Simultaneous Production from Two Reservoirs Through the Same Flow String

By J. W. HODGES
Sun Oil Co.

ABSTRACT

The constant search for methods to increase the efficiency of production systems and to reduce operating costs has led to the development of a wire line tool which makes it possible to produce and control two separate reservoirs through a single string of tubing. This paper is a progress report of the experience that one company has, with this tool, gained in eight of its dually completed wells in Louisiana and Texas. Field tests have clearly demonstrated that this device can be used to maintain separation of production from two reservoirs, to control and determine the rate of production from each, and to change the rate of production as required. The advantages in simultaneous, one string multiple completions are enumerated, and various applications of the method are discussed.

INTRODUCTION

It is now almost standard operating procedure to complete, wherever possible, wells in more than one zone, with the great majority of these multiples being dual completions. This procedure is a sign of the times. We must economize where we can; however, there is no need to expand on this theme: we are all painfully aware of the economic conditions within the Industry. It is sufficient to say that the multiple completion is here to stay and becoming more popular every day. The only question is whether or not it has evolved into its most acceptable form.

The earlier duals were the concentric type with one zone producing through the tubing and the other through the tubing-casing annulus. This method is still practiced to a large degree, and it is popular because it is relatively inexpensive. Unfortunately, it has some rather severe limitations, with which the reader is undoubtedly familiar.

The twin string dual is an improvement over the concentric in the sense that many of the problems associated with the concentric have been solved. However, the objectionable features of the twin string dual are the high cost of equipping the well with an extra string of tubing, plus accessories, and the complications brought on by cramming all this tubing into one string of casing.

Still another type of multiple is the tubingless completion in which two or more small casing strings are cemented in place and subsequent operations performed with miniaturized equipment.

It is the purpose of this paper to present a different concept in multiple completion -- the simultaneous production of separate reservoirs in a single flow string. This method combines the simplicity and low cost of the concentric with the flexibility of the twin string dual. In addition, it provides the unique advantage of prolonging natural flow from a low pressure zone by combining its production with the fluids produced from a higher pressure zone.

The wire line tool which makes this method possible is the Otis Multiple Completion Choke Assembly.

Construction and Operation of the Multiple Completion Choke Assembly

Figure 1 shows a well properly equipped to receive a Multiple Completion Choke Assembly. A conventional packer separates the two producing zones, but the upper packer is optional. In this landing nipple an Otis Type "S" side-door choke landing nipple hook-up is located and the Multiple Completion Choke Assembly will be locked in the tubing string above the lower packer. Normally located a joint or two above the upper zone, the position of the landing nipple hook-up can be varied to suit well conditions; for example, where the two zones are widely separated, it might be placed just above the lower packer to facilitate bottom hole pressure tests of the lower zone.

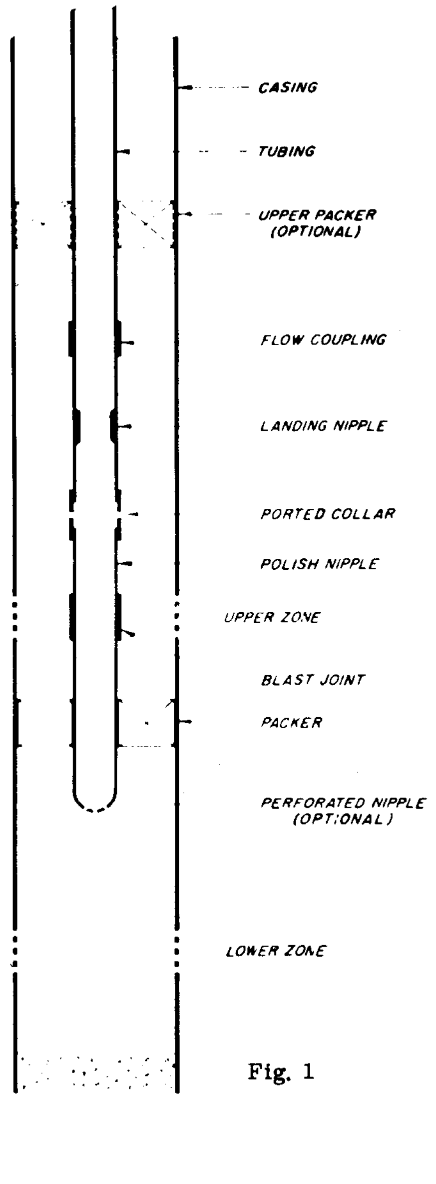

Fig. 1

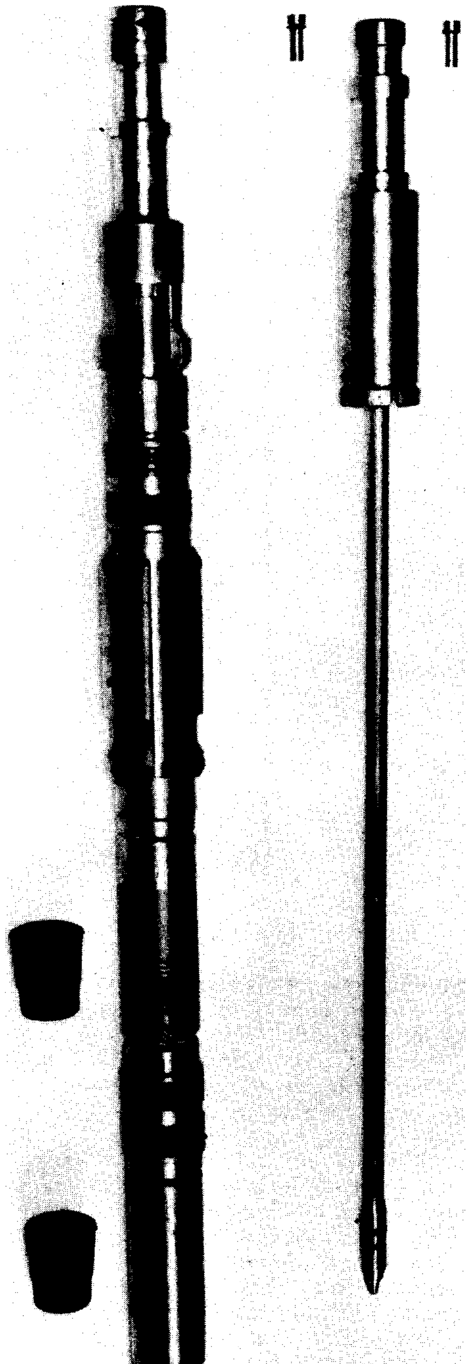

Fig. 2

The tool actually consists of two separate assemblies (Fig. 2). The outer assembly, which is run independently and locked in the landing nipple, contains the check valves and packing seals which prevent flow from one zone to the other. In practice, however, only one check valve is usually required and is installed to protect the zone with the lower pressure.

The orifice head assembly, which carries the tungsten carbide choke beans, is run separately and is seated and locked in the outer assembly. The method of running each section is illustrated in Figure 3.

Figure 4 is a schematic drawing which shows more clearly how the device works. Production from the lower zone enters the assembly through a slotted section, flows around a resilient sleeve type check valve, enters and flows through the tube of the orifice head assembly, is choked, and, now regulated, flows into the tubing. Produced fluids from the upper zone enter the casing opposite a blast joint on the tubing and flow through the ported collar of the Otis Type "S" side-door choke landing nipple hook-up, through the upper slotted section, around the upper check valve, into the annulus surrounding the tube, and through the upper zone choke bean into the tubing. Here, the two controlled flow streams, which have been kept separate up to this point, combine and flow to the surface.

Tubing Inlet Pressure

The pressure in the tubing at the junction of the two streams will be the minimum pressure required to lift the combined fluids to the surface (at zero surface pressure) and will be determined essentially by the gas-liquid ratio, production rate, and tubing size. There are also other factors, but they will have no significant effect on this pressure, which -- hereafter referred to as the tubing inlet pressure -- is of particular interest because of its importance in the application of the Multiple Completion Choke Assembly. For example, suppose that one is investigating the possibility of using the assembly in a two-zone oil well with the following characteristics:

	Upper Zone	Lower Zone
Producing Depth, Ft	6600	7200
Static Bottom Hole Pressure, psi	1500	3400
Productivity Index, BPD/psi Drop	0.5	1.0
BOPD	56	64
BPD of Salt Water	40	None
MCF Gas Produced Per Day	39	48
Gas-Liquid Ratio	406	750

The combined production rate is 160 bbl liquid (including salt water) and 87 MCF gas per day. The combined gas-liquid ratio is 543 cu ft per bbl. With a Multiple Completion Choke Assembly set at 6500 ft in 2-3/8" O D tubing, it can be determined from published depth-pressure gradient curves (1) that the tubing inlet pressure will be approximately 850 psi with the production of 160 BPD of liquid at a gas-liquid ratio of 543 cu ft per bbl.

The upper zone, with a productivity index of 0.5, will produce 96 BPD of liquid with a flowing bottom hole pressure of approximately 1308 psi. Since the flowing bottom hole pressure of the weaker zone is greater than is the tubing inlet pressure at the desired rate of production, this well can be produced by natural flow with a Multiple Completion Choke Assembly; and natural flow will be maintained as long as the flowing bottom hole pressure of the weaker zone (in this example, the upper zone) exceeds the tubing inlet pressure. At some point in the life of the upper zone, however, conditions favorable for natural flow as a single completion may no longer prevail. At this point the lower zone will be depended upon to provide energy sufficient to allow natural flow from the upper zone.

Allocation of Production

Allocation of fluids produced from each zone is based on separate, individual zone tests. To obtain such a test, the orifice head assembly is removed from the check

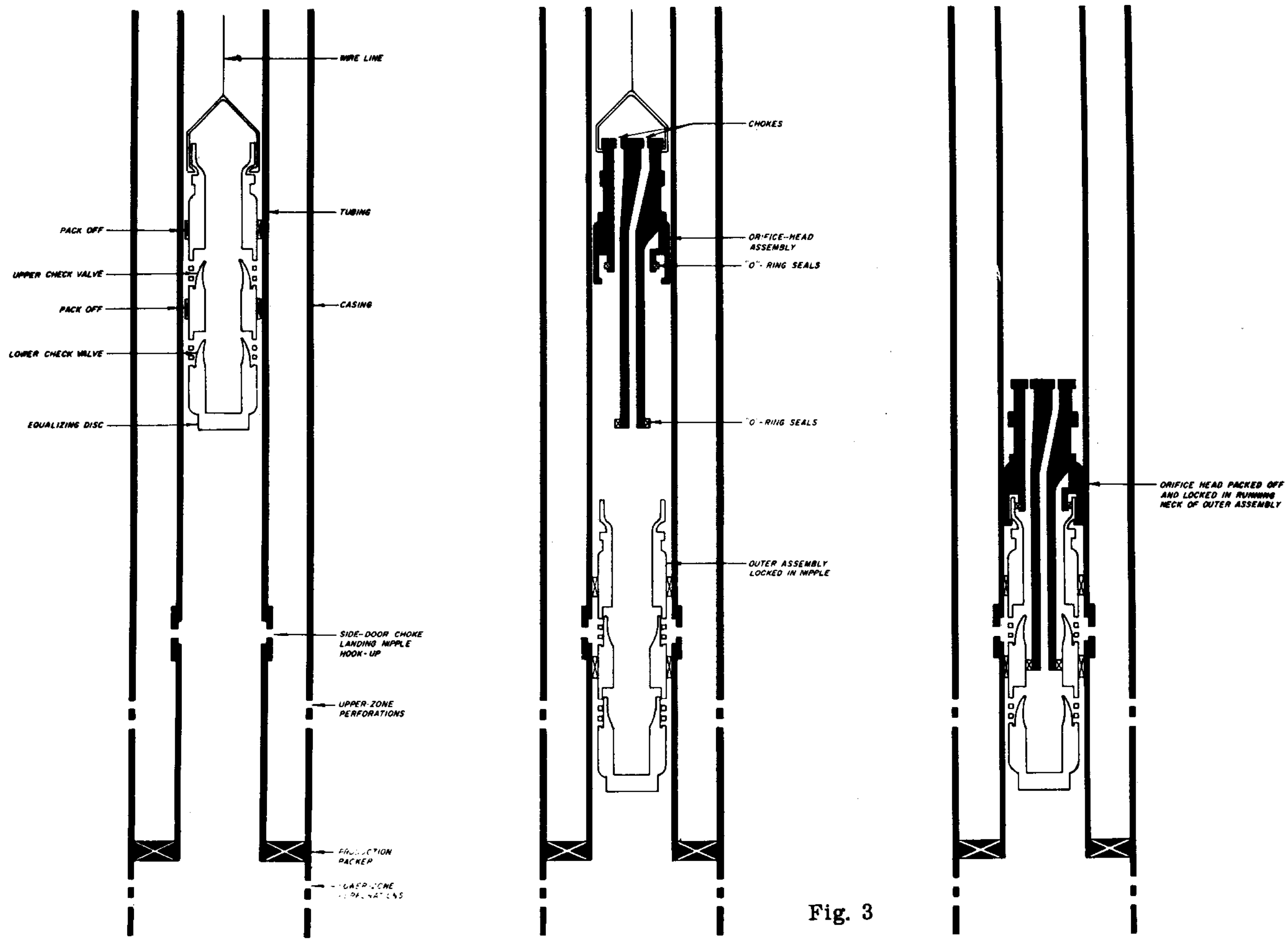

Fig. 3

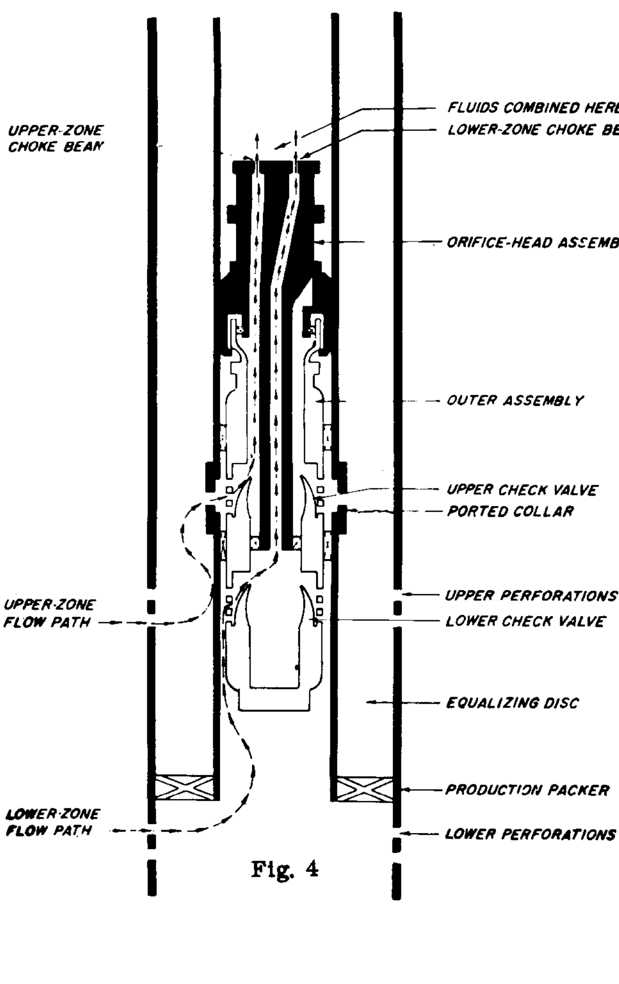

Fig. 4

valve assembly and brought to the surface with conventional wire line tools. (Removal of the orifice head does not result in inter-zone flow, because the check valve assembly remains in the well). If the lower zone is to be tested, a blank choke bean is inserted into the opening in the orifice head communicating with the flow path of the upper zone. A choke bean properly sized (1) to produce the desired volme of fluid from the lower zone is placed in the opposite side of the orifice head. The orifice head is then lowered into the well and landed and locked in the check valve assembly; and the upper zone cannot flow because of the blank choke bean. Produced fluids from the lower zone are measured into conventional surface facilities until a stabilized 24 hr test is obtained. The orifice head is again removed from the well; the blank bean is replaced with a production bean; and the assembly is returned to its operating position in the well. A stabilized test of the combined fluids produced is obtained, and the predetermined rate from the lower zone is subtracted from the combined total, with the difference assigned to the upper zone.

This particular method of testing is used when one of the zones is deficient. There would be no point in testing separately a deficient zone if its production rate is increased as a result of being combined with the production from the other zone.

The test procedure used will be determined by the flow conditions present in the well: specifically, whether or not one of the zones is in critical flow -- a stream is said to be in critical flow when alterations in pressure downstream from an orifice do not affect the rate of flow through the orifice. Referring to Figure 5, if P_1 remains constant and P_2 is reduced, the rate of gas flowing through the orifice will increase until P_2 is approximately

Fig. 5

53 per cent of P_1 .The stream at this point goes into critical flow, and any further reduction in P_2 will have no effect on the flow rate. The significance of this phenomenon in the operation of the Multiple Completion Choke Assembly is that, if one of the zones is in critical flow and the other is not, the zone not in critical flow can be regulated with a surface control without affecting the rate from the other. In the well described earlier, for example, if the tubing inlet pressure is not allowed to exceed approximately 1765 psi (53 per cent of 3336 psi), the rate from the lower zone will not be affected. In other words, back pressure at the surface can be increased to the point of actually shutting in the upper zone, with no effect on the rate from the lower zone.

In any well in which two reservoirs are being produced simultaneously through the Multiple Completion Choke Assembly, one of the following three conditions will exist: (1) one zone in critical flow; (2) neither zone in critical flow; (3) both zones in critical flow. The method of testing for allocation will depend on which one of these conditions exists.

The exact value of the critical P_2 /P_1 ratio, whether it be 53 per cent or some other value, is of no particular concern. The ratio is not used in the quantitative sense. As a matter of interest, however, in the wells in which this critical point has been observed, the value has appeared reasonably close to 53 per cent. However, it has not been measured exactly; this accuracy would involve measuring P_1, the flowing pressure below the tool, and, as has been stated, there is no practical advantage in determining the exact ratio. But, if a stream is in critical flow the exact ratio is determined by changing the surface tubing pressure with an adjustable choke, measuring the rate of flow into conventional test facilities, and observing the effect of the back pressure changes.

At the same time, it may be desirable to measure the tubing inlet pressure with a bottom hole pressure gauge.

For example, tests run on a certain zone in a dual completion might result in the following:

Surface Tubing Pressure, psi	Tubing Inlet Pressure, psi	Liquid Rate BPD
700	1300	50
500	1050	55
300	825	60
100	600	60

These data show that the stream is going into critical flow between a tubing inlet pressure of 1050 and 825 psi. This point can be determined more precisely if the results are shown graphically, as will be illustrated later in actual well tests.

A pre-determined rate for this particular zone on a specific choke size for this range of tubing inlet pressures has now been established. It makes no difference what effect, if any, the second zone may have on the tubing inlet pressure in the well; since this pressure can be determined, the rate from the first zone will be known. The difference is then assigned to the zone not tested individually, usually the lower pressure zone.

If each zone can produce its allowable independently of the other, there may be some reason to test each separately. This procedure will, of course, require additional wireline work, but is not essential in determining the production from each zone. The method has been occasionally used to demonstrate the consistency of flow rate control possible with the choke beans in the tool.

Summarizing, production tests will follow one of two patterns.

First, if either or both of the two zones is in critical flow when combined, a 24 hr stabilized test of the zone with the higher pressure is obtained. Back pressure is not adjusted during this test. Then following the test, both zones are combined and tested for 24 hr at a stabilized rate. The difference in production is known to have come from the zone not tested singly.

Secondly, if neither of the zones is in critical flow, the zone with the higher pressure is tested individually. The surface pressure is varied and the stabilized rates of production at the various back pressures are measured. Tubing inlet pressure is recorded with a bottom hole pressure gauge. This test predetermines the rate to be expected from this zone during periods of combined flow. The rate from the other zone will be determined by difference.

Similarity to Conventional Methods

Simultaneous production using the Multiple Completion Choke Assembly is essentially the same as producing two zones with separation maintained all the way to the surface. Figure 6 illustrates this point. The vertical flow string in the drawing on the right is in effect a part of the flow line. Thus, in both systems, the production from the two zones is segregated until the point of regulation is reached. Downstream from this point, the produced fluids are combined in a common flow line. It should be noted, however, that, in the twin string well, the pressure drop across the chokes is taken at the surface; in the single flow string this drop occurs near the bottom of the well in which any excess energy present, which otherwise might be wasted, can serve a useful purpose.

Also basically the same in one system as it is in the other is the method of allocating production: determining the rate from each zone by testing, combining the two streams in common facilities, and allocating the interim production between test periods on the basis of the single zone tests. In either method, accurate determination of the contribution from each zone during the interim period depends on accurate flow rate control. In the Multiple Completion Choke Assembly the tungsten carbide choke beans -- being more resistant to erosion and operating below the zone of paraffin deposition -- will out-perform surface chokes and will provide superior flow rate control.

Use of the Tool in Gas Lifting

The Multiple Completion Choke Assembly when used as a gas lift device is in effect a single-point injection, retrievable flow valve utilizing gas supplied direct from the formation at maximum efficiency. An expert in gas lift technology, in discussing conventional gas lift systems (2), has made the following pertinent observations:

"Which flow process, continuous or intermittent, will yield the greatest amount of produced stock tank liquid for the least amount of injected gas at the available pressures? The continuous flow process, if properly instituted, should be inherently more efficient than that of intermittent flow. The gas is put to work as needed and the high dissipation of initial energy in overcoming starting inertia is largely absent. Also, the external work done by the gas is negligible. The fact is, however, that maximum efficiency in the continuous flow process

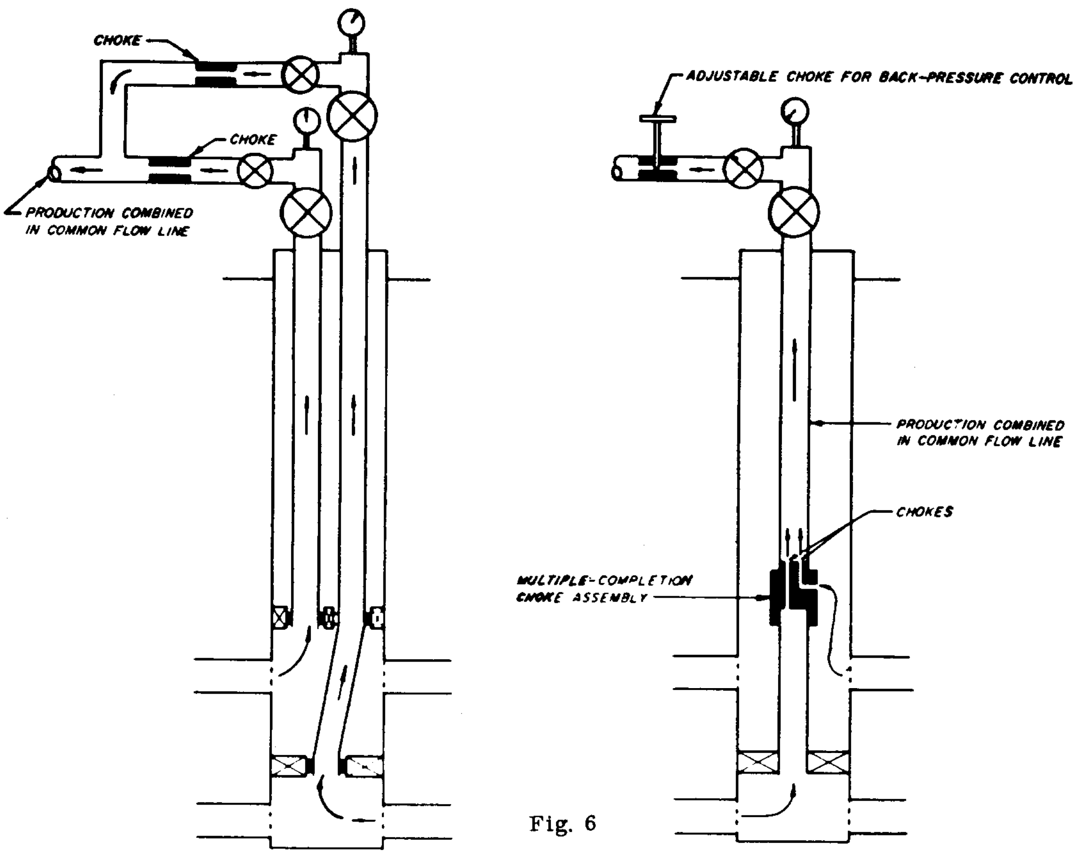

Fig. 6

can only be realized by putting the gas to work as soon as possible. This means high injection pressures at moderate depths. Because the high injection pressures necessary for maximum efficiency are seldom available, it has been found in practice that the intermittent flow process is frequently more efficient than that of continuous flow, for wells that produce moderate amounts of liquid.

"It is significant to point out here that the Phillips paper, previously referred to, lists data from some 34 flowing wells and 16 gas lift wells (continuous flow). The thermodynamic flow efficiency for the flowing wells was on the order of 85 to 95 percent, whereas the gas lift wells were mainly of the order of 40-60%. There is no reason why continuous flow gas lift wells should not closely approximate the efficiency of naturally flowing wells, if the installations are correctly designed.

"It is recognized that the high pressure requirements for maximum efficient operations is definitely a limiting factor in any practical well installation. It is most important to recognize that, as injection pressures are decreased below the optimum, the flow efficiency of the installation falls off very rapidly.

"Low injection pressures mean high injection GORs and should be avoided where possible.

"--and to emphasize the advantage of valve installations in which the valves may be retrieved and reset or replaced."

These statements make a strong case for using the Multiple Completion Choke Assembly as a gas lift mechanism. The high injection pressures necessary for maximum efficiency are now within practical reach; almost any well can be produced by continuous lift; the "flow valve" can be removed and replaced by wire line. All these advantages add up to maximum efficiency at minimum cost.

To illustrate the truly significant potential of the Multiple Completion Choke Assembly as it applies to gas lift, a comparison was made between gas lifting with a conventional system and with the Multiple Completion Choke Assembly in a well in the Sour Lake Field, Hardin County, Texas. Application has been made seeking permission to use in this well a gas sand at 9610 ft to supply gas lift gas through the Multiple Completion Choke Assembly to lift produced fluids from an oil sand at 9800 ft. The results of this study (3) were rather startling. The input gas required using the conventional system was calculated to be 560 MCF per day as compared to only 34 MCF using the Multiple Completion Choke Assembly, and in addition it should be remembered that the latter method does not require surface gas lift facilities, such as high pressure separators or compressors, heaters, dehydration equipment, delivery lines, etc.

Data pertinent to the analysis and the results thereof are presented below:

Conditions

Required Production	100 BOPD 100 BPD of salt water
Productivity Index	0.154 BPD/psi drop
Surface Pressure	100 psi
Static Bottom Hole Pressure Lower Zone	3800 psi
Static Bottom Hole Pressure Upper Zone	4000 psi
Gas-Oil Ratio Lower Zone	500 cu ft per bbl
Gas-Liquid Ratio Lower Zone	250 cu ft per bbl
Required Gas-Liquid Ratio for Well to Flow	420 cu ft per bbl
*Input Gas Pressure	700 psi

Comparison Between the Two Methods

Item	Conventional	Proposed
Number of Flow Valves	11	1
Depth of Lift, ft	4500	9500
Input Gas-Liquid Ratio cu ft per bbl	2800	170 (420-250)
Gas Required, MCF per day	560	34

*Assumed there are no gas lift facilities available)

Field Tests

Sun Oil Company's first test of the Multiple Completion Choke Assembly was in the Kinder Field, Allen Parish, Louisiana, in September, 1959. A type "S" assembly was run in one well and a type "H" (crossover) in another. As a result of these tests, it was decided to shelve the type "H" and "F" tools and to concentrate on the type "S". The letter descriptions simply indicate the type of landing nipple in which the tool is positioned.

Additional development and testing were done in the North Winnie Field in a surface manifold with a high pressure oil well flowing through the tool. Sand laden liquid was pumped into the flow stream where it entered the manifold. The severity of these and other surface and subsurface tests has resulted in the development of a very durable and rugged tool.

The first successful field test was begun March 31, 1960, in a well in the Kinder Field. The Conservation Commission approved a six month test period and after a three month interval granted permanent approval to use the tool in this well, which will be identified as Well No. 1.

Sun now has eight wells equipped with Multiple Completion Choke Assemblies, and several more installations are planned or in progress.

A description of the wells now equipped with the assembly follows:

Well No.	Location	Depth, ft	Static BHP,psi	BPD Prod.	Gas-Liquid Ratio, CF/bbl
1	Kinder, La.	8067	2575	6 Oil No SW	22,100
		8448	2460	19 Cond No SW	18,466
2	Bayou Sale, La.	14025	5870	75 Oil 75 SW	7,750
		14236	6533	20 Oil No SW	1,000
3	Kinder, La.	7678	3263	64 Oil No SW	784
		8379	3371	37 Cond No SW	19,100
4	Belle Isle, La.	13958	6500	129 Oil No SW	735
		13983	6500	129 Oil No SW	945
5	Kinder, La.	7394	3290	7 Oil 15 SW	643
		8390	3485	64 Cond No SW	16,188
6	Belle Isle, La.	12840	5670	115 Oil No SW	906
		13398	5781	129 Oil No SW	423
7	Bateman Lake, La.	10154	4538	71 Oil No SW	2,929
		11700	5060	65 Oil 10 SW	3,354
8	Sour Lake, Texas	4710	814	No Cond No SW	113 MCF Dry Gas
		4788	1093	14 Oil No SW	649

Well No. 1, prior to installation of the Multiple Completion Choke Assembly, was a concentric type dual completion with the upper zone flowing in the annulus between 2-3/8 in. tubing and 5-1/2 in. casing and the lower zone flowing through the 2-3/8 in. tubing. As a result of using the tool, the combined daily hydrocarbon production from the two zones was increased by approximately 20 bbl and 300 MCF, representing an annual increase in gross income of $48,400.00. The production increase can be attributed to the following:

1. Producing the upper zone through a bottom hole choke and in the tubing, and elimination of the surface heater reduced the gas oil ratio and increased the oil allowable.
2. Liquid from the lower zone no longer accumulates in the tubing to restrict flow.
3. The productivity of the lower zone was increased.

Other than increasing the current income from the well, additional advantages realized or anticipated are as follows:

1. An expected increase in ultimate recovery.
2. Elimination of the need for flow line heater, one separator, and meter run; no longer necessary to compress gas from the lower zone.
3. Removable of high pressure gas flow from casing.

Tables 1 and 2 illustrate the exact method used to allocate production from the two zones in Well No. 1. Table 1 represents four consecutive 24 hr tests of stabilized flow from the upper zone with the lower zone closed in by a blank choke bean in the orifice head. However, it is not necessary as a routine matter to run the tests this long, but the tool was experimental during this period, and the stabilized nature of the flow possible with the device was being demonstrated. Table 2 represents tests made of the combined flow, with the resulting allocation to each zone.

Table 3 shows the results obtained during the following months when testing the upper zone individually, and demonstrates the accurate flow rate control possible with the choke beans used in the assembly. The same 5/64 in. choke was used throughout the period shown. Gas production was measured by orifice meter and liquid production was gauged in a 210 bbl tank.

Table 1

Individual Test Data for Upper Zone, Well No. 1. Lower Zone Blanked Off

Date	Surface Tubing Pressure, psig	Oil Prod., BPD	Gas Prod., MCF/Day	Gas-Oil Ratio, CF/bbl
6-9-60	900	10.39	242	23,300
6-10-60	900	10.68	237	22,100
6-11-60	900	10.98	238	21,700
6-12-60	900	10.97	238	21,700
	Average	10.75	239	22,100

Table 2

Combined Production Data and Allocation to Each Zone, Well No. 1

Date	Surface Tubing Pressure, psig	Measured Production Total Liquid Prod. BPD	Measured Production Total Gas Prod. MCF/Day
6-16-60	900	28.92	498
6-17-60	900	30.07	463
6-18-60	900	23.69	442
6-19-60	900	26.87	452
6-20-60	900	27.45	466

Calculated Production

Oil Prod. Upper Zone BPD	Gas Prod. Upper Zone MCF/Day	Cond. Prod. Lower Zone BPD	Gas Prod. Lower Zone MCF/Day
10.75*	239*	18.17	259
10.75	239	19.32	224
10.75	239	12.94	203
10.75	239	16.12	213
10.75	239	16.70	227

*Based on predetermined tests shown in Table 1.

Table 3

Individual Test Data for Upper Zone, Well No. 1, Lower Zone Blanked off.

Date	Choke	Oil Prod. BPD	Gas Prod. MCF/Day
7-24-60	5/64	7.23	248
10-5-60	5/64	7.80	227
10-18-60	5/64	7.80	227
12-4-60	5/64	7.23	209
1-27-61	3.5/64	6.38	175
5-29-61	3.5/64	6.96	150

Figure 7 is a plot of surface tubing pressure versus tubing inlet pressure with each zone producing individually at different rates and with the two combined. The resulting curve shows the close correlation between surface and tubing inlet pressures under various conditions of flow, thus precluding measurement of the tubing inlet pressure during production tests. In other words, the production rate from the upper zone can be predetermined for any given surface tubing pressure, and this rate will not be affected by production from the lower zone.

Well No. 2 was completed in May, 1961. The upper zone on drill stem test was judged to be non-commercial but did produce some oil, a situation frequently confronting an operator: a zone looks doubtful on an electric log; a drill stem test is not conclusive; should he make a single or dual completion? It is a perplexing question. The great expense involved in twin string duals will not often justify a thorough evaluation of these doubtful zones; on the other hand, he may be passing up a commercial reserve. In this situation the Multiple Completion Choke Assembly can be used to good advantage. Doubtful producing horizons can be fully evaluated at low additional cost, and when combined with good producers, can be depleted without artificial lift. This action will result in the recovery of more oil and more gas.

Well No. 2 is a deep, directionally drilled, high pressure, high temperature well, a water location, and provided quite a test for the tool. The wireline operations in this well, however, have gone quite smoothly.

Tests of the lower zone shown in Table 4 again illustrate the accurate flow rate control imposed by the tungsten carbide beans in the Multiple Completion Choke Assembly. The well was being produced through a metering separator, in which total liquids were measured with a volume type meter and gas measured by an orifice meter; the oil and water flowed from the separator to a treater where the salt water was measured by a volume type meter; the oil was discharged from the treater into a 1000 bbl tank and gauged.

The orifice head was fitted with a 7/64 in. bean for the lower zone and a blank for the upper. A bottom hole pressure gauge was run in the tubing to a point just

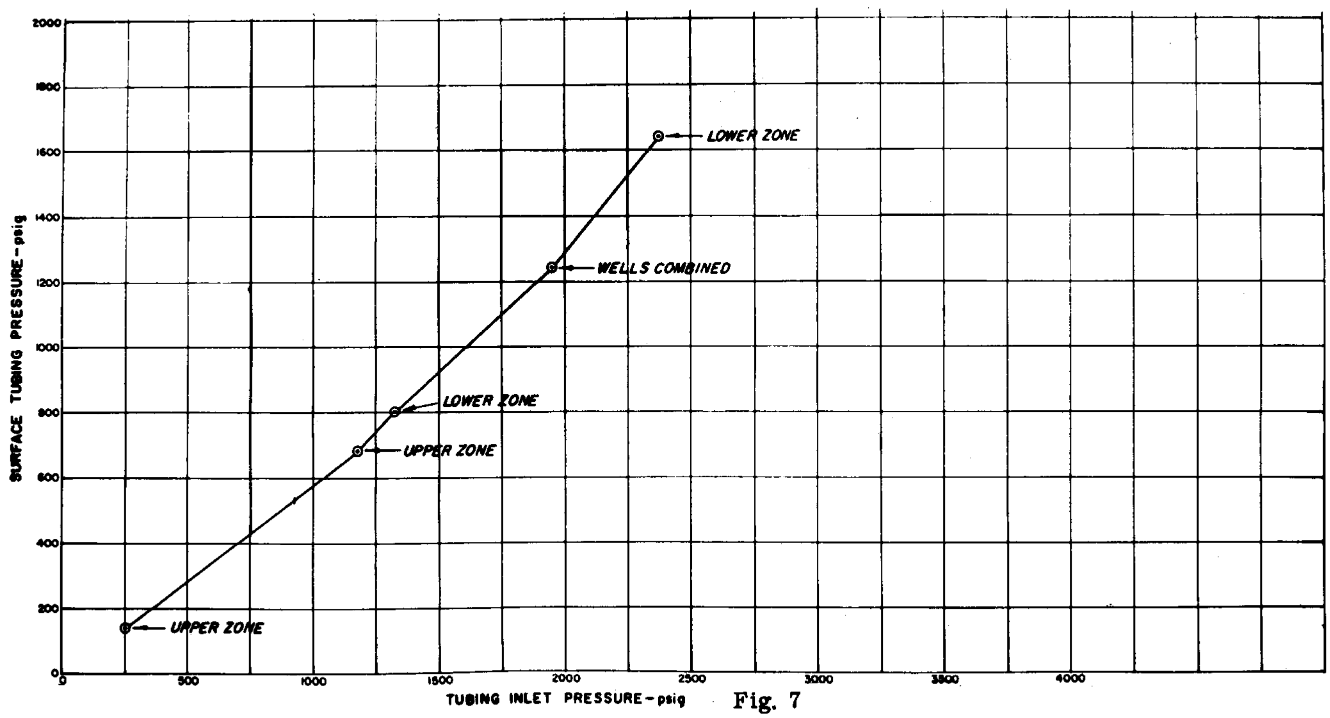

Fig. 7

Table 4

Individual Test Data for Lower Zone, Well No. 2, on 7/64 in. Choke Bean. Upper Zone Blanked Off.

Date	Oil Prod. BPD	Salt Water Prod. BPD	Gas Prod. MCF/Day
8-4-61	77	76	579
8-5-61	77	75	582
8-6-61	77	70	582
8-7-61	76	72	582
8-8-61	75	75	582
8-9-61	76	75	582
8-10-61	75	75	582

above the location of the tool at 12,500 ft. The pressure at this point (tubing inlet pressure) was recorded as 1370 psi. Using the depth-pressure gradient curves referred to previously, the tubing inlet pressure, with a surface pressure of 150 psi, is interpolated to be 1200 psi.

The actual results obtained throughout the field have been in reasonably good agreement with these published curves.

Well No. 3 was originally a single completion oil well. But in June, 1961, the oil zone was dualed with a deeper sand productive of gas and condensate.

Table 5 gives the results of single zone tests of the lower zone; Figure 8 is a graphic representation of these data. Note that the well goes into critical flow at a tubing inlet pressure of 1835 psi, or 55 percent of the upstream pressure of approximately 3300 psi.

After the tests of the lower zone were concluded, the upper zone was tested; then the two zones were combined. The tubing inlet pressure at 7550 ft was measured with a bottom hole pressure gauge and found to be 1720 psi with a surface tubing pressure of 1100 psi. As a check, the depth-pressure gradient curves were used to determine the tubing inlet pressure under these conditions of flow; and this value was interpolated to be 1650 psi. The lower zone is in critical flow under these conditions, and the predetermined rate of production of the lower zone is not affected by combining with the upper.

Table 5

Individual Test Data of Lower Zone, Well No. 3, Upper Zone Blanked Off.

Surface Tubing Pressure, psig	Tubing Inlet Pressure, psig	Cond Prod. BPD	Gas Prod. MCF/Day
790	1466	38.40	726,802
950	1549	39.41	726,802
1060	1835	37.34	708,654
1250	2091	32.12	638,787
1335	2345	30.06	555,196
1475	2517	22.82	454,251
1600	3125	12.44	222,078

Well No. 4, a water location, was completed in June, 1961. The upper zone is only eight ft thick and would not justify the additional cost of a twin string dual.

Production tests of the lower zone with a 4.5/64 in. choke bean in the orifice head were made as follows:

Oil Prod. BPD	Gas-Oil Ratio C.F./bbl	Surface Tubing Pressure
156	827	150
158	919	150
157	936	250
149	905	975
138	972	1075
122	957	1200
100	900	1450

These tests are reported to illustrate the critical flow phenomenon. Shown graphically in Figure 9, the flow becomes critical when the surface tubing pressure is 875 psi.

Following these tests, the orifice head was pulled and run back with the lower zone blanked and a 4.5/64 in. choke bean controlling production from the upper zone. On stabilized test in critical flow, the upper zone produced 152 BOPD (neither zone produces salt water) with a gas-oil ratio of 720 cu ft per bbl.

The orifice head was then pulled and returned with

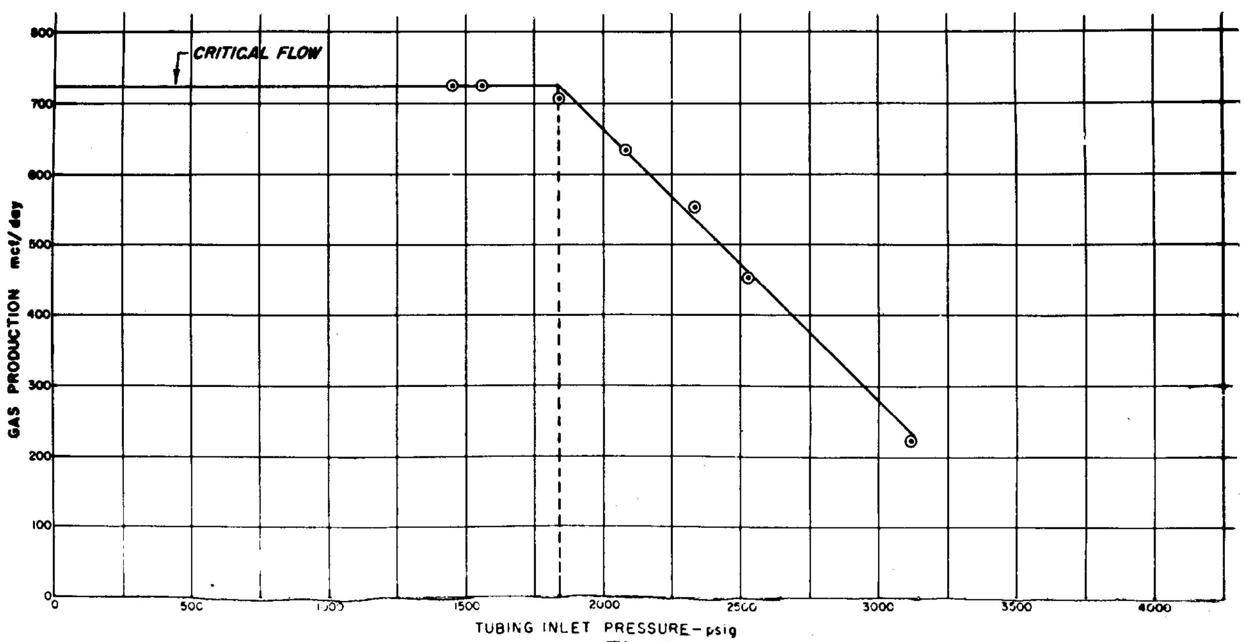

Fig. 8

each zone open to a 4.5/64 in. choke bean. Combined production was gauged at 311 BOPD, a good check with the individual zone tests (157 and 152, a total of 309 BOPD).

Well No. 5 was a singly completed, deficient oil well when it became necessary in August, 1961, to complete in a lower gas sand. The oil zone was not good enough to support a twin string completion and would have been abandoned had not the Multiple Completion Choke Assembly been available.

The two zones were produced simultaneously for about six months with no problems. Currently, however, the production of sand is becoming troublesome and may make it necessary to abandon the upper zone.

Well No. 6, a water location, was completed in August, 1961, and has been produced without incident.

Well No. 7, another water location, was completed in August, 1961. Tests show that both zones are in critical flow, and each zone was tested separately. The lower zone made 65 BOPD, and the upper zone was tested at 71 BOPD; but when combined, the two zones produced 132 BOPD. Each of the zones is penalized because of excessive gas-oil ratio. In this type of well, another advantage of the Multiple Completion Choke Assembly is seen. Bottom hole choking should reduce gas-oil ratios and provide greater allowables.

Well No. 8, the first test in Texas, was worked over and completed as a dual in October, 1961.

This well is completed in a low pressure gas sand and a low pressure oil sand. The gas is used to lower the gradient in the well to allow flow from the oil zone. The low bottom hole pressure existing in the gas sand will not justify the surface facilities that would be required for the sale of the gas, nor will the low pressure justify the use of this gas in a conventional gas lift system.

A new check valve received its first subsurface test in Well No. 8. Results were quite encouraging, and the valve has subsequently been used in other wells. The lower zone in Well No. 8 was acidized with the new check valve protecting the upper zone, and the treatment was successful mechanically, and the check valve functioned perfectly. During acidizing maximum differential pressure across the check valve was 4000 psi.

This new check valve is a sleeve-type steel valve incorporating both a metal-to-metal and O-ring seal. It may in time entirely replace the resilient type check valve.

The required packer leakage test in Well No. 8 was obtained by blanking off the upper zone in the orifice head and flowing the upper zone through the casing. The lower zone was opened to the tubing, and the casing and tubing pressures were simultaneously recorded. This is the method for obtaining a packer leakage test when there is no packer set above the upper zone. If the upper packer is set, packer leakage tests can be made by measuring the bottom hole pressure of one zone while flowing the other. A device is now being constructed which will allow a bottom hole pressure element to be run with the orifice head assembly. In the device, the shut in bottom hole pressure of one zone will be measured while the other is open to flow. This type of packer leakage test should be more realistic than is the conventional test in which surface pressure fluctuations are observed.

Allocation tests in Well No. 8 are made by blanking off the lower zone and measuring, through the tubing, the gas produced from the upper zone. The two zones are then combined and the increase in gas rate is calculated from the orifice meter chart. This increase represents the volume of gas produced from the lower zone. All liquids produced are known to have come from the lower zone, for the upper zone produces dry gas. Then the tubing inlet pressure is measured, and the results show that the upper zone is in critical flow. This means that production from the lower zone has no effect on the predetermined rate from the upper zone.

It can be argued that this method of gas measurement is considerably more accurate than is the usual method of measuring gas into and out of a conventional, intermittent type gas lift well.

Economics

When compared to twin string duals, use of the Multiple Completion Choke Assembly to produce simultaneously two reservoirs through a single flow string results in an initial saving in equipment and rig costs, and in later workover costs.

The savings possible cover a wide range. For example, the equipment costs of Well No. 6 are compared with those of a twin string dual in the same field, on a comparative footage basis, in the following table:

Item	Well "X"		Well No. 6	
Conductor	$ 788	(20")	$ 538	(16")
Surface Pipe	13,981	(11-3/4")	11,200	(10-3/4")
Oil String	61,500	(7-5/8")	39,600	(5-1/2")
Tubing	27,000	(2-3/8")	11,200	(2-3/8")
Wellhead Costs	5,200		3,800	
	$108,469		$66,338	

These totals represent a difference of $42,131 and does not include savings in rig time, or the considerable savings which may result in workover costs. Anyone

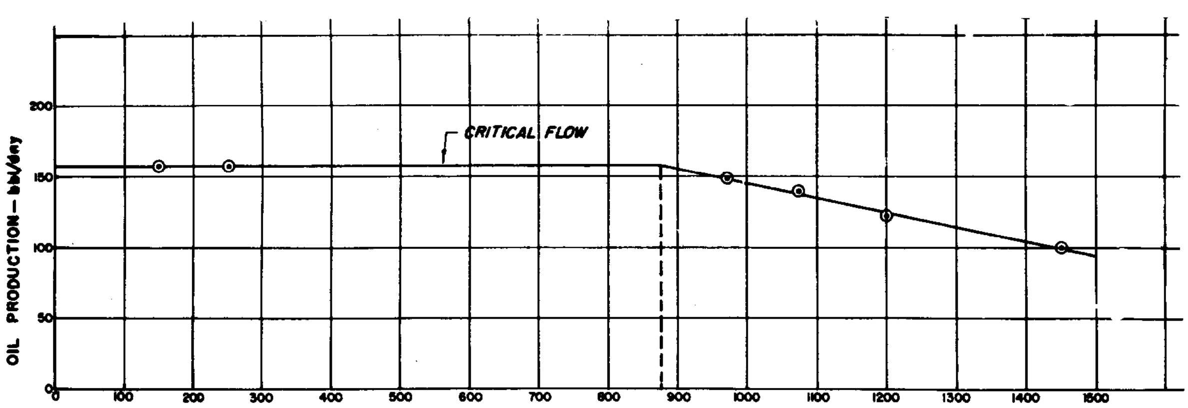

Fig. 9

who has worked over a deep, twin string dual in a water location will attest, perhaps grimly, to the costs that can be run up in such operations.

At the other end of the scale, in the relatively shallow wells, a cost comparison between tubular requirements in three different types of dual completions might look like this:

Item	Twin String		
Surface	500'	9-5/8" -	$ 1,750
Oil String	4600'	7" -	9,450
Tubing	9000'	2-3/8" -	5,600
Total			$16,800

Tubingless			Single String		
500'	9-5/8" -	$1,750	500'	9-5/8" -	$1,750
9000'	2-7/8" -	7,450	4600'	5-1/2" -	6,750
None			4500'	2-3/8" -	2,800
		$9,200			$11,300

Initial completion operations conceivably might result in the tubingless completion dual costing more than does the single string dual.

Simplicity and flexibility always should be taken into account when planning the system that will produce the most hydrocarbons for the least money.

The wireline expense associated with the simultaneous, one flow string method will depend primarily on operator skill, accessibility of location, depth, and testing requirements. This expense will be relatively high for the first month or two, then will taper off. For the year 1961 wireline costs in Well No. 1 have averaged $65 per month. In many wells, as in Well No. 1, the wireline expense will be more than compensated for by increased production, reduced lifting costs, and greater ultimate recovery.

Acceptance by Regulatory Agencies

Permission to use the Multiple Completion Choke Assembly in Well No. 1 was granted by the Conservation Commission on a six-month basis and then extended permanently for that particular well. Approval for the other two Kinder wells was obtained after a public hearing which was necessary because the lower producing sand was unitized and created a diversity of ownership in those wells.

Approval for the other Louisiana installations has been obtained after filing a routine request for permission to complete dually, with the provision that a review of the well be made after a six month operational period.

In Texas, the Railroad Commission has been somewhat stymied by Statewide Rule 15, which says, "No well shall be permitted to produce oil and/or gas from different strata through the same string of casing."

This rule was written some twenty-seven years ago to prevent an operator from opening indiscriminately two or more zones in the same well bore and from commingling this production without regulation or proper identification of the source.

In the case of Well No. 8 the Railroad Commission, after a public hearing, granted an exception to Rule 15. At the hearing it was emphasized that the old concept of commingling did not apply to wells equipped with the Multiple Completion Choke Assembly, and that there was no basic difference between this and conventional methods since commingling occurred after regulation, as it does in any tank battery where surface commingling takes place.

There are really no statutory obstacles to Railroad Commission acceptance of this producing method. "Opinion No. 0-2245; Re: The right of an operator to utilize gas produced from an upper horizon in lifting the oil produced from an oil sand at a lower horizon, without first producing the gas at the surface," approved on May 20, 1940, by Attorney General Mann and by the Attorney General's Opinion Committee, found that "so long as the proper steps are taken to insure against the escape of oil or gas from one stratum into another, we do not believe that the statutes prevent the Commission from permitting the more efficient method of introducing the gas into the tubing below the surface, instead of requiring that the gas first be brought to the surface through a separate string of casing and then reintroduced into the well."

Other Applications

Use of the Multiple Completion Choke Assembly is not limited to the applications that have been described; for example, the device is ideally suited to dual gas wells, and is being used in such wells in Mexico. Other, more specialized installations, are illustrated in Figures 10 through 18. The single string dual tubingless completion shown in Figure 18 must surely represent the final stage in the reduction of initial equipment costs for dual completions.

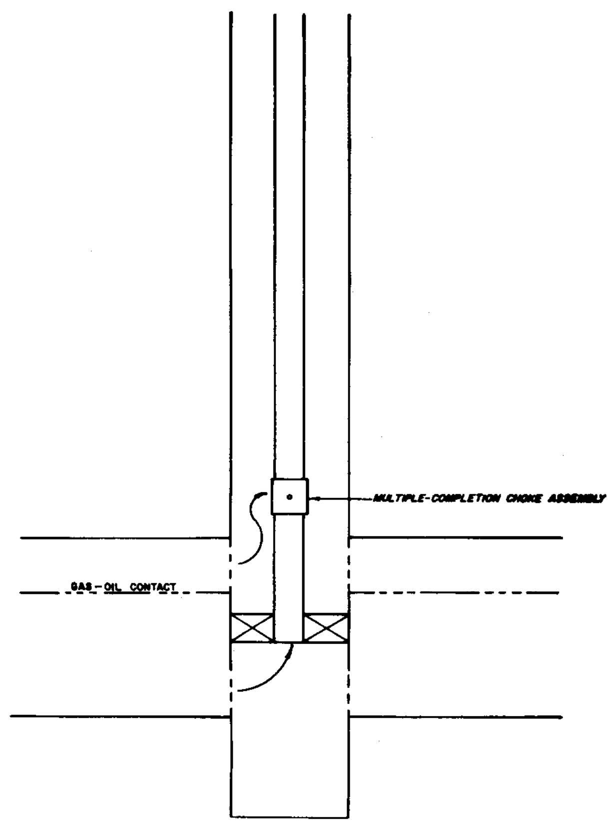

Fig. 10

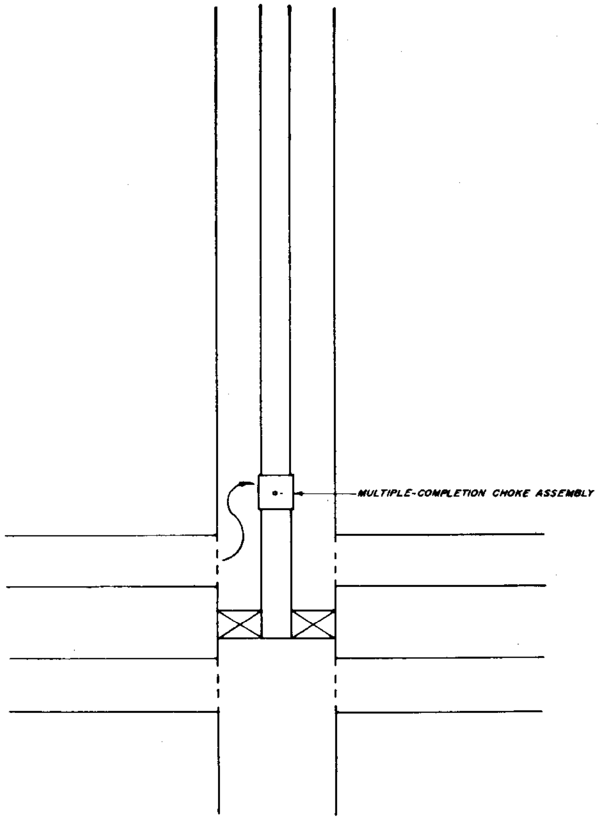

Fig. 11

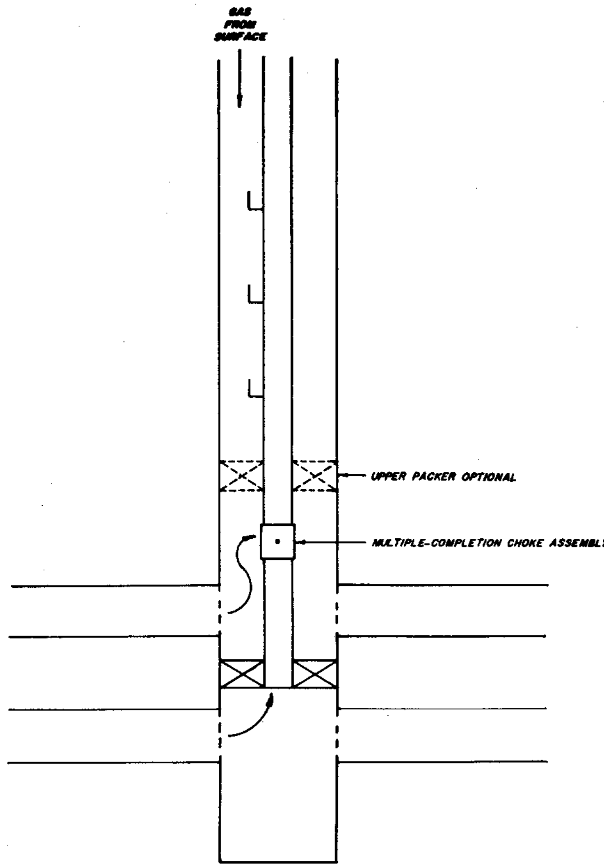

Fig. 13

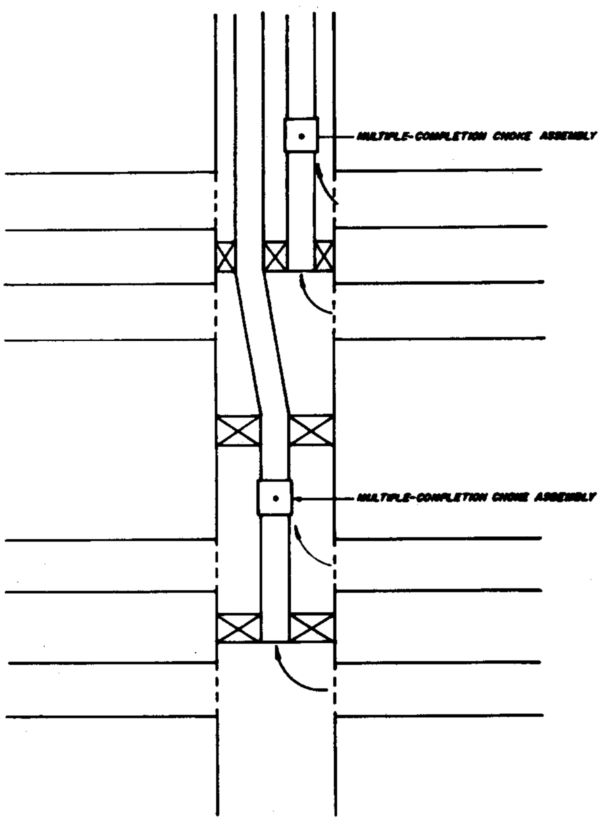

Fig. 12

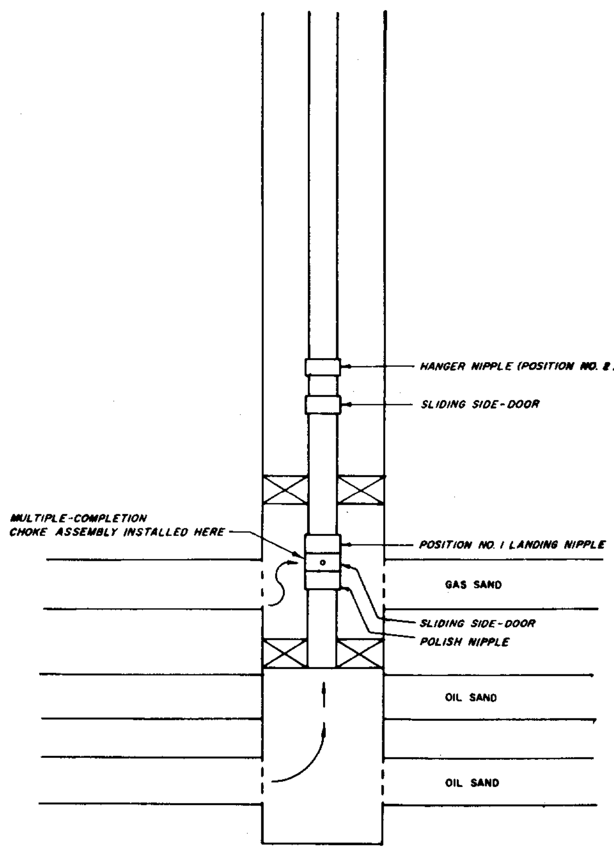

Fig. 14

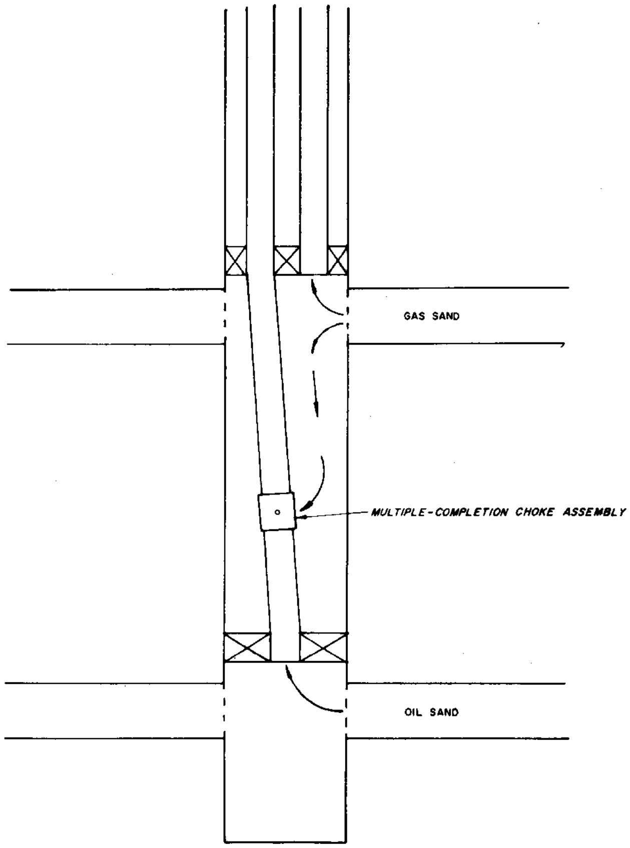

Fig. 15

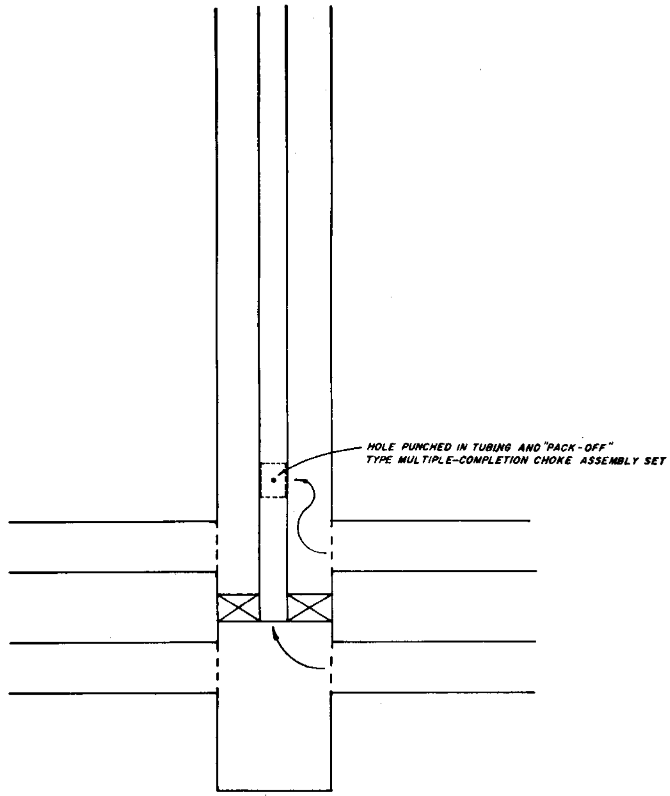

Fig. 17

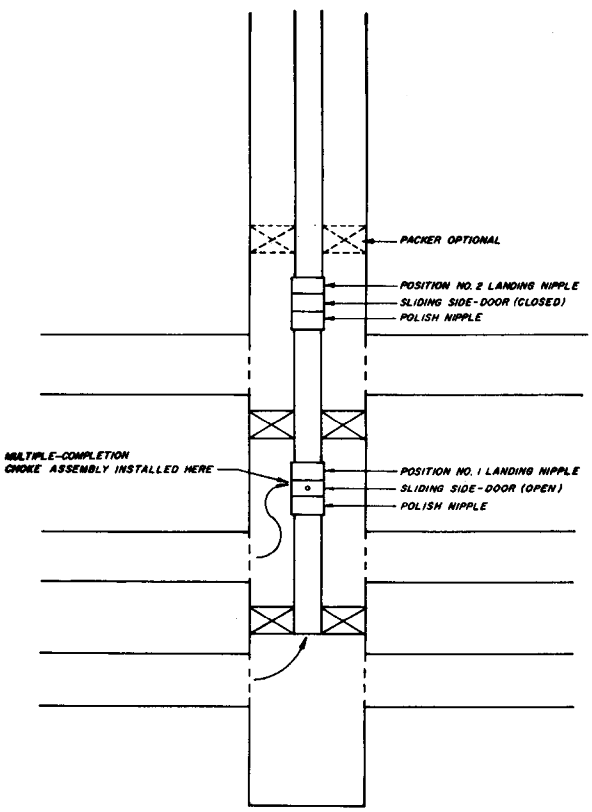

Fig. 16

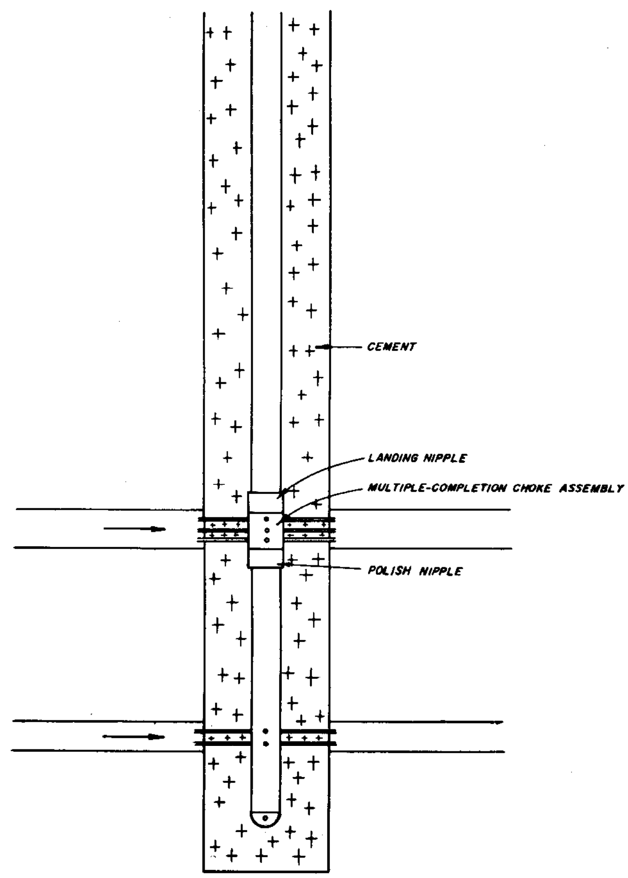

Fig. 18

Operational Suggestions

1. The following suggestions are offered to those who contemplate using the Multiple Completion Choke Assembly:

2. Set tubing with as little compression as possible to facilitate wireline operations.

3. Install side door choke in landing nipple when tubing is run to permit washing well around the bottom of the tubing.

4. Pull side door choke and clean both zones before running the check valve assembly.

5. Use a wireline operator experienced in the operation of the Multiple Completion Choke Assembly. Be sure that, on the job, he has good equipment, including a sensitive weight indicator.

6. If the lower zone is protected by a check valve, do not run the orifice head with a blank in the opening communicating with the lower zone. This action is similar to forcing a piston into a closed cylinder containing liquid, and will cause destruction of the O-ring seals on the tube and possible bending of the tube. However, this situation arises only when the lower zone is the weak zone and requires a check valve. Under these circumstances, when a test is made of the upper zone alone, the O-rings should be left off the tube of the orifice head assembly. The higher pressure of the upper zone acting against the check valve of the lower zone will prevent flow from the lower zone.

7. Take extra precaution to assure accurate measurement of the fluids produced during tests. This accuracy is very important and should be stressed with field personnel.

8. For extremely severe service, the metal sleeve-type check valve with an O-ring seal is recommended.

Future Development

The future development of the Multiple Completion Choke Assembly and the method of simultaneous production through a single flow string is projected along the following lines:

1. Improvement of materials and design so that there will be no occasions to pull the tools because of mechanical failure. This position is now well advanced, and the success of the metal and O-ring seal check valve has been quite a factor in this program.

2. Utilization of surface recorded bottom hole pressures to facilitate allocation and packer leakage tests. A large portion of the wireline work could be eliminated if one had knowledge of the two pressures upstream from the choke and of the tubing inlet pressure.

3. Presentation of informative material to state regulatory agencies in an effort to secure general acceptance of the process. This presentation is largely a matter of demonstrating the feasibility of the method, both legally and mechanically, and showing that it will effect conservation and prevent waste.

CONCLUSIONS

Simultaneous production of two reservoirs through a single flow string can result in a significant reduction in completion and lifting costs, and will increase current income and ultimate recovery. The Multiple Completion Choke Assembly can be used to maintain separation of the reservoirs and to control the rate of production from each. Test procedures have been developed which provide an acceptable method of determining the contribution from each zone. All requirements imposed by the various regulatory agencies can be satisfied.

REFERENCES

(1) W. E. Gilbert: Flowing and Gas-Lift Well Performance, Drilling and Production Practice, 126 (1954).

(2) C. V. Kirkpatrick: The Power of Gas, Camco, Inc., Houston, Texas, 1953.

(3) Fluid Gradient Curves, Camco Inc., Houston, Texas, 1961.