ANALYZING WELL PERFORMANCE VI

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INTRODUCTION

Analyzing well performance is an important step toward increasing profits by improving production techniques. Generally the analysis is made by field observations and examination of well data. The acoustic liquid level instrument offers valuable supplemental information since downhole pressures can be determined from the depth to liquid measurement.

FLUID FLOW (GENERALIZED)

Fluid flow in a reservoir is caused by a higher pressure pushing fluid into an area of lower pressure. Fluid flow into a wellbore occurs when fluids present in the wellbore are removed so that the pressure is decreased in the wellbore. Then fluid from an area of high pressure flows into the low pressure wellbore (Fig. 1).

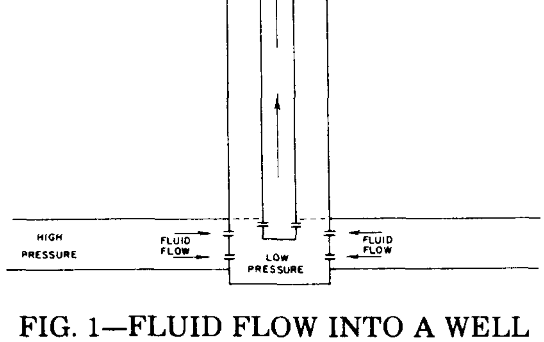


FIG. 1—FLUID FLOW INTO A WELL

Fluid flow into a wellbore is approximately proportional to the drawdown pressure—that is, the difference in pressure between the higher pressure reservoir and the lower pressure wellbore—the greater the difference, the greater the fluid flow. Figure 2 represents some ideal cases of fluid flow in a reservoir.

The importance of the static and producing wellbore pressures becomes obvious. Numerous techniques for determining wellbore pressures exist but the most common is the use of acoustic liquid level instruments which involve measuring the depth to liquid in a well. Using the depth to liquid, the casing pressure and certain other data, an operator can determine the pressure at the wellbore.

A minimum producing wellbore pressure is generally desired for maximum inflow.

NECESSARY DATA FOR WELL ANALYSIS

Four factors are extremely important in analyzing well performance: (1) static bottom hole pressure, (2) producing bottom hole pressure, (3) well test and (4) pump capacity.

For maximum withdrawal, the producing bottom hole pressure must be low compared to the static bottom hole pressure. A producing bottom hole pressure of 75 psi is low compared to a static reservoir pressure of 2300 psi and practically all of the production is being obtained. However, if the static reservoir pressure is 100 psi, only one-fourth of the production is being obtained. The well test must also be known. If the producing wellbore pressure is low compared to the static reservoir pressure, maximum inflow is occurring. But, if the maximum inflow is less than commercial production, action must be taken. Last, the pump capacity must be known. If the pump capacity

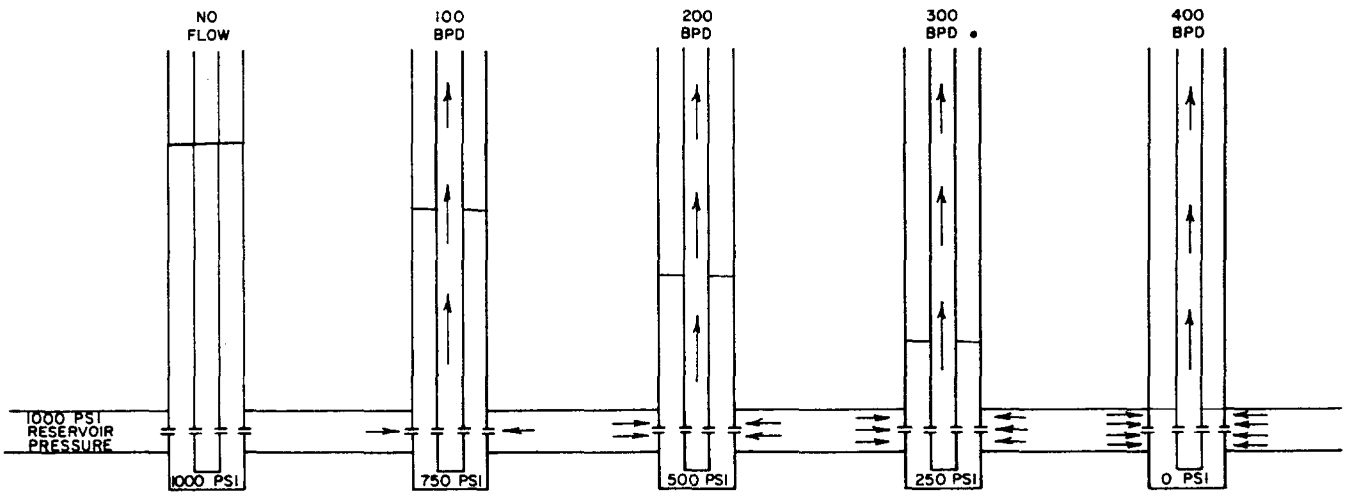


FIG. 2—FLUID FLOW AS A FUNCTION OF WELLBORE PRESSURE

is not matched suitably to the well's production, excessive wear and a mechanical loss of efficiency are occurring if the pump capacity greatly exceeds the production rate. A production loss occurs if the pump capacity is less than the well's producing capacity.

Note the importance of each item by trying to determine proper action on each of the wells in Table 1 when only one of the four items on each well is omitted.

TABLE 1

Well	Static Bottom Hole Pressure, psi	Producing Bottom Hole Pressure, psi	Well Test BOPD	BWPD	Total BPD	Pump Capacity BPD
1	1800	83	86	3	89	125
2	166	83	86	3	89	125
3	166	10	25	5	30	190
4	340	170	45	10	55	57
5	340	170	½	0	½	20
6	380	5	1	550	551	580

THE ACOUSTIC 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 echos 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, filtered 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 gas. Each tubing collar reflects a portion of this sound and the reflected sound energizes a microphone. This signal is amplified, filtered and recorded on a paper roll. The liquid level in the well reflects a 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 indicate the depth to the liquid. A sample chart from an Echometer is shown in Fig. 3.

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 the possible problems is worthwhile. Generally, the depth to liquid is reasonably accurate. The liquid can usually be determined within 30 ft and often much closer. Difficulties in obtaining accurate liquid level data and hence bottom hole pressure can be classed as: (1) gaseous liquid columns, (2) foaming liquid level, (3) interpretation of charts and (4) poor well response.

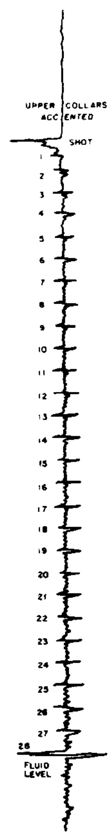


FIG. 3—ECHOMETER CHART

Gaseous Liquid Columns

The problem of a high liquid column being gaseous can occur. A gaseous liquid column exists only in wells which are venting gas from the casing. If gas is not being vented, the liquid column cannot be gaseous. Gaseous columns are formed when the density of a liquid column is greatly reduced due to large gas bubbles migrating up through the liquid column. The gas bubbles can be as large as 1 cu ft or even larger. The gas migration in the casing annulus results in lighter columns in slim hole completions than in large annular completions. The gaseous liquid column can almost always be identified during the liquid level test. The gaseous liquid column causes a noisy downhole condition to such an extent that the sensitivity control on a liquid level instrument cannot be set at high settings without considerable pen movement. This noise source is from downhole and not from surface vibration. The downhole source of the noise can be verified by merely closing the casing valve to the fluid level instrument wellhead. If closing the casing valve eliminates the noise, then the source is from the annulus. If closing the valve does not reduce pen movement, then surface vibration is causing the pen movement. When excessive downhole noises exist, always check for a gaseous liquid column.

The weight of a gaseous column varies considerably; hence, if a well has a high gaseous liquid level, the well may or 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 backpressure, and the well is pumped down.

Probably the best characteristic of the gaseous liquid column is the rapid movement of the liquid level. Repeated shots taken hours or days apart will not indicate the same liquid level depth. The gradients of gaseous columns in a well are difficult to determine. Probably the most accurate method is to increase casing pressure, allow the well to stabilize, then determine the liquid level. A series of these tests at increasing pressures permits extrapolation of the liquid level vs casing pressure to give the casing pressure necessary for the liquid level to be at the pump.

Gaseous columns are erratic, can be thousands of feet long, and are relatively noisy (gas "popping" out of the liquid). De-foamers are not of particular benefit.

The problem of a gaseous liquid column in a well having a low producing bottom hole pressure is the result of inefficient downhole separation of oil and gas. The separation of oil and gas can be improved by placing the tubing inlet perforations below the fluid entry from the reservoir into the wellbore so that gas does not flow upward through the liquid. Placing the tubing inlet perforations below the reservoir fluid entry results in better pump efficiency and more accurate fluid levels in gaseous wells. See Fig. 4—Downhole Gas Separation. If the pump cannot be set below the formation due to mechanical reasons or due to the need to pump from up the hole, a packer and crossover system must be used. See Fig. 5—Packer Gas Separator. Again, the gas is permitted to escape upward as the liquid flows downward toward the pump inlet.

Foaming Liquid Level

When fluids enter the wellbore, a drop in

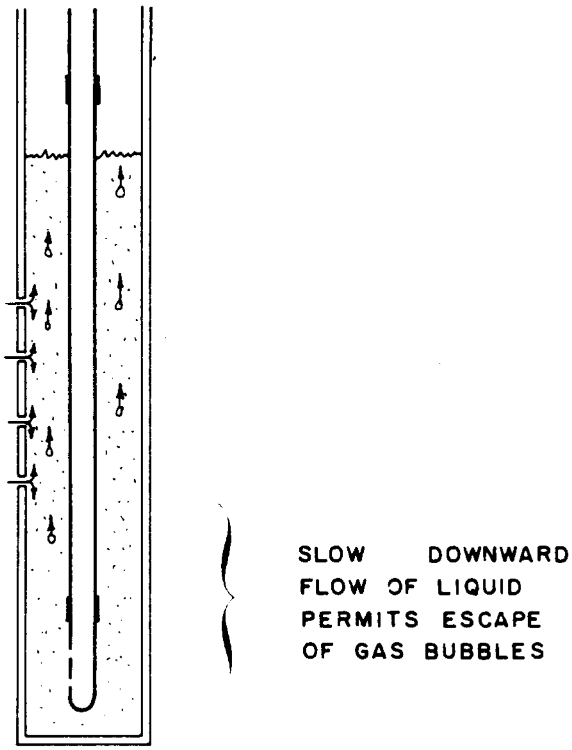


FIG. 4—DOWNHOLE GAS SEPARATION

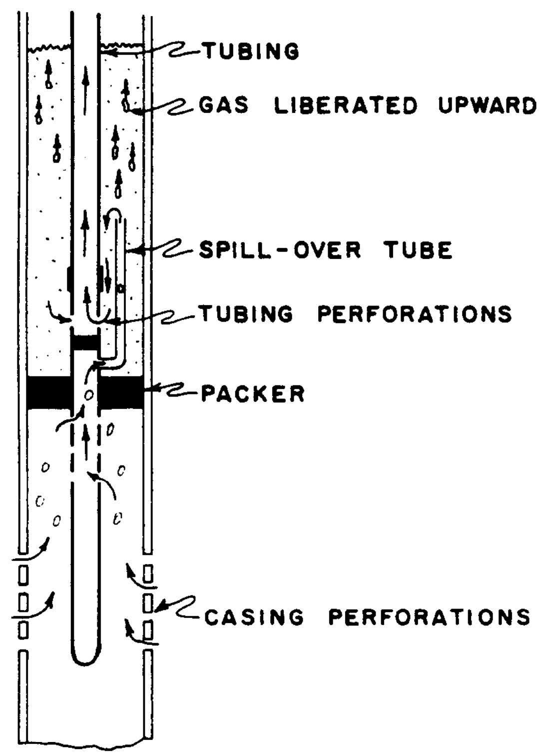


FIG. 5—PACKER GAS SEPARATOR

pressure occurs. Foam can occur when the pressure drop is relatively small, and small gas bubbles form within the liquid column. The gas bubbles are approximately 0.1 in. in diameter and smaller. These foamy liquid levels differ from gaseous columns. Foamy columns are much more stable, normally do not exist in columns of over 400 ft, and are quiet. The foamy liquid level absorbs sound to such an extent that the blank shell sound wave is absorbed by the foam rather than being reflected. The liquid level can be difficult to record on foamy columns. The foam exerts very little backpressure on the wellbore, and the well could be pumped down even though several hundred feet of foam exist above the pump. Defoamers can help in certain cases and should be injected into the formation if possible.

Interpretation of Charts

Two charts on the same well should repeat. If charts do not repeat, the difficulty should be corrected before attempting to interpret the chart. In attempting to make repeated charts, be sure the manufacturer's suggestions concerning well connections, control settings, etc. have been followed. When identical charts are being obtained, but the liquid level is not obvious because of multiple downhole reflections, the liquid level should be moved so that a movement on the chart will be obtained. A movement on the chart signifies the liquid level.

The liquid level can be moved by increasing the casing pressure or by shutting down a producing well. Increasing casing pressure results in a liquid level drop of 3 ft/psi of pressure increase. When shutting down a well, the fill-up will occur at a rate depending upon the producing rate of the well and the annular volume of the casing. A rate of fill-up chart is shown in Fig. 6. The initial rate of fill-up will be as shown on the chart. A decrease in the fill-up rate will occur as the liquid exerts a backpressure on the formation. The chart is convenient for estimating the time necessary to result in one joint of liquid level movement.

Poor Well Response

The physical properties of the well may be such that either collar depth or liquid level is extremely difficult to obtain. The collars can be masked by paraffin, scale, corrosion, dirt,

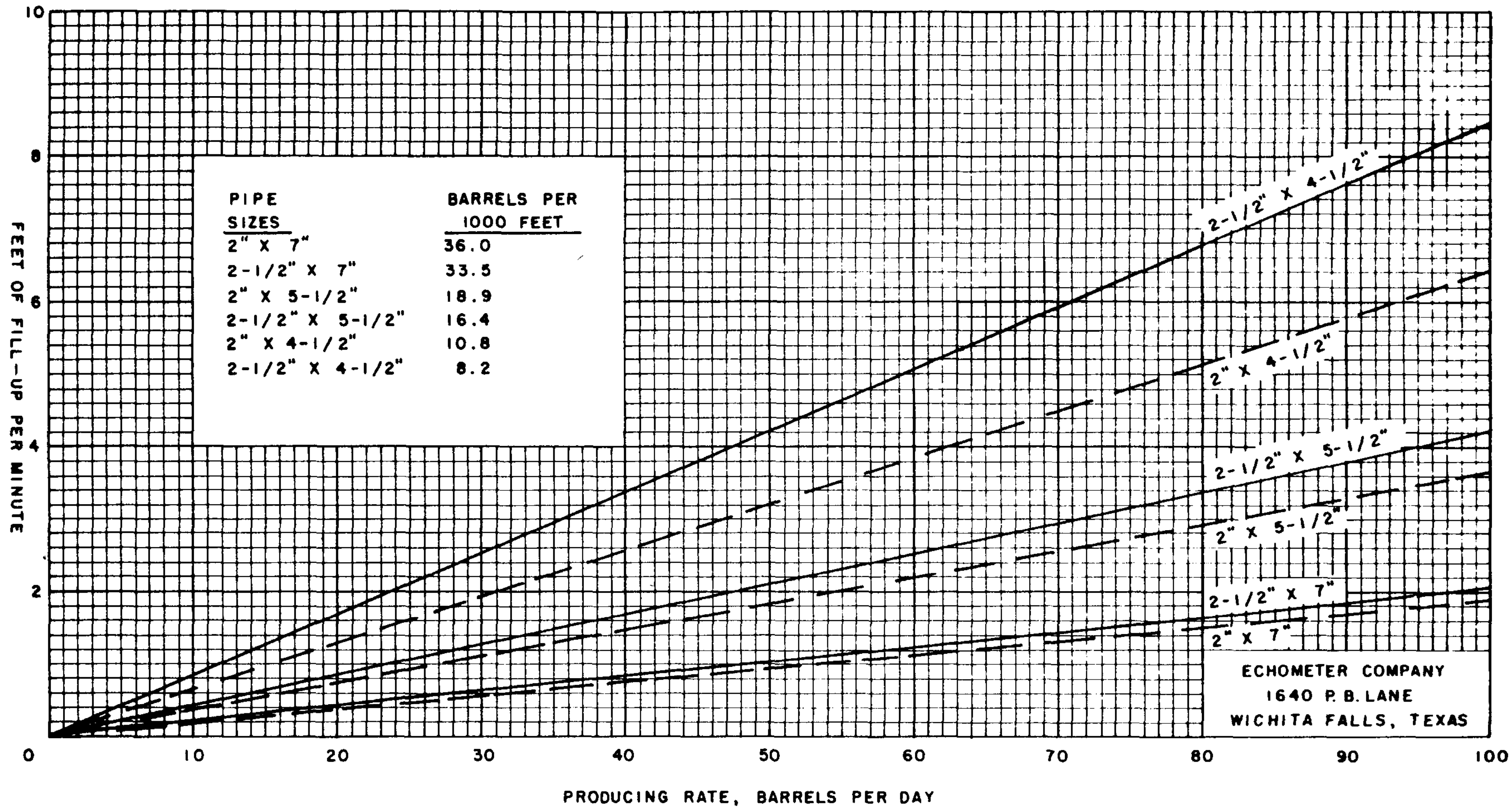


FIG. 6—FEET OF FILL-UP PER MINUTE
FOR VARIOUS PRODUCING RATES
IN DIFFERENT SIZES OF PIPES

etc. The liquid level is not possible when the reflected signal from the liquid level is weaker than background noise. In general, three techniques are commonly used to improve response. First, a large blank or larger blast can be employed to increase the reflected signals from down the well. Second, the casing pressure can be increased which increases the reflected response. Third, the well can be shut down for a few minutes to reduce background noise.

DETERMINING WELLBORE PRESSURE

The pressure at the wellbore can be obtained from the depth to the fluid, the casing pressure, and a knowledge of the fluids present in the casing annulus. The wellbore pressure (whether the well is at static or producing conditions) is the sum of the casing pressure, the hydrostatic head of the gas column pressure, and the liquid column hydrostatic pressure.

The casing pressure, gas column pressure and liquid column pressure must be totalled to determine the producing bottom hole pressure of a well making gas, oil and water. All the liquid above the pump will be oil due to gravity separation. This is often evidenced in a well which temporarily flows 100% oil out of the casing when sufficient bottom hole pressure exists, even though the well produces in excess of 90% water through the tubing. The liquid below the pump and above the formation will be oil and water in the same ratio as is produced from the well.

If the bottom hole pressure at static conditions is desired, additional information is necessary. If the well was pumped down before being shut in, the liquid that collects in the annulus will be approximately the same ratio of oil and water that is produced from the well (Fig. 7A). If the well was not pumped down before closing in the well, the liquid above the pump while the well was being produced must be determined. This liquid above the pump is entirely oil if the formation has produced enough oil to fill the annular space. The liquid level rise after the well is shut in consists of the same ratio of liquids that are normally produced (Fig. 7B). Thus, the total lengths of the gas, oil, and water columns are known. From this information and the surface casing pressure, the bottom hole pressure can be determined. If the static bottom hole pressure is desired on a well with raised tubing, the gradient of fluid below the tubing inlet perforations will be between a gradient of the fluids normally produced by the well and 100% water column. Since raised tubing is usually employed in high WOR wells, negligible error is usually found in such wells if a produced fluid gradient is assumed (Fig. 7C).

An improved technique for obtaining the static bottom hole pressure is possible by closing in the casing a sufficient time before shutting in the well so that the casing pressure will depress the liquid column. The gas will collect in the casing annulus, increase the casing pressure, and cause the liquid level to drop to the pump perforations (if gas bubbles are present at the wellbore). Then, after shut in, the fillup will be the same ratio of oil and water that is normally produced by the well (Fig. 7D).

Table 2 shows the pressure gradient, expressed as psi/ft for various API gravity crude oils and of waters. Pure water has a pressure gradient of 0.433 psi/ft. The range of pressure gradients for salt water is also given in the table. A simple method of obtaining the actual gradient of the salt water is to measure the specific gravity using a conventional battery hydrometer, and then to multiply the pure water gradient of 0.433 psi/ft by the specific gravity.

The gas column pressure due to the weight of the gas can be determined by any of the several methods. The gas column pressure can be closely approximated in low pressure wells by assuming that the gas column pressure increases 0.25 psi for each 100 ft of depth and for each 100 psi of casing pressure. For example, the gas column pressure of a gas column at 200 psi surface pressure which is 3500 ft in depth would be 0.25 x 2 x 35, or 17.5 psi. If the gas gravity and average gas temperature are known, the following formula is more accurate than the approximation which is a special case of this formula.

$$Pgc = 0.0188 \frac{PcGL}{T}$$

where Pgc = pressure due to weight of gas column, psi

Pc = casing pressure psia
G = specific gravity of gas (air = 1.0)
L = length of gas column, ft
T = average gas temperature, °R (°F + 460°)

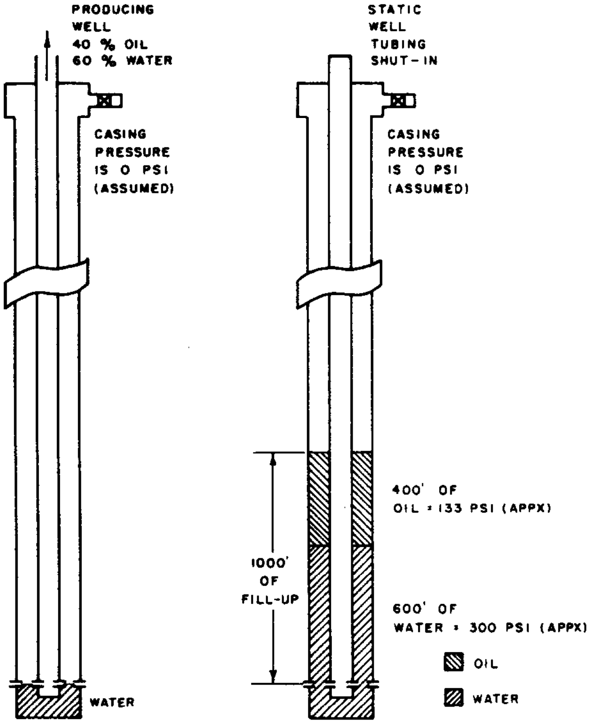


FIG. 7A—DETERMINING STATIC BOTTOM HOLE PRESSURES LIQUID LEVEL AT FORMATION WHILE PRODUCING

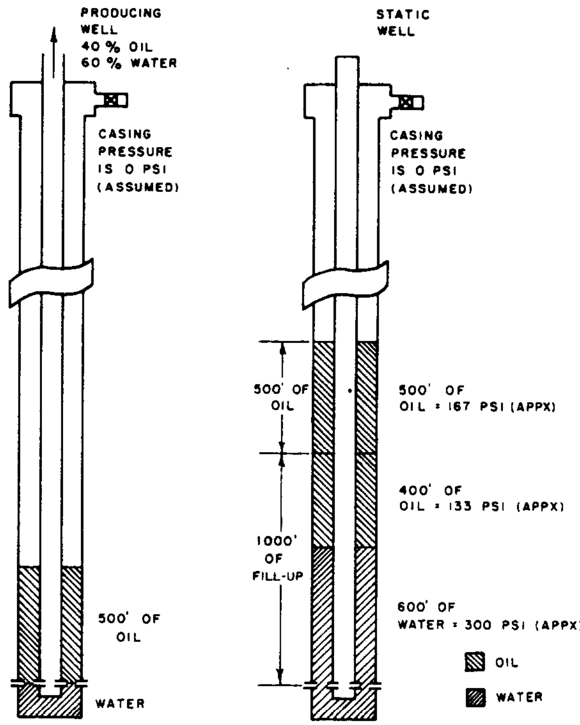
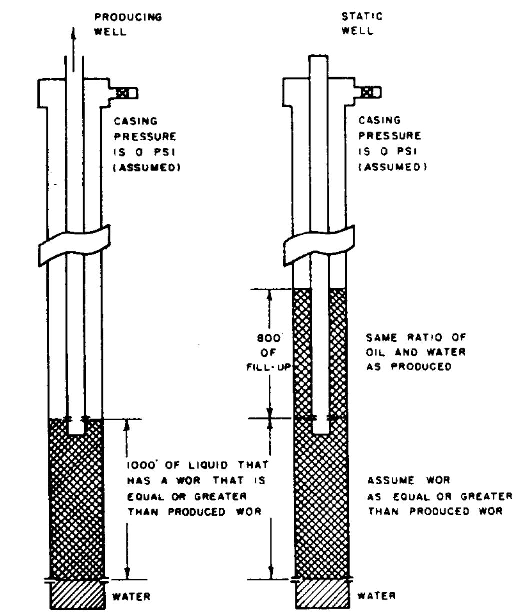


FIG. 7B—DETERMINING STATIC BOTTOM HOLE PRESSURES LIQUID LEVEL ABOVE FORMATION WHILE PRODUCING



IN HIGH WATER-OIL RATIO (WOR) WELLS, THE STATIC BOTTOM HOLE PRESSURE CAN BE CALCULATED ACCURATELY
IN LOW WATER-OIL RATIO (WOR) WELLS, THE STATIC BOTTOM HOLE PRESSURE MUST BE CALCULATED AFTER ASSUMING WOR

FIG. 7C—DETERMINING STATIC BOTTOM HOLE PRESSURES TUBING PERFORATIONS ABOVE FORMATION

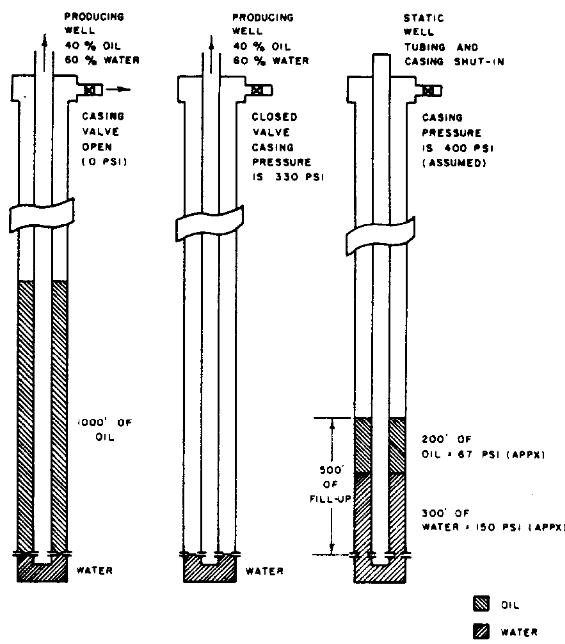


FIG. 7D—DETERMINING STATIC BOTTOM HOLE PRESSURES IMPROVED TECHNIQUE WHEN LIQUID LEVEL IS ABOVE FORMATION WHILE PRODUCING

TABLE 2—OIL AND WATER CONVERSION

API Gravity Degrees	Specific Gravity	Fluid Gradient Lb/Sq. In./Ft
80		0.290
75		0.297
70		0.304
65		0.312
60		0.320
55		0.329
50		0.338
48		0.342
46		0.345
44		0.349
42		0.353
40		0.358
38		0.362
36		0.366
34		0.370
32		0.375
30		0.380
28		0.384
26		0.389
24		0.394
22		0.399
20		0.405
18		0.410
15		0.419
12		0.427
water	1.000	0.322
salt	1.100	0.477
water	1.154	0.500
range	1.200	0.520

1 psi is approximately 2 ft of water
1 psi is approximately 3 ft of oil

A graphic solution to this equation is presented in Fig. 8. An example shown on the graph is the determination of the gas column hydrostatic pressure for a gas column 4000 ft long at a surface pressure of 100 psig (115 psia) with a gas specific gravity of 0.8. The dotted line shows the method of determining the gas column pressure, which is 12.8 psi for this example. At high pressures and long gas columns, it is advisable to use Fig. 9 or equations which take into consideration the deviation from the perfect gas laws. Figure 9 is a graphical solution to determine the gas column hydrostatic pressure of long columns under high pressures and takes into consideration the gas deviation factor. The graph is reprinted from an article by Spencer and Boyd.[1]

The calculations are very simple when the well produces only one fluid, and very accurate bottom hole pressures are obtained from liquid level information. Normally, the inaccuracy in obtaining bottom hole pressures in wells producing oil and water results from errors in estimating the fluid pressure gradient rather than errors in obtaining the fluid level.

THEORY OF WELL PRODUCTION

Numerous opinions exist about the proper method to produce wells. Some operators prefer to hold some casing pressure; other operators open the casing to atmospheric pressure. In order to study the factors involved, the following discussion presents some equivalent methods of producing wells and recommends an operating policy for producing wells. In this article, fluid refers to oil and/or water and/or gas, while liquid refers to oil and/or water.

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 wellbore. It can then be controlled only to a 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 wellbore, but he cannot control what enters the wellbore. After a brief stabilization period during which the fluid present in the wellbore is removed, the operator will produce from the wellbore the oil and/or gas that is migrating into the wellbore. The migration rates of oil and gas are dependent upon the difference in pressure between the wellbore and the reservoir pressure, and not upon what fluid was removed to cause the drop in wellbore pressure. Thus, the produced GOR 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 10 shows three different methods of producing a pumping well, which results in the same production from the well—both oil and gas. The fluid that enters the wellbore is dependent only on the producing wellbore pressure. In all three cases the producing bottom hole pressure is 500 psi, so the same gas and liquid enter the well in all of the cases. In Case A, the 500 psi producing bottom hole pressure is the result of maintaining a casing pressure of 455

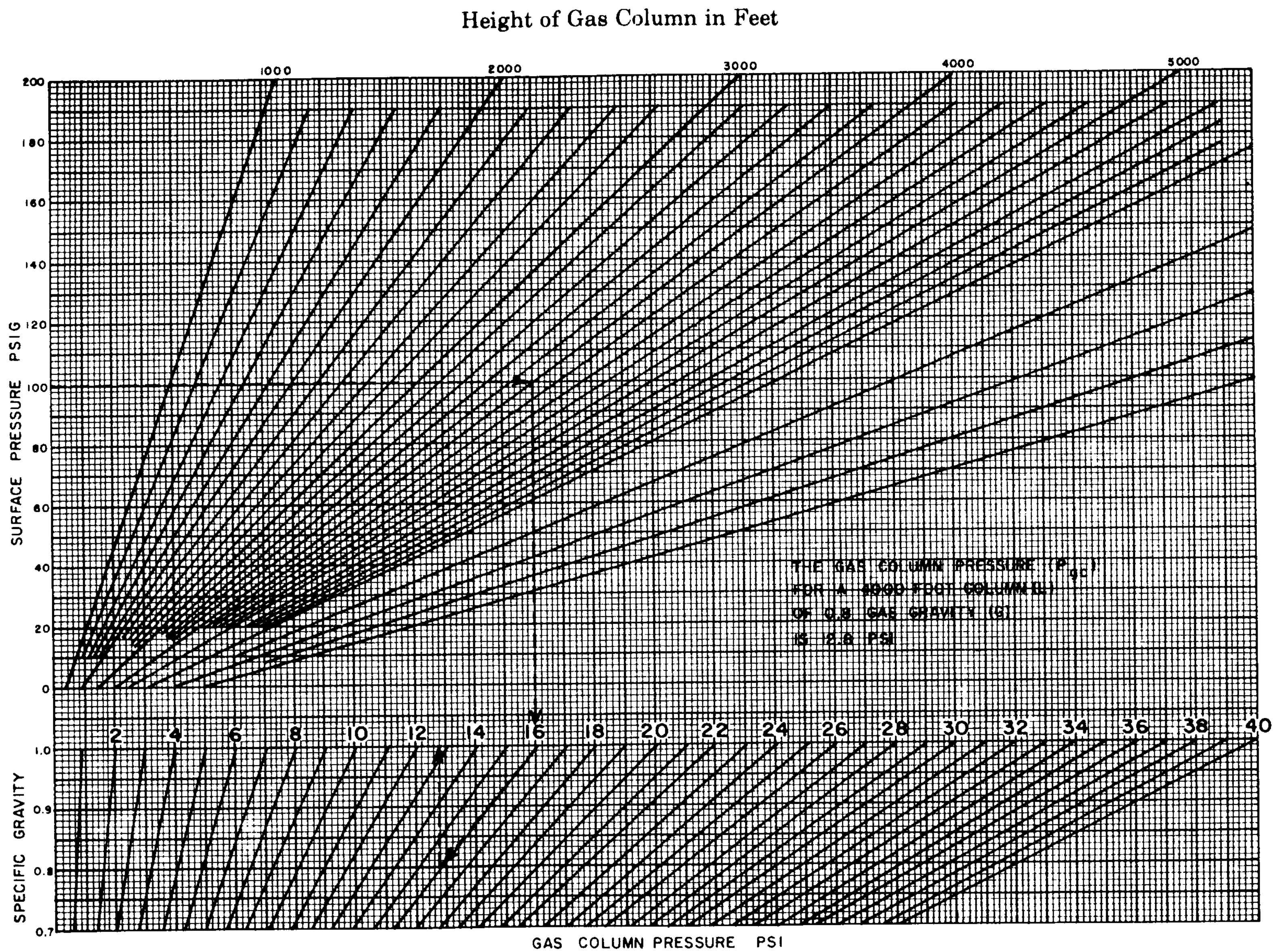


FIG. 8—GAS COLUMN PRESSURE
(LESS THAN 200 PSI)

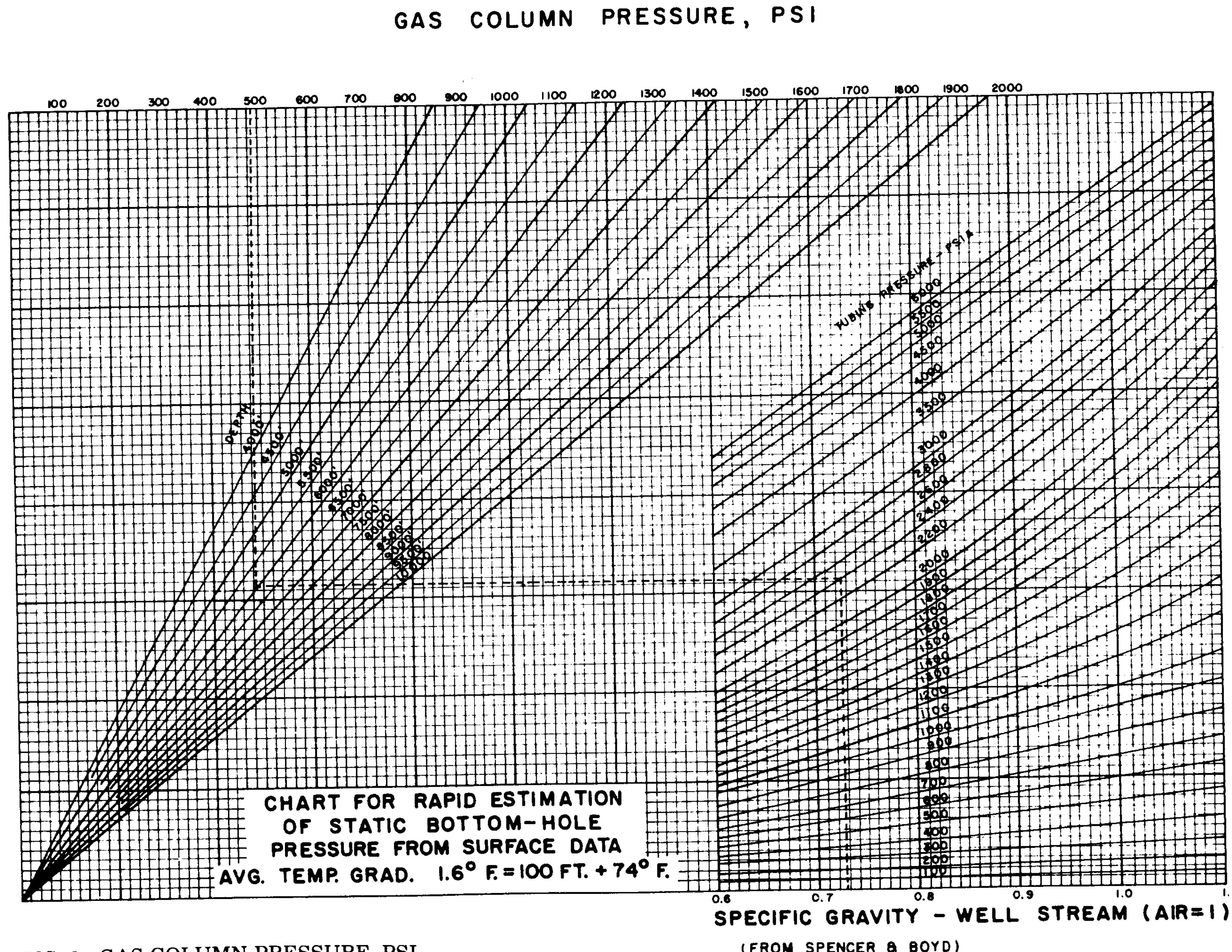


FIG. 9—GAS COLUMN PRESSURE, PSI

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 bubble point 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 bottom hole pressure. In Case B, the producing bottom hole 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.

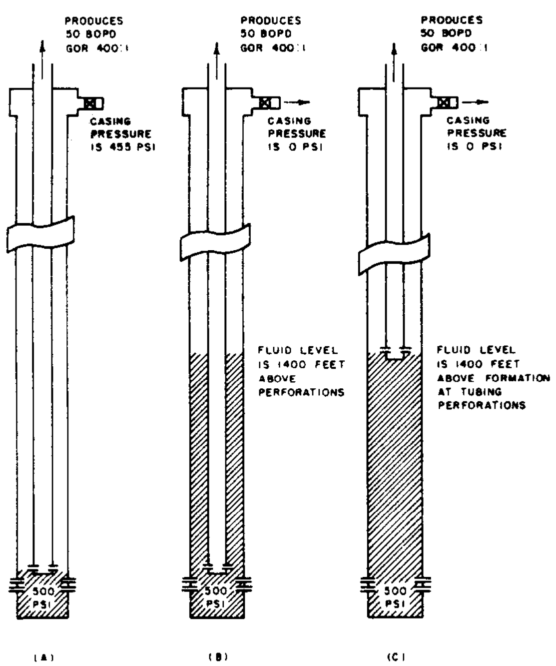


FIG. 10—METHODS OF PRODUCING A WELL AT PARTIAL CAPACITY

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 beam pumping, hydraulic pumping, 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 wellbore.

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 backpressure is being held at the wellbore. Whether the backpressure 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.

In a pumping well, the fact that a well is pumped down does not necessarily indicate that the maximum production is being obtained. To have a practical minimum producing bottom hole pressure, the casing pressure must also be low.

When the casing valves are closed, the well will always be pumped down if the pump is functioning at all, unless the producing bottom hole pressure is in excess of the bubble point pressure. The capacity of the pump is greatly reduced when the pump is required to handle the gas. The production from the well is restricted when the wellbore pressure and casing pressure increase as a result of this condition. The casing should be open to the flow line, a gathering system, or vented to prevent an excessive producing bottom hole pressure.

Control of the producing bottom hole pressure in relation to the static reservoir pressure is especially important. Many potential good producers have been abandoned for failure to observe due caution. For example, assume a reservoir which is 3500 ft deep with a static pressure of 75 psi. If a well is completed in this reservoir with the pump set two joints off bottom (to reduce frac sand problems, etc.) and 20 psi casing pressure is maintained (flow line pressure), then the formation backpressure is approximately 40 psi. This would restrict the production from the well to less than one-half of the maximum rate.

For the maximum production, a minimum producing bottom hole pressure is necessary. If mechanically possible, pipe should be set through the formation, the pump set at the base or below the formation, and a minimum casing pressure maintained. The casing pressure should be less than 5% of the static reservoir pressure if possible. Open casing below the formation will permit fluid to enter the wellbore during a short down time without restricting production from the well since the fluid would not exert a backpressure on the formation. This practice is adaptable to time-clock operation. Naturally, if some particularly unfavorable condition develops through use of this practice, additional consideration should be given to the method. This type of completion is also useful when gas production from a well has a tendency to gas-lock the pump. The interval of casing between the formation and the pump acts as a separator, with the liquid pumped out of the bottom and the gas being bled off the top. This is considerably different from setting the pump above the formation where both the gas and liquid must either pass by or through the pump.

A brief discussion about vacuum is appropriate. The maximum vacuum that can be pulled on a well is approximately a 50-ft oil column. Thus, in an oil reservoir, the same production from a well will be obtained if the pump is placed 50 ft above the formation and a complete vacuum is applied, or if the pump is placed at the formation and a vacuum is not applied. If the casing valves are closed (or a check valve is used) and the pump capacity exceeds both the oil production rate plus the gas production rate (expressed at 15 psia), then the well will tend to form its own vacuum in the casing annulus. A vacuum can often double the production from a well in a very low pressure reservoir (less than 30 psia) since the wellbore drawdown pressure can be doubled. In a tight, high pressure reservoir the results are negligible.

WELL PRODUCING A SINGLE LIQUID

The simplest type of producing well is one which produces a single liquid such as water or oil, with practically no solution gas. Water supply wells and very low solution gas reservoirs fit in this category. The production rate is directly proportional to the pressure drawdown between the reservoir and the wellbore. If the static reservoir pressure is 1000 psi and the producing wellbore pressure is 800 psi at a given producing rate, then reducing the wellbore pressure to zero psi will increase the production rate by a factor of five. The most common method of presenting the results, which gives considerable information to the operator, is in the form of a graph (Fig. 11).

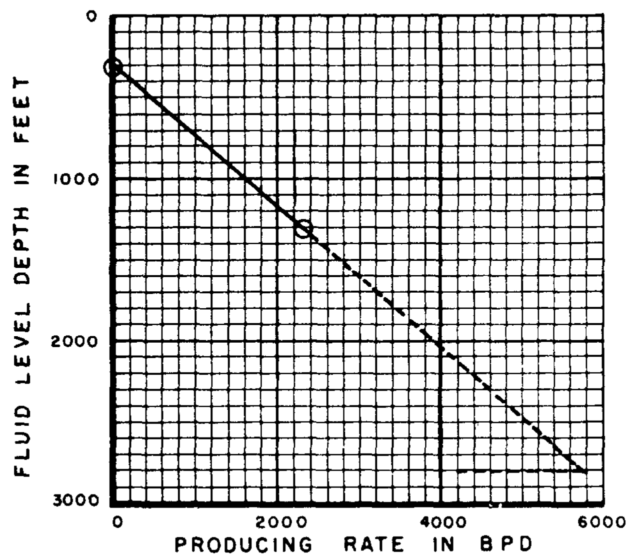


FIG. 11

Figure 11 is constructed from data given in Table 3. The static fluid level was 300 ft. The well was produced at a rate of 2300 BWPD, and the fluid level was found at 1300 ft. Extrapolating the line connecting these points gives the production which can be obtained at any depth, or the maximum production rate of 5750 BWPD at the reservoir depth of 2800 ft. Such tests are often used in determining the size of pumping equipment since both the amount of fluid and the depth from which it can be obtained must be known for efficient operation. For example, under the foregoing conditions, if 4000 BWPD is required for a waterflood, a pump designed for 4000 BPD should be set slightly below 2100 ft for maximum efficiency.

In the case of water supply wells, the water source and wellbore can be checked periodically during the life of the wells by taking producing and static liquid levels and by comparing these tests to the original tests. A drop in the static liquid level in a well would indicate that the reservoir is being depleted and that another source may be needed. However, a drop in the producing liquid level at any certain producing rate without an associated change in the static liquid level would indicate wellbore damage, which could be improved by some method of well stimulation. In the above cases, a constant casing pressure is assumed which normally exists in this type of production. If the casing pressure varies, it must be taken into consideration because the important factor is the pressure at the wellbore.

LOW PRESSURE OIL WELLS

Low pressure wells producing oil and solution gas respond similarly to wells producing a single liquid, but the relationship between the producing bottom hole pressure and the static reservoir pressure is often much more important. An estimate of the static reservoir pressure is very desirable in order to estimate the permissible producing bottom hole pressure. For low static pressure reservoirs, a minimum producing bottom hole pressure is desirable to obtain the maximum differential pressure between the reservoir and the wellbore, which will result in the maximum production into the wellbore. For high static pressure reservoirs, a higher producing bottom hole pressure can be tolerated. A producing bottom hole pressure of 70 psi (resulting from 50 psi casing pressure and a 60-ft oil column due to setting the pump this far above the formation) would not materially affect the production from a reservoir with a static reservoir pressure in excess of 1000 psi; but on the contrary, it would reduce the production rate from a well completed in a reservoir with a static pressure of 100 psi to less than one-third the maximum rate. A low static reservoir pressure is usually found in shallow reservoirs or deeper reservoirs which are partially depleted. Further discussion is presented under Discussion of Fluid Level Test Data.

HIGH PRESSURE WELLS

Oil wells which are producing from a reservoir subject to a waterflood or natural waterdrive are examples of wells discussed in this section.

Probably the greatest single use for the liquid level instrument is in determining whether an oil well, which is responding to a waterflood, is being produced at its capacity. A loss of oil occurs when oil bypasses a producing well because the well has excessive backpressure. The amount of this oil loss is dependent upon the location of the producing well with respect to other producing and water injection wells, the amount of backpressure in the well, and numerous other conditions. A substantial loss of oil occurs if oil bypasses a producing well located on the edge of a field and injected water continues to drive the oil into an undeveloped or plugged-out portion of the reservoir. Relatively less oil loss will occur from failure to maintain a minimum wellbore pressure in a producing well surrounded by a five-spot injection pattern. In this case, the chance of recovering the oil at a later time is greater due to the pressure distribution surrounding the well. However, at this later time, the waterflood may become uneconomical to operate which could result in abandonment of the project before the bypassed oil was actually produced.

The liquid level tests will often indicate a particular condition which cannot be found by any other means. For example, if a well producing at maximum capacity from a high static pressure reservoir had 100 ft of fluid above the pump, the pump would not pound and the

TABLE 3—FLUID LEVEL TEST DATA

Well No.	Average Joint Length, Ft.	No. of Joints to Fluid	Depth to Fluid Feet	Casing Pressure PSI	Producing Bottom Hole Pressure at Top of Pay, PSI (1)	Well Tests: Oil BPD	Well Tests: Water BPD	Well Tests: Total BPD	Pump Data: Rod & Tubing Size Inches	Pump Data: Number Strokes x Length (Inches)	Pump Size Inches	Capacity BPD	Efficiency Percent	Remarks
1	31.0	155	4805	20	26 @ 4810	60	4	64	3/4 - 2	12 x 54	1½	113	57	OK
2	31.2	157	4898	18	22 @ 4905	98	7	105	3/4 & 7/8 - 2	16 x 54	1½	171	61	OK
3	30.8	129	3973	10	302 @ 4847	17	5	22	3/4 - 2	11 x 48	1½	83	27	DEF
4	30.7	135	4145	137	393 @ 4870	4	83	87	3/4 & 7/8 - 2	15 x 54	1½	153	57	DEF
5	31.1	78	2426	19	835 @ 4870	88	109	197	3/4 & 7/8 - 2	16 x 54	1½	173	114	PPC
6	29.8	93	2771	185	888 @ 4840	69	27	96	3/4 - 2	16 x 34	1½	66	145	PPC
7	30.1	162	4876	470	527 @ 4875	66	44	110	3/4 - 2	12 x 54	1½	113	98	pumping (2)
7SI	30.1	143	4433	1305	1622 @ 4875	-	-	-	--	-	-	-	-	SBHP
8	30.9	157	4758	5	37 @ 4855	26	79	105	3/4 - 2	13 x 54	1½	123	85	pumping (3)
8SI	30.9	114	3523	920	1623 @ 4855	-	-	-	-	-	-	-	-	SBHP

Well No.	Average Joint Length, Ft.	No. of Joints to Fluid	Depth to Fluid Feet	Casing Pressure PSI	Time and Remarks
WSW #1	28.5	10.5	300	0	9:45 well not producing (static fluid level)
	28.5	10.5	300	0	10:00 shot fluid level, then started producing well
	28.5	25.5	727	0	10:05 producing well
	28.5	36.0	1026	0	10:10 producing well
	28.5	42.5	1211	0	10:15 producing well
	28.5	45.0	1283	0	10:20 producing well
	28.5	45.5	1300	0	10:25 producing well
	28.5	45.5	1300	0	10:30 producing well
	28.5	45.5	1300	0	10:45 well is stabilized and is producing at the rate of 2300 barrels per day. (producing fluid level)

DEF Downhole Equipment Failure
PPC Producing in Excess of Pump Capacity
SBHP Well Shut in 24 Hours for Static Bottom Hole Pressure
SI Shut-in

WSW #1 The well has a shut-in fluid level of 300' and a producing fluid level of 1300' at 2300 BWPD. The well will produce 2.3 BWPD for each foot that the fluid level is lowered, which would give a maximum producing rate of 5750 BWPD at its formation depth of 2800 feet.

(1) Assumed oil and water pressure gradients are 0.333 and 0.49 PSI/ft. The gas column pressure was determined using the approximate rule.

(2) This well has a static reservoir pressure of 1622 PSI (see #7SI) and a producing bottom hole pressure of 527 PSI. The productivity index (PI) is 0.1 barrels of fluid per day/PSI well bore drawdown or 0.06 barrels of oil per day/PSI well bore drawdown. The well's capacity is (0.1 BFPD/PSI drawdown x 1622 PSI maximum drawdown) or 162 barrels of fluid per day (97 BOPD and 65 BWPD)

(3) $PI = \frac{105}{1623-37} = 0.066$ BFPD/PSI drawdown
Maximum Producing Rate = 0.066 BFPD/PSI drawdown x 1623 PSI = 107 BFPD

operator would believe that additional fluid could be produced by installing larger equipment. It should be noted, however, that the back-pressure exerted by 100 ft of oil is less than 35 psi. Installing larger equipment to pump down the well probably would not be justified since only a very small increase in production would be obtained under these conditions.

The liquid level instrument is very beneficial in efficiently producing a well which has a high productivity index when the well cannot be pumped down due to the limited size of the mechanical equipment and where economics of a change do not justify the installation of larger equipment. If the high volume producer has a relatively high producing bottom hole pressure, the pump should be raised off bottom to obtain more production from the well. The proper depth to set the pump for maximum production can be determined in the following manner. A static and a producing bottom hole pressure will give a productivity index which can be used to show producing rates at various liquid level depths. The equipment can then be sized to the particular well by bringing the pump up the hole and enlarging the size of the pump to handle the liquid at the particular depth. The maximum efficiency from the producing equipment will then be utilized, since the equipment's maximum producing rate for a particular depth will be matched with the well's producing capacity at that depth. Table 4 is given to show a simplified method of using the producing and static bottom hole pressures for determining the proper pump setting depth. In Fig. 12 the pump capacity of the equipment is plotted vs pump depth. The producing rate of the well as the pump setting depth is varied is plotted on the same graph. Note that the producing rate of the well is plotted vs pump setting depth (with no liquid above the pump). The liquid gradient below the pump perforations will be the liquid produced by the well. Normally, this high pump condition exists in high water-oil ratio wells and the liquid gradient below the pump is approximately 0.5 psi/ft. The static liquid level at zero producing rate would be the top of the liquid normally produced by the well supported by the static bottom hole pressure. The intersection of the two curves gives the maximum producing rate which can be obtained from the well with existing equipment. In this particular example, the producing rate would be increased from 200 BPD (30 BOPD and 170 BWPD) with the pump at 6000 ft to a producing rate of 340 BPD (51 BOPD and 289 BWPD) with the pump at 4400 ft. Approximately 21 BPD additional oil would be obtained by raising the pump to the proper depth—an increase of 70%. Kelley and Willis[2] present a set of curves showing the pump capacity at various depths for the standard size API pumping units. Figure 13 is taken from the article and shows approximate capacities at various depths for standard API pumping units. The charts are very useful for determining approximate pump depths. The API paper "RP11L" recommends design procedure.

The static bottom hole pressure is not always known and some operators are reluctant to shut down wells making a high percentage of water to obtain the static reservoir pressure. This static reservoir pressure, or the producing bottom hole pressure at a different producing rate, is necessary to determine the slope of the producing-rate curve. In the previous example, one point on the curve was known from the producing fluid level test. This point is the 200 BPD rate at a producing bottom hole pressure of 1500 psi (or 3050 ft of fluid above the formation). The static reservoir pressure gives the depth to liquid at static conditions and establishes the slope of the curve. In a natural water-drive reservoir, the static pressure can be estimated from bottom hole pressure tests on other nearby wells. Drillstem test data can often be used. In a waterflood, the static reservoir pressure is necessarily less than the bottom hole pressure of the nearby water injection wells. For example, if a 6000-ft water injection well has 500 psi shut-in surface pressures, the bottom hole pressure in the well would be approximately 3500 psi. If this water from the injection well is driving oil to the producing well, then the static pressure in the producing well must be less than 3500 psi. Another way to estimate this static liquid level is to note the liquid level on the tubing when the well is being serviced. The fluid column should be converted to a static bottom hole pressure. Then the producing and static bottom hole pressures can be converted into equivalent produced liquid columns. The assumption of water in the liquid column will tend to slightly lower the optimum setting depth of the pump. This is desirable where the percentage

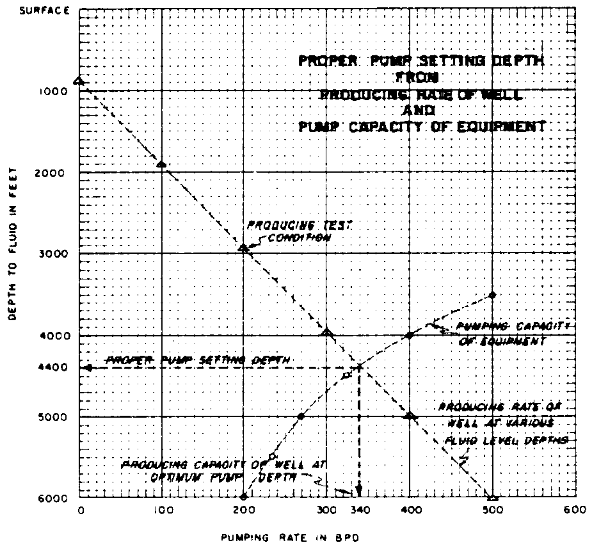


FIG. 12—FLUID LEVEL DEPTH VS PRODUCING RATE

TABLE 4

Data:

Static Bottom Hole Pressure - 2,500 PSI
Producing Rate - 200 BPD (30 BOPD and 170 BWPD) at a producing bottom hole pressure of 1500 PSI
Formation and Pump Depth - 6,000′
Pumping Unit - 228,000″ # gear box

$$\text{Productivity Index} + \frac{\text{Producing Rate}}{\text{Pressure Drawdown}} = \frac{200\ \text{BPD}}{1000\ \text{PSI}} = 0.2\ \text{BPD/PSI}$$

Example Tabulation

Shut-in Pressure PSI	Producing Bottom Hole Pressure, PSI	Equivalent Fluid Above Pump, Ft.*	Depth to Fluid Feet	Drawdown Pressure PSI	Producing Rate BPD
2500	2500	5100	900	0	0
2500	2000	4100	1900	500	100
2500	1500	3050	2950	1000	200
2500	1000	2050	3950	1500	300
2500	500	1000	5000	2000	400
2500	0	0	6000	2500	500

* assuming a produced liquid gradient of 0.49 psi/ft

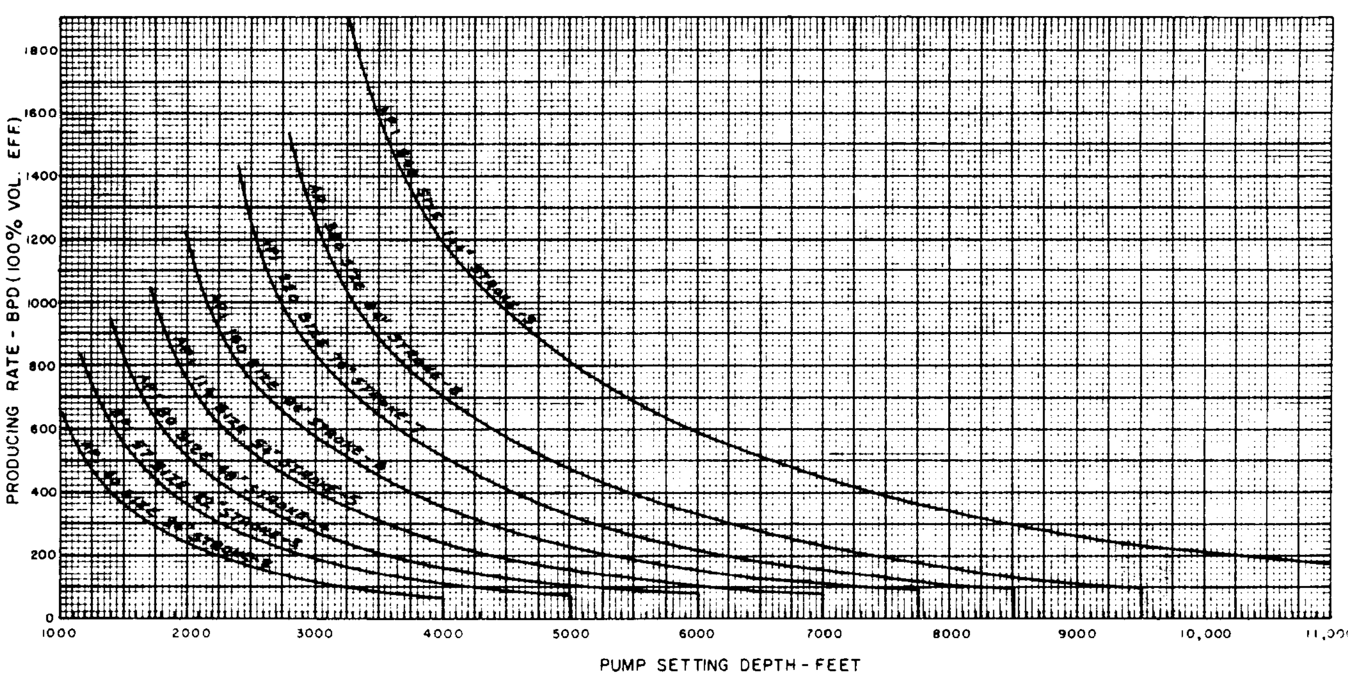


FIG. 13—PUMPING UNIT CAPACITY CHART

of water is increasing or where the producing capacity of the well is decreasing.

The proper depth to set the pump can be estimated on the basis of the producing liquid level test alone, provided the producing capacity of the pumping equipment is not greatly increased at the new setting depth. The producing bottom hole pressure can be converted to an equivalent column of the heaviest fluid produced by the well. Note that raising a pump to a high liquid level will decrease production since a heavy, predominately water, column will exist below a high pump where a light oil column existed above a deep pump. Be cautious when raising a pump over two-thirds of the distance to a high liquid level. The pump should normally be raised to a depth about midway between the fluid level and the pump perforations depth. Setting the pump off bottom will result in additional production due to larger pump diameter, less rod and tubing stretch and less wear on the equipment.

DISCUSSION OF FLUID LEVEL TEST DATA

Table 3 is a summary of some typical liquid level tests made on wells. The producing bottom hole pressures, well tests and pump capacities are given for several wells which were producing under different conditions. The producing bottom hole pressures were calculated by the method given earlier. The pump capacities were calculated assuming that the well was pumped down. Wells 1 through 6 have static bottom hole pressures of approximately 1000 psi.

Wells 1 and 2 were being produced efficiently. The producing bottom hole pressures were 22 and 26 psi, respectively, which is reasonable for wells of this depth. Wells 3 and 4 had considerable wellbore pressure which restricted the entry of fluid into the wellbore. The normal pump capacity was in excess of the well's producing capacity, and the excessive pumping bottom hole pressure indicated by the high liquid level and casing pressure was indicative of a failure in the downhole equipment. This failure could be due to a bad pump or a leak in the tubing.

Wells 5 and 6 have producing capacities exceeding the pump capacities. This almost always occurs in the later stages of a waterflood and in full water-drive reservoirs. Considerable amounts of fluids were prevented from entering the wellbores, as shown by the backpressures in excess of 800 psi. Additional fluid production is possible, and the feasibility of increasing the pump capacities should be considered. The pump should be raised and increased in size if the economics do not justify larger equipment.

Well 7 has a static bottom hole pressure of 1622 psi and a producing bottom hole pressure of 527 psi. The resulting productivity index is 110 bbl of fluid per day per (1622 to 527) psi drawdown, or 0.1 BPD/psi wellbore drawdown. The maximum producing capacity would be 0.1 BPD/psi times 1622 psi, or 162 BFPD. More production could be obtained if additional producing pump capacity were available. Assuming the present equipment is loaded and a change to larger equipment is not economically justified, the pump should be raised in order to produce more fluid without any additional load on the equipment. Using the method previously given by an example, the production could be increased to 135 BPD by raising the pump to the proper depth of 4300 ft without overloading the pumping unit. This would result in an increase in production of approximately 23%.

Well 8 had a static bottom hole pressure of 1623 psi and a producing wellbore pressure of 37 psi. Most of the producing wellbore pressure is the result of liquid above the top of the pump. The productivity index is 0.066 BFPD/psi wellbore drawdown. The maximum producing rate (or well capacity) is 0.066 BPD/psi times 1623 psi, or 107 BPD. This is an example of a well that does not pound fluid, but servicing the well or installing larger equipment would not appreciably increase the producing rate.

ANALYSIS OF DOWNHOLE EQUIPMENT

One of the more common uses of the acoustic well sounder is to determine if the fluid is being removed from the wellbore. If the fluids are not being produced from the wellbore due to a mechanical failure such as rod breakage, bad pump conditions, tubing leak, etc., the liquid level will be found above the pump level, provided sufficient reservoir pressure exists to maintain a head of fluid. In such cases the operator knows that a mechanical failure has occurred and the well needs to be pulled or serviced. However, if a liquid level test and casing pressure information indicate that the wellbore pressure is already at the minimum value for the particular conditions, then pulling the well will not increase its production.

Liquid level tests are often used to determine the pumping conditions of a new well where the maximum production rate is not known. Trouble with pumping equipment is often encountered in a newly completed well and this test will show if the fluid is being removed from the wellbore.

The dynamometer is a valuable tool to pinpoint a failure in the downhole equipment. The condition of the traveling valve, standing valve, tubing perforations and other possible trouble sources can be readily checked. This will permit the operator to select the proper procedure to correct the equipment failure. Just because a well is pumped down does not necessarily mean that the maximum production is being obtained from the well since an excessive casing pressure may exist.

SPECIAL RESERVOIR ANALYSIS

Several important reservoir characteristics can be determined by the rate at which the fluid enters the wellbore when a producing well is shut in or when a shut-in well is put on production. Probably the one most important characteristic that can be measured is the amount of formation damage that is present immediately surrounding the wellbore.

Usually a permeability block can be treated to increase production from the well. Several different methods are in use for determining this damage. Two other factors often determined from pressure buildup and drawdown data are formation permeability and a true static reservoir pressure, without an excessively long shut-in period.

SPECIAL USES OF THE INSTRUMENT

Since the instrument records sound reflections from within the annular space, several other special uses are possible. Any enlargement or obstruction in the casing is shown on the chart. For example: perforations, liners, parted tubing, shot holes, collapsed casing, tubing anchors, paraffin deposits, salt rings and gas lift valves are recorded. These conditions produce particular curve characteristics which generally permit the operator to distinguish which condition is present.

Other special related uses have recently come into use. The liquid level instruments are capable of recording pressure pulses in any system. Thus, pressure pulses in lines feeding downhole hydraulic pumps can be measured and timed for analyzing downhole pump efficiency. Pressure surges in pump inlets and outlets can be measured. Distance to obstructions, or liquid in gas lines, or untubed casing filled with gas is possible by data on the velocity of sound in gas developed by Thomas[3] or Andsager and Knapp.[4]

CONCLUSION

Analyzing well performance is a daily job. Careful attention, planning and testing are necessary to determine and maintain favorable downhole conditions. More efficient producing methods and an increase in oil production are possible through a sound well-performance analysis program.

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