PREDICTING PLUNGER PERFORMANCE

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INTRODUCTION

Now that we are into the "energy crunch", (that many oil men could see coming years ago) we are looking for new methods of finding oil and gas, new methods of producing oil and gas, and re-examining some of the existing production methods.

The price of oil and gas at the wellhead will not be going down in the future. With exploration costs and new well completion costs at their all-time high, and with the price of "new" oil now very attractive, some of the least expensive "new" oil will be the additional production that can be attained from already existing low production or stripper wells whose operation may previously have been considered uneconomical.

The object of this paper is to show how good analysis will identify wells that are candidates for increased production and to show how proper selection and correct installation of plunger equipment can turn a borderline well into a profitable producer.

IDENTIFYING PLUNGER APPLICANTS

A subsurface plunger is an excellent tool for producing a well to reservoir depletion. The applicability of this method of production is dependent on numerous factors such as: gas-to-liquid ratio (GLR); total liquid production; reservoir pressure; reservoir producing characteristics; and depth of well.

To simplify the identification of those wells where plunger lift can be installed successfully, a series of tables are available that correlate the required GLR (in MCF per barrel), gas required (in MCF per cycle), P_c (the required average surface casing pressure, the maximum production attainable in barrels per day, and the maximum cycles per day. The tables are prepared for two tubing sizes, 2-3/8 in. and 2-7/8 in., and for six tubing wellhead pressures, 0, 30, 60, 100, 150, and 200 psi. These tables (which are available through the author) represent the normal performance that can be expected using plunger lift under the given well conditions. Productivity index and inflow performance are not included.

The tables are based on the performance charts presented by Foss and Gaul[1]. While none of their charts and graphs are presented here, they were used for the thousands of points that were picked and placed in tabular form.

According to Foss and Gaul[1], it is possible to operate a subsurface plunger installation over a wide range of average casing pressures. But for any given set of well conditions, it is desirable to operate with the lowest possible casing pressure in order to achieve the greatest well drawdown since flowing bottomhole pressure is a direct function of casing pressure. It should also be noted that gas requirements per cycle decrease as casing pressures decrease. However, total production increases as casing pressure increases. Consequently, the most effective subsurface plunger operation must be a compromise between these two limits, with an operating casing pressure that reflects the balance between optimum drawdown and optimum production.

Any plunger lift well has limitations as to pressure (P_c) or volume of gas, and one of these will be a governing factor. Similarly, for a given depth of well, the liquid delivery per cycle (load) is directly related to the volume of gas available for that cycle. Furthermore, the liquid delivery per cycle (load) varies with P_c. As P_c decreases, the load decreases; and conversely. All of these complex interrelationships have made plunger performance difficult to predict.

The tables reflect the expected results of optimum operation (called Class B) and are a balance among the above mentioned variables. Rarely will a well match these optimum conditions, but they can be used as a norm in categorizing the wells that are being considered for plunger lift equipment or for evaluating the performance of existing plunger installations.

Matching the well's conditions to those shown in the tables will quickly reveal whether the particular well is a plunger applicant, and if so, how to optimize its performance.

When interpreting the data given in these tables, the following facts should be kept in mind:

1. If the P_c of the producing well is higher than the required P_c, production will be less.
2. If the P_c of the producing well is less than the P_c required, then the plunger will not operate.
3. If the produced GLR is greater than the required GLR, production will be less. Gas should be produced from casing in this instance.
4. If the produced GLR is less than the required GLR, cycles per day and production will be less.
5. If the produced GLR is less than any required GLR shown on the table, then the plunger will not run.

DETERMINING PLUNGER APPLICANT CLASSIFICATION

Wells that are being considered as plunger candidates will fall into two categories. Whether you classify the well as an oil well or a gas well does not matter. These categories are:

CATEGORY	WELL CONDITION
1	The well does not have sufficient gas volume or pressure to operate a plunger.
2	The well has the required volume and pressure of gas to operate a plunger.

By comparing the data of the well in question with the appropriate table, it can quickly be determined whether or not the well is a plunger applicant.

If the well fits Category 1, it is obviously *not a plunger applicant* and no further investigation is necessary - a plunger is not workable. If an outside source of high-pressure gas is available, a Category 1 well would be considered the same as Class C2.

If the well fits Category 2, *it is a plunger applicant,* and further analysis is required to determine its secondary classification (Class A, B, or C) to determine its plunger requirements:

CLASS	WELL CONDITION
A	The well produces more gas than is required to run a plunger.
B	The norm where the well has the required volume of gas to run the plunger most efficiently. (This is the basis for the tables.)
C	The well has sufficient gas volume to run the plunger but not at its greatest efficiency.

Class A primarily describes a situation in which a plunger is run in a gas well to keep liquid unloaded. Gas wells tend to load up with liquid if the gas velocity in the tubing string is so low that liquid is not brought out of the wellbore with the gas flow. This "loading up" is indicated by a continuous loss in tubing pressure at the wellhead. This "loading up" may occur in a period of hours, days or even weeks before gas production from the formation ceases. Surface indications of "loading up" are a continuous loss of wellhead tubing pressure or constantly decreasing gas volume where the well is floating on the line.

Wells of this nature are often blown to the atmosphere for some period of time to clear the liquid from the wellbore. After this procedure, the well will produce at a high gas rate until the wellbore again loads up with liquid. To obviate this, a plunger and a time cycle intermitter allows the well to be automatically cycled as required to prevent the flowing bottomhole pressure from becoming unduly high. Maximum drawdown is maintained, and maximum gas production is achieved. This is possibly the most common application of plunger lift.

This class of well always has a much higher GLR than is required to operate the plunger (maximum liquid production is realized when a plunger installation has the optimum GLR). Either a higher or lower GLR will result in a lower liquid production from the well.

Hacksma[2] uses a pseudo-load size and IPR curves to show that a GLR higher than optimum results in lower production because bottomhole pressure cannot be reduced as much. The reader should refer to Hacksma for these conditions.

Wells falling in Class A can be produced by plunger lift in two ways as described below:

CLASS	WELL CONDITION
A1	For wells in which all gas and liquid are produced through the tubing with liquid production less than maximum due to high GLR.
A2	For wells in which excess gas is produced from the casing, and liquid and gas are produced through the tubing at optimum GLR for maximum liquid and gas production.

Class B describes wells in which the gas volume produced through the casing between cycles is exactly the volume required to lift the liquid produced between cycles. As soon as the plunger arrives on bottom, conditions are such that it can immediately start back up the tubing. This may also be referred to as the optimum producing GLR. It is the most efficient form of plunger lift with the plunger making the greatest number of cycles per day.

Class C describes wells that have a lower GLR than is required to operate the plunger at maximum production. Maximum liquid production can be realized only when a plunger installation is operating at optimum GLR.

Wells falling in Class C can be produced by plunger lift two ways as described below:

CLASS	WELL CONDITION
C1	For wells in which all gas and liquid is produced through the tubing with liquid production less than optimum due to low GLR.
C2	For wells that have supplementary gas sources. If high-pressure surface gas line is available, these wells can use this supple- mentary gas by injection into the casing. This develops the opti- mum GLR and produces maximum liquid production through the tubing.

EXAMPLE CALCULATIONS

Example No. 1

Stated well conditions:

2-7/8 in. OD tubing
100 psi wellhead back pressure
70 BPD producing rate
210 MCF/D gas production
3000 GLR produced
Tubing depth is 8000 ft

Enter Table No. 1 at 8000 ft depth on GLR line and proceed to right to GLR = 3.0. Observe that the required GLR is from 3.7 to 14.0 which exceeds the produced GLR value of 3.0. It is concluded that this well is not a plunger candidate since the produced GLR is less than required GLR for this depth. (Category No. 1)

Example No. 2

Stated well donditions:

2-7/8 in. OD tubing
100 psi wellhead back pressure
20 BPD producing rate
600 MCF/D gas production
30,000:1 GLR
Tubing depth is 9000 ft

Enter Table No. 1 at 9000 ft on the BPD line and proceed right to 20 BPD (in this case 19). From the table, read the following values:

GLR	= 16 MCF/BBL required
MCF	= 4.0 MCF/cycle required
P_c	= 162 psi (this is the lowest average casing pressure possible)
Cycles	= 78 cycles per day (maximum)
Liquid Delivery	= 0.25 barrels per cycle (This value is read at the top of the column.)

It is concluded that this well is a plunger candidate since the produced GLR (30,000:1) is greater than the required GLR of 16 MCF/BBL (16,000:1) provided P_c is 162 psi or higher. This well fits Category No. 2.

Example No. 3 (Classes A1 and A2)

Wells fitting Category No. 2, Class A1 can not be solved by the method presented herein.[2]

An example calculation for wells fitting Category No. 2, Class A2 is shown below. For the same well conditions as in Example No. 2, enter the table at 9000 ft on the BPD line and proceed right to a value of 20 BPD (in this case 19 BPD) and read the same values as in Example No. 2 for required GLR, MCF/cycle, P_c, cycles/day and liquid delivery. Since the well produces 600 MCF/D, the gas volume required for plunger lift is:

4.0 MCF x 78 cycles/MCF = 312 MCF/D

an excess of (600 - 312 = 288) 288 MCF/Day. This means that 288 MCF of gas can be produced from the casing with the remaining 312 MCF used to lift the 20 BPD liquid. This allows the well to operate at the lowest casing pressure possible (P_c = 162) for maximum production.

Example No. 4

Given the following well conditions:

2-7/8 in.OD tubing
100 psi wellhead back pressure
50 BPD producing rate
250 MCF/D gas production
5000:1 GLR produced
Tubing depth 10,000 ft

The well will have to operate the plunger using its own produced gas (namely 250 MCF/D at 5000:1 GLR) so the required GLR cannot exceed the produced GLR of 5.0 MCF/BBL.

Enter Table No. 1 at 10,000 ft depth. On the GLR line, proceed to the right until reaching 5.0 and read the following values:

MCF	= 13.7 MCF/cycle required
P_c	= 493 psi
BPD	= Does not apply in this example
Cycles	= Do not apply in this example
Liquid Surface Delivery	= 2.75 barrels per cycle (This value is read at the top of the column.)

The number of cycles is calculated as:

250 MCF gas/13.7 MCF cycle = 18 cycles

The possible production without outside gas is:

18 cycles at 2.75 barrels per cycle = 48.5 BPD

It is concluded that a P_c of 493 psi is required for this well to lift the required production (Class C1).

Example No. 5

Given the following well conditions:

2-7/8 in. OD tubing
100 psi wellhead back pressure
50 BPD producing rate
250 MCF/D gas production
5000:1 GLR produced
Tubing depth 10,000 ft

Enter Table No. 1 at 10,000 ft depth. On the BPD line proceed to the right until intersecting the column closest to 50 BPD (in this case 51) and read:

GLR	= 8.4 MCF/BBL required
MCF	= 6.3 MCF/cycle required
P_c	= 232 psi (this is the lowest average casing pressure possible)
Cycles	= 69 cycles/day (maximum)
Liquid Surface Delivery	= 0.75 barrels/cycle (read at top of column)

The following calculations are made:

GLR Required	= 8.4 MCF/BBL
GLR Produced	= 5.0 MCF/BBL

Gas required from outside source = 3.4 MCF/BBL

It is concluded that good plunger lift is possible if 170 MCF/D gas is available from an outside source. The P_c of 232 psi is the lowest possible at which this well could be operated. (It should be noted that with gas from an outside source, P_c is reduced to 261 psi less than the P_c value in Example No. 4). Consequently, liquid and gas production would increase depending on the well's productivity index.

EQUIPMENT RECOMMENDATIONS

Plunger equipment is very versatile, and the installations can be adapted to suit virtually any condition desired by the operator. Figs. 1 through 4, however, illustrate two of the more common wellhead and downhole installations.

Figures 1 and 2 show the recommended wellhead and downhole installation, respectively, for a well that produces more gas than required to run the plunger (as in Category 1). The type well suitable for this equipment is one having excess gas production flowing through the casing with liquid production through the tubing.

TABLE 1

SUB-SURFACE PLUNGER APPLICATION INFORMATION

DEPTH OF WELL — FEET		LIQUID SURFACE DELIVERY PER CYCLE — BARRELS															
		0.25	0.50	0.75	1.00	1.25	1.50	1.75	2.00	2.25	2.50	2.75	3.00	3.25	3.50	3.75	4.00
2000	GLR	2.4	1.6	1.4	1.1	1.1	1.0	1.0	.9	.9	.9	.8	.8	.8	.8	.8	.8
	MCF	.6	.8	1.0	1.1	1.3	1.4	1.6	1.7	1.9	2.1	2.2	2.3	2.5	2.7	2.9	3.1
	Pc	143	171	199	225	254	282	311	340	367	393	422	450	479	506	533	562
	BPD	84	160	227	288	342	393	437	480	515	552	585	618	643	672	697	720
	~	339	320	303	288	274	262	250	240	230	221	213	206	198	192	186	180
3000	GLR	4.8	2.8	2.2	1.8	1.7	1.6	1.5	1.4	1.4	1.4	1.3	1.3	1.3	1.3	1.3	1.3
	MCF	1.2	1.4	1.6	1.8	2.1	2.3	2.6	2.8	3.0	3.3	3.6	3.8	4.1	4.3	4.6	5.0
	Pc	146	174	203	230	259	288	318	347	374	401	431	459	489	517	544	574
	BPD	57	110	159	206	247	288	325	360	391	422	451	480	503	528	551	576
	~	230	221	213	206	198	192	186	180	174	169	164	160	155	151	147	144
4000	GLR	6.4	4.0	3.1	2.5	2.4	2.2	2.1	2.0	1.9	1.9	1.9	1.8	1.8	1.8	1.8	1.8
	MCF	1.6	2.0	2.3	2.5	2.9	3.2	3.6	3.9	4.2	4.6	5.0	5.3	5.6	6.1	6.4	6.9
	PC	148	178	207	234	265	294	324	354	382	410	440	469	499	527	556	586
	BPD	43	84	123	160	193	226	251	288	315	342	368	393	416	437	457	480
	~	174	169	164	160	155	151	147	144	140	137	134	131	128	125	122	120
5000	GLR	8.4	5.0	3.9	3.3	3.0	2.8	2.7	2.5	2.4	2.4	2.4	2.4	2.3	2.2	2.2	2.2
	MCF	2.1	2.5	2.9	3.3	3.7	4.1	4.6	5.0	5.4	5.8	6.4	6.8	7.3	7.6	8.3	8.8
	Pc	151	182	211	239	270	300	331	361	390	418	449	478	509	538	567	598
	BPD	35	68	100	131	160	187	213	240	263	287	310	330	351	371	390	400
	~	140	137	134	131	128	125	122	120	117	115	113	110	108	106	104	100
6000	GLR	10.0	6.0	4.7	4.0	3.6	3.4	3.2	3.1	3.0	2.9	2.9	2.8	2.8	2.7	2.7	2.7
	MCF	2.5	3.0	3.5	4.0	4.5	5.1	5.6	6.2	6.7	7.2	7.8	8.3	8.9	9.4	10.0	10.6
	Pc	154	185	215	244	275	306	338	368	397	427	457	488	519	549	579	610
	BPD	29	57	84	110	135	159	182	204	227	247	266	288	305	322	341	360
	~	117	115	113	110	108	106	104	102	101	99	97	96	94	92	91	90
7000	GLR	12.0	7.2	5.6	4.7	4.4	4.0	3.8	3.7	3.6	3.5	3.4	3.3	3.3	3.3	3.2	3.2
	MCF	3.0	3.6	4.2	4.7	5.4	6.0	6.6	7.3	8.0	8.6	9.2	9.9	10.6	11.2	11.9	12.6
	Pc	157	189	219	248	281	312	344	375	405	435	466	497	529	559	590	622
	BPD	25	49	72	96	117	138	159	180	198	217	236	252	269	287	303	320
	~	101	99	97	96	94	92	91	90	88	87	86	84	83	82	81	80
8000	GLR	14.0	8.4	6.6	5.5	5.1	4.7	4.4	4.3	4.1	4.0	3.9	3.9	3.8	3.8	3.7	3.7
	MCF	3.5	4.2	4.9	5.5	6.3	7.0	7.7	8.5	9.2	9.9	10.7	11.5	12.2	13.0	13.7	14.6
	Pc	160	192	223	253	286	318	351	382	412	444	475	507	539	570	602	634
	BPD	22	43	64	84	103	123	141	160	175	192	209	225	240	255	270	284
	~	88	87	86	84	83	82	81	80	78	77	76	75	74	73	72	71
9000	GLR	16.0	9.6	7.5	6.3	5.8	5.4	5.1	4.9	4.7	4.6	4.5	4.4	4.3	4.3	4.2	4.2
	MCF	4.0	4.8	5.6	6.3	7.2	8.0	8.8	9.7	10.5	11.4	12.2	13.1	14.0	14.8	15.6	16.7
	Pc	162	196	228	258	292	324	358	390	420	452	484	516	549	581	613	646
	BPD	19	38	57	75	92	109	126	144	159	177	189	204	217	234	251	264
	~	78	77	76	75	74	73	72	72	71	71	69	68	67	67	67	66
10000	GLR	18.0	11.0	8.4	7.2	6.5	6.0	5.8	5.5	5.3	5.1	5.0	4.9	4.9	4.8	4.7	4.7
	MCF	4.5	5.5	6.3	7.2	8.1	9.0	10.0	10.9	11.8	12.7	13.7	14.7	15.7	16.6	17.6	18.8
	Pc	165	200	232	262	297	330	364	397	428	461	493	526	560	591	625	658
	BPD	17	35	51	68	83	100	117	132	144	160	173	189	198	213	225	240
	~	71	71	69	68	67	67	67	66	64	64	63	63	61	61	60	60
11000	GLR	20.0	12.2	9.5	8.0	7.3	6.8	6.4	6.2	6.0	5.8	5.6	5.5	5.4	5.4	5.3	5.3
	MCF	5.0	6.1	7.1	8.0	9.1	10.2	11.2	12.2	13.3	14.3	15.4	16.5	17.5	18.6	19.7	21.0
	Pc	168	203	236	267	302	336	371	404	435	469	502	535	570	602	636	670
	BPD	16	32	47	63	76	91	105	120	132	145	159	171	185	196	206	220
	~	64	64	63	63	61	61	60	60	59	58	58	57	57	56	55	55
12000	GLR	22.4	13.4	10.4	8.8	8.0	7.5	7.1	6.8	6.6	6.4	6.3	6.1	6.0	6.0	5.9	5.9
	MCF	5.6	6.7	7.8	8.8	10.0	11.2	12.4	13.5	14.7	15.8	17.1	18.3	19.5	20.7	22.0	23.3
	Pc	171	207	240	272	308	342	378	411	443	478	511	545	580	613	648	682
	BPD	14	29	43	57	71	84	96	110	121	135	145	159	169	182	191	204
	~	59	58	58	57	57	56	55	55	54	54	53	53	52	52	51	51

LEGEND: GLR: — Required Gas Liquid Ratio MCF/BBL.
MCF — MCF Required Per Cycle.
Pc — Required Surface Casing Pressure* (average)
BPD — Maximum Production BBLS./DAY
~ — Maximum Cycles Per Day.

2⅞ O.D. TUBING
100 PSI WHBP

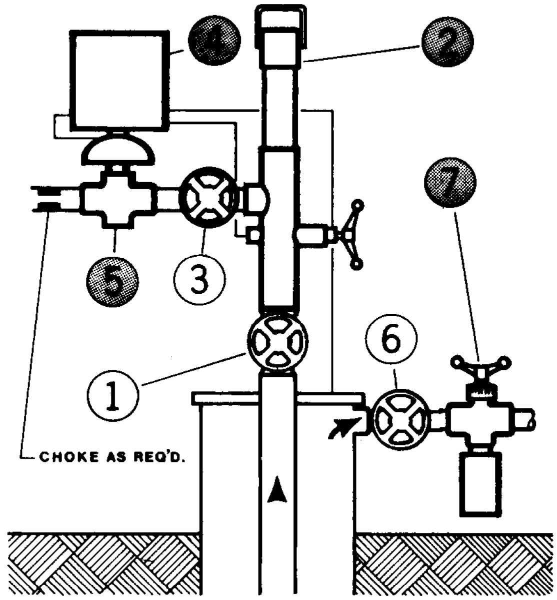
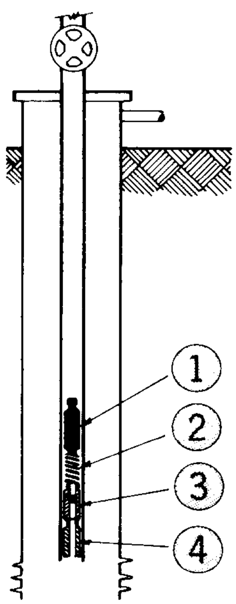


FIG. 1—WELLHEAD FOR WELL PRODUCING MORE GAS THAN REQUIRED TO RUN PLUNGER



EQUIPMENT REQUIRED

1. SUBSURFACE PLUNGER
2. BUMPER SPRING
3. RETRIEVABLE STANDING VALVE
4. RETRIEVABLE TUBING STOP

FIG. 2—DOWNHOLE INSTALLATION FOR WELL PRODUCING MORE GAS THAN REQUIRED TO RUN PLUNGER

The surface equipment required for such a well includes:

Number on Figure	Equipment Item
1	Full bore master valve
2	Lubricator w/automatic "plunger arrival" signal
3	Flow valve.
4	Surface controller
5	Type AM motor valve
6	Flow valve
7	Control valve

The downhole equipment required for this type of well is listed in Fig. 2.

Standard plunger lift operation is sequentially described in Table 2.

TABLE 2—STANDARD PLUNGER OPERATION FOR WELL PRODUCING MORE GAS THAN REQUIRED TO RUN PLUNGER

1. Plunger at bottom of well.
2. Excess gas flows from casing through control valve to sales.
3. Pressure build-up or time signal opens surface controller which lowers the tubing pressure, creating the differential necessary to lift the liquid and plunger to the surface.
4. Gas and liquid are delivered through flow outlet to sales or low-pressure system.
5. Plunger arrives in lubricator, partially closing off outlet.
6. Differential pressure between lubricator and flow line created by plunger arrival activates automatic "plunger arrival" signal shutting off motor valve on flow outlet. Time cycle with low casing pressure (or low casing pressure shutoff only) will also close motor valve.
7. Plunger falls to bottom and cycle recommences.

This equipment arrangement would also apply for Category 2 wells, where the optimum GLR exists. The only difference would be that gas would not be produced from the casing, the flow and control valves (valves 6 and 7 of Fig. 1) would be shut or eliminated, and all gas and liquid production would flow through the tubing.

Figures 3 and 4 show a typical wellhead and downhole installation for a well that produces insufficient gas to run the plunger, as in Category 3. This well is being gas-lifted on packer and all flow is through the tubing.

The surface equipment required for such a well includes:

Number on Figure	Equipment Item
1	Full bore master valve
2	Lubricator
3	Second flow outlet
4	Flow valve
5	Control valve or time cycle intermitter
6	Flow valve

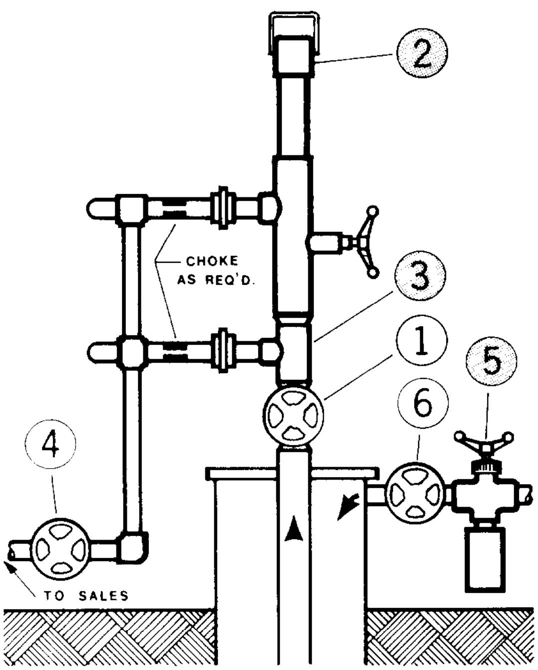


FIG. 3—WELLHEAD FOR WELL PRODUCING INSUFFICIENT GAS TO RUN PLUNGER

The downhole equipment required is listed in Fig. 4.

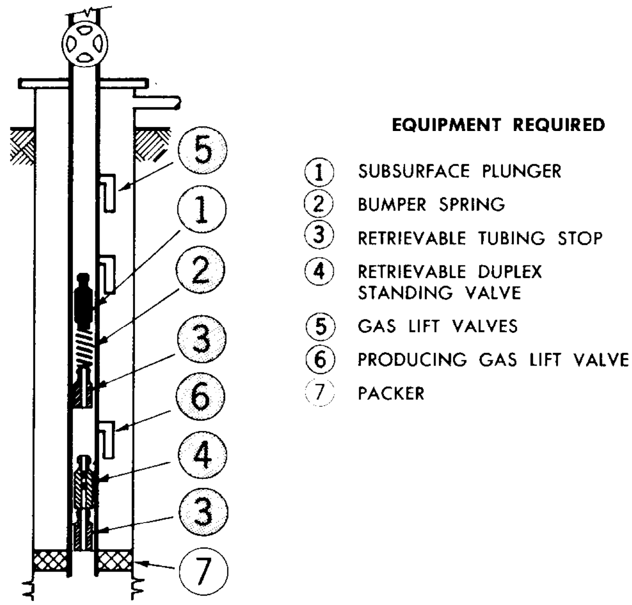


FIG. 4—DOWNHOLE INSTALLATION FOR WELL PRODUCING INSUFFICIENT GAS TO RUN PLUNGER

Standard plunger operation is categorically listed in Table 3.

TABLE 3—STANDARD PLUNGER OPERATION FOR WELL PRODUCING INSUFFICIENT GAS TO RUN PLUNGER

1. Plunger is at bottom of well.
2. Gas flows through control valve (or time cycle intermitter) and opens the gas lift valve down hole, creating the differential necessary to lift the liquid and plunger to the surface.
3. Gas and liquid are delivered through upper outlet.
4. Gas lift valve then closes.
5. Plunger arrives in lubricator, partially closing off upper outlet.
6. Tail gas is rapidly dissipated through lower outlet.
7. Plunger falls to the bottom of the well and the cycle recommences.

Note that this installation utilizes gas lift valves to unload the well and operate the plunger. A packer can be set (as shown) to isolate the casing, thereby keeping the lift gas pressure off the formation. However, the use of a packer is optional.

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