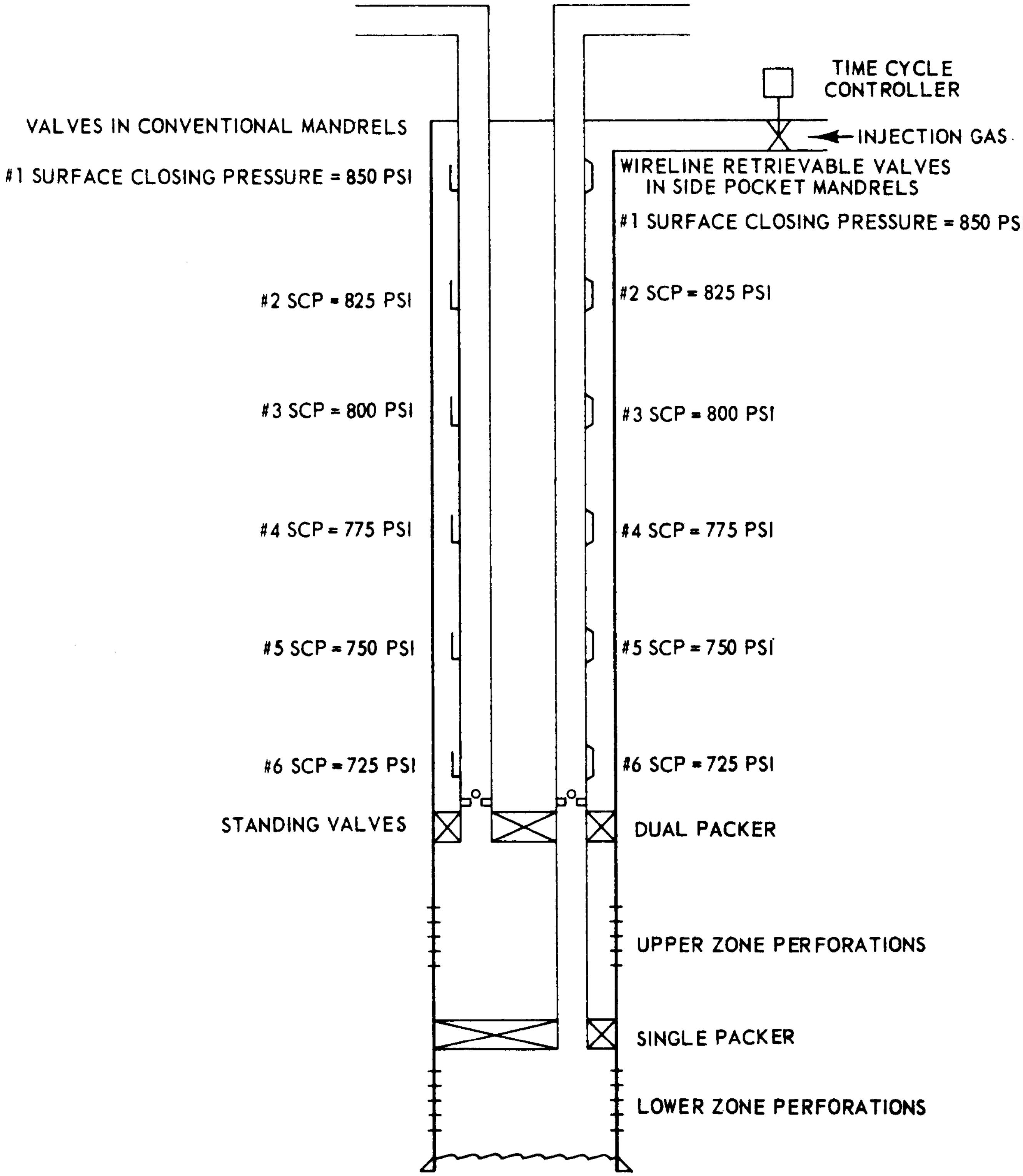
NITROGEN CHARGED, SINGLE ELEMENT CASING PRESSURE OPERATED VALVE

FIGURE 1

WIDELY SEPARATED ZONES

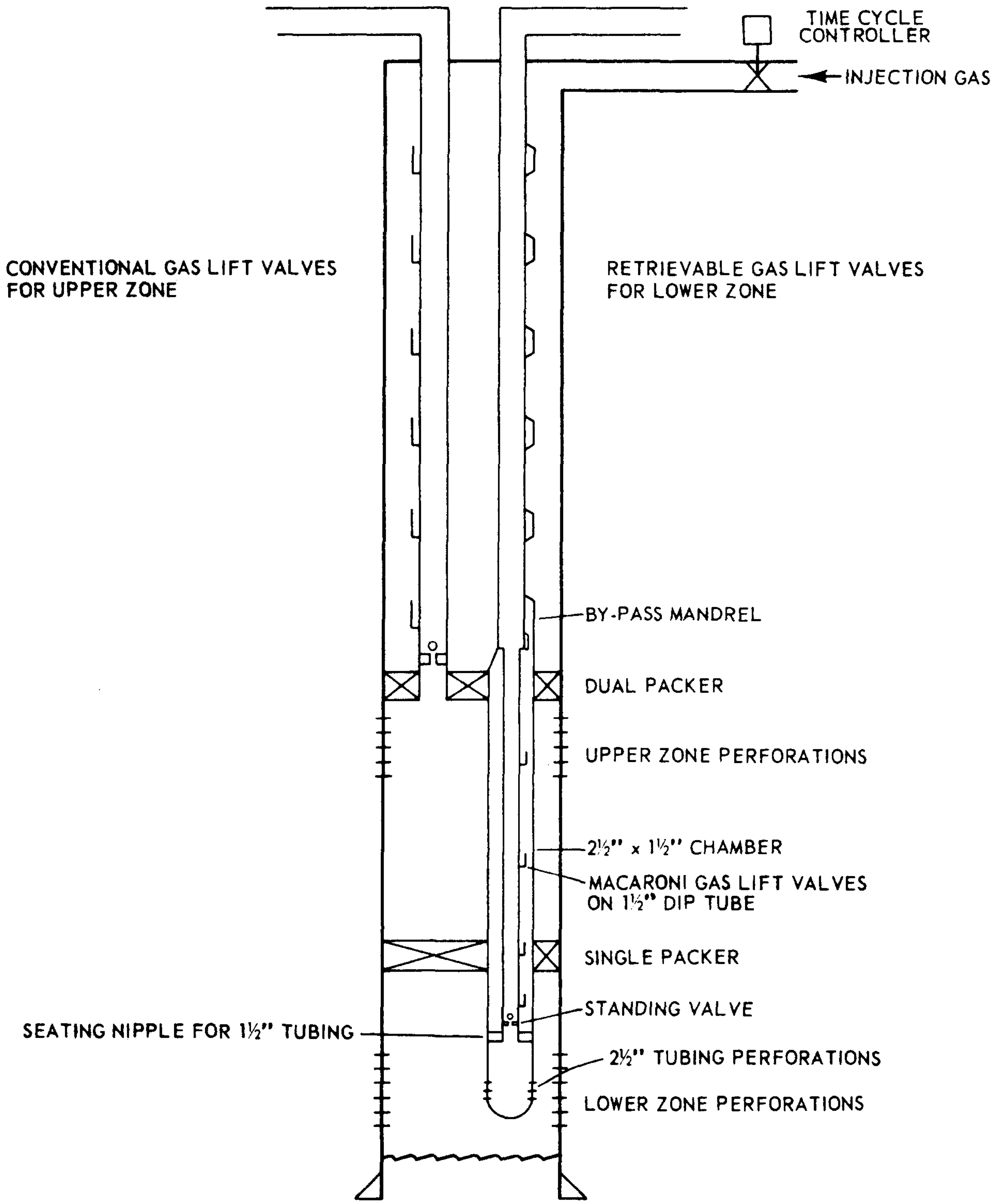
The usual method of producing the lower zone in wells that had a considerable distance (more than 700 ft) between zones was with macaroni valves on a dip tube in a chamber between the dual and permanent packers, Fig. 3. This type of operation was not entirely satisfactory because of the small annulus area in the 1-1/2 in. x 2-1/2 in. chamber, and the more distance between the zones the less satisfactory it became.

During the first half of 1961 two dual gas lift installations were run that provided a common annulus above and below the upper zone. The equipment, see Fig. 4, consisted of a permanent single packer to isolate the lower zone, a retrievable dual packer just under the upper zone and a retrievable triple packer immediately above the upper zone. The tubing connecting the secondary openings in the dual and triple packers served as a bypass through the upper zone. This allowed the gas to communicate freely between the annulus above the triple packer and the annulus between the dual and permanent packers. This innovation permitted the use of conventional size valves and tubing below the upper zone. It was very successful in improving the operation. The cost of the third packer was offset by the elimination of the long chamber and macaroni valves on a dip tube. This type of installation proved entirely satisfactory in providing lift from the valves below the upper zone and allowing the lower zone to be produced from bottom, but it did not solve the problem of incompatibility of pressures of the two strings of gas lift valves.



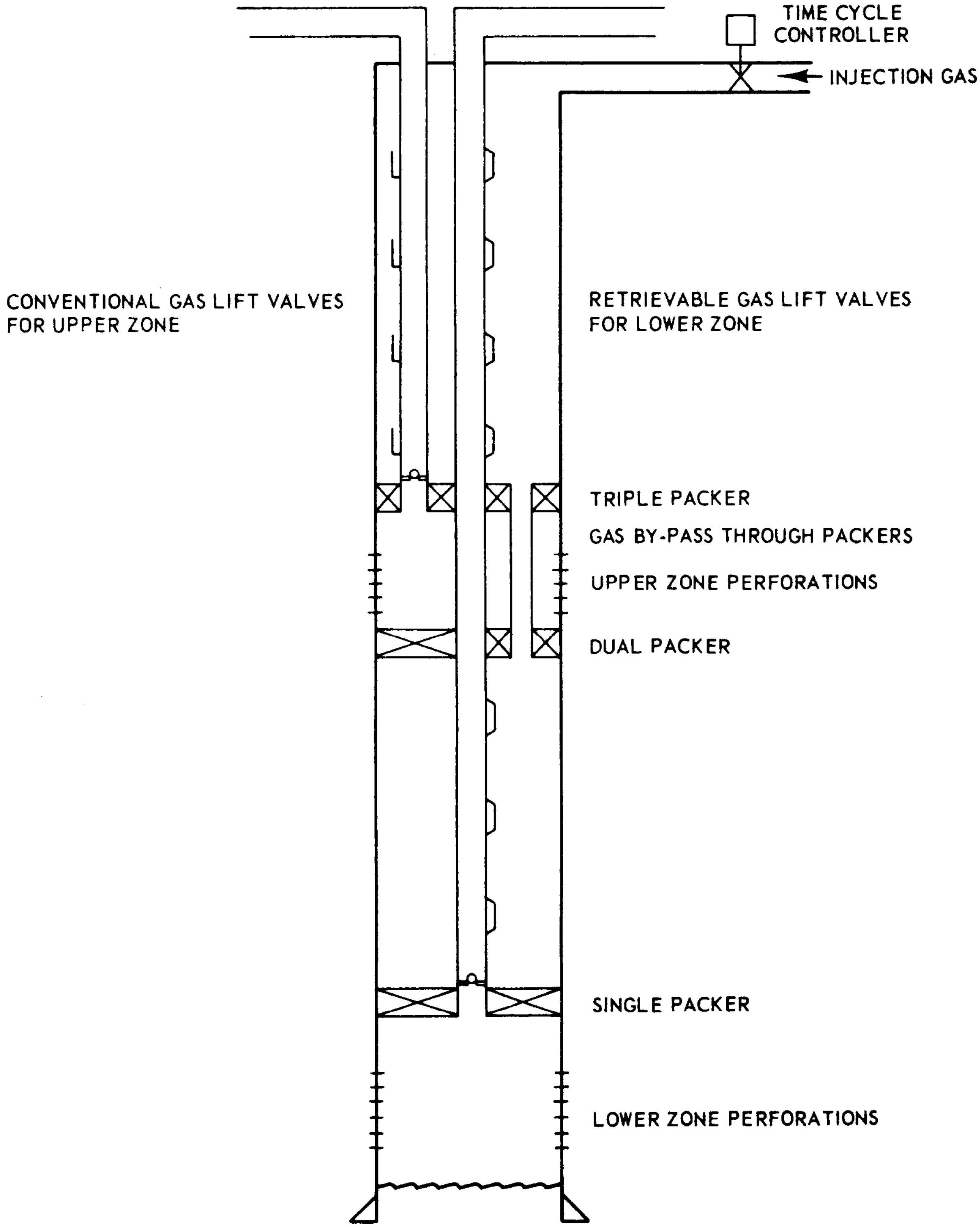
DUAL INTERMITTENT GAS LIFT INSTALLATION WITH DECREASING SET PRESSURES

FIGURE 2



DUAL INTERMITTENT GAS LIFT INSTALLATION WITH CHAMBER FOR LOWER ZONE IN DUAL WITH WIDELY SEPARATED ZONES

FIGURE 3



THREE PACKER DUAL GAS LIFT INSTALLATION FOR WIDELY SEPARATED ZONES

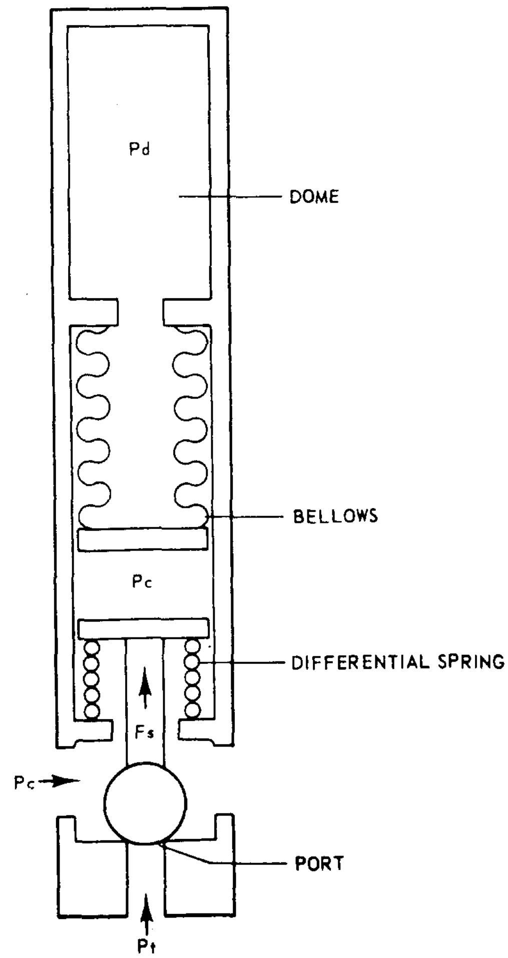
FIGURE 4

COMBINATION DIFFERENTIAL AND PRESSURE OPERATED VALVES

In January, 1962, a dual gas lift installation in the South Andrews Field was redesigned for optimum production rates from both zones and more efficient gas lift operation. The bottom valve of each string was replaced with a combination differential and pressure operated valve, Fig. 5. The valves were opened by a combination of casing pressure-tubing pressure build-up and closed by casing pressure drawdown. A dual surface controller was installed to operate in conjunction with the valves. This controller was designed so that no gas was injected into the casing annulus after the operating valve opened until there was first an increase and then a decrease in the surface tubing pressure. Although there was some problem in the operation of the surface controller due to the low surface tubing pressure of one of the zones, this was one of the few wells where simultaneous intermittent lift of both zones had been successful. It was necessary later to redesign this installation due to the drop in bottom-hole pressure of one of the zones.

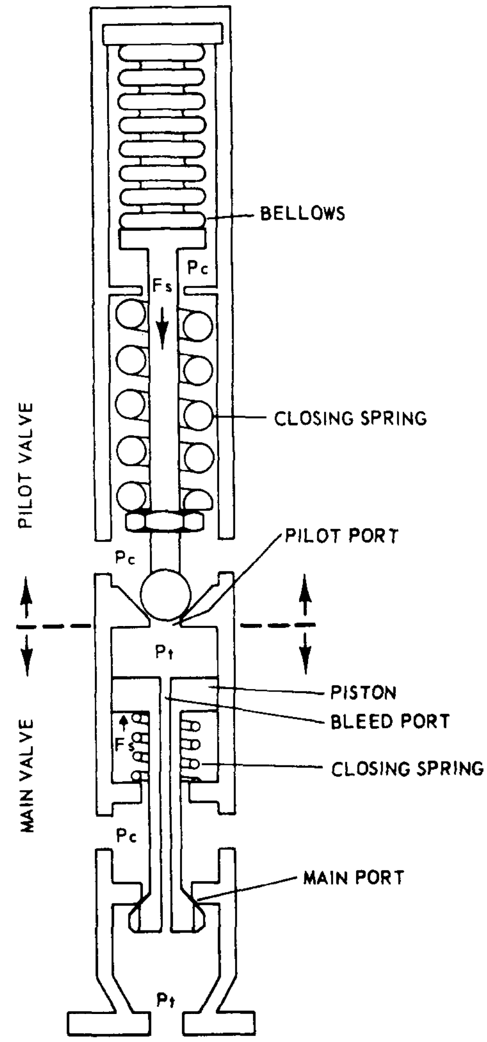
PILOT CONTROLLED VALVES

The small port, single element, nitrogen charged valves in use in the TXL Field provided fair operation but were found to cause excessive



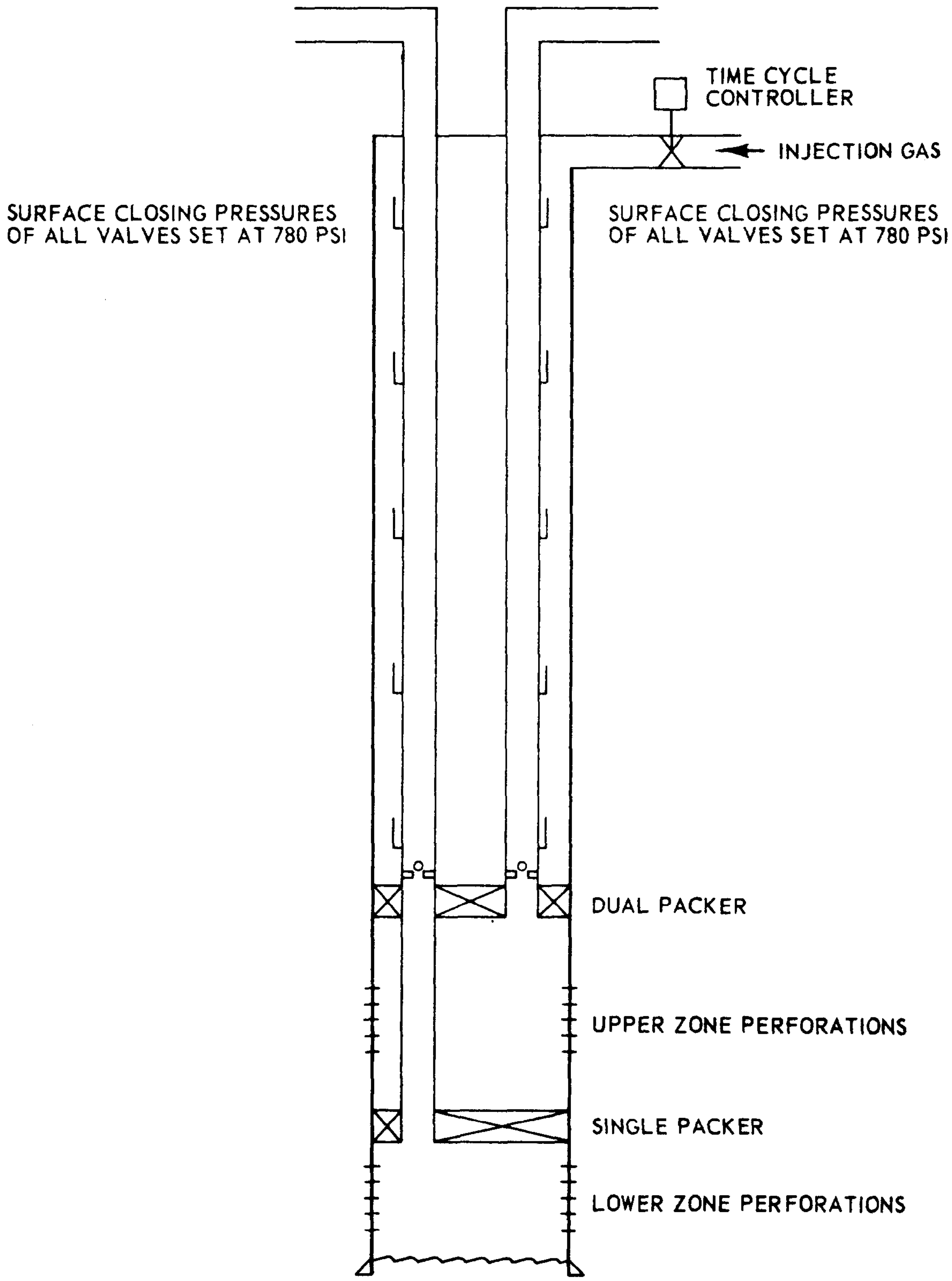
CASING - TUBING DIFFERENTIAL PRESSURE OPEN - CASING PRESSURE CLOSE GAS LIFT VALVE

FIGURE 5



PILOT CONTROLLED CASING PRESSURE OPERATED VALVE

FIGURE 6



DUAL INTERMITTENT GAS LIFT INSTALLATION
DESIGNED FOR MULTIPOINT INJECTION

FIGURE 7

fallback in the low bottom-hole pressure wells. With this in mind, three wells of the 150 to 300 psi producing bottom-hole pressure category were selected and the bottom valve in each side of the duals was replaced with a pilot controlled casing pressure operated valve with a low spread (tubing effect) and a large port (1/2 inch). This valve will be referred to as a pilot valve, Fig. 6. In all cases, operation in both zones was from the bottom valve.

All three installations were successful to the extent that both bottom valves would open for the same number of cycles in response to rapid increases in casing pressure. The rise in casing pressure was caused by the time-cycle controlled motor valve on the gas injection line opening at regular intervals. Recovery proved to be better and an overall increase of approximately 25 per cent of the previous total production was achieved.

This type of operation has its limitations; it is confined to those wells both zones of which can be lifted from bottom and wells which produce approximately the same volume of liquid from each zone.

MULTIPOINT DESIGN

The first multipoint gas lift design was installed in the South Andrews Field in mid-1963 using seven pressure-operated valves for each zone to a depth of approximately 8400 feet. All valves in this installation were set for the same surface closing pressure of 780 psi, Fig. 7. This design, to a great extent, eliminated the difficulty of incompatible pressures for different producing depths; however, even though all the valves were set for the same surface closing pressure, the spread factor in the valves caused the opening pressures of the valves to vary proportionately to the tubing load. Even so, this installation proved very satisfactory, and the production from the well more than doubled due to simultaneous operation.

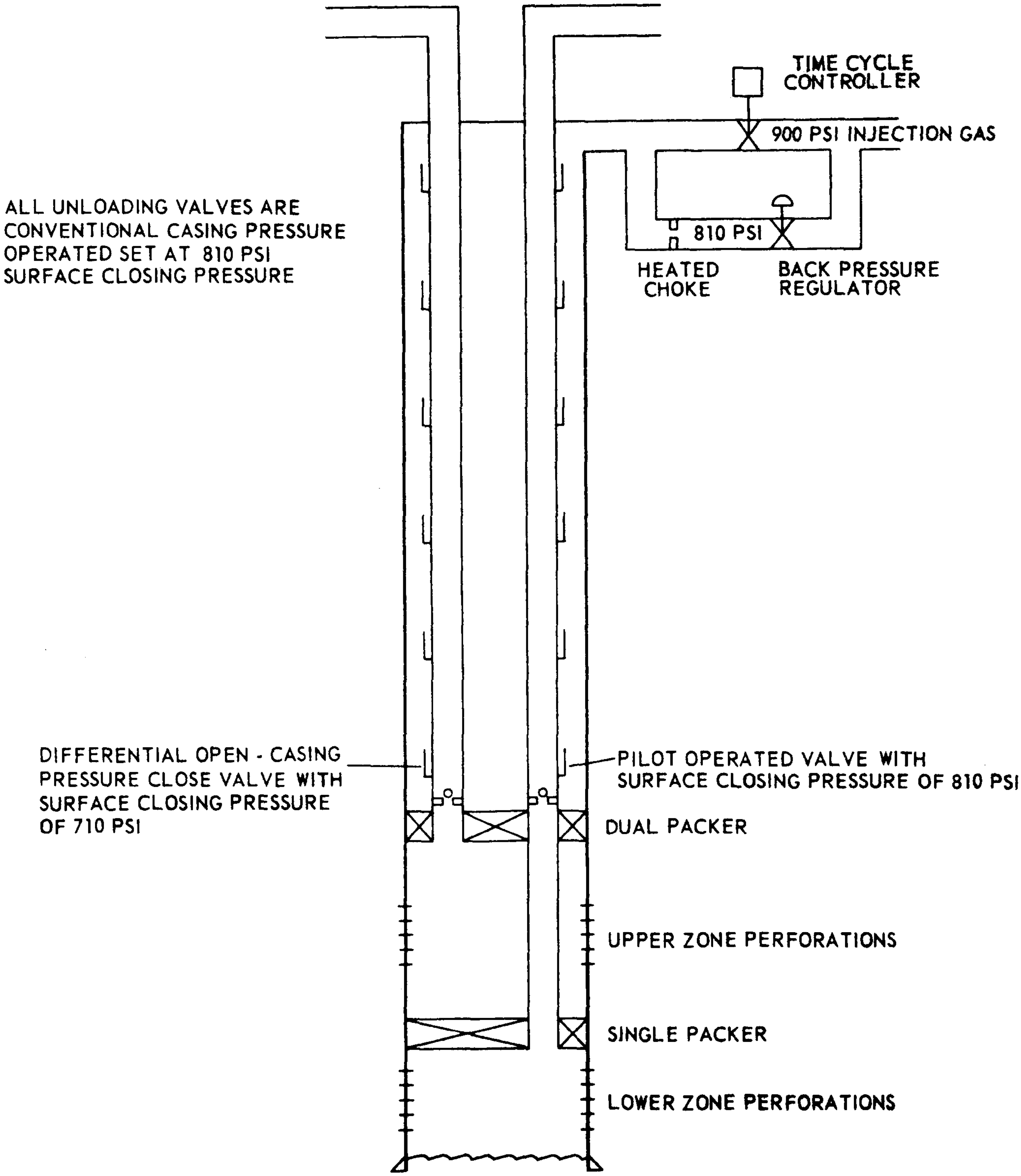
In 1964, since this first installation proved successful, thirteen wells in the TXL Field were reworked to obtain simultaneous lift by setting all valves in both strings for the same surface closing pressures. Multipoint injection was rarely achieved; however, with this design the maximum injection gas operating pressure could be utilized from the lowest valve, and two zones with different producing fluid levels could be lifted simultaneously.

Although each of these dual wells was an individual problem, these systems generally used the same type large ported, small spread pilot valves as the operating valves. Single element, nitrogen charged valves were used for unloading valves in some cases for economic reasons. Nine of the thirteen workovers proved successful simultaneous lift installations. Later in the life of these installations, lower bottom-hole pressures and changing well conditions caused some of the duals to become incompatible. This resulted in manual alternate day production.

DIFFERENTIAL OPEN-CASING PRESSURE CLOSE VALVE AND PILOT VALVE COMBINATION

Early in 1966 a different method was used in a well in the South Andrews Field. This method used a casing pressure operated pilot valve for lifting one zone and casing-tubing differential pressure open-casing pressure close (similar to Fig. 5) on the other zone. The production rate was increased 100 per cent by achieving simultaneous dual intermittent lift. The zones produced daily the same amount of liquid with the same gas usage as they had on alternate days. As shown in Fig. 8, a pilot valve with a closing pressure of 810 psi was installed on the deeper, less productive zone. A differential open valve with a closing pressure of 710 psi was installed on the upper, more productive zone. The pilot valve was operated every two hours by the time-cycle controller on the injection gas line motor valve. With the casing pressure at surface equal to 810 psi, a three-barrel slug was required to open the differential open valve. If the intermitter opened to increase the casing pressure and operate the pilot valve, the differential open valve remained closed because an increase in casing pressure requires an increase in tubing pressure to open the valve, thus eliminating valve interference. The surface operating pressures through normal cyclic operation are illustrated in Fig. 9.

A back-pressure regulator and heated choke were installed in a bypass line around the injection gas line motor valve. The regulator was set to maintain 810 psi on the casing. The choke metered the gas into the annulus at a rate slower than the differential open valve could pass it. This allowed the casing pressure to decrease until the differential open valve closed. This method



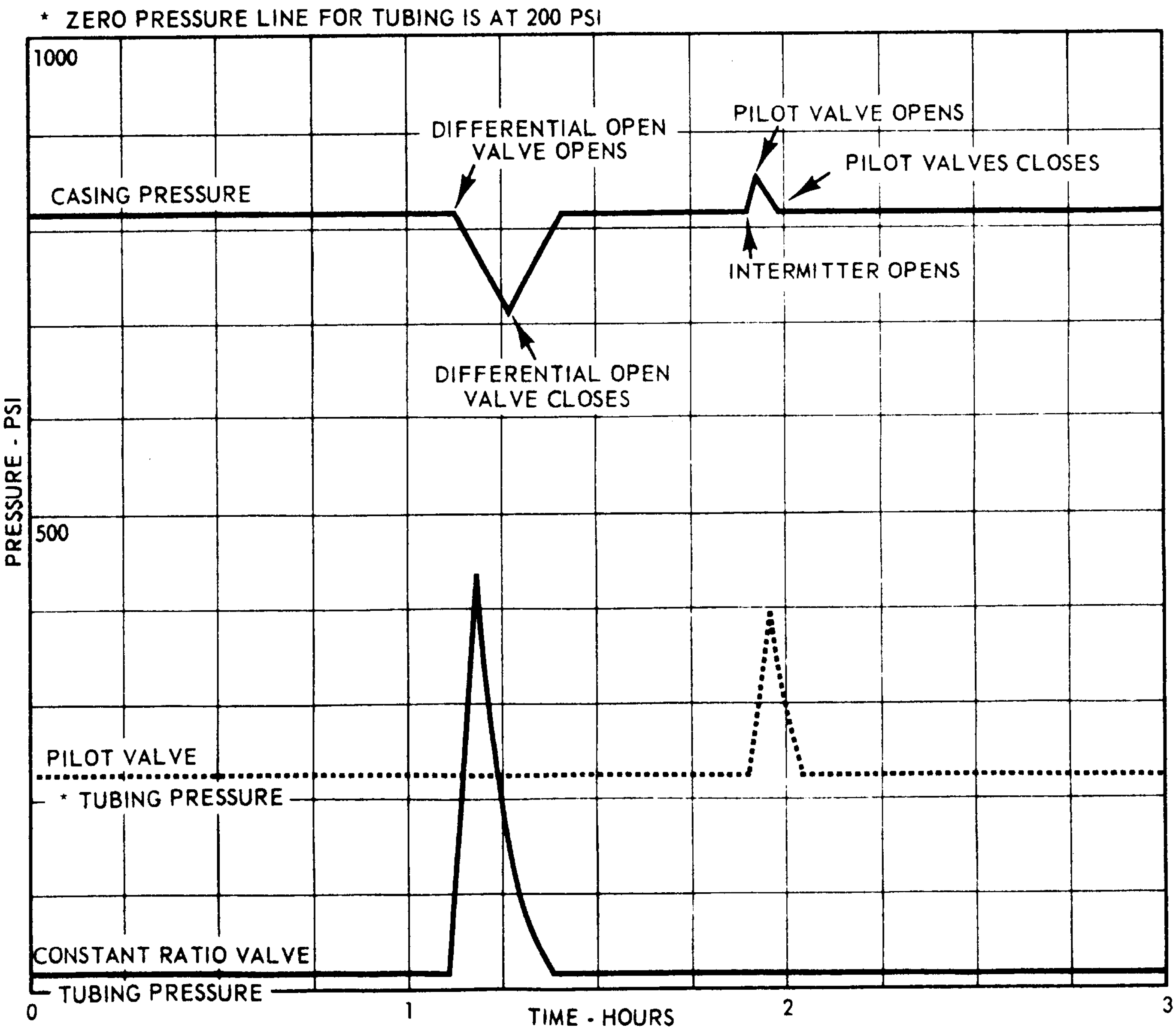
DUAL INTERMITTENT GAS LIFT INSTALLATION WITH DIFFERENTAL OPEN - CASING PRESSURE CLOSE AND PILOT VALVES AS OPERATING VALVES

FIGURE 8

of simultaneous dual intermittent lift is satisfactory where the tubing pressure build-up is sufficient to trip the differential open valve.

THREE TUBING STRING DUAL

By 1966 all TXL Field producing formations, except the Ellenburger, had static bottom-hole pressures of 500 to 900 psi and productivity in-



NORMAL SURFACE PRESSURE OPERATING CYCLE FOR THE DIFFERENTIAL OPEN AND PILOT VALVE DUAL GAS LIFT INSTALLATION

FIGURE 9

dices of 0.05 to 0.08 barrels per psi drawndown. Previous experience showed that these characteristics preclude successful long-term use of either multipoint injection gas lift design or the system using a differential open valve.

A successful method was installed in the TXL Field using three packers and three tubing strings. The two zones had separate controllers and injection gas sources, and thus, were actually lifted as two single gas lift wells. This was the only positive means available for producing wells of this type, and therefore, the $11,000 additional cost of this installation compared with the two-packer, two-tubing-string method was justified. This well produced 25 BOPD compared with 15 BOPD using the established method of producing each zone on an alternate day basis. The installation is schematically illustrated in Fig. 10. The third tubing string conducted gas from the surface to an isolated chamber between the two bottom packers. Here a pilot valve with a large port and large spread lifted the production, which averaged one barrel per cycle, from the lower zone. Since the gas volume in the tubing and chamber was small, this design could not have operated without a large capacity surface gas system. The upper zone was lifted in the conventional manner using the 7-in. casing annulus as a volume chamber. The lower zone unloading valves were set for higher operating pressures than the upper zone valves. After unloading the lower zone to the pilot valve in the chamber, there would be no interference between the valve strings.

The lift from each zone, using this method, could be controlled from the surface as an individual installation. The strict limitations are that the wells must have at least 7-in. casing and widely separated zones or a large volume injection gas system.

TIME CONTROLLED VALVE

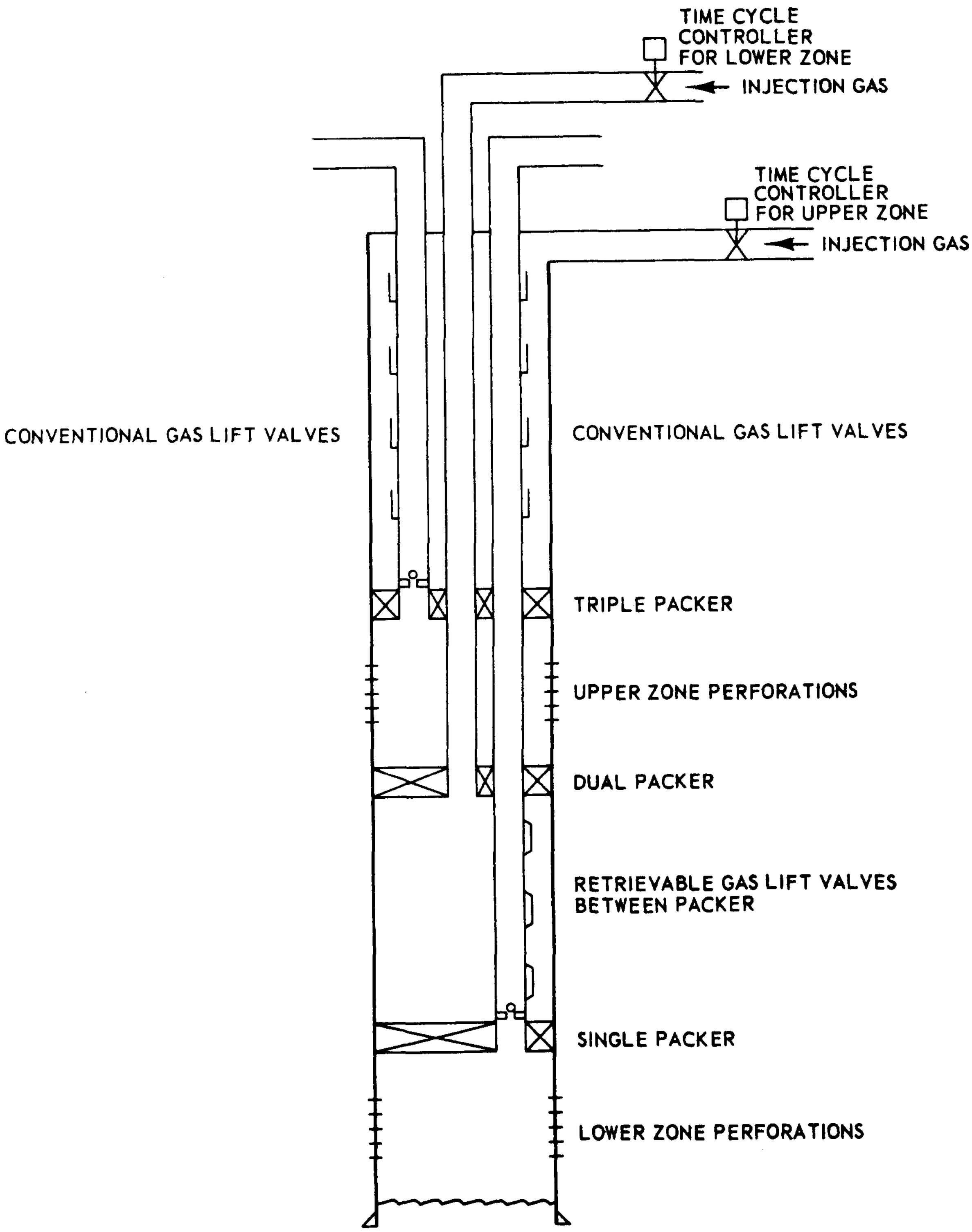
Through 1966, practically all types of intermittent gas lift valves were tried in the different combinations presented here. All this was done in an attempt to best solve the problem of simultaneous dual gas lift using a common annulus injection gas source.

Although the valve types used are different and react in varying degrees to tubing and casing pressures, they all have the same governing factor in that they depend on a preset definite closing casing pressure. This casing closing pressure limits the system operation to a fairly narrow range of tubing pressures where dual operation is involved.

Early in 1967 a new type of gas lift valve, which embodies a completely new principle of operation, was undergoing its first field testing. This valve, as is the case with the valves referred to as differential open valves, opens on a preset pressure differential between casing pressure and tubing pressure. There the similarity ends, because instead of closing on a preset casing pressure, it closes after a preset period of time which is independent of either tubing or casing pressure. Utilizing this principle, a large ported valve can be run without fear of excessive gas usage due to a high spread. The valve will be referred to as a time controlled valve, Fig. 11.

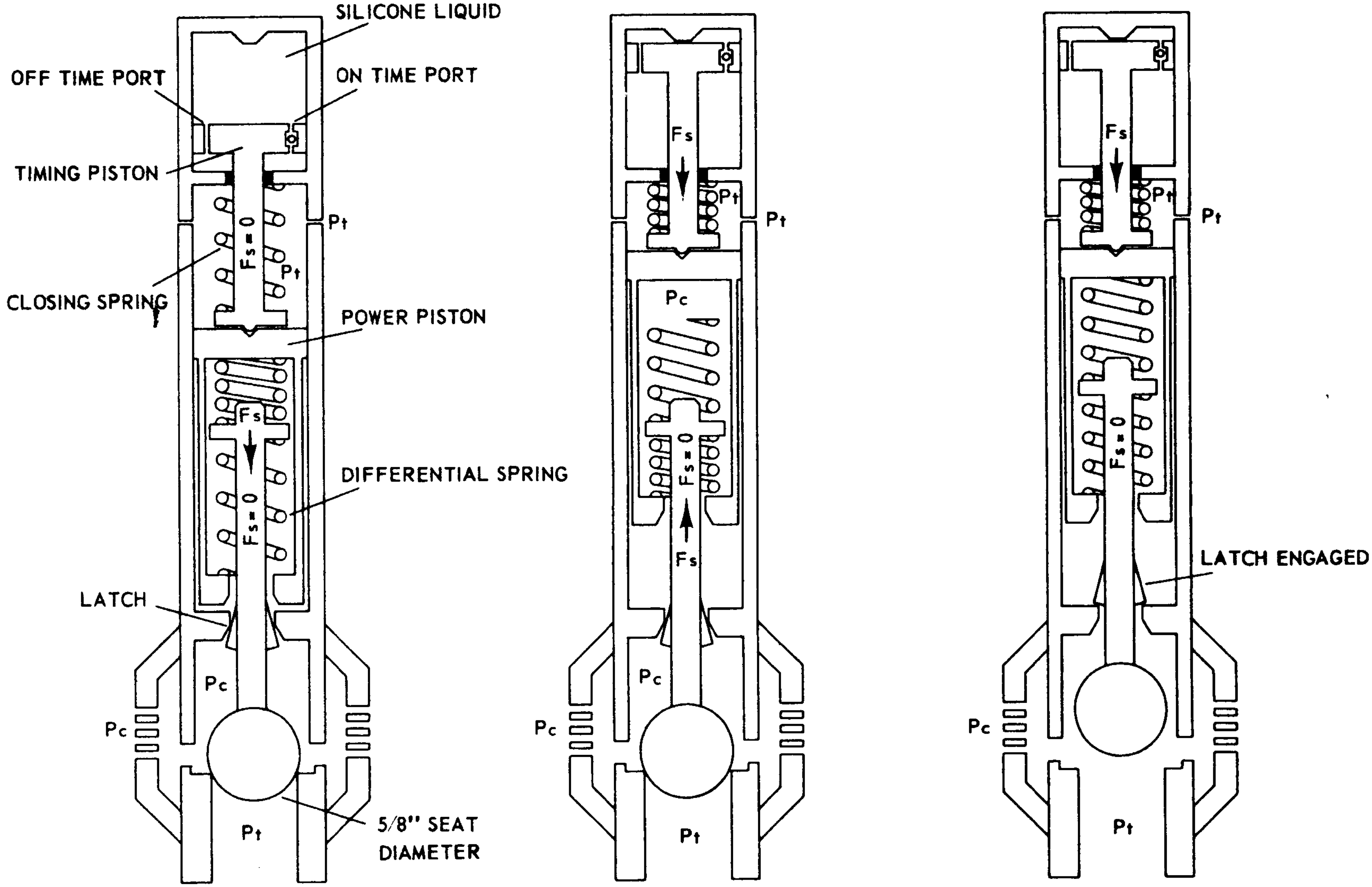
An installation using the time controlled valve for lifting one zone and a pilot valve for the other was run and tested early in 1967. This installation, Fig. 12, is similar to the earlier installation described that uses the differential open valve in conjunction with a pilot valve. The main advantage of the time controlled valve is that it does not need to be set for any particular casing pressure and therefore, automatically operates at the casing pressure provided by the valves on the other tubing string. Another advantage is that the gas supply for this valve can be provided by a regulator which does not need the heated choke assembly to restrict the input rate.

Three additional installations using the time controlled valve were made in wells where both zones have 150 to 200 psi producing bottom-hole pressures and productivity indices of 0.05. One zone is lifted by a pilot valve. A motor valve on the injection gas line is opened intermittently to allow gas to enter the annulus. The annular pressure is thus increased until the pilot valve is opened. The frequency the motor valve is opened and the duration of time it is open is controlled by a time cycle controller. The motor valve is also controlled by a casing pressure regulator which opens the motor valve to inject gas into the casing and maintain the pressure in the casing as gas is used by the time controlled valve. The maintained pressure is the same as the closing pressure of the pilot valve. There is no need for a heated choke because the time controlled



THREE TUBING STRING DUAL GAS LIFT INSTALLATION

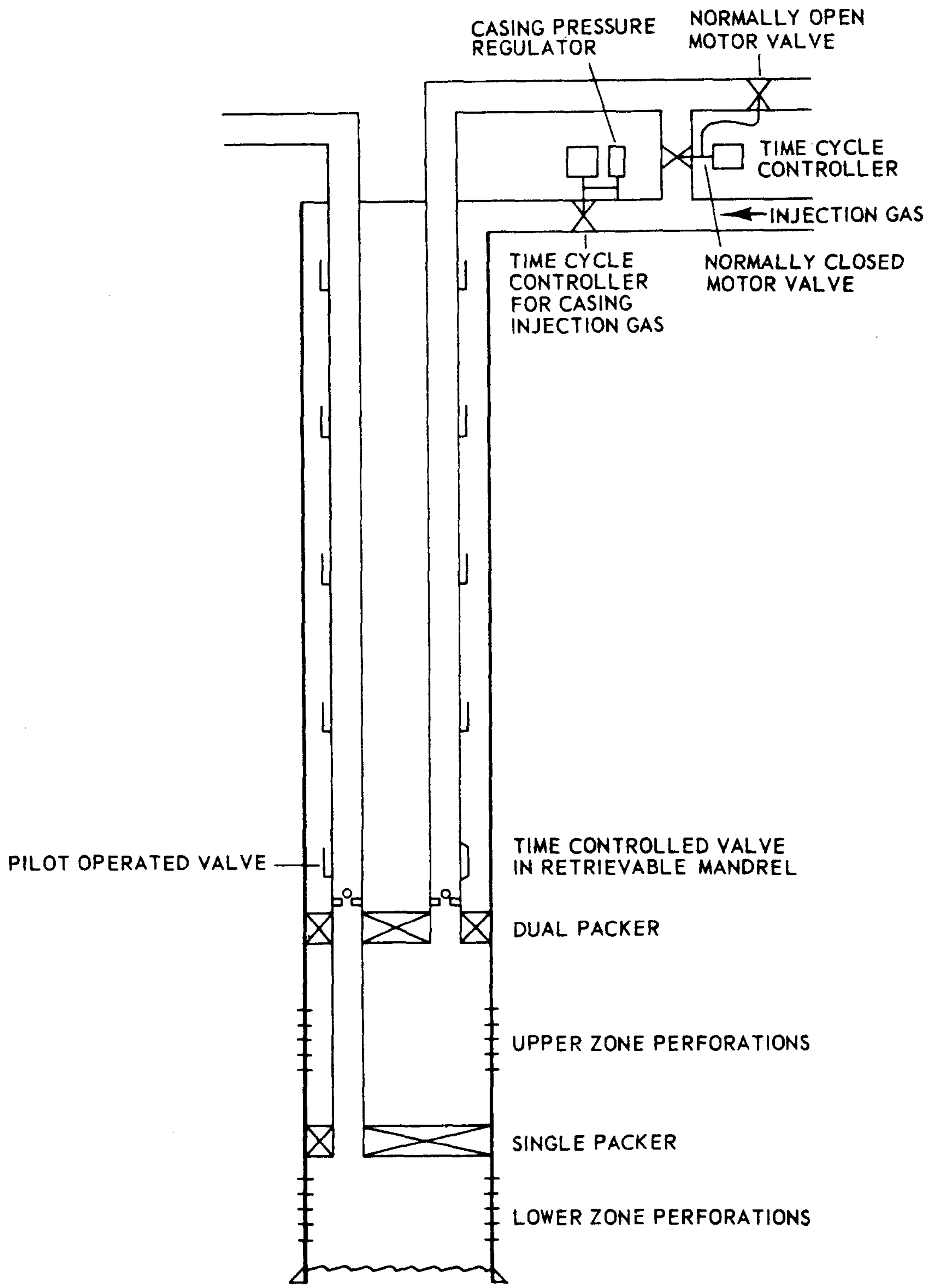
FIGURE 10



CLOSED COCKED OPEN

TIME CONTROLLED VALVE

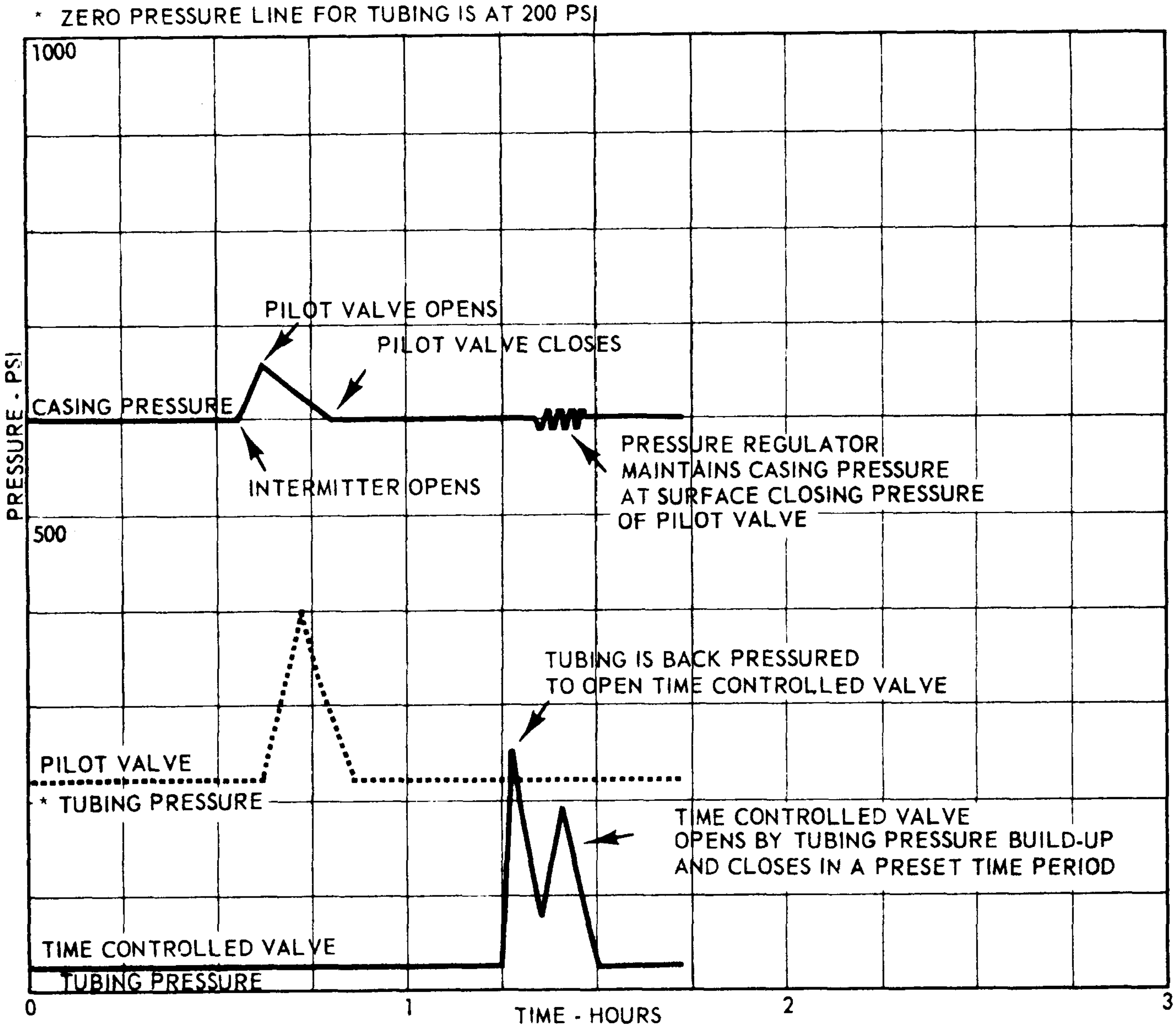
FIGURE 11



DUAL INTERMITTENT GAS LIFT INSTALLATION
WITH TIME CONTROLLED AND PILOT VALVES
AS OPERATING VALVES
FIGURE 12

valve closes on time regardless of pressures in the casing or tubing.

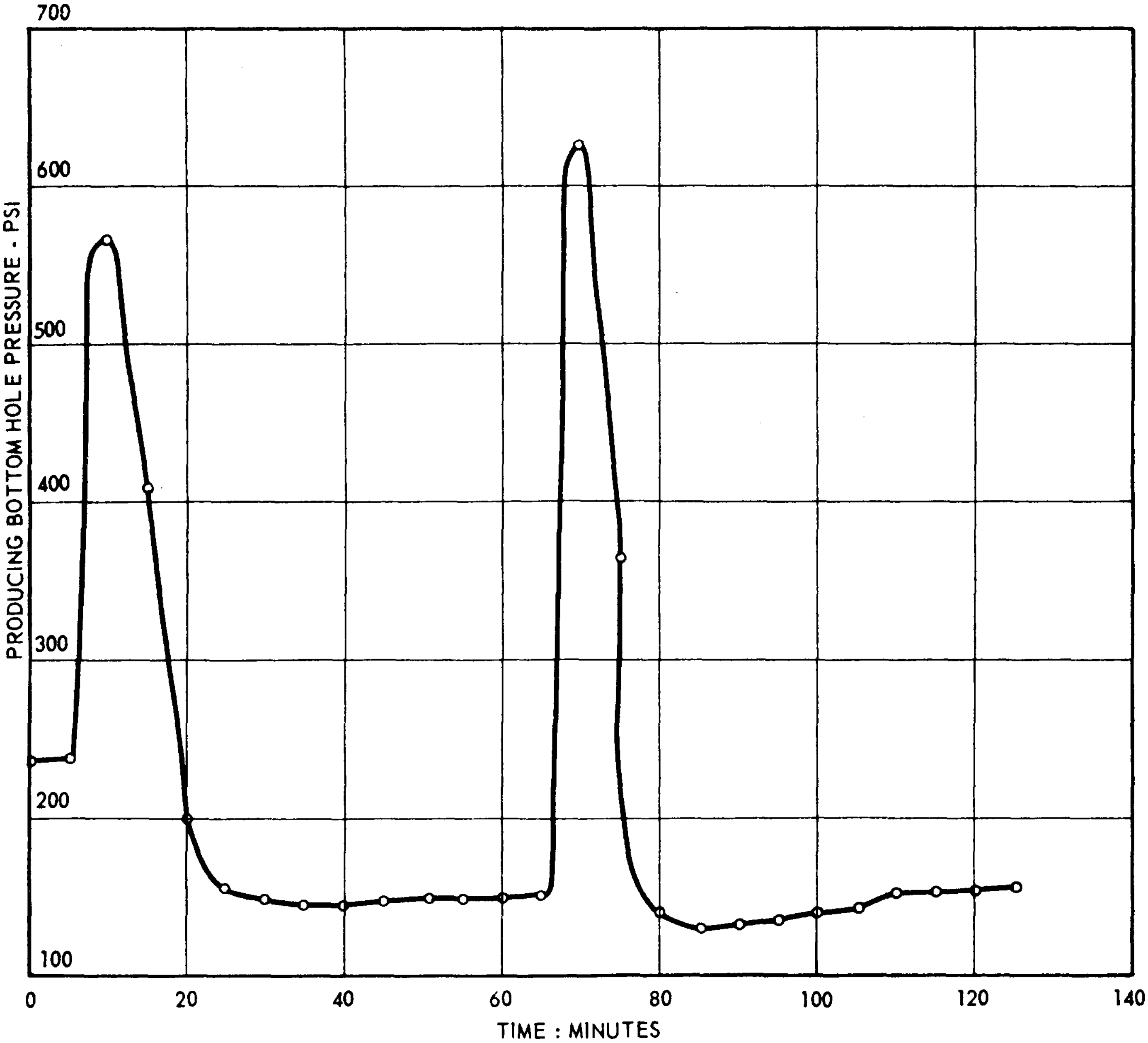
The bottom-hole pressure of the zones in these three wells is not sufficient to build a pressure in the tubing to trip the time controlled valve. An arrangement at the surface gets around this problem by providing a 100 to 200 psi pressure increase at regular intervals. This is done by using a time cycle controller, a normally open motor valve on the flowline and a normally



NORMAL SURFACE PRESSURE OPERATING CYCLE FOR THE TIME CONTROLLED AND PILOT VALVE DUAL GAS LIFT INSTALLATION

FIGURE 13

closed motor valve on a high pressure gas supply line. The time cycle controller, at regular intervals, allows pressure to be applied to the motor valve diaphragms simultaneously. The flowline is closed in, and the high pressure supply gas is injected down the tubing momentarily to furnish the pressure necessary to trip the time controlled valve. The pressure is released from the diaphragms, the high pressure gas shut off and the flowline opened. This allows the added pres-



TYPICAL OPERATING CYCLE AT VALVE DEPTH FOR WELLS IN TXL FIELD

FIGURE 14

sure to be bled off and not interfere with the slug that is being lifted. A typical operating cycle is illustrated in Fig. 13. The surface trip arrangement is also being used with differential open valve installations.

All four of the time controlled valve installations have operated successfully as simultaneous, common annulus, dual installations. There were only the early mechanical difficulties that are inherent in newly developed equipment.

CONCLUSION

In the past, dual intermittent gas lift designs have been dependent on the producing bottom-hole pressures and pressure build-up between cycles to varying degrees. Where the producing characteristics of both zones are similar and consistent, dual lift can be achieved with casing pressure controlled valves as the operating valves on both zones. However, of the 57 such designs presently installed, only 18 are actually maintaining simultaneous dual lift due to the incompatibility of the zones being lifted. Where at least one zone has relatively high bottom-hole pressure and a rapid feed-in rate, tubing pressure operated valves on one or both strings can be utilized for successful dual lift. Bottom-hole pressures and feed-in rates have now declined to the point where tubing pressure operated valves alone cannot be used in the majority of wells, Fig. 14.

The present producing conditions in this area demand the flexibility of being able to selectively lift either zone independently of the other at an optimum cycle frequency. The three-tubing-string installation and the surface-tripped (differential open or time controlled) valve-pilot valve combination are the two most successful lift systems to date for these conditions. The surface-tripped valve-pilot valve combination is the most economical due to the lower capital cost of equipment and has proved to be as reliable as the three-string duals. These systems are certainly the most profitable dual installations presently in use because of their ability to reliably lift both zones of a dual well every day.