FEATURE ARTICLE

THEORETICAL and PRACTICAL ASPECTS of FREE PISTON OPERATION

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Abstract

Theory of operation of the free piston as well as practical limits of the device in prolonging flowing life of wells producing from volumetric type reservoirs are discussed. Reservoir behavior and the gas expansion work formalae are used to exhibit utility of free piston in prolonging natural flowing life. Examples are exhibited to show actual performance of the tool in West Texas. Investment and operating costs of the free piston are compared with those required for other artificial lift methods. A nomograph which may be used in determining adaptability of the tool is exhibited. Use of the free piston in intermittent gas lift operations is briefly mentioned.

Introduction

The basic idea of interposing in the tubing of a producing well of a solid interface, between gas and liquid phases of the produced fluid, to increase the efficiency of the lift is not new. In the original plunger lift the interface used was a solid critical diameter piston. The increase of efficiency of lift was obtained by better utilization of the energy of the compressed gas, either of the formation gas or of compressed gas supplied to the well from an outside source. Reduction to a minimum of the channeling of gas through the liquid phase and the falling back of the oil and water to be produced resulted in better utilization of the energy. This type of installation required a perfectly cylindrical and uniform diameter tubing to permit the travel of the tool.

Several years ago a free piston was developed which incorporated an expanding rubber element for sealing against the tubing wall and was therefore applicable in any conventional tubing string. Fig. 1 shows the piston.

The piston is manufactured in two types: Type 1, which is designed for installations using an outside source of gas; and Type 2, which is designed for those installations which use the well's own energy as a driving mechanism. This paper will consider only the latter type of free piston which has had considerable success in operations in West Texas, with the performance of the Type 1 only very briefly mentioned later in the text.

Operation of Free Piston

The operation of the free piston has been described in the literature.[1] Fig. 2 shows the sequence in the operation of the free piston.

The time-cycle rather than a pressure control cycle has proved most effective in that better control of the flow cycle can be achieved with a time controller in the West Texas wells. The time-cycle control can be set to close immediately after surfacing of the tool and is not effected by small fluctuations in well characteristics.

Experience indicates that each well must be considered individually with tests conducted to establish the optimum cycle of operation. Flow periods varying from 22 minutes per hour to 30 minutes every three hours have been observed. In order to secure maximum production, considerable experimenting with various flow cycles is often necessary. This fact must be impressed upon operating personnel. Otherwise, the tool may be condemned prematurely whereas satisfactory operation could be eventually obtained through experimentation.

Application

As mentioned previously, the Type 2 free piston is designed for those installations which require no outside source of gas. It has been found that the following type wells producing from volumetric type reservoirs are ideally adapted to the use of this tool.

A. Wells which tend to die during their flowing life, necessitating swabbing or other methods of lift to reestablish flow.

B. Wells which require agitation to bring about flow.

C. Intermittent flow wells which tend to load up.

An example of Type A occurred in a well in the Fullerton Clearfork field. Prior to the installation of the free piston, the well tended to load up and die, requiring frequent swabbing. After installation of the piston in Sept., 1952, the well has produced an average of 34 BOPD.

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[1]References given at end of paper.

A second well in the Fullerton field, which can be classified as Type B, had been on the pump for approximately four years before installation of the free piston. The well required periodic pumping to agitate the well fluid and maintain natural flow. A free piston was installed Feb. 1, 1953, and the pumping unit transferred to another well on March 25, 1953. The production was 27 BOPD and 2 BWPD, both pumping and using the free piston as a means of artificial lift.

An example of Type C is a well in the Keystone-Devonian field which exhibited a tendency to die unless produced at rates higher than the daily allowable. Swabbing costs were approximately $200 per month. A piston was installed during March, 1954, and the calendar day allowable of 56 BOPD has been obtained to date without failure of the tool. No swabbing jobs have been necessary since the piston was placed in operation.

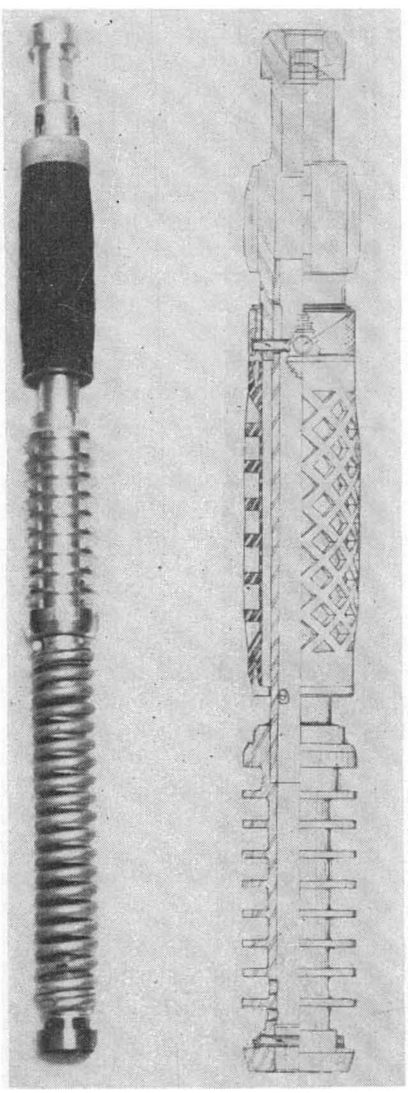

Fig. 1 — View of free piston and half-section drawing.

TABLE 1 — PERFORMANCE SUMMARY OF FREE PISTON IN WEST TEXAS OPERATIONS.

Well No.	Setting Depth Bottom Stop	Producing Formation	Production Before BOPD	Production Before BWPD	Production Before GOR	Production After BOPD	Production After BWPD	Production After GOR	Remarks
1	7,000	Clearfork	28	0	7,719	37	0	5,660	
2	6,700	Clearfork	28	1	4,640	28	1	1,670	Well on pump for four years previously.
3	6,800	Clearfork	28	0	3,624	30	0	2,969	
4	8,020	Devonian	65	0	2,767	56	0	3,310	Well required $200/mo swabbing before piston removed by free piston.
5	8,032	Devonian	32	0	6,250	65	0	1,860	High GOR penalty.
6	8,100	Devonian	24	0	1,750	20	0	1,850	Well on pump before piston installed.
7	6,299	Clearfork	17	0	4,639	34	0	3,362	Well died, piston installed 8-13-53.
8	5,057	Clearfork	27	0	2,745	17	17	1,685	Producing under packer.
9	4,157	San Andres	5	0	28,469	22	0	2,364	
10	4,161	San Andres	21	1	4,529	17	0	3,794	Well on pump before piston installed.
11	7,806	Spraberry	65	5	1,250	0	0	650	Beam equipment installed.

Table 1 lists some of the successful applications in West Texas and all have been in volumetric or solution gas type fields. Well No. 1 is an example of Type A; Well No. 2, Type B; and Well No. 4, Type C.

The only unsuccessful application to date is Well No. 11 and serves to aid in establishing limitations of the device in assisting natural flow. The test was started in Jan., 1953, at which time the well was flowing but swabbing was occasionally required to maintain the flowing production. The well had a gas-oil ratio of 1,250 cu ft/bbl at the outset, and the piston functioned somewhat erratically from the start of the trial installation. The test was suspended during the Spraberry shut-in period and tests were resumed after the field was returned to production. The gas-oil ratio had declined to approximately 500 cu ft/bbl and the piston did not function. The well is now pumping with beam type pumping equipment.

That the tool is particularly adapted to wells producing from volumetric type reservoirs is effectively illustrated by Figs. 3, 4 and 5. Fig. 4 converts the volume-pressure relationship to an energy function from the work formula plotted in Fig. 5. It emphasizes that during the phase of life of a volumetric reservoir when the bottomhole pressure becomes low, a very large amount of energy is available to maintain the flow of the well, because of increase in volumes of produced gas. Calculation of the values involved in the flow system by Bernoulli's thermodynamic equation becomes extremely complex in the multicomponent, two-phase flow system in a producing oil well. However, all factors such as friction losses, heat losses, and others may be conveniently reduced by an empirical overall efficiency factor which may be applied to the calculated gas expansion energy.

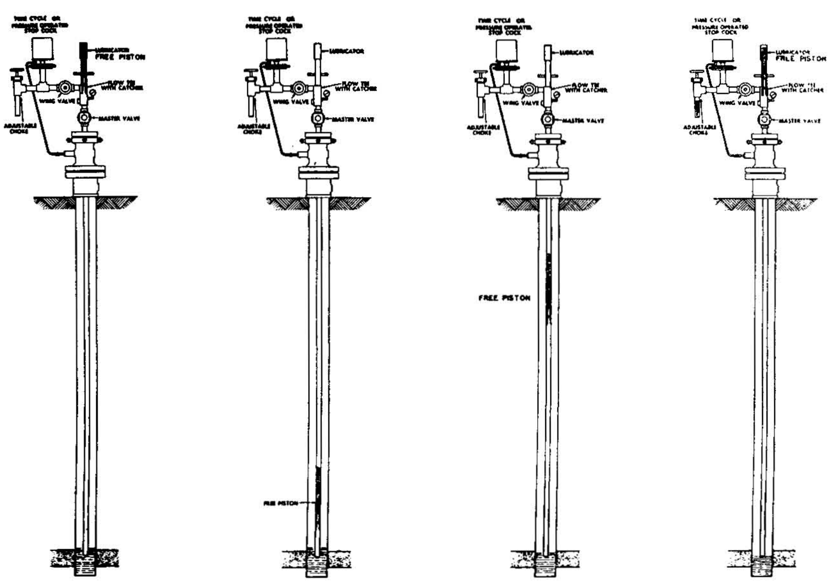

Fig. 2 — Sequence in operation of free piston: (1) piston is introduced to the well, packing elements in collapsed position; flow line valve is closed; (2) piston falls to lower stop, fluid builds up above piston; (3) flow line valve opens and piston starts to surface, packing expanded; and (4) piston passes into lubricator assembly, fluid passes down flow line to separator and cycle is repeated.

The lift efficiency of the work system in a flowing well is calculated by determining the input energy by expansion of formation gas between the limits of the flowing bottomhole well pressure and the flowing wellhead pressure with the output work being the hydraulic horsepower necessary to elevate the liquid from the reservoir datum to the surface. A few of these efficiency values calculated from flowing wells are plotted in Fig. 6 as a function of the gas-oil ratio. It will be noted that for the wells on which data was obtained the efficiency values fell between 10 per cent to 30 per cent. With these observed efficiencies it then becomes quite easy to develop the work requirements for maintaining flowing production. The efficiency of the flow system is improved by the free piston in that slippage of gas through produced fluid is reduced to a minimum. The work necessary to elevate a barrel of fluid even at low efficiencies is quite small compared to the energy per barrel available from the expanded gas (Fig. 4).

Application of the free piston may be determined by the nomograph presented as Fig. 7. The nomograph is derived from work and energy calculations assuming a fluid specific gravity of unity and an overall system efficiency of 33 per cent. The assumed efficiency compares favorably with the minimum value shown in Table 2. Flowing bottomhole and wellhead pressure plus depth to the working fluid level are used to determine the minimum producing gas-oil ratios necessary for operation of the piston. If the producing gas-oil ratio exceeds the minimum, there is an excellent prospect for sustaining flowing production with the free piston. The curves have proved realistic in determining applicability in numerous wells. Additional experience in use of the free piston will possibly lead to minor corrections in the efficiency factor upon which the curve is based.

Gas Requirements

In producing a well with the free piston, in most instances the casing annulus acts as a storage chamber for gas under pressure. Energy is stored in the form of gas under pressure and the build-up is over a period of time. Delivery of energy is rapid and in many respects is identical to stopcock flow of weak wells. As pointed out previously, the lift work is done by the gas expanding from a high to a low pressure. The inspection of charts recording the tubing and casing pressures reveals an almost instantaneous drawdown to the lowest tubing pressure recorded followed by build-up until the fluid reaches the surface. This is followed by other small fluctuations for any additional slugs of fluid. Casing pressure then drops off until the flow line valve closes. These data permit calculation of the gas volume withdrawn from the annulus during a flow cycle. In view of the sudden drawdown, it is not believed justified to assume an expansion to the lowest tubing pressure observed. Instead, the average drawdown pressure is considered more nearly accurate for calculations.

Casing and tubing pressure behaviors during the flow cycle are illustrated in Fig. 8. A correction is made to compensate for the pressure head of the compressed gas column, inasmuch as the actual work is done by the casing gas expanding as it enters the tubing.

It is also assumed that all the gas drawn from the casing during the cycle is utilized in lifting the free piston from its setting depth to the surface. In order to obtain the volume of gas used, the maximum and minimum casing pressure during the cycle are observed. The total annular volume is known, and it is relatively simple to calculate the volume of gas which must be removed from the annulus during each cycle to bring about the observed pressure change. In making these calculations, it is assumed that the casing gas behaves as an ideal gas, compressibility and other factors being neglected. It is believed that the values given by this method of calculation are of suf-

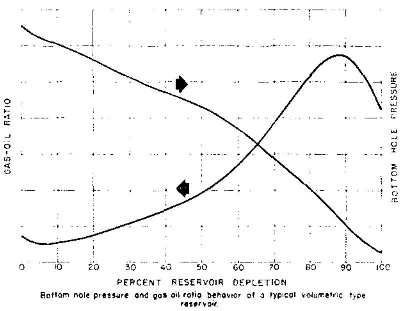

Fig. 3 — Bottomhole pressure and gas-oil ratio behavior of a typical volumetric type reservoir.

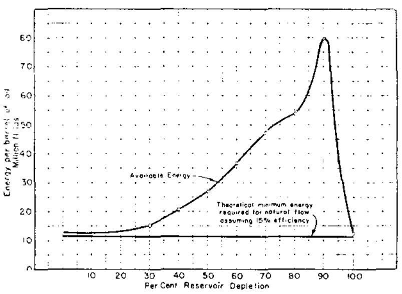

Fig. 4 — Available energy per barrel of oil at stages of depletion for a volumetric type reservoir.

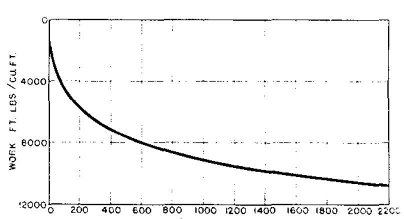

Fig. 5 — Plot of $W = RT \ln \frac{P_1}{P_2}$, gas expansion work formula by which GOR-pressure function is converted to available work.

TABLE 2 — THEORETICAL AND ACTUAL GAS LIFT REQUIREMENTS BASED ON DELIVERY FROM THE CASING AND ANNULUS ON TWO WELLS.

Flow Interval	Casing Pressure	Tubing Pressure	BOPD	Choke	Lift Gas Cu Ft/Bbl, per 1,000 Ft Theoretical	Lift Gas Cu Ft/Bbl, per 1,000 Ft Actual	Per cent Efficiency
Well No. 1							
14½ hrs every 24 hrs	950-660	950-375	29	14	238	75	*
6 hrs every 12 hrs	920-660	920-380	27	15	243	129	*
30 min every 4 hrs	885-645	840-210	25	24	188	386	49
30 min every 2 hrs	830-720	800-300	29	18	225	300	75
20 min every 1 hr	640-530	600-180	40	24	196	457	43
22 min every 1 hr	600-490	560-160	38	24	194	476	41
24 min every 1 hr	580-470	540-210	37	24	219	491	45
Well No. 2							
30 min every 2½ hrs	475-300	290-20	28	Open	130	404	32
30 min every 2 hrs	460-300	290-25	28	Open	135	469	29
20 min every 2 hrs	400-300	260-30	27	Open	141	299	47
15 min every 1½ hrs	450-350	330-40	26	Open	154	406	38

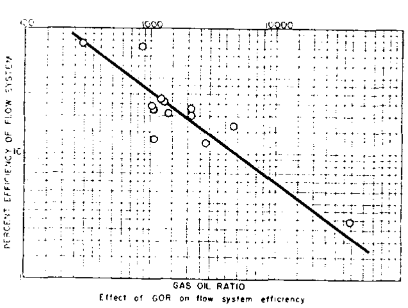

Fig. 6 — Effect of GOR on flow system efficiency.

ficient accuracy for approximating gas volumes drawn from the annulus during a flow cycle. The actual amount of gas used (cu ft/bbl/1,000 ft of lift) is calculated from Equation 1.

Equation 1

$$\text{Actual gas used (cu ft/bbl/1,000 ft)} = \frac{\text{Gas from casing annulus per cycle (cu ft)}}{\text{Fluid lifted (bbl)} \times \text{setting depth of piston (1000's of ft)}}$$

The theoretical gas requirement is determined using the isothermal work of expansion of the gas from the highest annular pressure to the average tubing pressure.

Equation 2

$$\text{Theoretical gas requirement (cu ft/bbl/1000 ft)} = \frac{\text{lbs/bbl} \times 1{,}000 \text{ ft}}{\text{Expansion work (ft lbs/cu ft)}}$$

From Table 2, it can be seen that in most instances as the casing pressure decreased, the theoretical gas requirements also decreased. As shown previously, theoretical gas requirements were computed from expansion energy while actual gas used was computed from the change in gas volume in the casing annulus. It should be noted that this latter value includes the work necessary to overcome all frictional resistance present in the tubing while this same resistance is neglected in calculating the theoretical gas volume requirement.

The very low values of the actual lift gas requirements for the 14½- and 6-hour flow periods are due to the fact that only pressure drops and no time factors were taken into account. Based on observations, approximately 22 minutes are required for the free piston to surface from 7,000 ft. If the flow-line valve is allowed to remain open after the piston reaches the surface, the casing pressure continues to bleed down to a certain point, depending upon the choke size, and then levels off. Inasmuch as only the overall pressure drop was considered in calculating the gas volumes rather than the pressure at the instant the piston reached the surface, the small gas requirement is due to use of the lower pressure with a resultant increase in expansion work.

It can be seen that Well No. 2 has a much lower theoretical lift ratio than Well No. 1, which is due to the choke being open and the gas expanding to a lower pressure, thus securing additional work of expansion.

It is interesting to note that the actual gas required for lift is essentially the same for both wells. If the assumption that the casing supplies all the lift gas is valid, the theoretical lift ratio can be taken as approximately 225 cu ft/bbl/1,000 ft of depth and the actual gas requirements taken as 400 to 450 cu ft/bbl/1,000 ft of lift. No attempts were made to evaluate the frictional resistance of the tubing, for it would be of little significance as it would pertain to only the two wells in question.

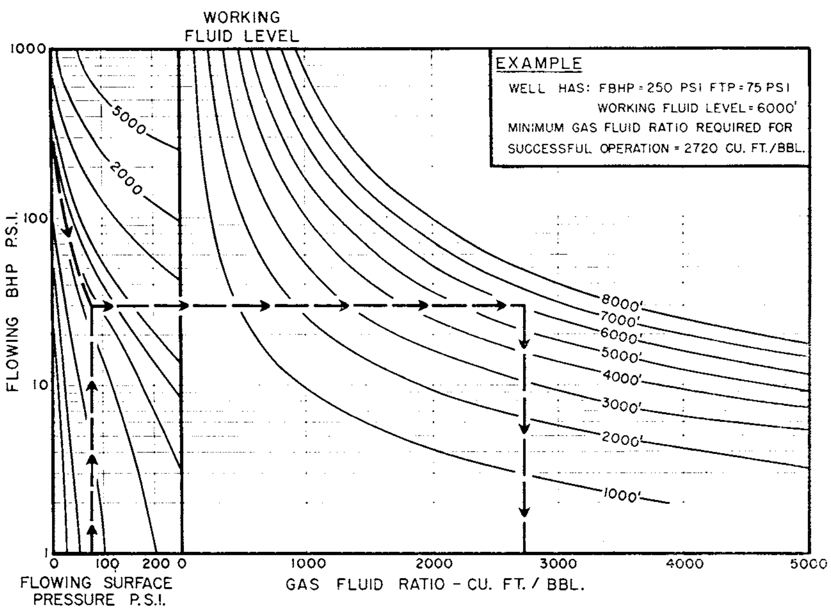

Fig. 7 — Nomograph for estimating limits of free piston application.

In order to verify the contention that the casing acts as a storage chamber for almost all the lift gas, a gas balance was made for a 24-hour period on two wells. These pertinent data and gas balances are as shown in Table 3.

TABLE 3

Well No. 1

Piston Setting Depth — 6,700 ft
Production — 39 bbl of oil
Flow Cycle — 22 minutes every hour
Fluid Produced per cycle — 1.625 bbl
Gas-oil ratio — 5,660 (metered)
Total gas produced/cycle — 9,240 cu ft
Net tubing volume allowing for fluid buildup — 128 cu ft
Amount of gas in tubing at start of cycle — 4,900 cu ft
Tubing pressure — 550
Lift gas furnished by casing — 5,150 cu ft
Total gas account/cycle — 10,050 cu ft
Deviation $\frac{10{,}050 - 9{,}240}{9{,}240} \times 100 = 8.9$ per cent

Well No. 2

Piston Setting Depth — 7,000 ft
Production — 28.29 BOPD: 2.07 BWPD
Flow Cycle — 20 minutes every 2 hours
Fluid Produced per cycle — 2.53 bbl
Gas-Oil Ratio — 3,000:1 (metered)
Total gas produced/cycle — 7,060 cu ft
Net Tubing volume allowing for fluid buildup — 139 cu ft
Amount of gas in tubing at start of cycle — 2,730 cu ft
Tubing pressure — 275
Lift gas furnished by casing — 5,170 cu ft
Total gas accounted/cycle — 7,900 cu ft
Deviation $\frac{7{,}900 - 7{,}060}{7{,}060} \times 100 = 11.9$ per cent

The 9 per cent and 12 per cent deviation between actual gas produced and that accounted for by calculations is considered to be well within limits of method of accuracy, particularly as no corrections for temperature and density were made in the gas volume calculations.

Producing gas-oil ratios, shown in Table 1, have shown a reduction after installing the free piston as compared with unassisted flow. Gas-oil ratio is an inherent function of reservoir behavior and characteristics and it is difficult to present a plausible theory in explanation of these results. The gas measurements have been made carefully within the limits of accuracy of techniques. The order of magnitude of differences is too high to be ascribed to measurement errors. The data are presented therefore as a factual reporting of the information collected.

Piston vs Intermitters

In order to determine the effectiveness of the free piston as compared to stopcock flow, the free piston was removed and Well No. 1 allowed to flow on the same time cycle using the intermitter alone. Production dropped from 34 to 26 BOPD during the 13-day period in which the piston was removed. Immediately after rerunning this tool. the production increased to 31

BOPD and the following day to 32 BOPD, at which time the test was discontinued.

Based on these tests, it is believed that a straight intermitting cycle cannot produce as much oil as a free piston installation in a solution gas reservoir. It is furthermore believed that, in the case of a well which produces water, the removal of the free piston will bring about a more pronounced decrease in production than that in the above well which produced no water. The reason for this is that the water being heavier than the oil will tend to drop downhole through the rising gas column until eventually the hydrostatic head will exceed the formation pressure and the well will cease to flow.

Cost

Based on data obtained, it is believed that the free piston can prolong the flowing life of a well and thus pay out the investment of approximately \$1,000 per well, at the same time delaying and in some cases eliminating the expenditure of up to \$15,000 for a pumping installation. Pumping units have been replaced by the free piston in three of the West Texas wells in which the main function of the pump was to agitate the well and remove the water from the bottom. Value of the salvaged equipment equals approximately \$33,000 for the three wells. The installation of the free piston requires setting a stop or using the seating nipple, if the well has been on the pump.

The total installation cost for the free piston, including the time cycle control and surface lubricator, as well as installing the bottom stop, is approximately \$1,000, which is considerably less than that required for any other method of artificial lift. The use of the plunger can be justified by a savings in operating costs alone.

Another advantage to the use of the free piston is in preventing paraffin accumulation in the wells. Some wells in which the tool has been installed required paraffin removal by scraping before installing the tool. There has been no necessity for scraping paraffin after the installation of the tool which contributes to the payout.

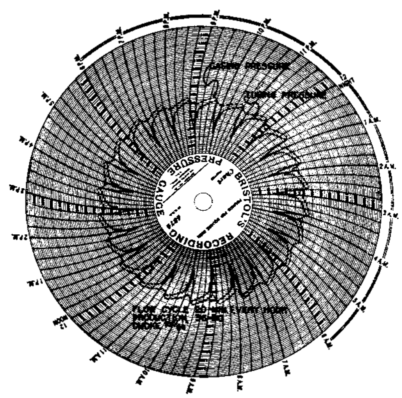

Fig. 8 — Casing and tubing pressure behaviors during the flow cycle.

Limitations

As mentioned previously, the average velocity obtained in the installations has varied from 250 ft to 650 ft per minute. Based on these data alone, a maximum production of approximately 80 B/D of fluid can be realized with the 2 in. piston. At present, 70 BOPD from approximately 8,000 ft is the maximum daily production being obtained continuously in the operations observed. However, this figure may be increased somewhat in future installations.

Pressured Bellows Controlled Free Piston

The previously mentioned Type 1 piston is used to improve the efficiency of intermittent gas lift operations. The pre-pressured metallic bellows controls the expansion and contraction of the sealing element of the piston.

Between the cycles of operation the piston rests in the bottom of the tubing with the seal contracted. When a pre-determined head of well fluid accumulates above the piston, the bellows is compressed expanding the seal. High pressure gas is then injected under the piston and the fluid delivered to the surface. When the fluid head has been removed from the tubing and the tubing pressure bled down below the pressure charge of the bellows, the bellows elongates, the seal contracts and the piston returns to the bottom for the next cycle of operation.

A number of installations of this type of free piston are in routine operation in different oil fields of the country. Last year a three-month test of the piston was performed in a well in southern Oklahoma. The well was previously produced with a reciprocating type subsurface pump. Overall piston efficiencies of around 40 per cent were indicated. It is interesting to note that attempts were unsuccessful to obtain comparison in the same well of operation of the piston with conventional intermittent gas lift. Because of severe paraffin conditions, the well could not be produced satisfactorily with conventional intermittent gas lift, while the travel of the piston kept the tubing free of paraffin.

Conclusions

An innovation of an old method of artificial lift has been presented. Data have shown that by the use of the tool a large capital investment of other types of artificial lift installations can be deferred or eliminated in many wells producing from volumetric type reservoirs and at the same time, the cost of the free piston can be amortized within one year through the savings in operating costs alone. The tool is not an answer to all producing problems; however, based on the results to date, satisfactory operation can be secured in many wells producing from solution gas drive reservoirs.

Acknowledgment

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