Maximizing Individual Well Performance

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INTRODUCTION

Maximizing individual well performance is one of the important steps of efficiently producing oil. This job exists from the day a well is completed until the day it is plugged. The task consists of daily field observation, supplemented by detailed examination of well records and well data. The sonic liquid level instrument[1] offers valuable supplemental information since downhole pressures can be determined from the depth to liquid measurement. Efficient well performance results in considerably more oil in a shorter period of time. A barrel of oil produced today through better production methods is worth many times the barrel of oil that is produced years from now when the income barely exceeds the expenses.

THE SONIC LIQUID LEVEL INSTRUMENT

The instrument works on an echo principle much like a person's echo in a mountainous area, except the original sound is made by discharging a blank shell and the echoes are sound reflections from tubing collars and the liquid. A microphone is used to receive the initial sound and the reflected echos, and these signals are amplified and recorded on a moving strip of paper.

During actual operation, the instrument is connected to the casing annulus opening. The tubing in the well, and rods, if present, are not disturbed in any manner. A blank shell is discharged into the casing annulus emitting a sound wave which travels down the annulus. Each tubing collar reflects a portion of this sound and the reflected sound energizes a microphone. This signal is amplified and recorded on a paper roll. The liquid level in the well reflects a very high percentage of the sound and is recorded as a relatively large pulse on the paper. The number of collar reflections to the top of the liquid and a tubing tally or estimate of the average joint length indicates the depth to the liquid. A sample charge from the Echometer is shown. See Fig. 1.

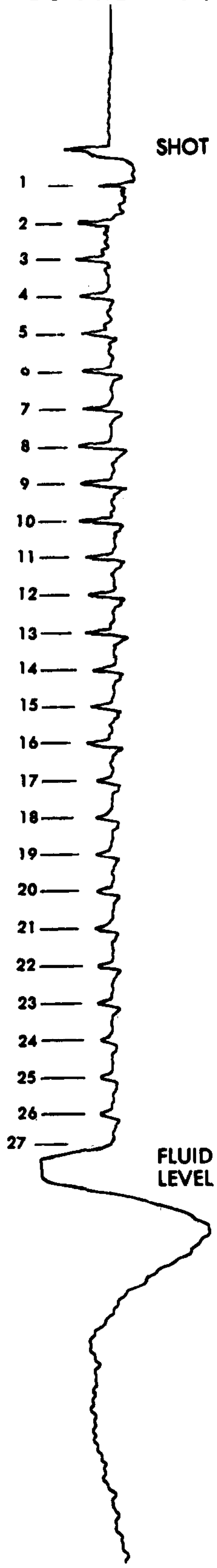
ACCURATE LIQUID LEVEL DATA

Liquid level data is generally very accurate and accurate downhole pressures can be calculated. Errors sometime occur, however, and a discussion of possible problems is worthwhile. Generally, the depth to liquid is reasonably accurate—the liquid can usually be determined within 30 ft, often times much closer.

The problem of a high liquid column being gaseous or foamy can occur. A gaseous liquid column exists only on wells which are venting gas from the casing. If gas is not being vented, the liquid column cannot be gaseous. The gaseous liquid column can almost always be identified during the liquid level test. The gaseous liquid column results in a noisy downhole condition to such an extent that the sensitivity control on a liquid level instrument cannot be turned up without considerable pen movement. When excessive downhole noises exist, always check for a gaseous liquid column or a tubing leak. The weight of a gaseous column varies considerably; hence, if a well has a high gaseous liquid level, the well may not be pumped down. From the author's experience, if the liquid level varies considerably (over 500 ft) at a constant producing rate, the gaseous liquid column is mostly gas causing very little back pressure and the well is pumped down.

Interpretation can also be a problem. Several anomalies are sometimes recorded on a chart. Always reshoot the well to verify all anomalies are actually present and a stray signal did not result in the anomaly. Either shut-in the well or produce the well at a different rate so that the liquid level will move. Then, after the liquid level has had a chance to move, reshoot the well. The anomaly that moved must be the liquid level because only the liquid level can move to any extent. Figure 2 is a graph showing the rate of liquid build up depending upon the well's producing rate and the tubing and casing size. Figure 2 is convienient for estimating liquid buildup rates.

FIGURE NO. 1



DETERMINING WELLBORE PRESSURE

Downhole pressures are obtained by summing the casing pressure, gas column pressure, and liquid column pressure. The casing pressure is a surface measurement made at the time of the test. The gas column pressure can be estimated by assuming that the gas column pressure increases ¼ of a psi for each 100 ft of depth and each 100 psi of casing pressure. Figure 3 shows the gas column pressure in cases where the gas column pressure is less than 200 psi. Figure 4 shows the gas column pressure when the casing pressure is above 200 psi and allows for the Z factor.[2]

In a producing well, the liquid column above the tubing perforations is oil. The liquid column between the pump and the formation consists of oil and water in almost the same percentage as is being produced from the well. The producing wellbore pressure for a well which has the pump set at the pressure datum consists of the casing pressure plus the gas column pressure plus the oil column pressure. The oil column pressure will be the length of the oil column times the oil gradient for the particular oil shown in Table 1.

When the wellbore pressure at static conditions is needed, additional information is desired. The liquid level at producing conditions must be known since all of the liquid above the pump at the producing condition will be oil. When the well is shut-in, the build-up will consist of the same ratio of oil and water that is normally produced from the well. Hence, the static pressure will consist of the casing pressure, gas column pressure, oil column pressure, and water column pressure. The oil column length is the total of the oil above the pump before shut-in conditions plus the oil inflow after shut-in, which consists of oil percentage times additional liquid level build-up. The water column length is the additional level build-up times water percentage.

If the gas gravity and liquid gradient are known, very acurate downhole pressures can be determined. An error in estimating the gas gravity normally does not affect the downhole pressure as much as an error in estimating the liquid gradient. Under normal conditions, the maximum accuracy can be obtained by shutting in the casing and producing the well for a short time so that the gas pressure will build up in the casing and thus lower the liquid level. The effect of any error in estimating the liquid

FEET OF FILL-UP PER MINUTE
FOR VARIOUS PRODUCING RATES
IN DIFFERENT SIZES OF PIPES

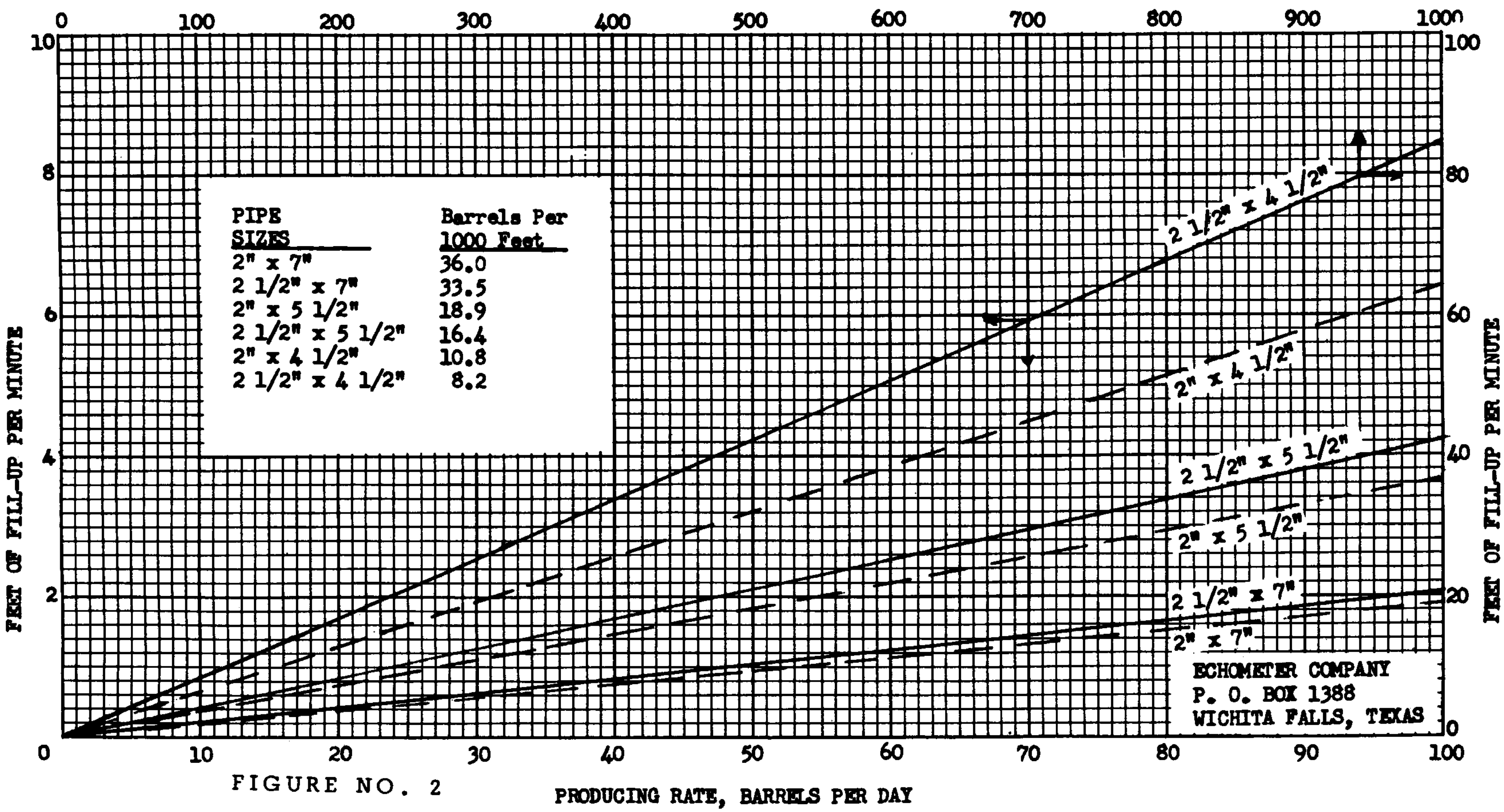


FIGURE NO. 2

GAS COLUMN PRESSURE

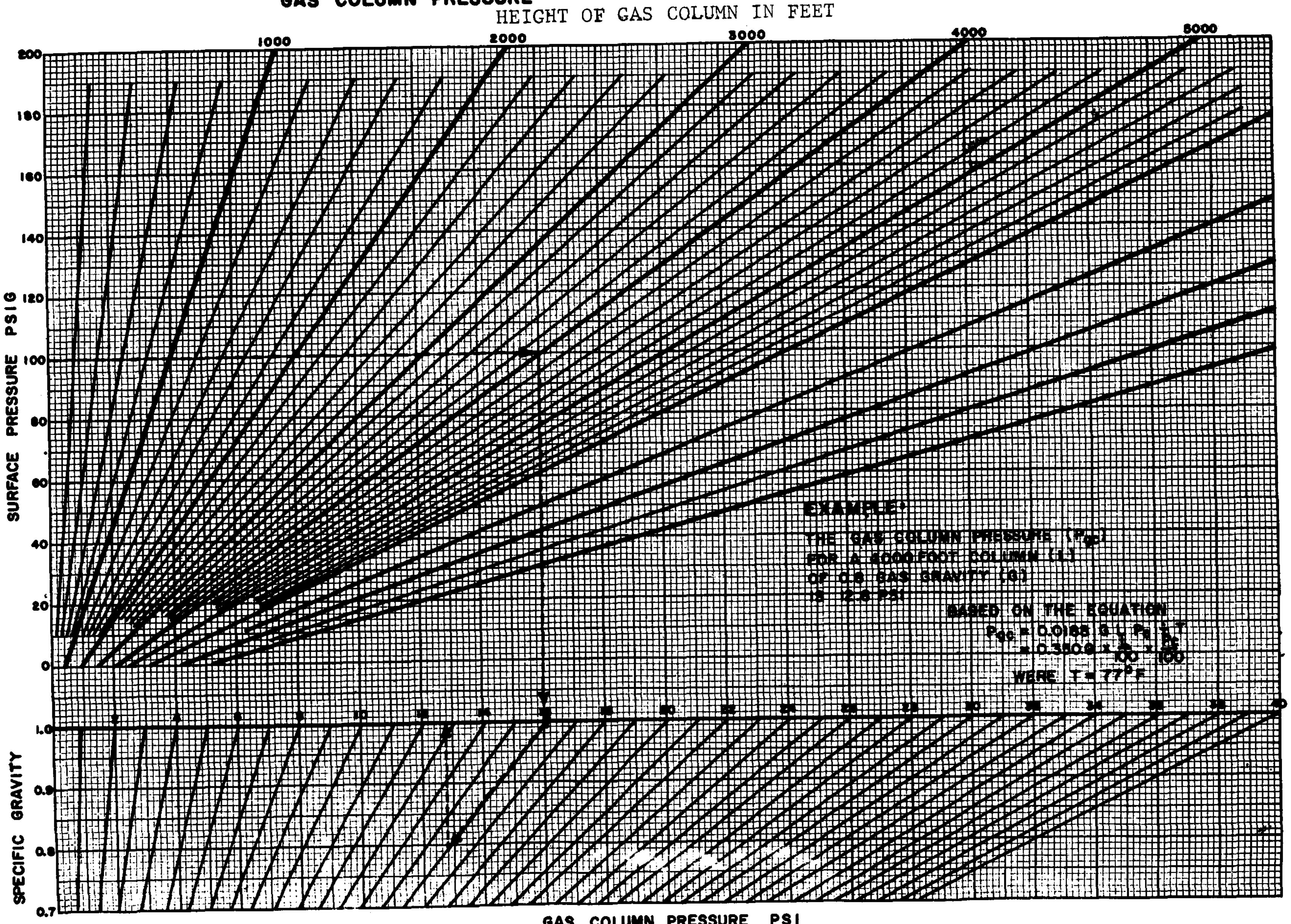
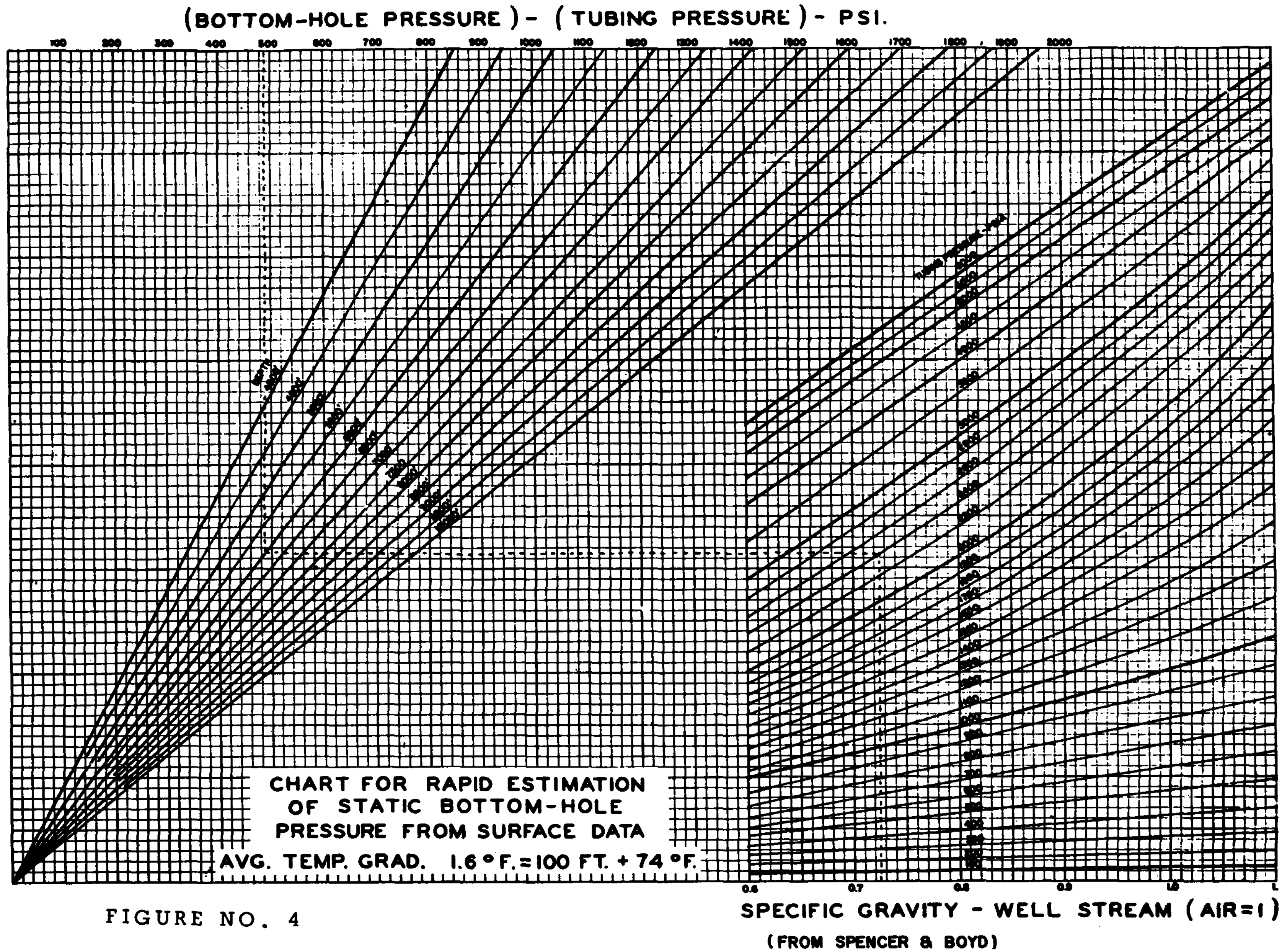


FIGURE NO. 3



(BOTTOM-HOLE PRESSURE) - (TUBING PRESSURE) - PSI.
100
200
300
400
500
600
700
800
900
1000
1100
1200
1300
1400
1500
1600
1700
1800
1900
2000
CHART FOR RAPID ESTIMATION
OF STATIC BOTTOM-HOLE
PRESSURE FROM SURFACE DATA
AVG. TEMP. GRAD. 1.6 °F.=100 FT. + 74 °F.
0.6
0.7
0.8
0.9
1.0
SPECIFIC GRAVITY - WELL STREAM (AIR=1)
(FROM SPENCER & BOYD)

FIGURE NO. 4

pressure gradient will be minimized since the length of the liquid column has been reduced.

A flowing or producing oil well which has the surface casing valves closed always has the liquid level at the tubing perforations. The only exception, which seldom exists, occurs when the producing wellbore pressure is above the bubble point pressure so that gas is not liberated from the oil. The reason for the liquid level always being at the tubing perforations in a producing well with the casing valves closed is because the gas and liquid separate in the casing annulus by gravity forces and the interface of the two must be at the outlet which is the tubing perforations.

THEORY OF WELL PRODUCTION

Numerous opinions exist about the proper method to produce wells. Some operators prefer to close the casing valve, some operators hold a low pressure, and other operators open the casing to atmospheric pressure. In order to study the factors involved, the discussion which follows presents some equivalent methods of producing wells.

The oil and gas production from a well cannot be controlled independently of each other except in very rare cases when a primary or secondary gas cap is present in the well bore. It can then be controlled only to a very limited extent. The gas production from the normal well will not be increased or decreased by the opening or closing of surface casing valves for a constant oil producing rate. An operator can only remove the oil and/or gas that is present in the well bore, he cannot control what enters the well bore. After a brief stabilization period during which the fluid present in the well bore is removed, the operator will produce the oil and/or gas that is migrating into the well bore. The migration rates of oil and gas are dependent upon the difference in pressure between the well bore and the reservoir pressure, and not upon what fluid was removed to cause the drop in wellbore pressure. Thus, the produced gas/oil ratio is the same for any certain oil production rate regardless of whether the gas is freely produced from the casing, or whether an attempt is made to restrict gas production by holding gas pressure in the casing. In the latter case, the balance of the gas is produced through the tubing.

Figure 5—Methods of Producing a Well at Partial Capacity—shows three different methods of producing a pumping well, which result in the same production from the well—both of oil and gas. The fluid that enters the well bore is dependent only upon the producing wellbore pressure. In all three cases, the producing bottom-hole pressure is 500 psi, so that the same amounts of gas and liquid enter the well in all three cases. In case A, the 500 psi producing bottom-hole pressure is the result of maintaining a casing pressure of 455 psi plus the hydrostatic head of the gas column amounting to 45 psi. When the casing valves are closed, the gas which migrates out of the oil collects in the casing annulus. This gas migration causes a high casing pressure which depresses the liquid to the pump perforations unless the gas pressure in the casing at the liquid level reaches the gas saturation pressure. When this pressure is obtained, the gas is held in the oil. If gas is held in the oil and the producing bottom-hole pressure is in excess of the casing pressure plus the gas column pressure, then a column of oil above the pump is formed to give the necessary producing bottomhole pressure. In case B, the producing bottomhole pressure is 500 psi as the result of approximately 1400 ft of liquid above the formation. In producing this well, the casing pressure is maintained at zero psi by bleeding gas, and the fluid is pumped from the tubing. Some gas will be removed with the oil through the tubing. In case C, the pump is set at the liquid level which also results in the 500 psi producing bottom-hole pressure when the casing pressure is 0 psi. In this case, oil and gas are removed through the tubing, and the gas is also bled from the casing. In all three cases, the oil and gas production from the well is the same after a brief stabilization period.

The same principles can be used to show that the oil, water, and gas production from a well cannot be controlled independently of each other. If the same producing bottom-hole pressure exists using any one of numerous methods of producing a well, the oil, water, and gas production will be the same. This applies whether the well is produced by flowing, beam pumping, hydraulic lift, gas lift, turbine lift, or any other method. Erroneous conclusions are sometimes reached in this regard, on the basis of brief production tests, which are caused by changes in the fluid content of the casing, or by transient changes in fluid concentrations in the immediate vicinity of the well bore.

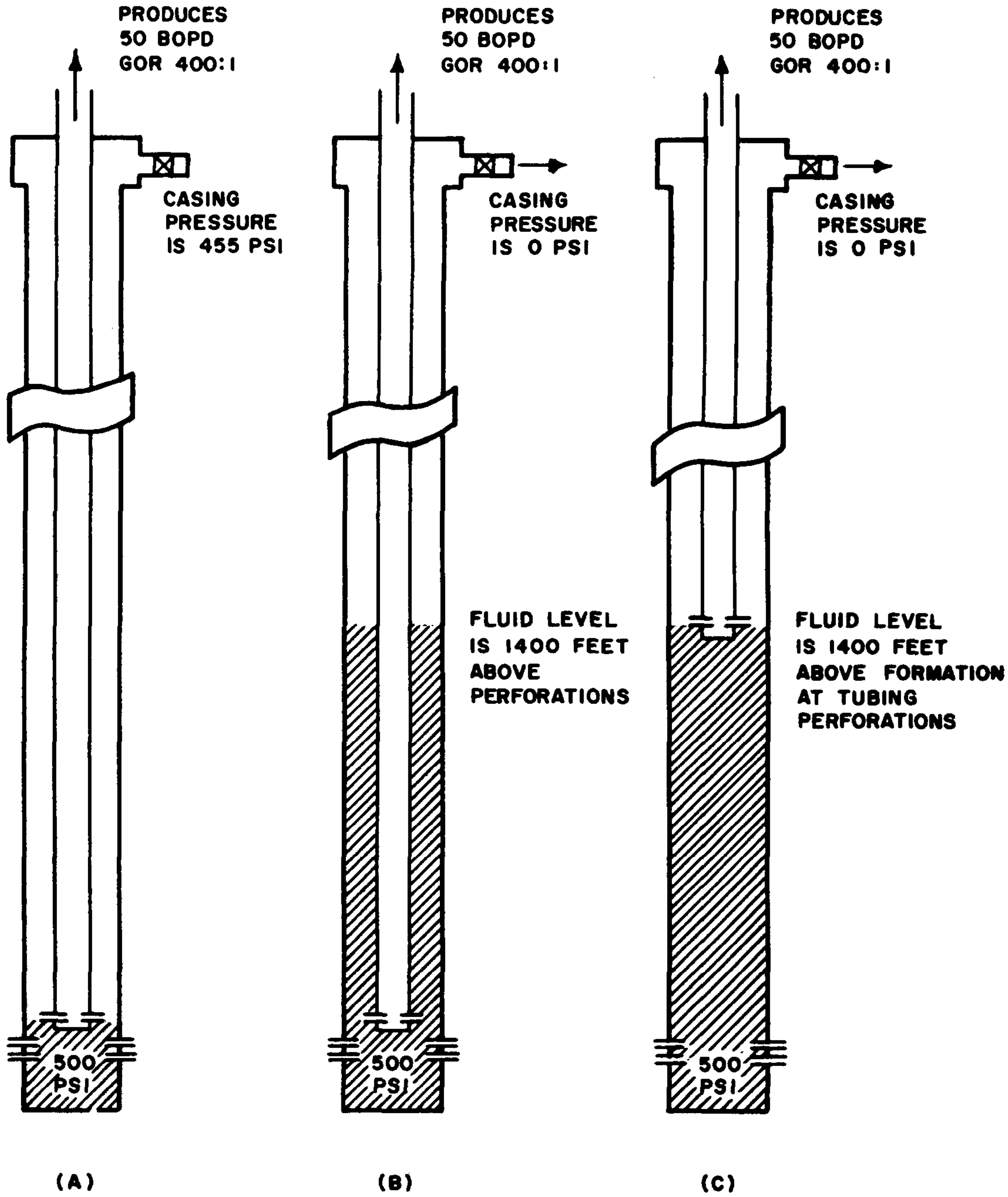


FIGURE NO. 5 **METHODS OF PRODUCING A WELL AT PARTIAL CAPACITY**

From the foregoing discussion, the present production, cumulative production, and reservoir performance resulting from the manner in which the well is being produced, will be the same if (1) approximately 100 psi casing pressure is held on a well with the pump set at the formation, or (2) the pump is set approximately 300 ft above the formation and no casing pressure is held. In either case, approximately 100 psi back pressure is being held at the well bore. Whether the back pressure is the result of an oil column or gas pressure, the actual production from the well will be the same in either case.

Holding some casing pressure is popular with many operators, even though setting the pump off-bottom would result in the same production from the well and the same reservoir performance. If some wellbore pressure is maintained, more gas is kept in solution and a better relative permeability to oil is obtained. The viscosity, surface tension, and interfacial tension properties of the fluids are also changed as gas is brought out of solution. However, actual field practice and theoretical calculations indicate that the wellbore pressure should be held to a minimum in the later stages of depletion to obtain the maximum present production and maximum cumulative production.

GOOD PRODUCTION PRACTICES AND PUMPING EQUIPMENT

This discussion of pumping equipment is limited to cases in which the formation abandonment pressure will be low, and the maximum producing rate is desired.

The most common pumping equipment consists of beam pumping, hydraulic pumping, gas lift, and downhole centrifugal pumps. The beam pump is the most conventional pump and is excellent for "pumping down" low volume wells by setting the pump below the formation, maintaining a low casing pressure, and maintaining the pump capacity in excess of the well's producing capacity. Hydraulic pumping, gas lift, and centrifugal pumps are more ideally suited to large volume wells and oftentimes are not intended to actually "pump down" the well. However, each installation must be analyzed individually.

When hydraulic pumping, gas lift, or centrifugal pumps are used to "pump down" a well, be sure that the producing wellbore pressure is sufficiently low to give maximum production rate. For example, assume a gas lift well with 2-in. tubing set 25 ft above the producing zone on a packer, and a check valve located at the bottom of the tubing to prevent fluid from being forced back into the formation. Further assume that the formation will support 600 ft of liquid and the well is produced intermittently. Each time gas is discharged below the liquid and the gas and liquid are forced up the tubing, a certain liquid fall-back occurs. If 200 ft of fall-back occurs, a considerable back pressure is held against the formation at all times. The production rate in this case will be restricted to less than 66-2/3 per cent of the maximum production rate.

With conventional beam pumping, forcing gas through a downhole pump is very inefficient. When zones are isolated by a packer or a well is completed slim hole without tubing, the production rate may be restricted considerably unless the gas is vented separately. If the pump is forced to handle both gas and oil from the well, the efficiency is reduced greatly. Again assume a typical case. An average reservoir barrel of oil will liberate 600 cu ft of gas or 107 bbl of gas at standard conditions. Thus, if a well makes 20 BOPD with a GOR of 600:1, the actual production from the well is 20 BOPD and 2140 bbl of gas. If the pump capacity is 60 BPD, the oil and gas must be compressed sufficiently to be contained in the 60 bbl. Assuming average conditions, the oil with its solution gas plus the liberated gas must be compressed to a pressure of approximately 475 psi. Thus, the producing wellbore pressure for an average 20 BOPD well with a GOR of 600:1 being produced through a pump with a capacity of 60 BOPD will have a back pressure of 475 psi. Venting gas so that the pump does not have to handle the gas would permit additional production due to the reduction in the producing wellbore pressure. This same example will also apply if the casing valves are closed so that the gas is forced to be produced through the pump.

The depth to set a conventional rod pump is also important. The rod pump should be set below the producing formation unless mechanical reasons or special conditions prevent this depth. If the pump is set below the formation, the casing itself acts as a separator where the inflow is near the bottom, the gas discharge is at the top and the liquid outlet is at the bottom (being the tubing perforations). Maximum gas liquid gravity separation will occur without the need of gas anchors which necessarily cannot have the separating area already present between the tubing and casing.

With conventional rod pumping equipment, set the pump below the producing formation, maintain a minimum casing pressure, and maintain a pump capacity in excess of the well's producing capacity.

TABLE No. 1

Oil & Water Conversion Table

A.P.I. Gravity Degrees	Specific Gravity	Fluid Gradient Lbs./Sq. In./Ft.
80	.669	.290
75	.685	.297
70	.702	.304
65	.720	.312
60	.739	.320
55	.759	.329
50	.780	.338
48	.788	.342
46	.797	.345
44	.806	.349
43	.811	.351
42	.816	.353
41	.820	.355
40	.825	.358
39	.830	.360
38	.835	.362
37	.840	.364
36	.845	.366
35	.850	.368
34	.855	.370
33	.860	.373
32	.865	.375
31	.871	.377
30	.876	.380
28	.887	.384
26	.898	.389
24	.910	.394
22	.922	.399
20	.934	.405
18	.946	.410
15	.966	.419
12	.986	.427
water	1.000	.433
salt	1.100	.477
water	1.154	.500
range	1.200	.520

1 PSI is equivalent to 2.3 ft water
0.433 PSI is equivalent to 1 ft water

CONCLUSION

The problem of efficiently lifting production necessitates careful selection of equipment, proper installation of the equipment, proper operation of the equipment, and constant supervision and checking to assure that the program is understood and properly performed.

REFERENCES

1. Four instruments are presently available—The Echometer by the Echometer Company, Box 1388, Wichita Falls, Texas; The Sonolog by Keystone Development Company, 2813 Westheimer Rd., Houston, Texas; The Accoustical Well Sounder by Associated Engineering & Equipment Company, Inc., Box 6067, Houston, Texas; and the Fluid Level Finder by Servco, 2440 Cerritos Ave., Long Beach, California.

2. Spencer & Boyd, "Direct Determination of Bottom Hole Pressures," The Oil & Gas Journal, November 10, 1952.