GIAC 15

A COURSE IN THE PHASE BEHAVIOR OF HYDROCARBON RESERVOIR FLUIDS

Presented by the
RESERVOIR FLUID ANALYSIS DEPARTMENT
of
CORE LABORATORIES, INC.

COURSE OUTLINE

- I. Basic Phase Behavior
  - A. Introduction
  - B. Pure Component
  - C. Binary System
  - D. Various Multi-Component Systems
  - E. Other
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    - 2. Volatile Oil Depletion Treatment
    - 3. GOR Ranges for Various Hydrocarbon Systems
    - 4. P-T Diagrams for Oil and Associated Gas Cap
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  - B. Well Conditioning
    - 1. Saturated Reservoir
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  - C. Subsurface Sampling
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- III. Reservoir Fluid Study - Oil
  - A. Discussion of Individual Tests
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  - C. Material Balance Calculation
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- V. Extrapolation of Reservoir Fluid Data

INTRODUCTION

Hydrocarbon systems found in petroleum reservoirs are known to exhibit multi-phase behavior over extremely wide ranges of pressures and temperatures. Two phases have been found to exist at temperatures as low as -250°F. and as high as 1000°F., or more. With todays deep drilling, two-phase reservoirs at pressures in excess of 15000 psi are not uncommon. The molecular compositions of the gas and liquid phases in a reservoir rock are different, and hence the physical properties of the phases differ. This difference in phase properties, along with the relative permeability characteristics of the reservoir rock, cause the complex behavior of hydrocarbon reservoirs.

Hydrocarbons, of course, are molecules consisting of carbon and hydrogen atoms. The complexity of hydrocarbon mixtures may best be understood through the extremely large number of unique hydrocarbon molecules. Hydrocarbon molecules have traditionally been referred to by the total number of carbon atoms within the molecule. Methane is C1, Ethane is C2, Propane is C3, etc. For each of the first three carbon numbers, there is one possible configuration of the molecule. There are two possible configurations for C4. There are three for C5. There are eight for C6. By the time you reach C10, there are 75 possible configurations. By the time you reach C30, there are an estimated 1 to 3 billion possible configurations of the hydrocarbon molecule. When you consider that virtually every naturally occurring hydrocarbon system contains some C30, the complexity of hydrocarbons comes into focus a little more clearly.

The phase behavior of hydrocarbon systems takes on a higher degree of complexity when you consider that the variables of pressure and temperature must now be added to the problem. To circumvent some of the complexity, we will begin a stepwise discussion of phase behavior of hydrocarbons:

1) First we will discuss a pure component.
2) Secondly, we will discuss a binary, or two-component system.
3) Lastly, we will discuss several generalized multi-component systems.

Notes:

PRESSURE-TEMPERATURE DIAGRAM
FOR
PURE ETHANE

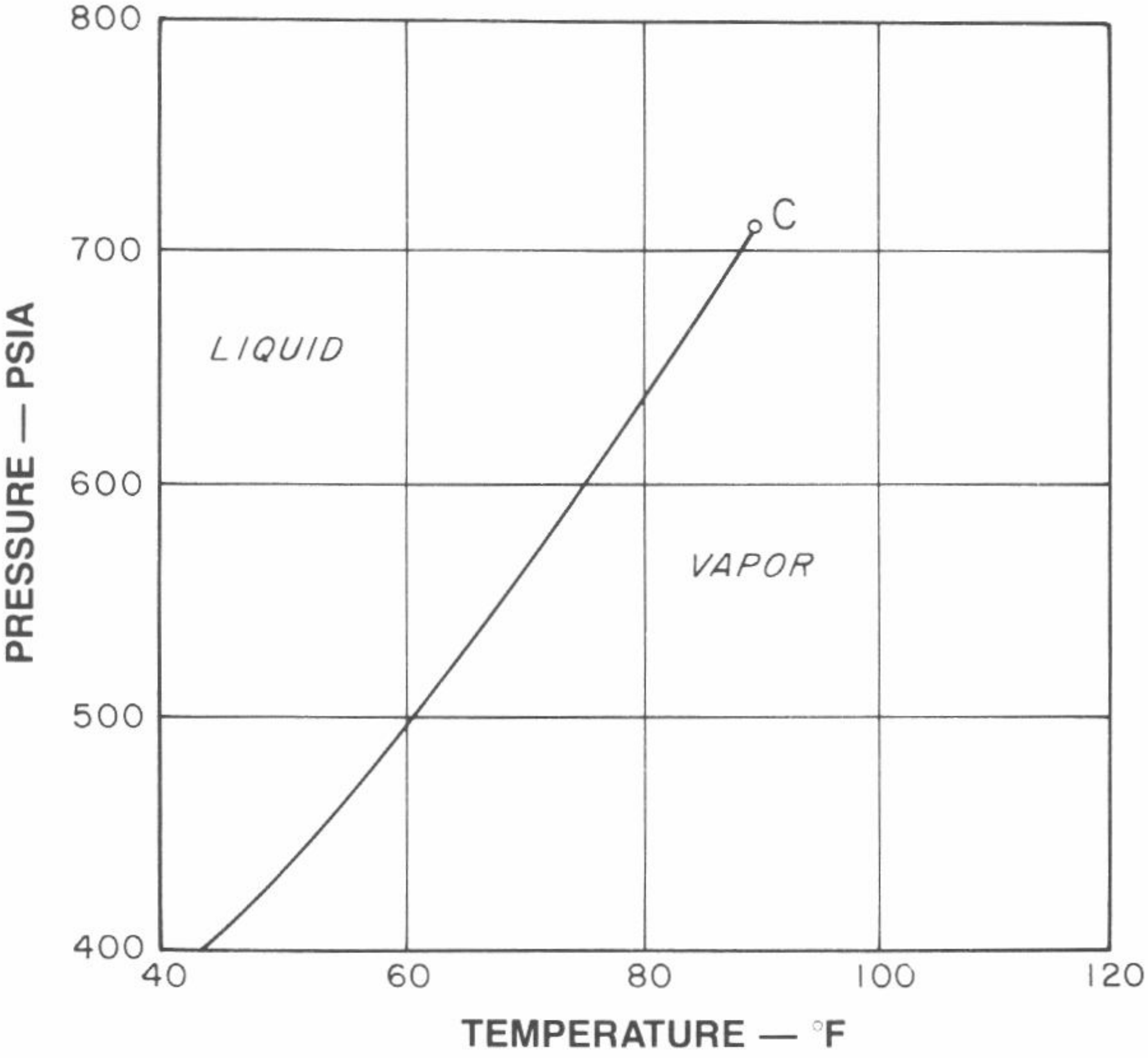


FIGURE 1

Figure 1 is the pressure - temperature diagram for pure ethane. At pressures and temperatures above and to the left of the curve, ethane is in the liquid phase. Below and to the right of the curve, ethane is in the vapor phase. The curve is both the bubble point locus and the dew point locus. C is the critical point.

Critical Temperature - The critical temperature of a pure component is defined as the temperature above which two phases cannot exist, regardless of the pressure on the system.

Critical Pressure - The critical pressure for a pure component is that pressure above which vapor and liquid cannot exist in equilibrium.

Notes:

PRESSURE-TEMPERATURE DIAGRAM

FOR

96.83% ETHANE - 3.17% N-HEPTANE MIXTURE

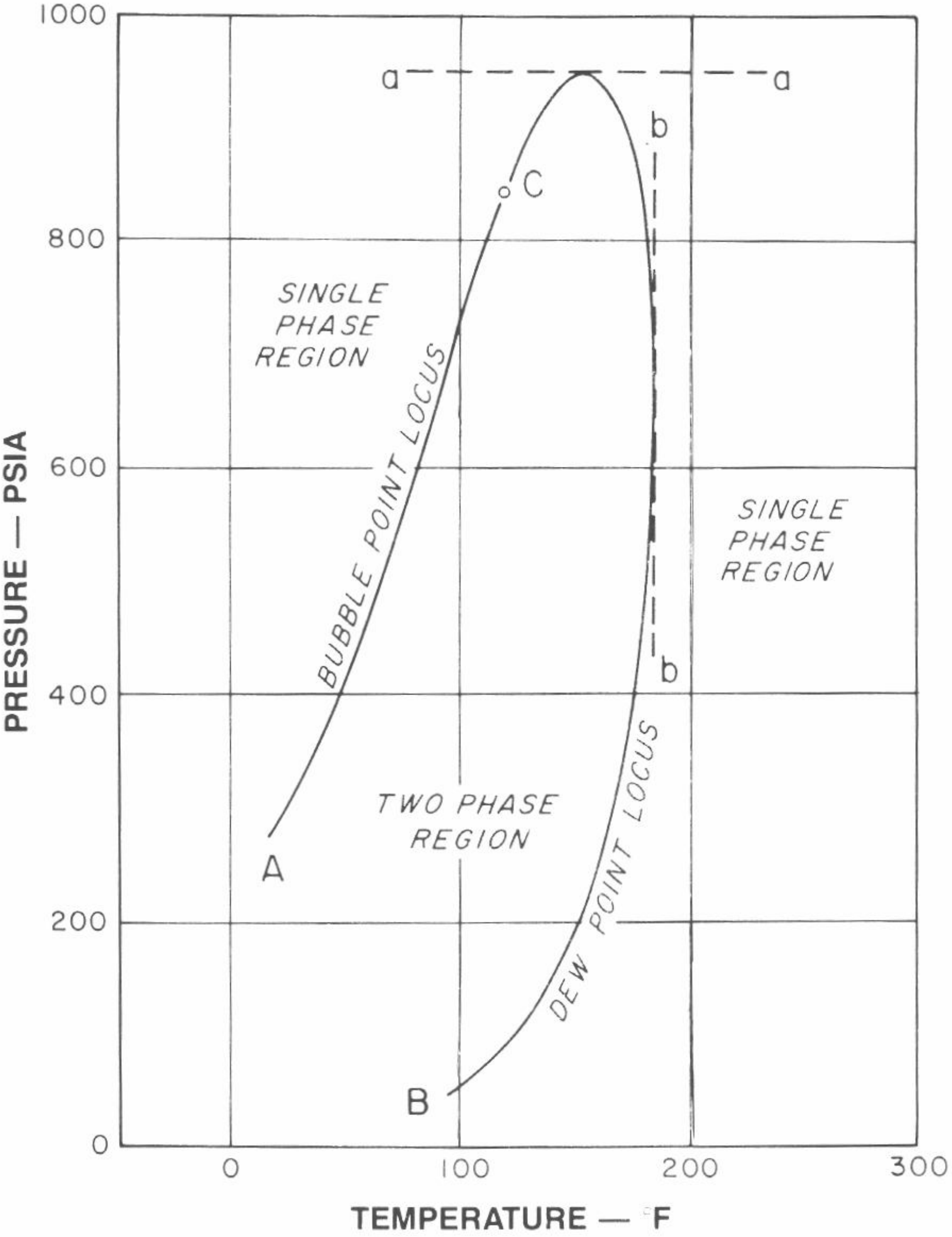


FIGURE 2

Figure 2 is the pressure - temperature diagram for a mixture of 96.83 percent ethane and 3.17 percent normal heptane. At all pressures and temperatures outside of the phase diagram, the mixture is single phase. At all pressures and temperatures within the phase diagram, the mixture exists in two phases. Line A-C is the bubble point locus and B-C is the dew point locus. C is the critical point.

Critical Point - The critical point for a multi-component mixture is the point at which all intensive properties of the gas and liquid phases are equal. Intensive properties are properties that are independent of the amount of fluid. Some intensive properties are: density, pressure, temperature, viscosity, surface tension, and composition.

Cricondenbar (a---a) - The cricondenbar is the maximum pressure at which two phases can exist in equilibrium.

Cricondentherm (b---b) - The cricondentherm is the maximum temperature at which two phases can exist in equilibrium.

Notes:

PRESSURE-TEMPERATURE DIAGRAM

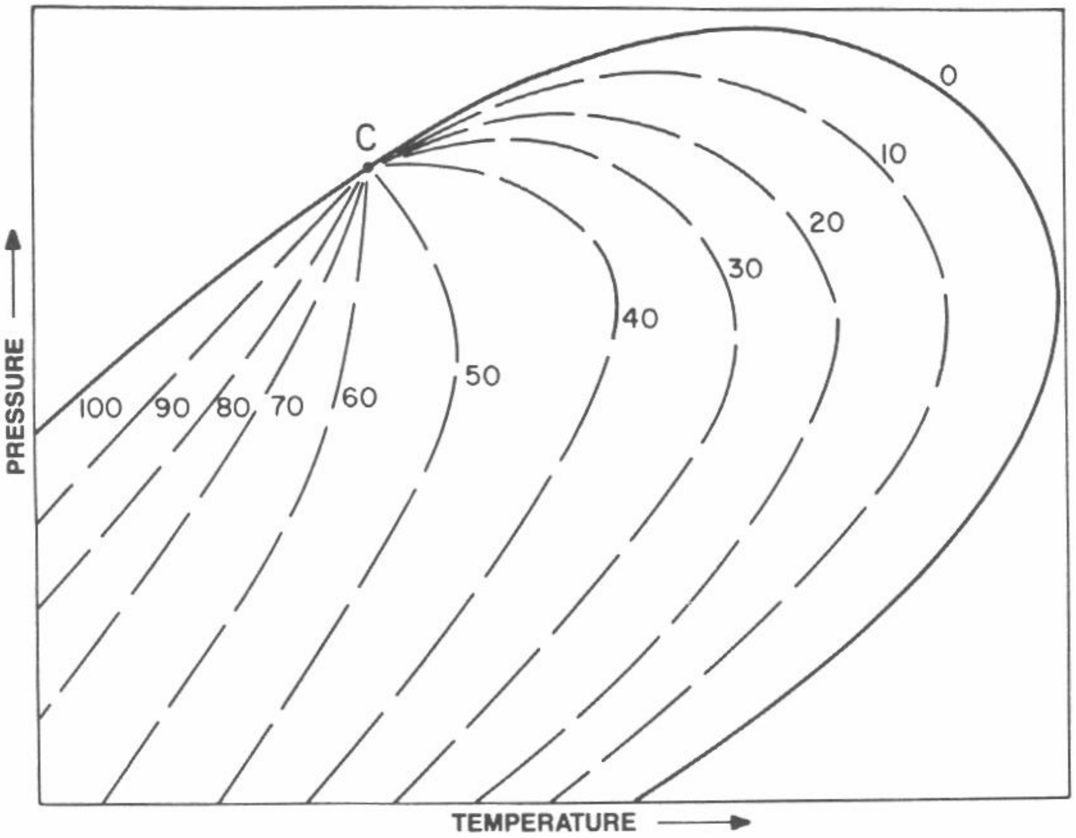


FIGURE 3

LIQUID VOLUME CURVE FOR TYPICAL BLACK OIL

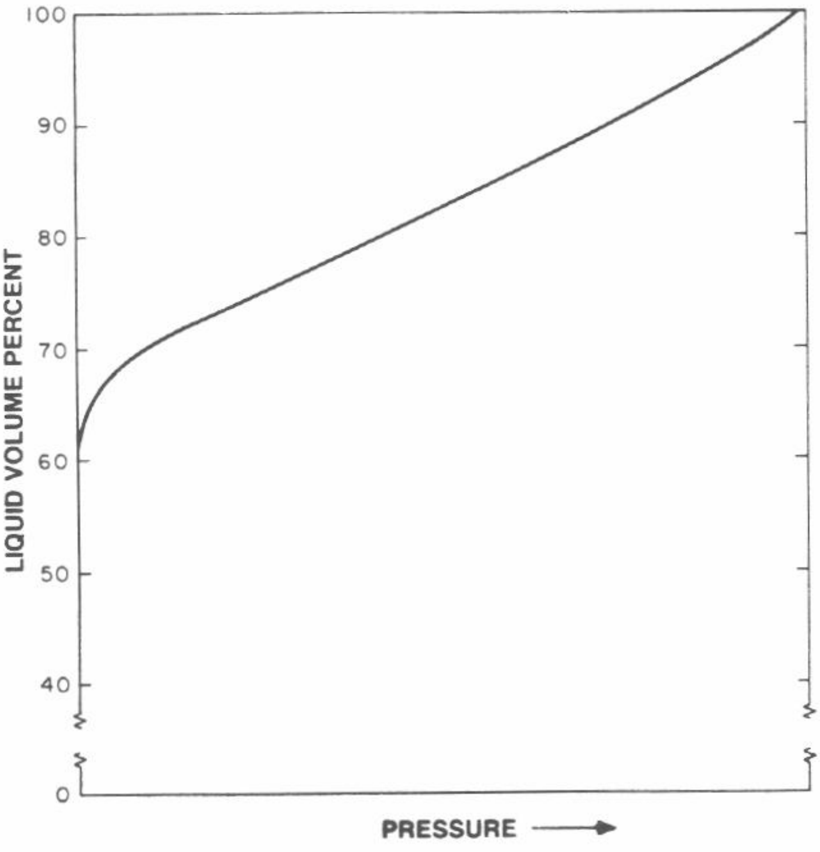


FIGURE 4

Figure 3 is the pressure-temperature diagram of a hypothetical mixture. The dashed lines within the phase diagram are called quality lines. They describe the pressure and temperature conditions for equal volumes of liquid. Note that the quality lines converge at the critical point.

Assume we have a reservoir fluid with the characteristics described by the phase diagram in figure 3. Also assume that the reservoir temperature is Tr as shown at the left side of the phase diagram. If we were to measure the liquid volumes as we lowered the pressure we would measure a liquid shrinkage curve as illustrated in figure 4. Note that the quality lines are approximately equally spaced. The liquid shrinkage curve approximates a straight line except at very low pressures. This behavior characterizes what is commonly called an ordinary black oil.

Notes:

PRESSURE-TEMPERATURE DIAGRAM

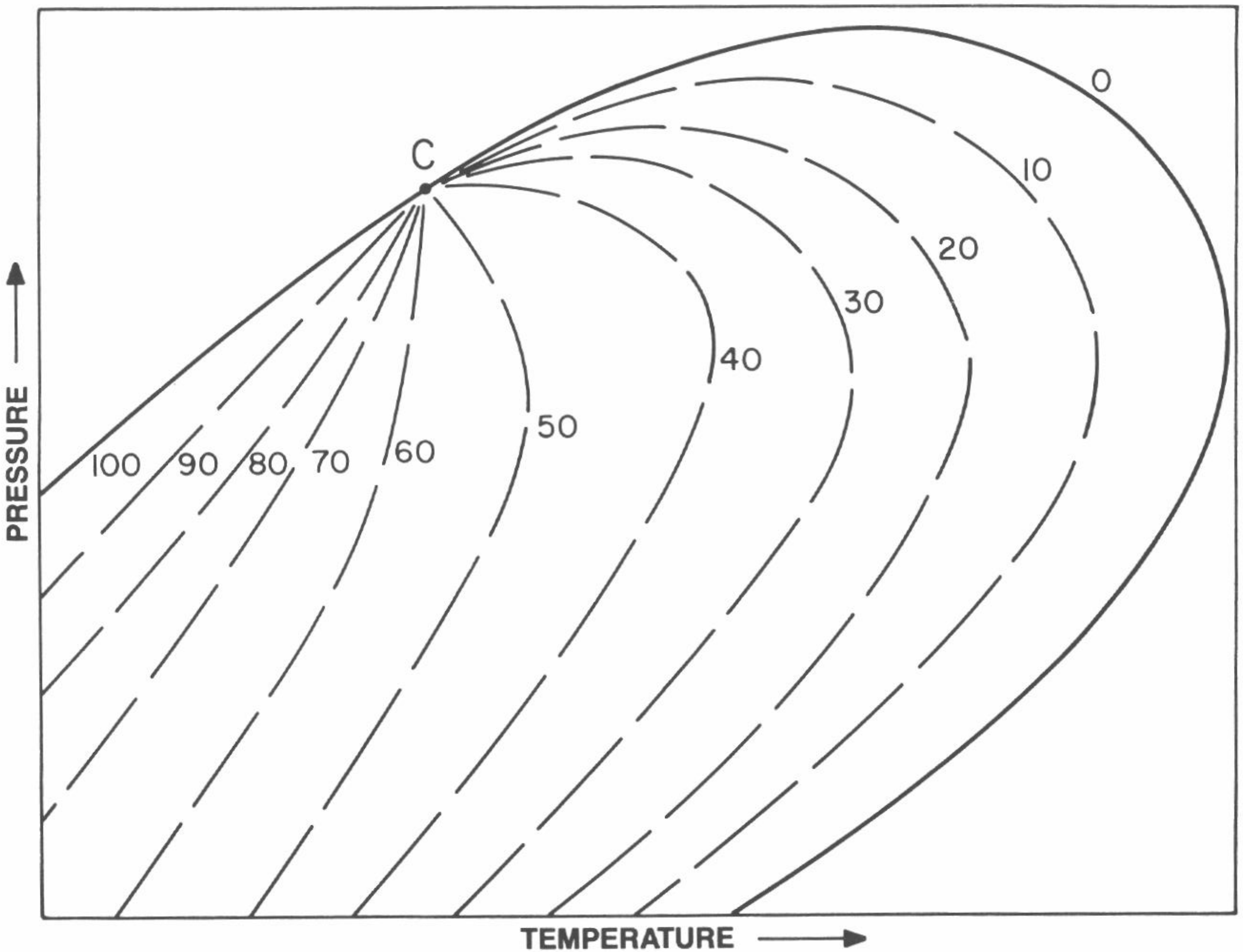


FIGURE 5

Figure 5 illustrates the phase diagram of a reservoir fluid with the reservoir temperature near but below the critical temperature. Note that the quality lines are very close together near the bubble point. At lower pressures they are spaced wider.

Notes:

LIQUID VOLUME CURVE

FOR

TYPICAL VOLATILE OIL

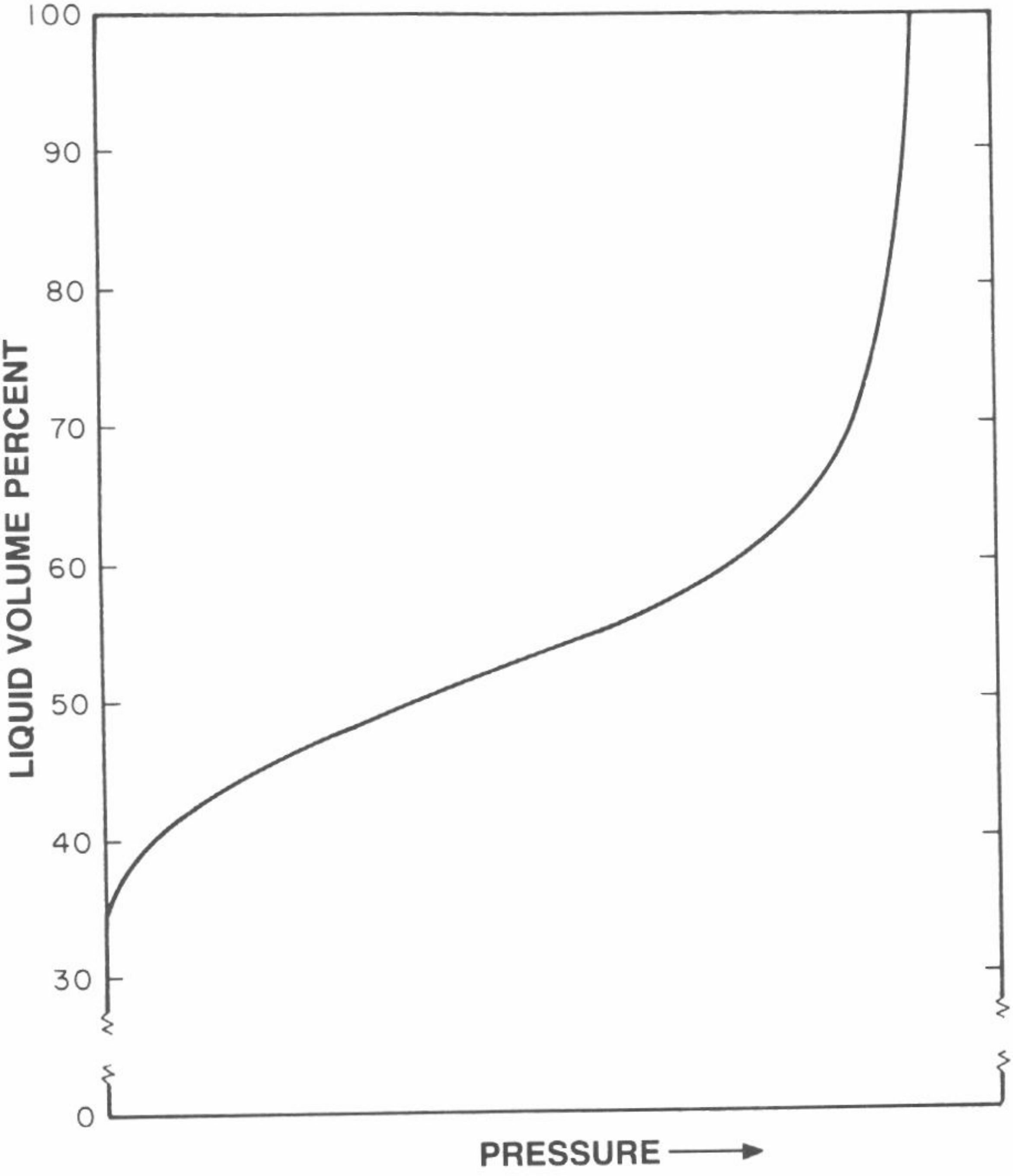


FIGURE 6

Figure 6 is the liquid shrinkage curve of a near critical oil. These oils are called volatile oils. They are characterized by a high liquid shrinkage immediately below the bubble point. Depending upon the position of the reservoir temperature relative to the critical temperature, the liquid shrinkage curve may have curvature varying from that of a black oil to that of a volatile oil. There is no sharp demarcation between a black oil and a volatile oil. Volatile oils will generally have an API gravity above 40 degrees, a gas-oil ratio above 2000-2500 cubic feet per barrel and a separator formation volume factor in excess of two.

Notes:

LIQUID VOLUME CURVE

FOR

NEAR CRITICAL OIL

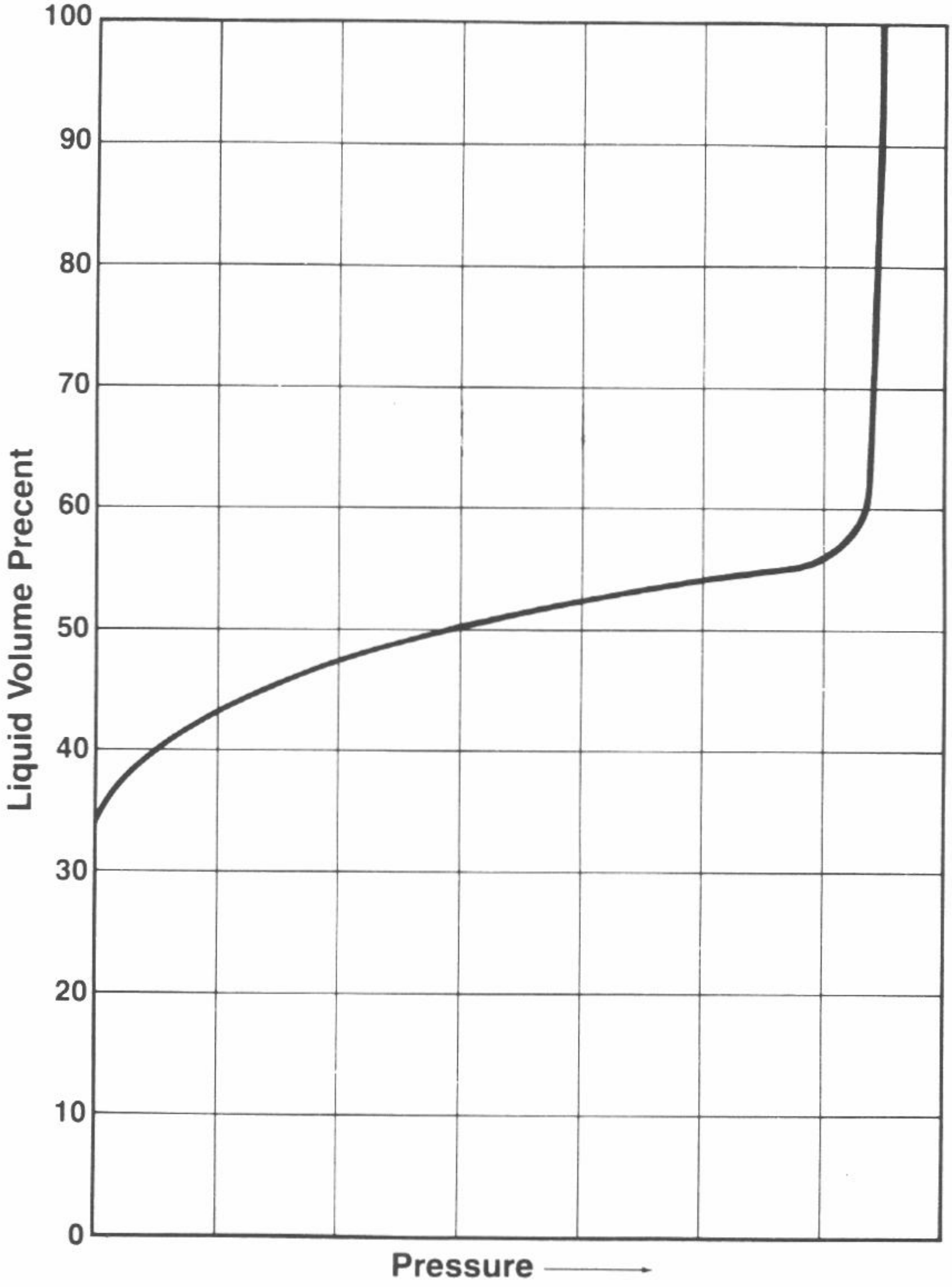


FIGURE 7

Figure 7 is the liquid shrinkage curve of a very near critical oil. The liquid may shrink from 100 percent of the hydrocarbon pore volume at the bubble point to 55 percent or less at a pressure 10 to 50 psi below the bubble point.

Notes:

PRESSURE-TEMPERATURE DIAGRAM

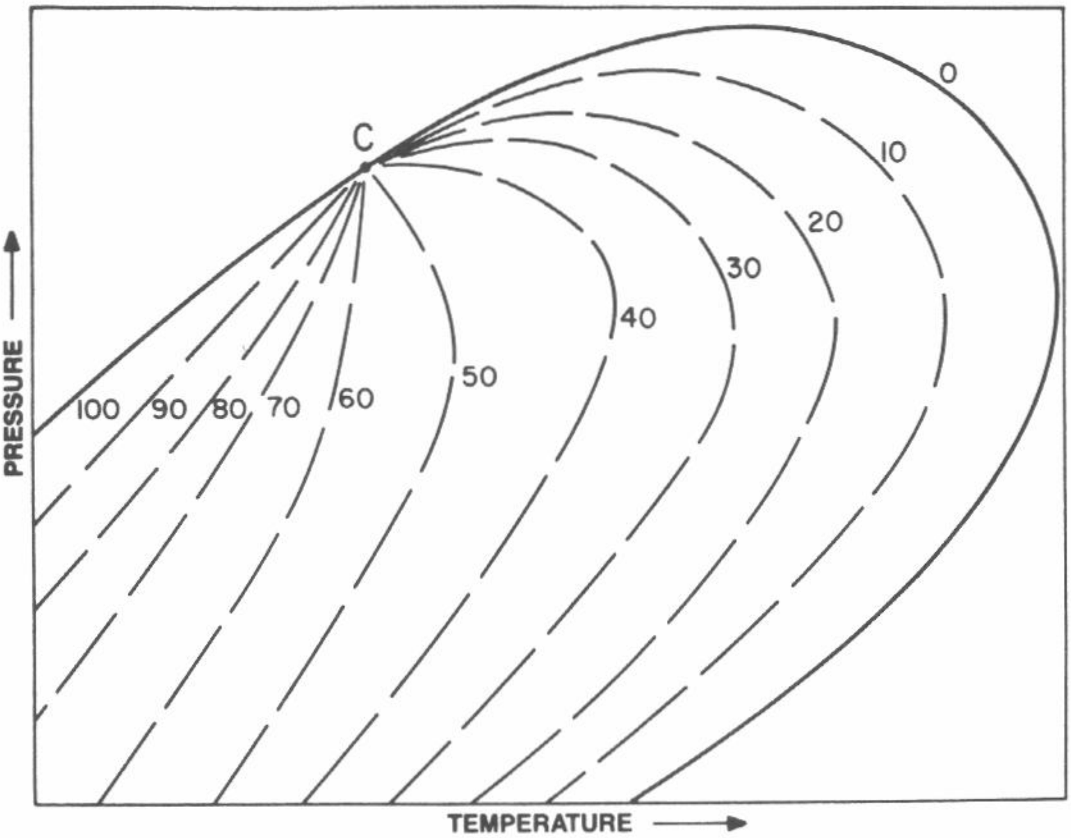


FIGURE 8

RETROGRADE LIQUID CURVE FOR NEAR CRITICAL GAS-CONDENSATE

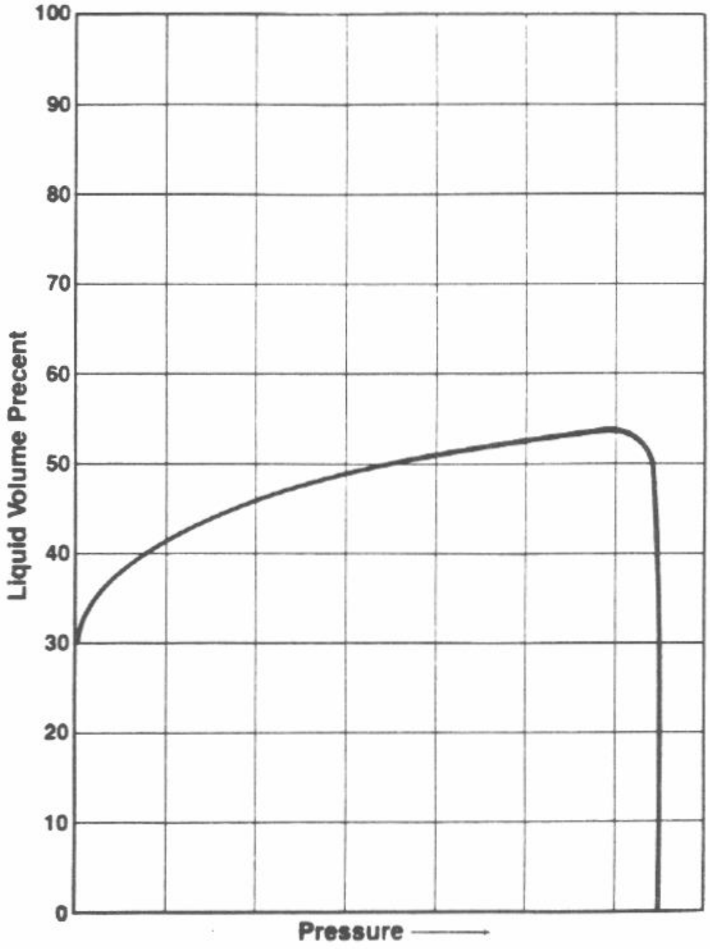


FIGURE 9

If the reservoir temperature is near but higher than the critical temperature, as in Figure 8, the reservoir fluid will be a gas-condensate. Note that as the pressure is reduced at the reservoir temperature, the zero percent quality line is intersected first. The ten, twenty, thirty, forty and fifty percent lines are crossed very rapidly. Note that as pressure is reduced, several of the quality lines are crossed a second time. Figure 9 is a plot of the liquid curve obtained if liquid volume is plotted versus pressure. This is called the retrograde liquid curve. Note the very rapid liquid build up immediately below the dew point. At the point where the liquid ceases to build up and begins to shrink again, the reservoir goes from the retrograde region to a normal vaporization region.

Notes:

Figure 10 is a gas-oil relative permeability curve. The curve will be used to solve a producing GOR problem for a volatile oil that has recently dropped below its original bubble point pressure. For this example, lets say that the fluid had an original bubble point pressure of 6000 PSIG, and at this point the fluid had the following physical characteristics:

P_b = 6000 PSIG
R_s = 3000 SCF/STB
μ_o = 0.10 centipoise
B_o = 3.0 RVB/STB

Further, let us assign the following properties to the producing gas and liquid phases at 5950 PSIG, only 50 PSIG below the original bubble point pressure:

P_b = 5950 PSIG
R_s = 2000 SCF/STB
μ_o = 0.12 centipoise
B_o = 2.0 RVB/STB
μ_g = 0.048 centipoise
B_g = 0.00066 RVB/SCF
S_o = 0.55, based upon the hydrocarbon pore volume only

The producing gas-oil ratio may be calculated by the formula.

$$R = \frac{K_g}{Ko} \times \frac{\mu o}{\mu g} \times \frac{B_o}{Bg} + R_s$$

First, we must determine Kg/Ko from the curve provided. In order to do this, we need to know the total liquid saturation. Assuming a connate water saturation of 0.20 (for the purpose of this problem), and converting the oil saturation to total pore volume (rather than hydrocarbon pore volume), we have:

$$S_L = 0.20 + (1-0.20)(0.55)$$
$$= 0.64$$

For the relative permeability curve provided, we can pick off a Kg/Ko = 3.0. Solving for producing gas-oil ratio:

$$R = 3.0 \times \frac{0.12}{0.048} \times \frac{2.0}{0.00066} + 2000$$

$$= 24700 \text{ SCF/STB}$$

Notes:

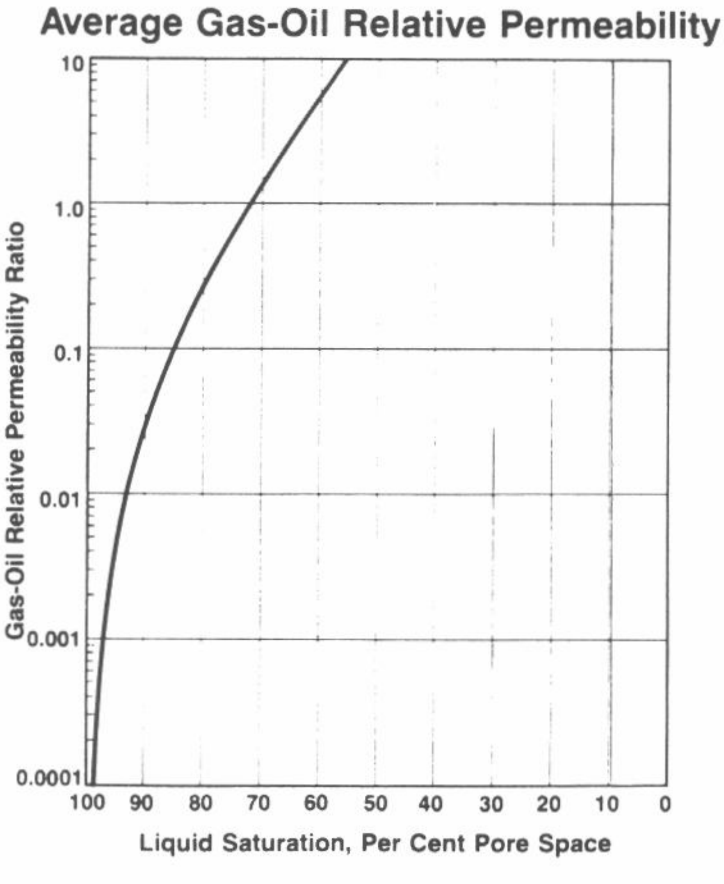


FIGURE 10

	CONVENTIONAL MATERIAL BALANCE	VOLATILE OIL MATERIAL BALANCE	ACTUAL PERFORMANCE
ULTIMATE OIL RECOVERY			
PER CENT OF OIL IN PLACE	8	20	22
BARRELS	880,000	2,200,000	2,400,000
MAXIMUM GOR CU FT/BBL	170,000	32,000	29,000

FIGURE 11

The producing gas-oil ratio determined in the preceding problem would be correct if all of the material that left the reservoir as gas phase stayed in the gas phase. In fact, the gas phase produced from a volatile oil reservoir is an extremely rich gas phase, and substantial amounts of this gas will condense into the liquid phase as it is produced to the surface. The net result is that the producing GOR for a volatile oil will increase somewhat as the fluid is produced below its original bubble point, but not as rapidly as would be indicated by the producing GOR formula, which is normally used for black oil material balance calculations. Figure 11 is a statement of performance predictions for a volatile oil reservoir, using both the conventional black oil and the volatile oil material balance approaches. These results were published by Jacoby and Berry in the AIME Transactions of 1957. The comparison indicates that the volatile oil material balance, which is a compositional treatment based upon a constant volume depletion of the reservoir fluid, achieves a much closer match to the actual performance of the reservoir during pressure depletion.

Notes:

PRESSURE-TEMPERATURE DIAGRAM

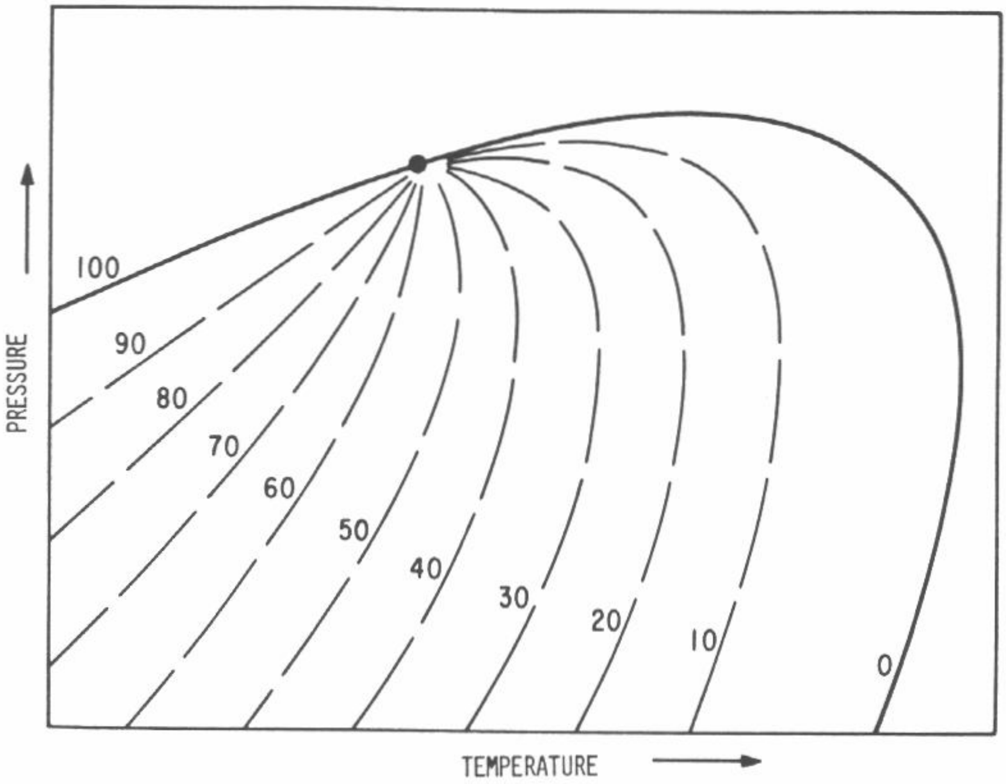


FIGURE 12

RETROGRADE LIQUID CURVE FOR LEAN GAS-CONDENSATE

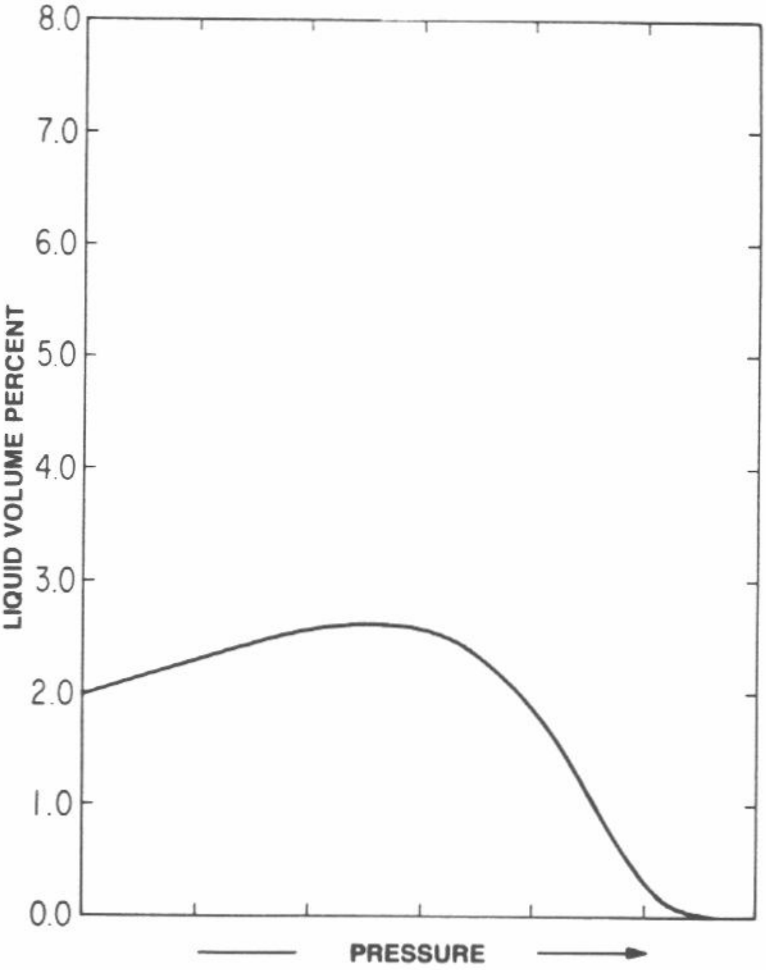


FIGURE 13

Figure 12 illustrates the pressure-temperature diagram of a reservoir fluid where the reservoir temperature is located at the far right hand side of the diagram, but still below the cricondentherm. If we draw a pressure depletion slice through the diagram, and translate this slice on to a graph of liquid volume percent versus pressure, Figure 13 would be the result. Figure 13 is a retrograde liquid curve for a typical lean gas-condensate system. Such a fluid might have a surface yield of about 30 barrels of stock tank condensate per MMSCF of separator gas. Figure numbers 9 and 13 serve to illustrate that gas-condensate fluids have been found to exist that deposit anywhere from trace amounts (less than 0.1 percent) to approximately 55 percent retrograde condensate during pressure depletion of the reservoir.

Notes:

PRESSURE-GOR DIAGRAM

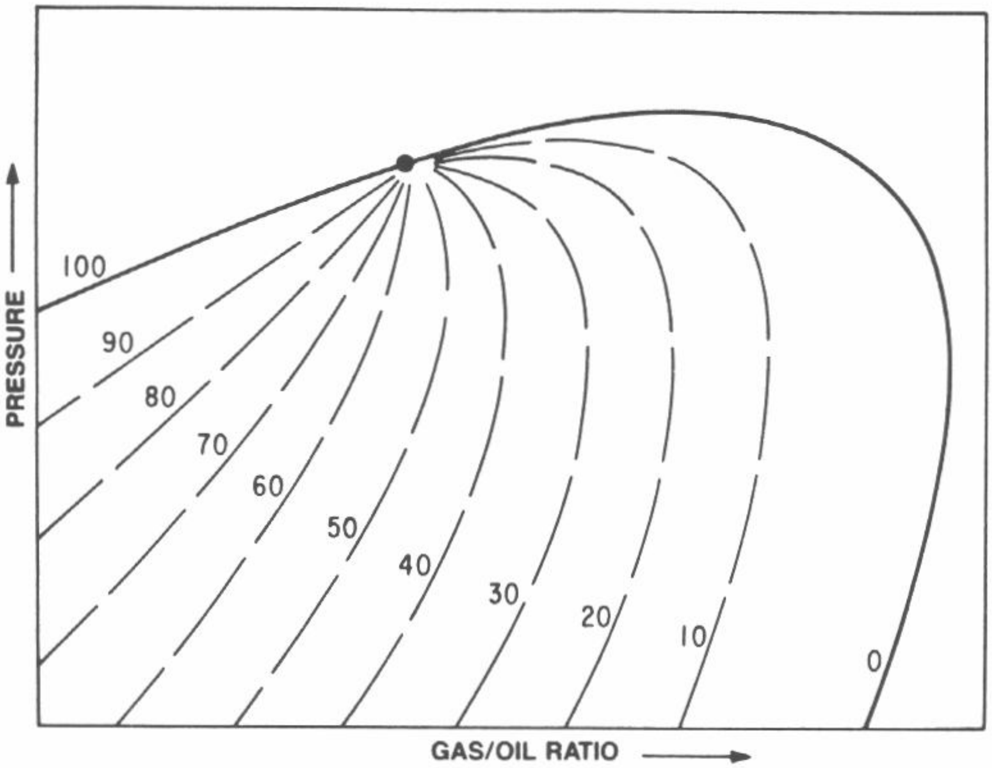


FIGURE 14

TYPICAL SOLUTION GAS/OIL RATIOS

FOR

VARIOUS HYDROCARBON SYSTEMS

OIL	**0-2000 Cu. Ft./Bbl.**
VOLATILE OIL	**2000-3000**
RETROGRADE CONDENSATE	**3000-150,000**
WET GAS	**150,000 - ∞**
DRY GAS	**∞**

FIGURE 15

Figure 14 looks similar to the pressure-temperature diagrams that we have been examining, but the X-axis has been changed from temperature to gas-oil ratio. As would be expected, the oil systems will be located at gas-oil ratios to the left of the critical GOR, while the gas systems will be located to the right of the critical. Figure 15 tabulates typical solution (single-phase) gas-oil ratios for various types of hydrocarbon systems. Based upon this table, the critical solution GOR would be about 3000 SCF/STB. Both the wet gases and dry gases would exist at gas-oil ratios to the right of the 0 percent quality line on Figure 14. This means that both would remain single-phase gas in the reservoir during pressure depletion. The wet gas (but not the dry gas) would have some condensation to liquid phase occur as the fluid is produced to the surface.

Notes:

Pressure-Temperature Diagram
Gas Cap and Associated Oil

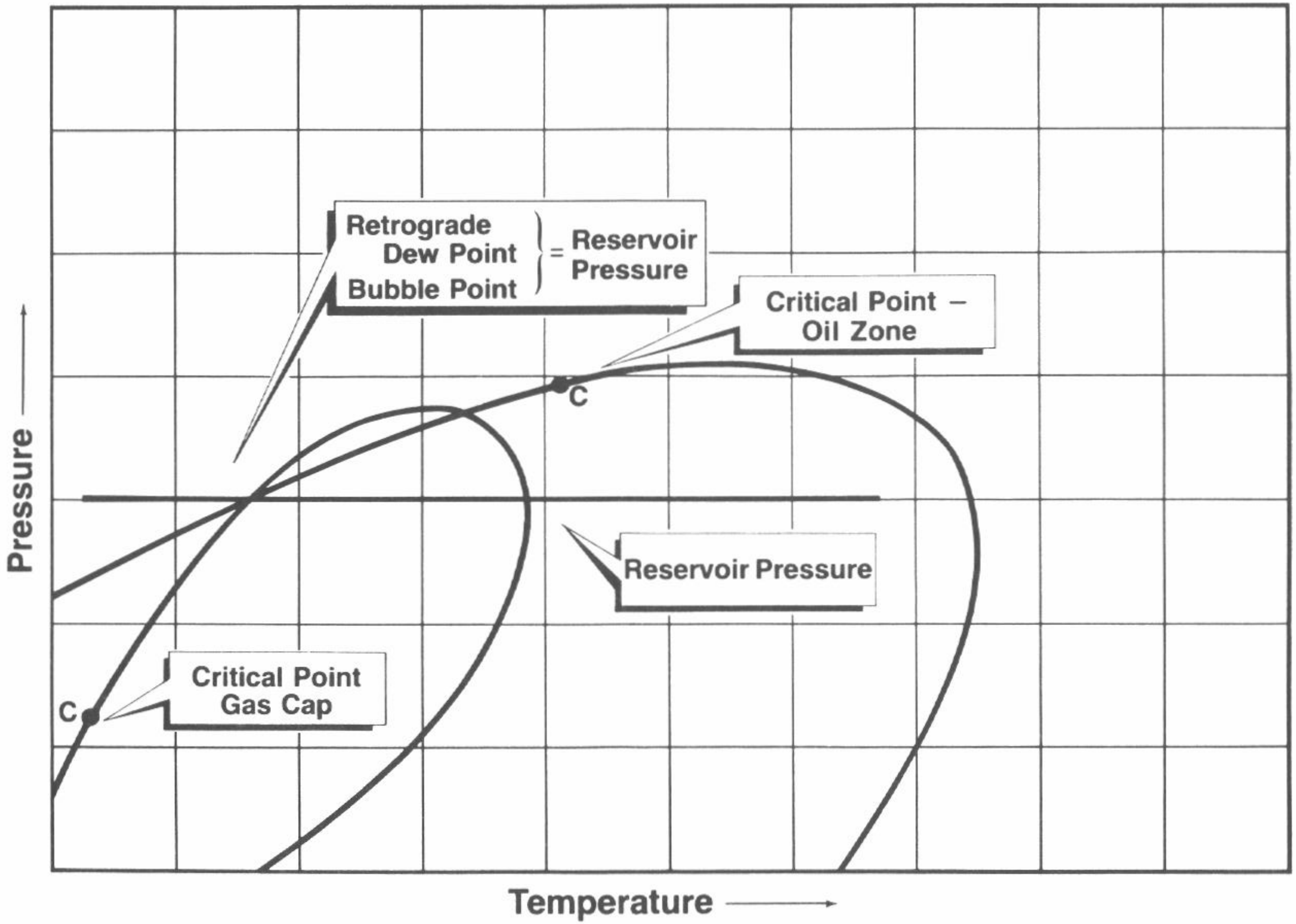


FIGURE 16

Figure 16 illustrates the relative relationship of the pressure-temperature diagrams for a typical oil system and the gas cap associated with that oil system. The significant point to be made is that when an oil system exists in intimate contact with an associated gas cap, the bubble point pressure of the oil will be equal to the dew point pressure of the gas cap. Moreover, both of these values will be equal to the static reservoir pressure at the gas-oil contact.

Notes:

INTRODUCTION

Reservoir fluid analysis provides some of the important basic data necessary to the petroleum engineer. The fluid studies performed by a competent PVT laboratory are such that precise quality control can be maintained through the use of accepted analytical procedures, data evaluation techniques and a series of built-in quality control checks. The overall quality of the study and the subsequent engineering calculations based upon that study can unfortunately be no better than the quality of the fluid samples originally collected during the field sampling process.

Having thus established that the activities surrounding the sampling process are the entire basis for a successful reservoir fluid analysis, we can now take a look at the recommended well conditioning procedures that should preceed the actual collection of the samples. Following the discussion on well conditioning, we will examine the two basic methods of sample collection: subsurface (bottomhole) and surface (separator).

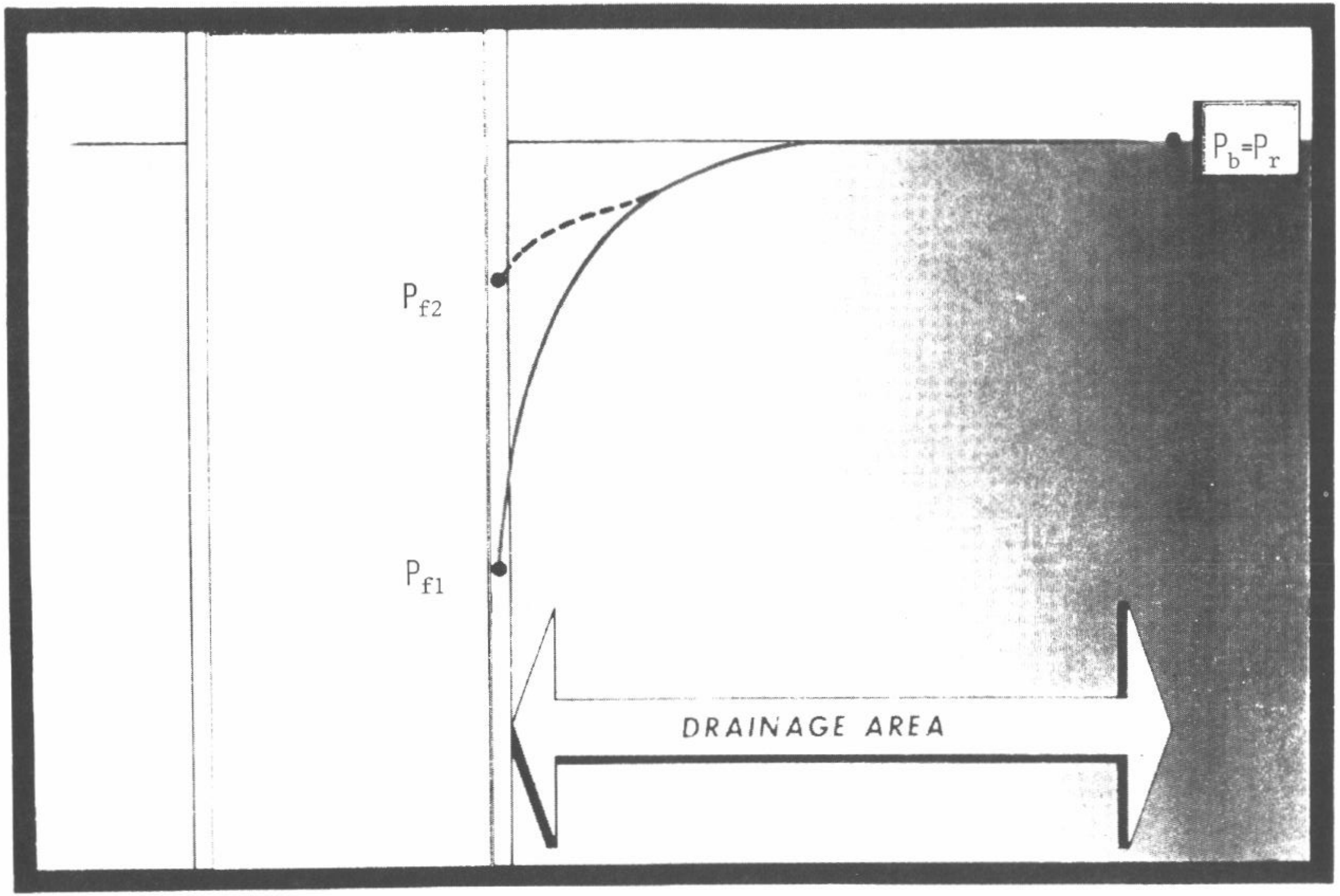
Notes:

WELL CONDITIONING

The well conditioning procedure is a part of sampling that is extremely important, but often neglected or completely ignored. The pressure drawdown associated with normal production rates will cause two-phase flow near the wellbore, if the fluid in the formation was initially saturated or only slightly undersaturated. Relative permeability effects may then cause the material entering the wellbore to be different from the original reservoir fluid existing at the boundary of the drainage area.

The problem of drawdown in a saturated reservoir cannot be avoided, therefore the purpose of well conditioning is to reduce the pressure drawdown by reducing the flow rate to the lowest possible stable rate. At the lower flowrate, the fluid entering the wellbore will now more closely approximate the reservoir fluid. This desired change will occur quickly if the involved drainage area is not too extensive.

Figure 1 is a schematic representation of a saturated reservoir ($P_b = P_r$) penetrated, at the left, by a wellbore. Superimposed is a curve of pressure distribution as a function of distance from the wellbore, assuming normal flow rate. At this normal flow rate, the flowing bottomhole pressure would be P_{f1} and the fluid entering the wellbore would be saturated at this pressure, rather than P_r, the pressure at the drainage boundary. By reducing the flow rate substantially, much of the excess gas saturation around the wellbore can be removed, the flowing bottomhole pressure elevated to P_{f2}, and the fluid entering the wellbore will more closely approximate the reservoir fluid existing at



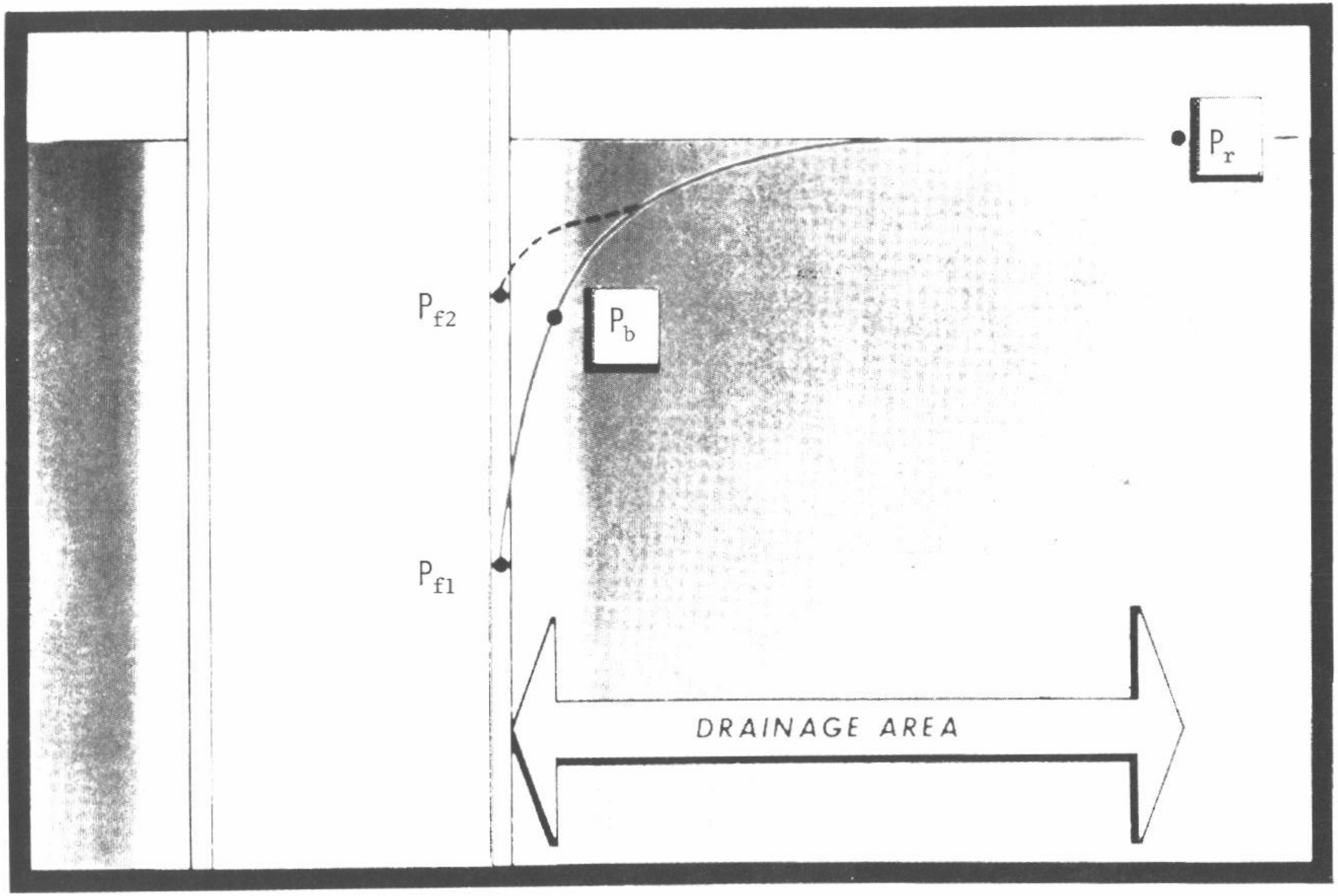
SATURATED RESERVOIR

FIGURE 1

the drainage boundary. The pressure distribution curve in the saturated reservoir associated with the period of reduced flow rate is shown as the dashed line in Figure 1.

Figure 2 is a schematic representation of an undersaturated reservoir ($P_b < P_r$) penetrated, at the left, by a wellbore. Again, a curve of pressure distribution versus distance from the wellbore has been superimposed, assuming normal flow rate. Note that free gas saturation does not occur until that point where the pressure distribution curve drops below the bubble point pressure, P_b. The conditioning process for the undersaturated reservoir is identical to that employed for the saturated reservoir. By reducing the flow rate, we can raise the flowing bottomhole pressure from P_{f1} to P_{f2}. If P_{f2} happens to be higher than the bubble point pressure (P_b) of the fluid, the free gas saturation around the wellbore can be completely eliminated, and fluid identical to that existing at the drainage boundary will enter the wellbore.

The fluid sampling method to be used dictates the remainder of the conditioning process. If bottomhole samples are to be collected, the period of reduced flow rate will generally last from one to four days, depending upon formation and fluid characteristics, and the drainage area affected. After this reduced flow rate period, the well would be shut-in and allowed to reach static pressure. The shut-in period would generally last from one day up to a week or more, based primarily upon formation characteristics. For the case of the saturated reservoir, the shut-in period has the resultant effect of forcing gas into solution



UNDERSATURATED RESERVOIR

FIGURE 2

in the oil, thus raising the saturation pressure. In some cases, the desired value of P_b is obtained; however in most cases this value is only approached and the final difference is a function of well productivity, production rate and fluid properties. At the conclusion of the shut-in period, the well would be properly conditioned and ready for bottomhole sampling.

If separator gas and liquid samples are to be collected, the gas and liquid rates must be monitored continually during the period of stable flow at reduced flow rate. A minimum test of 24 hours is recommended, but much longer may be needed if the pressure drawdown at the formation has been high. At the conclusion of the stabilized low flow rate period, with accompanying gas and liquid rate measurements, the well would be properly conditioned and ready for the collection of separator samples.

Notes:

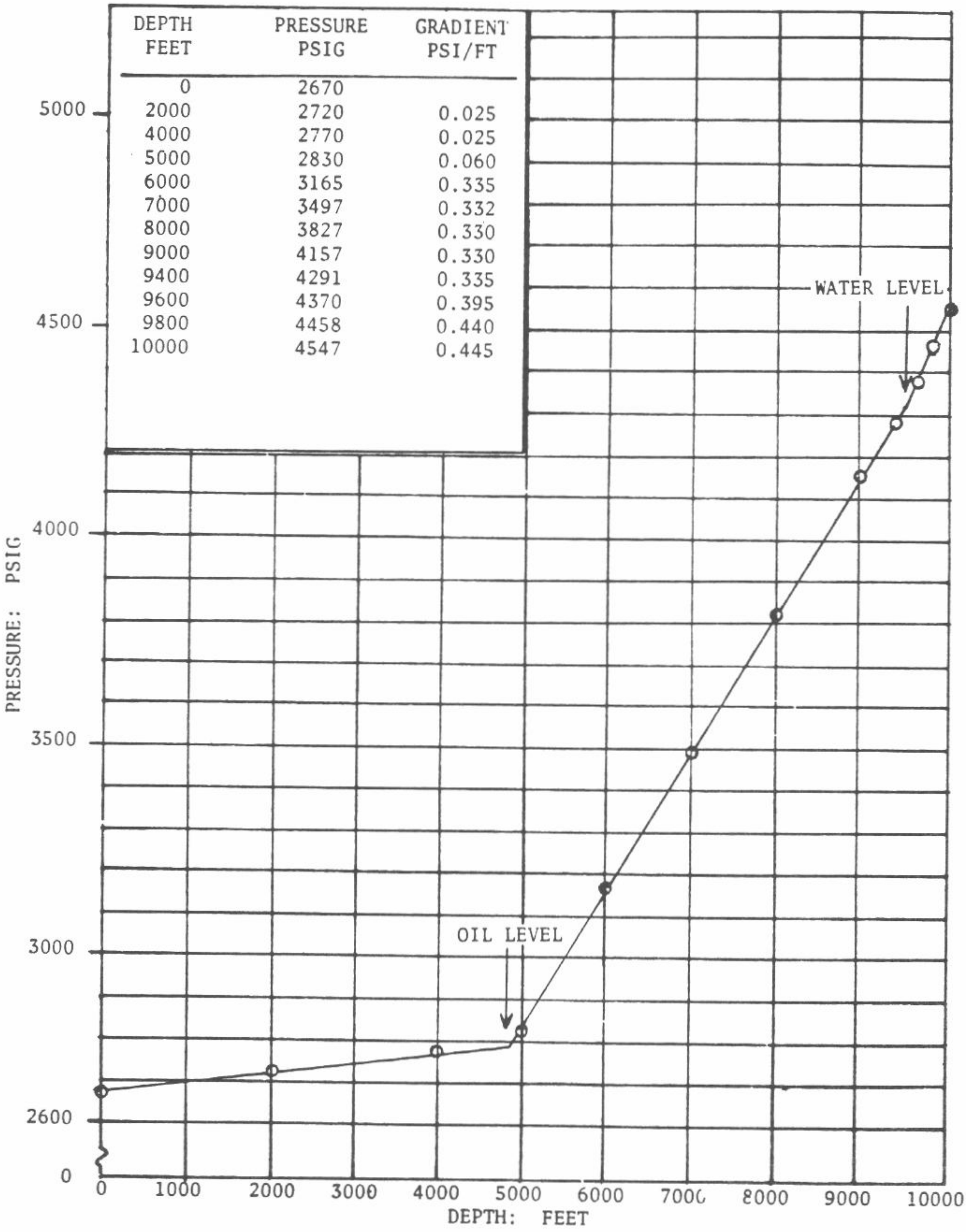
SUBSURFACE SAMPLING

It would be worthwhile to note the limitations of subsurface fluid sampling, at this point. Subsurface sampling is generally not recommended for gas-condensate reservoirs, nor for oil reservoirs producing substantial quantities of water. The liquid phase standing in the tubing of a shut-in gas-condensate reservoir would definitely not be representative of the reservoir fluid. A large water column standing in the tubing of a shut-in oil reservoir would prevent sampling at the proper depth, and could create a situation where the collection of representative subsurface fluid would be impossible.

Water frequently stands at the bottom of the hole, even in wells which normally produce no water. For this reason, a static pressure gradient should be run and interpreted to determine the gas-oil interface and oil-water interface in the tubing. Figure 3 is the interpretation of a typical static pressure gradient. In the actual run of the bottomhole sampler, care would be exercised as the sampler is lowered through the gas-oil interface. Lack of due care could result in the premature tripping of the mechanism that closes the valves at the top and bottom of the sampler. A non-representative sample would be the result of early closure of the valves. Also, the sampler should not be lowered below the oil-water interface, as a reservoir water sample would be collected as a result of this action.

Core Lab uses the Wofford type bottomhole sampler in all of its operations. Some of the internal schematics for this instrument are

STATIC PRESSURE GRADIENT



DEPTH FEET	PRESSURE PSIG	GRADIENT PSI/FT
0	2670	
2000	2720	0.025
4000	2770	0.025
5000	2830	0.060
6000	3165	0.335
7000	3497	0.332
8000	3827	0.330
9000	4157	0.330
9400	4291	0.335
9600	4370	0.395
9800	4458	0.440
10000	4547	0.445

FIGURE 3

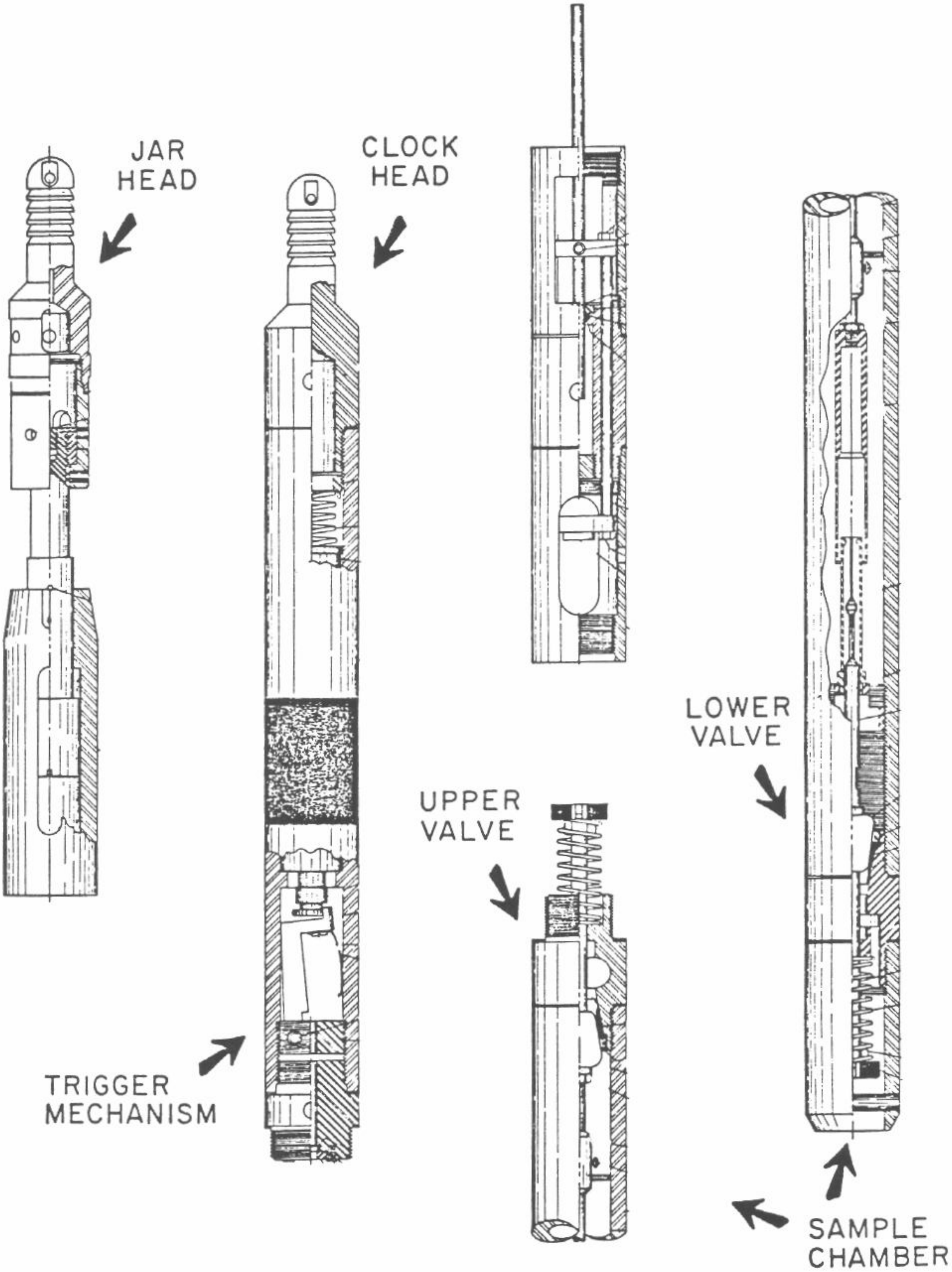
shown in Figure 4. The sampler is approximately six feet in length and 1-1/2 inches in diameter. The sampler is lowered into the well on a standard (0.072 inch) wireline. A typical schematic of the sampler lowered into a well may be seen in Figure 5. The bottomhole sampler is assembled with one of two types of devices to activate the trigger that closes the valves on both ends of the sampler: a jar head or a clock head. The jar head, which is used for most applications, is activated by imparting a sharp snap to the wireline at the surface. In applications where this jarring effect is not possible, such as heavy crude reservoirs and deviated holes, the clock head mechanism is used.

After the sampler has been lowered to a point adjacent to the producing formation (but never below the final tubing stop or the oil-water interface), the valves on the sampler, which heretofore have been open, are closed by either the jar head or the clock head mechanism. The trapped sample is then brought to the surface, and a transfer head is attached to the sampler. The ambient temperature bubble point of the fluid is then measured by attaching one valve of the transfer head to a mercury pump, injecting increments of mercury into the sampler, with each injection followed by an agitation of the sampler and a recording of equilibrium pressure. A plot of mercury injected versus sampler pressure would indicate the bubble point pressure of the material in the sampler (see Figure 6). After pressuring the fluid into single phase, the second valve of the transfer head is attached to a high pressure storage cylinder and the contents of the sampler are transferred by gravity flow (see Figure 7).

The sampler is run into the hole a second time and the entire process repeated. The second sample should be transferred only if the ambient temperature bubble points of the first two samples are with reasonable agreement with one another. Usually this means that the two bubble points are within 20 - 30 psi. If the bubble points are not within generally accepted limits, more runs of the bottomhole sampler may be required.

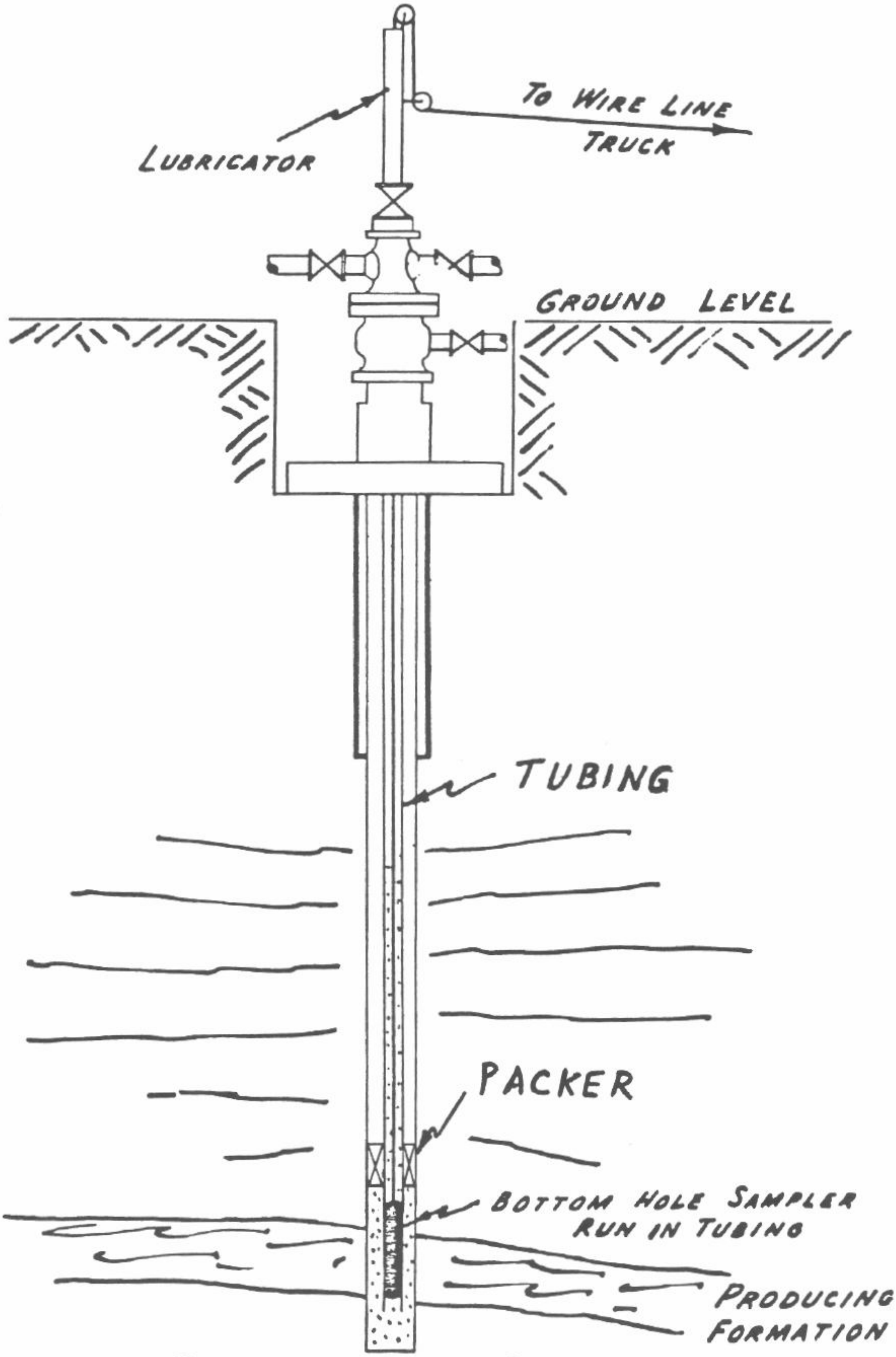
After two bottomhole samples with similar opening pressures and ambient temperature bubble points have been collected and transferred, the sampling procedure is complete. As a safety measure, some mercury should be drained from each storage cylinder prior to transit, and plugs should be threaded into both valves of each storage cylinder. Tags should be attached to the storage cylinders, labeling the samples adequately. All pertinent well information, including reservoir temperature and static reservoir pressure, should be forwarded to the testing laboratory.

Notes:



WOFFORD SAMPLER

FIGURE 4



SUBSURFACE SAMPLING

FIGURE 5

AMBIENT TEMPERATURE

BUBBLE POINT DETERMINATION

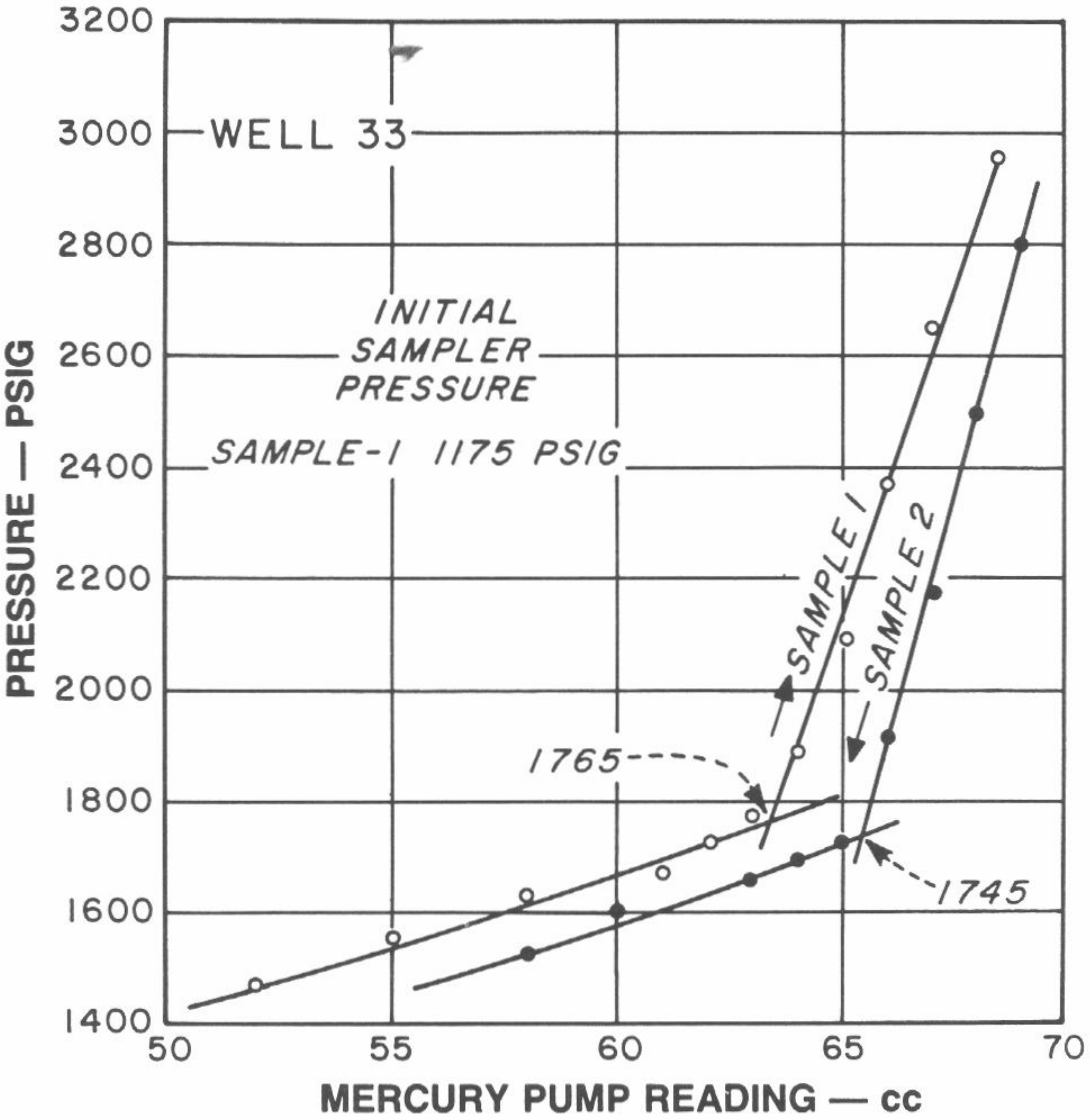
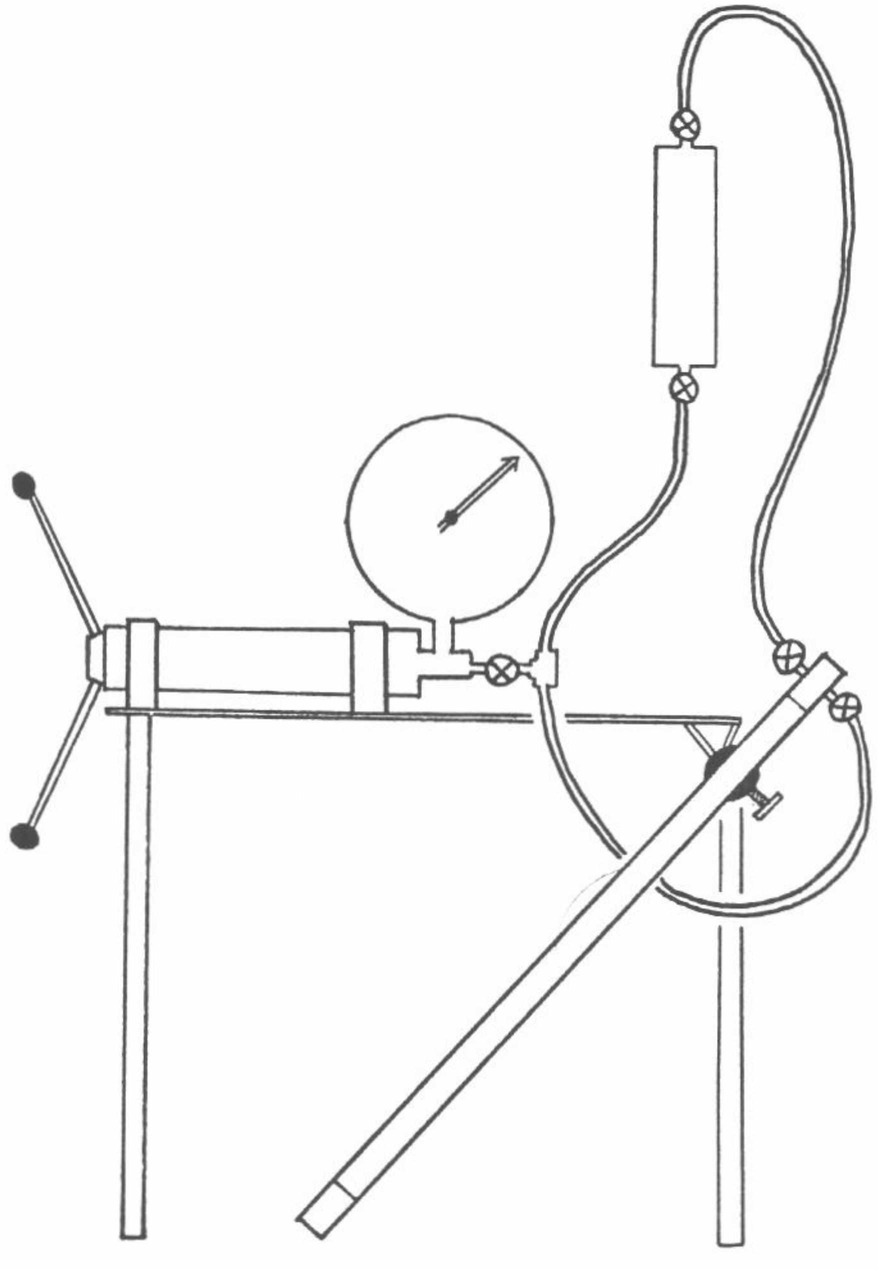


FIGURE 6



APPARATUS FOR TRANSFERRING
BOTTOM-HOLE SAMPLE BY GRAVITY FLOW

FIGURE 7

SURFACE SAMPLING

Surface sampling, also referred to as separator sampling, has somewhat wider applications than subsurface sampling. Separator sampling is the only recommended way of sampling a gas-condensate reservoir, but in many cases can be used with good success for oil reservoirs, as well. The keys to successful separator sampling are threefold:

1. Stable production at a low flow rate,
2. Accurate measurement of gas and liquid flow rates, and
3. Collection of representative samples of first stage gas and first stage liquid.

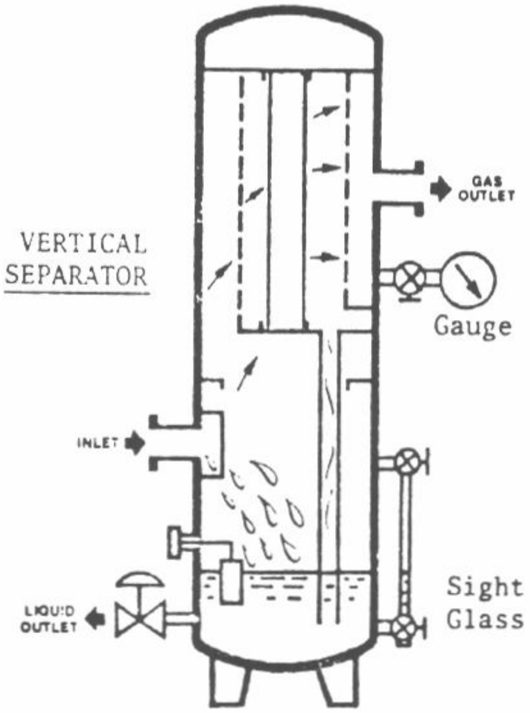
For the purpose of our discussion, let us assume that step (1) has been accomplished, through experimentation with different size surface chokes. Incidentally, the low stabilized flow rates that we have referred to will generally not exceed 100 barrels of oil per day for oil reservoirs, or one MMSCF of separator gas per day for gas-condensate reservoirs, unless the reservoirs are known to have high deliverability. Also, let us assume that proper equipment is in place to achieve separation of the full stream into gas and liquid phases and measurement of these phases by generally accepted techniques. Gas measurement will usually be accomplished via a properly engineered meter run, with the meter pressure range and the orifice plate size selected so that all measurements will fall between 20 and 90 percent of the maximum range. All factors pertaining to the gas rate measurement should be supplied to the testing laboratory. Liquid rate measurement may be made at any point (i.e. primary separator, second stage separator, or stock tank), but the point of measurement and the conditions existing between the primary separator and the point of measurement should also be reported to the testing laboratory. The gas and liquid rate information will be used to further refine the gas rate measurement and to apply a separator volume factor, if required.

Assuming that we have satisfied the first two of our three necessary requirements, we are now ready to collect representative samples of first stage gas and liquid. Oilfield separators come in a variety of configurations, two of which are shown in Figure 8. In the separator, the well stream is separated into gas and liquid phases which then go their separate ways. The compositions and relative amounts of gas and liquid are dependent upon the well stream composition and the separator pressure and temperature. By collecting samples of first stage gas and liquid, and measuring the relative rates of production, we are physically able to reconstruct the producing well stream material in the laboratory, utilizing a process referred to as a physical recombination. Although there are several methods of collecting gas and liquid samples, we will discuss only those methods that are most highly recommended.

Before we start our discussion of the actual steps involved in the sampling procedure, lets take a look at Figure 9, which will offer some explanation for the procedures which will be outlined. The figure shows the relative relationship of pressure-temperature diagrams for separator gas and liquid samples. Note that the separator gas sample will exist in two-phases at separator pressure and temperatures below the separator temperature. For this reason, we recommend that the purging method of gas sampling be avoided, especially when the ambient temperature is below the separator temperature. Also note that the separator liquid is at its bubble point pressure at separator temperature. This is the reason to avoid a pressure drop in the flexible line and the liquid sample cylinder by slowly opening the cylinder outlet valve during the liquid sampling procedure.

Notes:

TYPICAL OIL FIELD SEPARATORS



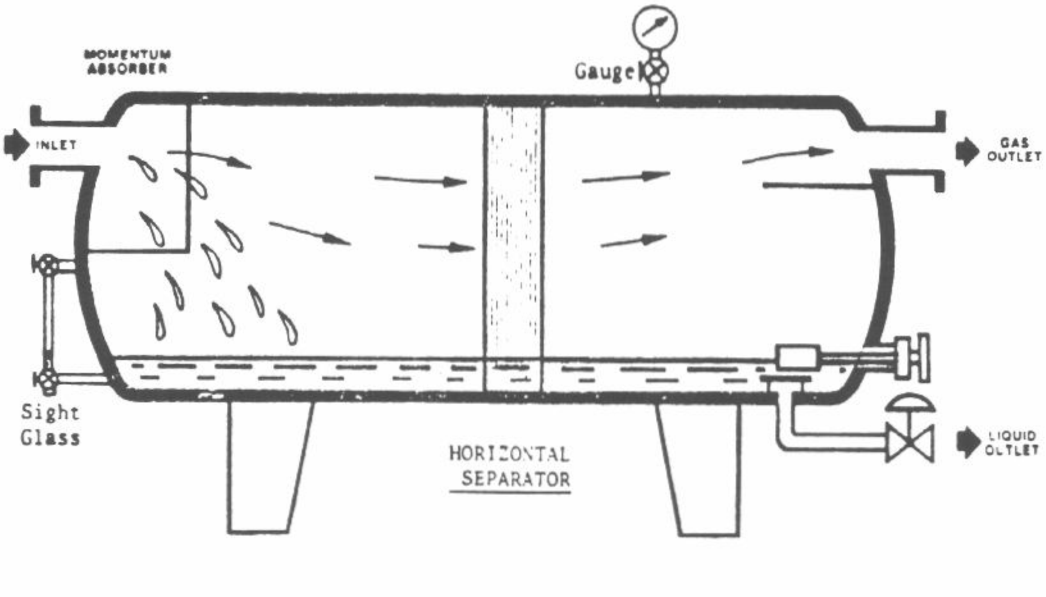


FIGURE 8

Pressure-Temperature Diagram Separator Gas and Separator Liquid

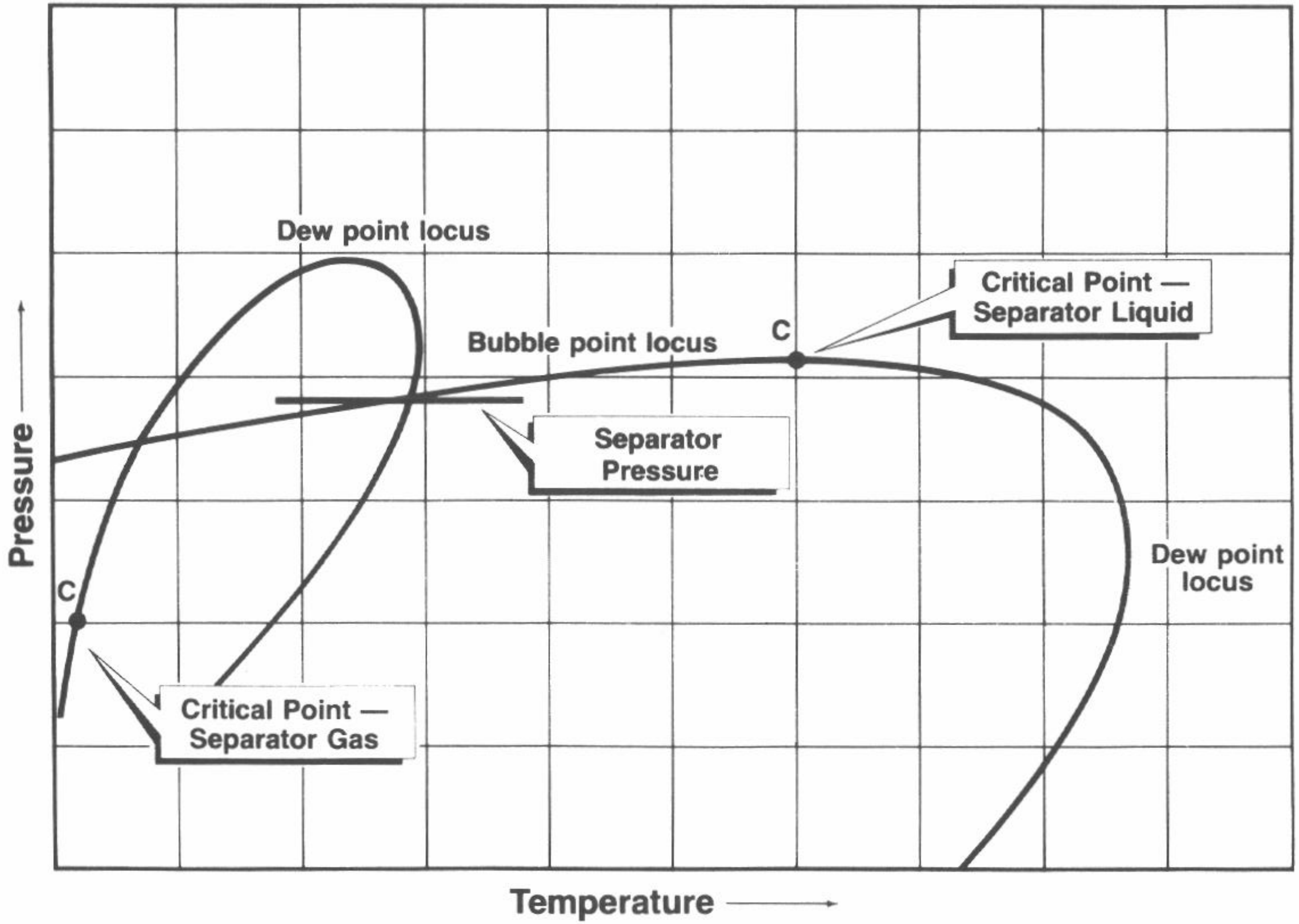


FIGURE 9

SEPARATOR GAS SAMPLING

The EVACUATED CYLINDER method is recommended for all separator gas sampling. This is by far the simplest way to get good gas samples. The only disadvantage is that the gas sample cylinders must be thoroughly evacuated before being taken to the field. The vacuum removes virtually all air from the cylinder, and no excess liquid can accumulate in the cylinder since there is no purging.

If no evacuated cylinders can be obtained, the PURGE method is the second choice. Here the cylinders are filled with gas and then blown down several times. This will remove the air, but may contaminate the gas with heavy components.

Evacuated Cylinder Method

1. Evacuate all the gas cylinders and clean the sampling equipment before going to the field.
2. On location, select the gas and liquid sample source valves and remove all trash from them. Check both source valves by opening them briefly.
3. Connect a clean flexible hose to the gas source valve and one gas cylinder valve. See Figure 10.
4. Purge the hose, tighten the fittings, and open the gas source valve.
5. Fill the gas cylinder slowly by cracking the cylinder inlet valve. You will hear gas flowing into the cylinder.
6. When the cylinder is full, close ALL the valves and disconnect the

cylinder. Leave the hose connected if more gas samples are needed, or if liquid samples will be taken by gas displacement.

7. Plug both cylinder valves.
8. Complete the tag and attach it to the inlet valve.

SEPARATOR GAS SAMPLING

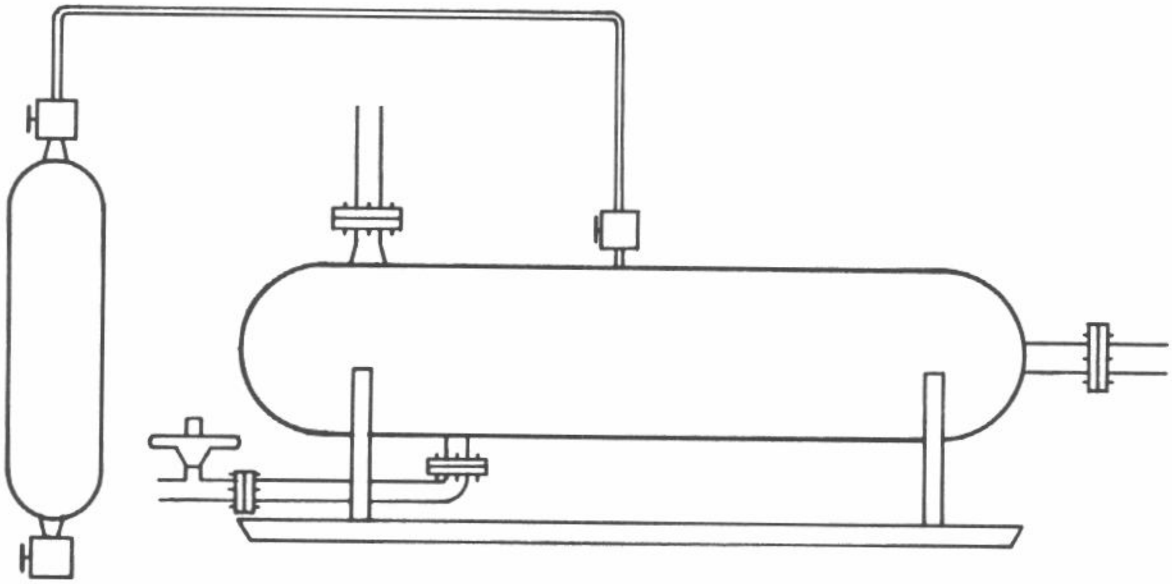


FIGURE 10

SEPARATOR LIQUID SAMPLING

The GAS DISPLACEMENT method is recommended for collecting separator liquid samples. The cylinder is filled with separator gas, which is then displaced from the cylinder by separator liquid at the separator pressure. Since the pressure is not allowed to drop, the liquid composition cannot change during the displacement.

The most widely used method of liquid sampling is the WATER DISPLACEMENT method, in which separator liquid displaces water from the cylinder at separator pressure. Either liquid sampling method is perfectly acceptable.

Gas Displacement Method

1. Fill the liquid cylinder with gas, vent the gas, and fill it with gas again.
2. Hang the cylinder upright in a convenient location.
3. Connect a clean flexible hose to the liquid source valve and the cylinder inlet (lower) valve. See Figure 11.
4. Purge the hose, tighten the fittings, and open the liquid source valve.
5. Open the cylinder inlet (lower) valve. No liquid can enter the cylinder yet, since the cylinder is full of gas at separator pressure.
6. Connect the tee-gauge-valve rig to the cylinder outlet (upper) valve. Close the vent valve and open the outlet valve. The gauge should read separator pressure.

7. Crack the vent valve and slowly bleed all the separator gas to the atmosphere. Control the flow rate to prevent pressure drop on the gauge.
8. When liquid shows at the vent valve, turn the cylinder upside down and continue producing liquid. Watch for water. After water production (if any) stops, close ALL the valves and disconnect the cylinder. Leave the hose connected if more liquid samples are needed.
9. TAKE OUTAGE by allowing a small amount of liquid to flash out of the BOTTOM valve for about one second. This will not affect the sample quality, but is a very important safety procedure. Taking outage creates a small gas-cap in the cylinder.
10. Plug both cylinder valves.
11. Complete the tag and attach it to the inlet valve.

SEPARATOR LIQUID SAMPLING
BY GAS DISPLACEMENT

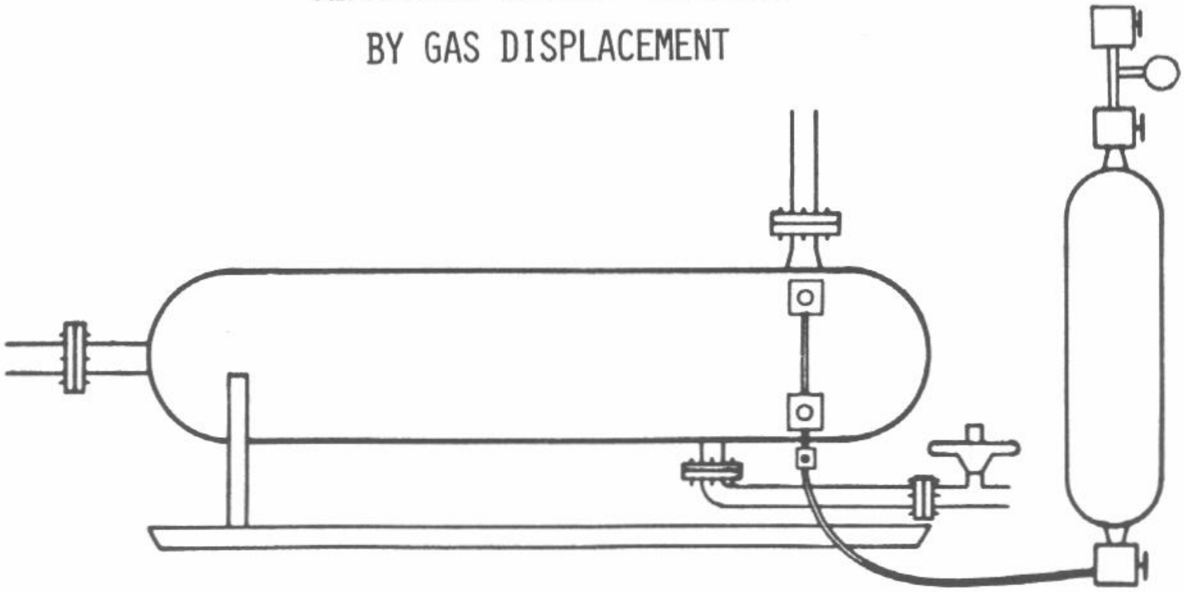


FIGURE 11

Water Displacement Method

1. Fill the liquid cylinders with water.
2. Hang the cylinder upright in a convenient location.
3. Connect a clean flexible hose to the liquid source valve and the cylinder inlet (upper) valve. See Figure 12.
4. Purge the hose, tighten the fittings, and open the liquid source valve.
5. Open the cylinder inlet (upper) valve.
6. Connect the tee-gauge-valve rig to the cylinder outlet (lower) valve. Close the vent valve and open the outlet valve. The gauge should read separator pressure.
7. Crack the vent valve and slowly drain all the water from the cylinder. Control the flow rate to prevent pressure drop on the gauge.
8. When liquid shows at the vent valve, close ALL the valves and disconnect the cylinder. Leave the hose connected if more liquid samples are needed.
9. TAKE OUTAGE by allowing a small amount of liquid to flash out of the BOTTOM valve for about one second. This will not affect the sample quality, but is a very important safety procedure. Taking outage creates a small gas-cap in the cylinder.
10. Plug both cylinder valves.
11. Complete the tag and attach it to the inlet valve.

SEPARATOR LIQUID SAMPLING
BY WATER DISPLACEMENT

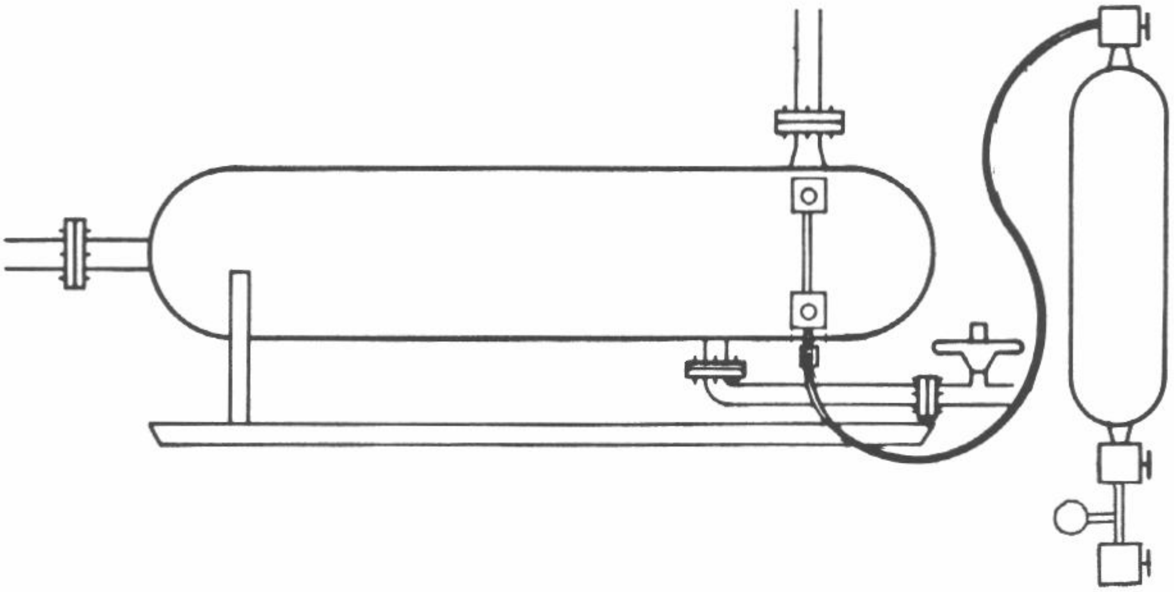


FIGURE 12

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

A METHOD FOR EXTRAPOLATING RESERVOIR FLUID DATA

Extrapolation of Reservoir Fluid Data

In collecting fluid samples from oil wells, the possibility exists of obtaining samples the saturation pressure of which may be lower than the actual saturation pressure of the reservoir. This condition may be due to either of two circumstances. Water in the tubing may have necessitated sampling the well above the producing formation; or in the case of low productivity wells, the drawdown at the base of the wellbore could not be completely overcome during the well conditioning period prior to sampling. If either of these conditions exists or if the reservoir pressure had declined below the original saturation pressure prior to sampling, it is then necessary for the fluid data to be extrapolated to the original saturation pressure prior to its use in engineering calculations. In the case of a reservoir with an original gas cap, the original saturation pressure is normally chosen as the reservoir pressure at the gas-oil contact at the time of discovery. If possible, extrapolation should not be over 10 to 15 percent of the final saturation pressure.

Methods for carrying out this extrapolation are described on the following pages.

Procedure

1. Pressure-Volume Relationship (V/V_{sat} vs. Pressure). The "Y" function, $(Ps - P/Pabs \Delta V$, is calculated for each point below saturation pressure, Table 3. P_s is the measured saturation pressure, P is any pressure, Pabs is P + 15, Δ V is the measured $V/V_{sat}-1$. Points so obtained are plotted against P, and the best straight line drawn through them, line A, Fig. 1. Points in the neighborhood of P_s may be erratic and need not be calculated above $P/P_s = 0.9$ as the line is determined by the points in the middle pressure range, $P/P_s = 0.3$ to $P/P_s = 0.9$. The line is extended through the new saturation pressure, P_s'. At desired pressures, points are read from this line and new V/V_{sat}' values are calculated, Table 4.

To determine points above the new saturation pressure, Ps', points above the old saturation pressure are plotted on an extended scale, line B, Figure 1, and a line parallel to it drawn through $V/V_{sat} = 1.0$ at Ps', line C, Fig. 1. Points for the desired pressures above Ps' are read from line C and entered in Table 4. Relative volume points for the new saturation pressure P_s' are then copied on the extrapolated reservoir fluid sample tabular data sheet, Table 6.

Through the point on the extended viscosity curve at P_s', draw a straight line parallel to C, line D, Fig. 4. Viscosities above the new saturation pressures are then read from line D. The viscosities are entered in column 3, page 6.

4. Separator Tests.

A. Stock Tank Gas-Oil Ratio and Gravity are not changed.

B. Separator Gas-Oil Ratio. The total gas-oil ratio is changed in the same proportion as the differential ratio was changed. New gas in solution is divided by original gas in solution. The factor so obtained is multiplied by each total gas-oil ratio to obtain the new total gas-oil ratio. The separator gas-oil ratio is the difference between the total gas-oil ratio and the stock tank gas-oil ratio.

Example: $\frac{895}{734} = 1.219$

Total GOR = (1.219)(814+0) = 992
Separator GOR = 992-0 = 992

Total GOR = (1.219)(758+8) = 934
Separator GOR = 934-8 = 926

C. Formation Volume Factor $V_{sat}/V_{residual}$
These values are changed in the same proportion as the change in differential values. New V/V_r at P_s' from the extrapolated differential liberation is divided by the original V/V_r at P_s. The factor so obtained is multiplied by $V/_{sat}/V_r$ from the original separator tests, to obtain the new formation volume factors.

Example: $\frac{1.496}{1.426} = 1.049$

1.049 x 1.475 = 1.547

1.049 x 1.431 = 1.501

D. Shrinkage Factor is the reciprocal of the Formation Volume Factor.

E. Specific Gravity of flashed gas is not changed.

Tables 6 and 7 now form a new set of reservoir fluid sample analysis data for a saturation pressure equal to the previously selected 2817 PSI gauge.

TABLE 1

Reservoir Fluid SAMPLE TABULAR DATA (Measured)

PRESSURE PSI GAUGE	PRESSURE-VOLUME RELATION @ 147 °F. RELATIVE VOLUME OF OIL AND GAS, $V/V_{SAT.}$	VISCOSITY OF OIL @ 147 °F. CENTIPOISES	DIFFERENTIAL LIBERATION @ 147 °F.		
			GAS/OIL RATIO LIBERATED PER BARREL OF RESIDUAL OIL	GAS/OIL RATIO IN SOLUTION PER BARREL OF RESIDUAL OIL	RELATIVE OIL VOLUME, V/V_R
3500	0.9803	0.86			
3400	0.9817				
3300	0.9837				
3200	0.9851				
3100	0.9862				
3040		0.80			
3000	0.9883				
2900	0.9897				
2800	0.9913				
2700	0.9926				
2600	0.9945				
2500	0.9961				
2480		0.73			
2400	0.9974				
2300	0.9991				
2248	1.0000		0	734	1.426
2223	1.0041				
2201	1.0069				
2184	1.0099				
2164	1.0127				
2110	1.0215	0.73			
2055	1.0315				
1982	1.0462				
1955			91	643	1.382
1914	1.0609				
1852	1.0757				
1740	1.1055				
1710			160	574	1.349
1570	1.1655	0.85			
1455			236	498	1.315
1373	1.2563				
1200			304	430	1.283
1189	1.3781				
1130		0.97			
1000	1.5617				
955			380	354	1.252
828	1.8075				

V = Volume at given pressure
$V_{SAT.}$ = Volume at saturation pressure and the specified temperature.
V_R = Residual oil volume at 14.7 PSI absolute and 60° F.

TABLE 1 (Cont'd)

Reservoir Fluid SAMPLE TABULAR DATA (Measured)

PRESSURE PSI GAUGE	PRESSURE-VOLUME RELATION @ 147 °F. RELATIVE VOLUME OF OIL AND GAS, V/V_{SAT}.	VISCOSITY OF OIL @ 147 °F. CENTIPOISES	DIFFERENTIAL LIBERATION @ 147 °F.		
			GAS/OIL RATIO LIBERATED PER BARREL OF RESIDUAL OIL	GAS/OIL RATIO IN SOLUTION PER BARREL OF RESIDUAL OIL	RELATIVE OIL VOLUME, V/V_R
700			442	292	1.221
684	2.1154				
560		1.28			
540	2.6089				
450			516	218	1.192
370	3.6900				
201	6.5251				
200			594	140	1.161
0		2.05	734	0	1.045
				@ 60°F. =	1.000

Gravity of residual oil = 40.4°API @ 60°F.

V = Volume at given pressure
V_{SAT} = Volume at saturation pressure and the specified temperature.
V_R = Residual oil volume at 14.7 PSI absolute and 60° F.

TABLE 2

SEPARATOR TESTS OF Reservoir Fluid SAMPLE (Measured)

SEPARATOR PRESSURE, PSI GAUGE	SEPARATOR TEMPERATURE, ° F.	SEPARATOR GAS/OIL RATIO See Foot Note (1)	STOCK TANK GAS/OIL RATIO See Foot Note (1)	STOCK TANK GRAVITY ° API @ 60° F.	SHRINKAGE FACTOR, V_R/V_{SAT} See Foot Note (2)	FORMATION VOLUME FACTOR, V_{SAT}/V_R See Foot Note (3)	SPECIFIC GRAVITY OF FLASHED GAS
0	75	814	0	39.2	0.678	1.475	1.007
10	75	758	8	39.8	0.699	1.431	
20	75	735	16	40.0	0.703	1.423	
148	75	589	116	40.6	0.714	1.400	

(1) Separator and Stock Tank Gas/Oil Ratio in cubic feet of gas @ 60° F. and 14.7 PSI absolute per barrel of stock tank oil @ 60° F.

(2) Shrinkage Factor: V_R/V_{SAT} is barrels of stock tank oil @ 60° F. per barrel of saturated oil @ 2248 PSI gauge and 147 ° F.

(3) Formation Volume Factor: V_{SAT}/V_R is barrels of saturated oil @ 2248 PSI gauge and 147 ° F. per barrel of stock tank oil @ 60° F.

TABLE 3

CALCULATION OF $(P_s - P)/P_{abs} \Delta V$

Pressure PSIG	$P_s - P$	$\Delta V = V/V_{sat} - 1$	P_{abs}	$P_{abs} \Delta V$	$\left(\frac{P_s - P}{P_{abs} \Delta V}\right)$
2248	0				
2223	25	0.0041	2238	9.2	2.72
2201	47	0.0069	2216	15.3	3.07
2184	64	0.0099	2199	21.8	2.94
2164	84	0.0127	2179	27.7	3.03
2110	138	0.0215	2125	45.6	3.02
2055	193	0.0315	2070	65.2	2.96
1982	266	0.0462	1997	92.2	2.88
1914	334	0.0609	1929	117.4	2.84
1852	396	0.0757	1867	141.3	2.80
1740	508	0.1055	1755	185.1	2.74
1570	678	0.1655	1585	262.3	2.58
1373	875	0.2563	1388	355.7	2.46
1189	1059	0.3781	1204	455.2	2.32
1000	1248	0.5617	1015	570.1	2.19
828	1420	0.8075	843	680.7	2.08
684	1564	1.1154	699	779.6	2.00
540	1708	1.6089	555	892.9	1.91
370	1878	2.6900	385	1035.6	1.81
201	2047	5.5251	216	1193.4	1.71

TABLE 4

PV EXTRAPOLATION

Pressure PSIG	$\left(\frac{P_s'-P}{P_{abs}\Delta V'}\right)$	$P_s'-P$	$P_{abs}\Delta V$	Pabs	$\Delta V'$	V/Vsat'
3500						0.9892
3400						0.9907
3300						0.9923
3200						0.9939
3100						0.9954
3000						0.9970
2900						0.9986
2817						1.0000
2800	3.458	17	4.916	2815	0.0017	1.0017
2783	3.445	34	9.869	2798	0.0035	1.0035
2761	3.430	56	16.327	2776	0.0059	1.0059
2724	3.406	93	27.305	2739	0.0100	1.0100
2688	3.380	129	38.166	2703	0.0141	1.0141
2658	3.357	159	47.364	2673	0.0177	1.0177
2611	3.325	206	61.955	2626	0.0236	1.0236
2563	3.291	254	77.180	2578	0.0299	1.0299
2514	3.258	303	93.002	2529	0.0368	1.0368
2444	3.208	373	116.272	2459	0.0473	1.0473
2372	3.156	445	141.001	2387	0.0591	1.0591
2260	3.078	557	180.962	2275	0.0795	1.0795
2098	2.967	719	242.332	2113	0.1147	1.1147
1852	2.791	965	345.754	1867	0.1852	1.1852
1740	2.744	1077	392.493	1755	0.2236	1.2236
1570	2.585	1247	482.398	1585	0.3044	1.3044
1373	2.460	1444	586.992	1388	0.4229	1.4229
1189	2.326	1628	699.914	1204	0.5813	1.5813
1000	2.189	1817	830.059	1015	0.8178	1.8178
828	2.086	1989	953.500	843	1.1311	2.1311
684	2.006	2133	1063.310	699	1.5212	2.5212
540	1.913	2277	1190.277	555	2.1446	3.1446
370	1.813	2447	1349.697	385	3.5057	4.5057
201	1.715	2616	1525.364	216	7.0619	8.0619

TABLE 5

EXTRAPOLATION OF VISCOSITY

Pressure, PSIG	μ	$\frac{1}{\mu}$	$\frac{1}{\mu'}$	μ'
3500	0.86			0.70
3040	0.80			0.64
2817			1.63	0.61
2480	0.73		1.51	0.66
2110	0.73	1.37		0.73
1570	0.85	1.18		0.85
1130	0.97	1.03		0.97
560	1.28	0.78		1.28
0	2.05	0.49		2.05

TABLE 6

Reservoir Fluid SAMPLE TABULAR DATA (Extrapolated)

PRESSURE PSI GAUGE	PRESSURE-VOLUME RELATION @ 147 °F. RELATIVE VOLUME OF OIL AND GAS. $V/V_{SAT.}$	VISCOSITY OF OIL @ 147 °F. CENTIPOISES	DIFFERENTIAL LIBERATION @ 147 °F. GAS/OIL RATIO LIBERATED PER BARREL OF RESIDUAL OIL	GAS/OIL RATIO IN SOLUTION PER BARREL OF RESIDUAL OIL	RELATIVE OIL VOLUME. V/V_R
3500	0.9892	0.70			
3400	0.9907				
3300	0.9923				
3200	0.9939	0.67			
3100	0.9954				
3000	0.9970	0.65			
2900	0.9986				
2817	1.0000		0	895	1.496
2800	1.0017				
2783	1.0035				
2761	1.0059				
2724	1.0100				
2688	1.0141				
2611	1.0236				
2563	1.0299				
2516			94	801	1.452
2514	1.0368				
2480		0.68			
2444	1.0473				
2372	1.0591				
2260	1.0795				
2248			169	726	1.416
2110		0.73			
2098	1.1147				
1955			252	643	1.377
1852	1.1852				
1740	1.2236				
1710			321	574	1.345
1570	1.3044	0.85			
1455			397	498	1.315
1373	1.4229				
1200			465	430	1.283
1189	1.5813				
1130		0.97			
1000	1.8178				

V = Volume at given pressure
$V_{SAT.}$ = Volume at saturation pressure and the specified temperature.
V_R = Residual oil volume at 14.7 PSI absolute and 60° F.

TABLE 6 (Cont'd)

Reservoir Fluid **SAMPLE TABULAR DATA** (Extrapolated)

PRESSURE PSI GAUGE	PRESSURE-VOLUME RELATION @ 147 °F. RELATIVE VOLUME OF OIL AND GAS, V/VSAT.	VISCOSITY OF OIL @ 147 °F. CENTIPOISES	DIFFERENTIAL LIBERATION @ 147 °F.		
			GAS/OIL RATIO LIBERATED PER BARREL OF RESIDUAL OIL	GAS/OIL RATIO IN SOLUTION PER BARREL OF RESIDUAL OIL	RELATIVE OIL VOLUME, V/VR
955			536	359	1.252
828	2.1311				
700			603	292	1.221
684	2.5212				
560		1.28			
540	3.1446				
450			677	218	1.192
370	4.5057				
201	8.0619				
200			756	140	1.161
0		2.05	895	0	1.045
					@ 60°F.= 1.000

Gravity of residual oil = 40.4°API @ 60°F.

V = Volume at given pressure
$V_{SAT.}$ = Volume at saturation pressure and the specified temperature.
V_R = Residual oil volume at 14.7 PSI absolute and 60° F.

TABLE 7

SEPARATOR TESTS OF Reservoir Fluid SAMPLE (Extrapolated)

SEPARATOR PRESSURE, PSI GAUGE	SEPARATOR TEMPERATURE, °F.	SEPARATOR GAS/OIL RATIO See Foot Note (1)	STOCK TANK GAS/OIL RATIO See Foot Note (1)	STOCK TANK GRAVITY, ° API @ 60° F.	SHRINKAGE FACTOR, $V_R/V_{SAT.}$ See Foot Note (2)	FORMATION VOLUME FACTOR, $V_{SAT.}/V_R$ See Foot Note (3)	SPECIFIC GRAVITY OF FLASHED GAS
0	75	992	0	39.2	0.646	1.547	1.007
10	75	926	8	39.8	0.666	1.501	
20	75	899	16	40.0	0.670	1.493	
148	75	743	116	40.6	0.681	1.469	

---

(1) Separator and Stock Tank Gas/Oil Ratio in cubic feet of gas @ 60° F. and 14.7 PSI absolute per barrel of stock tank oil @ 60° F.

(2) Shrinkage Factor: $V_R/V_{SAT.}$ is barrels of stock tank oil @ 60° F. per barrel of saturated oil @ 2817 PSI gauge and 147 ° F.

(3) Formation Volume Factor: $V_{SAT.}/V_R$ is barrels of saturated oil @ 2817 PSI gauge and 147 ° F. per barrel of stock tank oil @ 60° F.

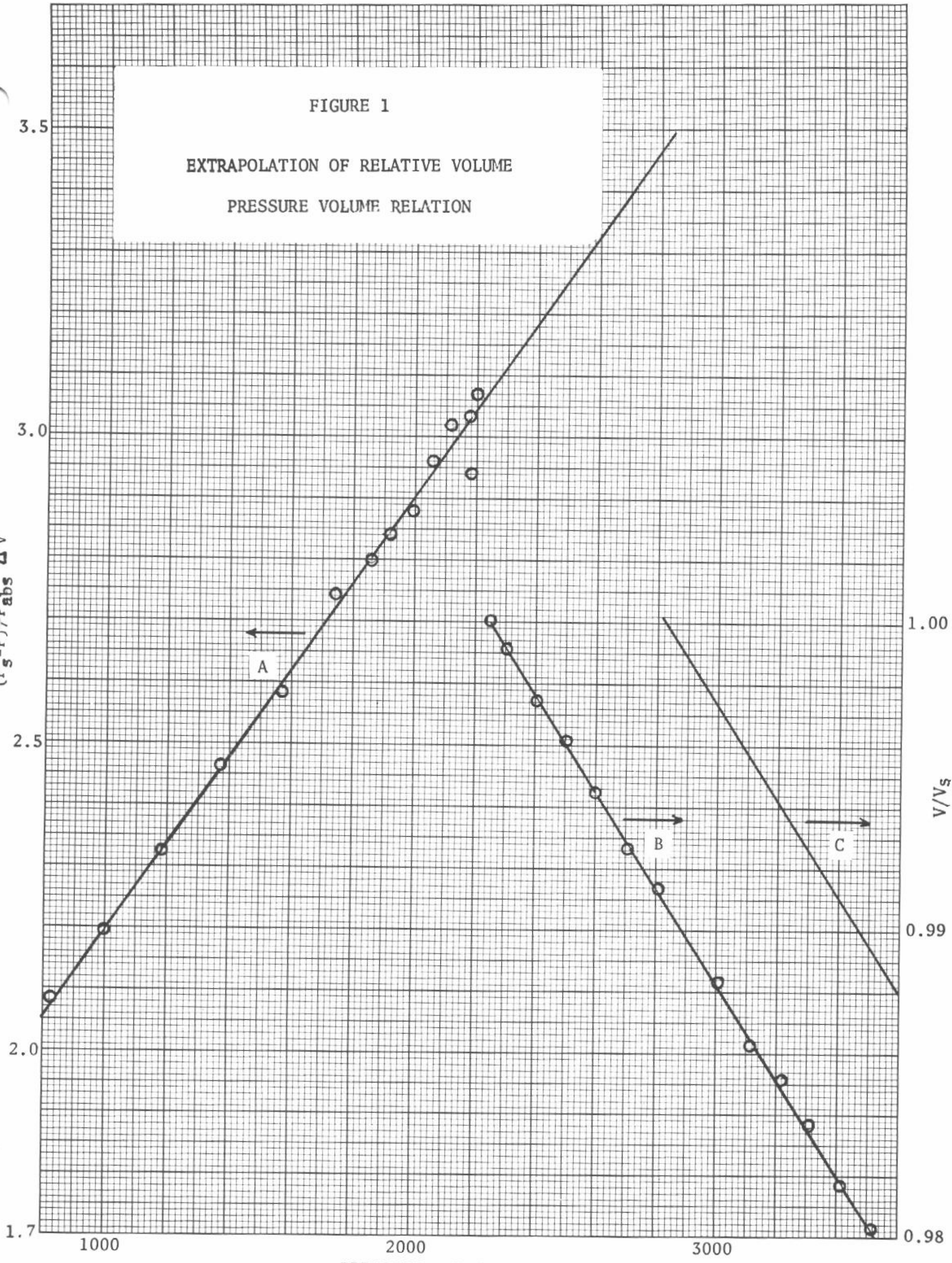


FIGURE 1

EXTRAPOLATION OF RELATIVE VOLUME

PRESSURE VOLUME RELATION

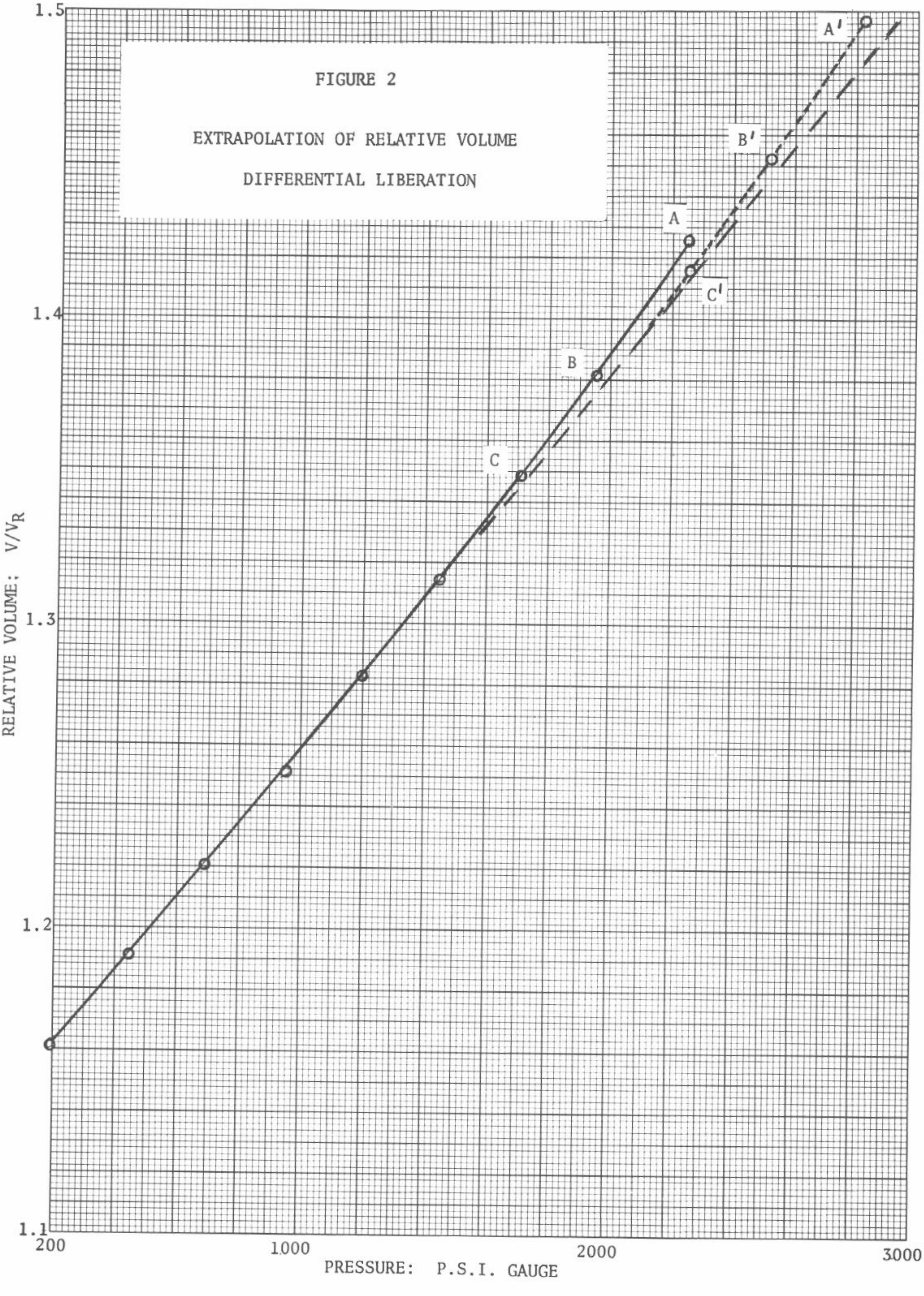


FIGURE 2

EXTRAPOLATION OF RELATIVE VOLUME

DIFFERENTIAL LIBERATION

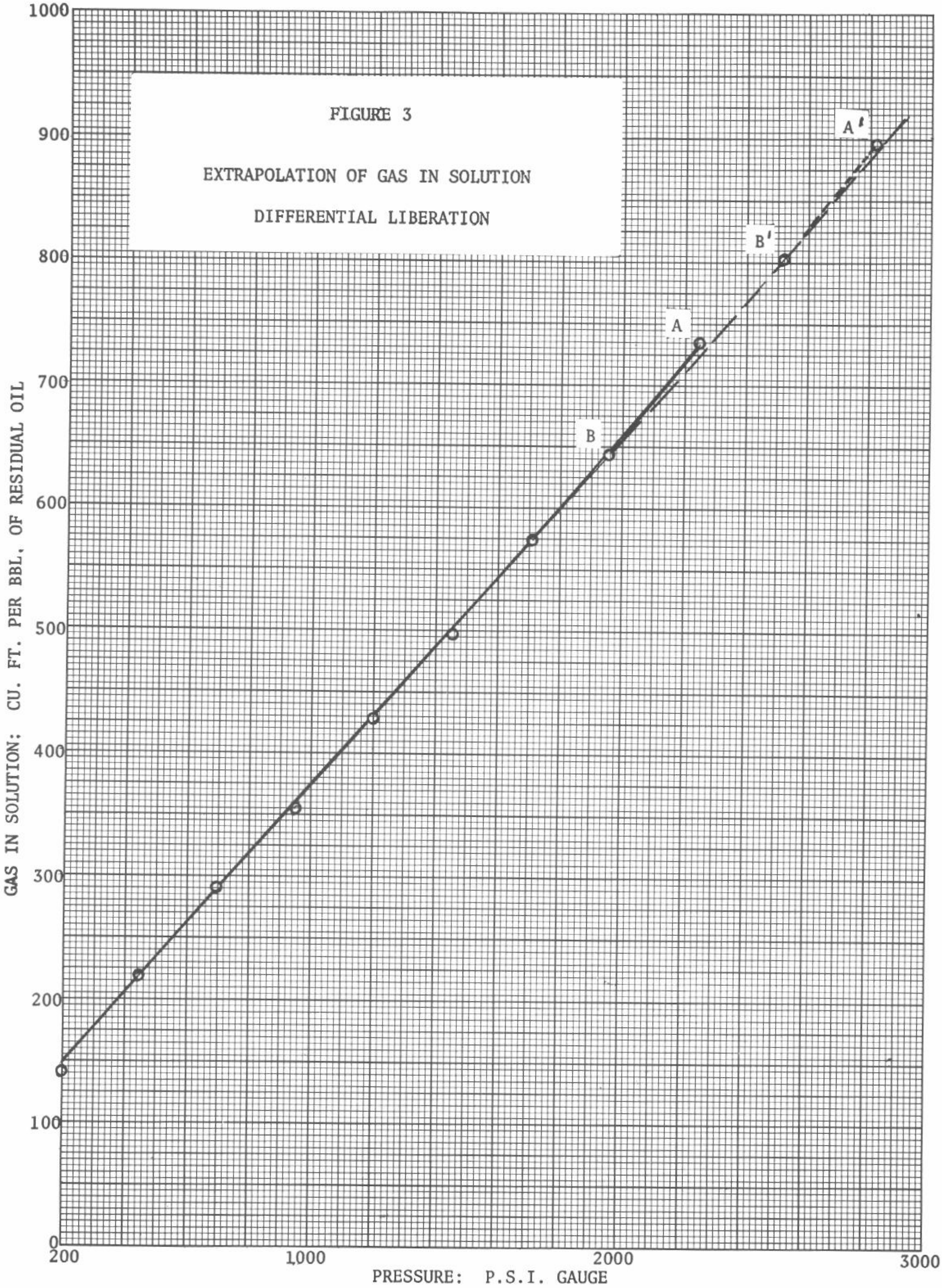


FIGURE 3

EXTRAPOLATION OF GAS IN SOLUTION

DIFFERENTIAL LIBERATION

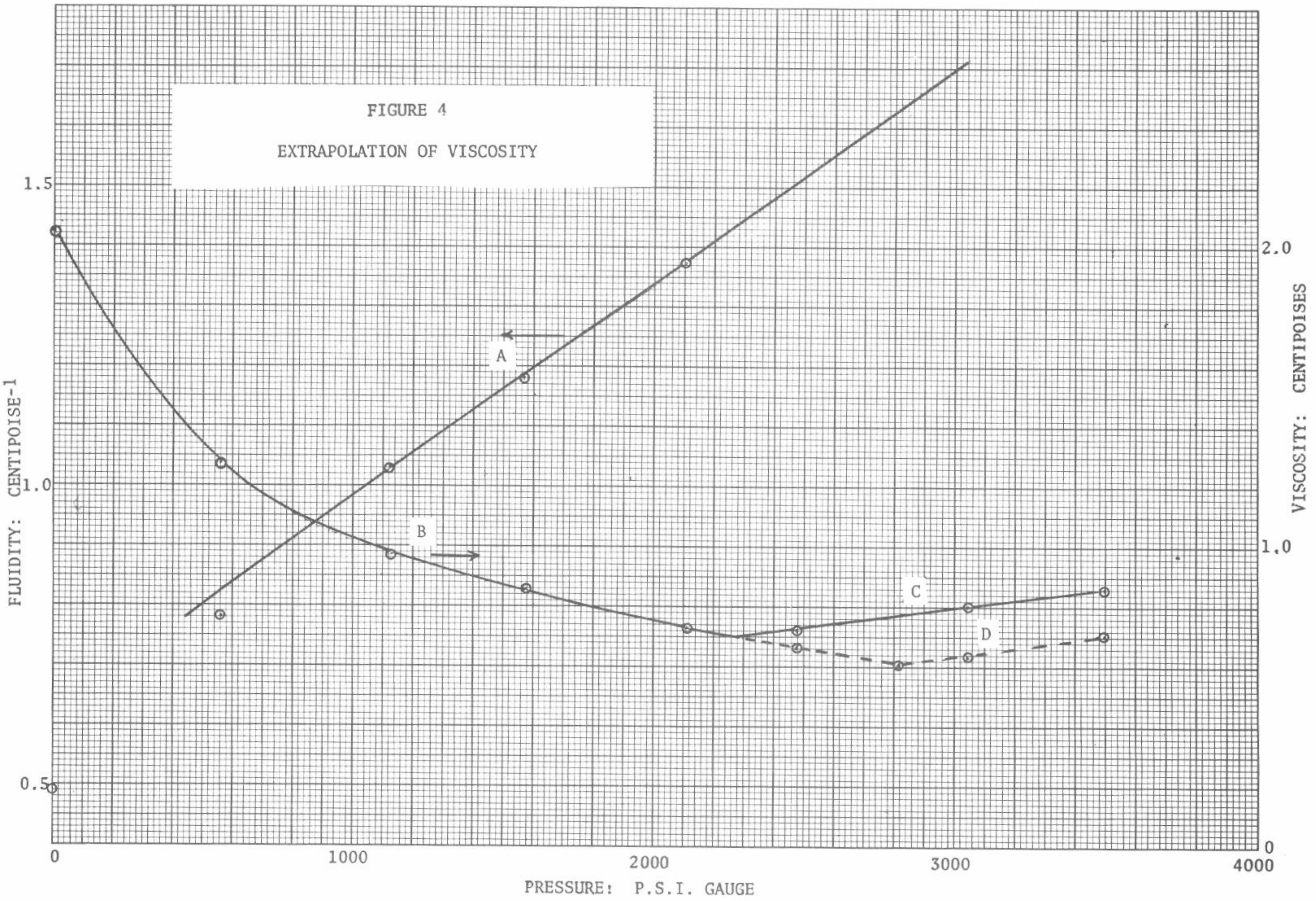


FIGURE 4
EXTRAPOLATION OF VISCOSITY
1.5
1.0
0.5
FLUIDITY: CENTIPOISE-1
2.0
1.0
0
VISCOSITY: CENTIPOISES
A
B
C
D
0
1000
2000
3000
4000
PRESSURE: P.S.I. GAUGE

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

Reservoir Fluid Study

for

GOOD OIL COMPANY

Oil Well No. 4
Productive Field
Samson County, Texas

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS 75207

RESERVOIR FLUID DIVISION

Good Oil Company
P. O. Box 100
Oil City, Texas 10010

Attention: Mr. John L. Jones

Subject: Reservoir Fluid Study
Oil Well No. 4
Productive Field
Samson County, Texas
Our File Number: RFL 76000

Gentlemen:

Duplicate subsurface fluid samples were collected from the subject well and these samples were submitted to our laboratory for use in a reservoir fluid study. Presented in the following report are the results of this study as requested by Good Oil Company.

As a quality check, the room temperature saturation pressure of each sample was initially determined. At 75°F., subsurface fluid sample Nos. 1 and 2 were found to have bubble point pressures of 1880 psig and 1885 psig, respectively. These values were considered to be in good agreement with one another and subsurface fluid sample No. 2 was selected for use in the reservoir fluid study.

The hydrocarbon composition of the subsurface fluid was determined by low temperature fractional distillation. The results of this distillation in terms of both mol percent and weight percent are presented on page two.

A small quantity of the reservoir fluid was charged to a high pressure windowed cell and thermally expanded to the reservoir temperature of 220°F. During a constant composition expansion at this temperature, the fluid was found to have a bubble point pressure of 2620 psig. The results of the pressure-volume measurements at reservoir temperature may be found on page four.

When subjected to differential pressure depletion at the reservoir temperature, the fluid evolved a total of 854 cubic feet of gas at 14.65 psia and 60°F. per barrel of residual oil at 60°F. The resulting relative oil volume factor was 1.600 barrels of saturated fluid per barrel of residual oil. The oil density and the properties of the evolved gases were measured at each point during the differential pressure depletion and these data are included in the summary of the differential depletion data on page five.

The viscosity of the reservoir fluid was measured over a wide range of pressures at 220°F. in a rolling ball viscosimeter. The viscosity of the fluid was found to vary from a minimum of 0.373 centipoise at the saturation pressure to a maximum of 1.286 centipoises at atmospheric pressure. The results of the viscosity measurements are tabulated on page six.

Four single-stage separator tests were performed at laboratory temperature to determine the effects of separator pressure upon gas-oil ratio, stock tank oil gravity and formation volume factor. The results of these separator tests are tabulated on page seven and they indicate optimum separation to occur in the vicinity of 100 psig. The separator gas from each of the four tests was collected and analyzed. The results of these separator gas analyses are given on pages eight through eleven.

Thank you for the opportunity to be of service to Good Oil Company. If you have any questions or if we may be of further assistance in any way, please feel free to call upon us.

Very truly yours,

Core Laboratories, Inc.

Manager
Reservoir Fluid Analysis

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

Page 1 of 15
File RFL 76000

Company	Good Oil Company	Date Sampled	
Well	Oil Well No. 4	County	Samson
Field	Productive	State	Texas

FORMATION CHARACTERISTICS

Formation Name	Cretaceous
Date First Well Completed	, 19
Original Reservoir Pressure	4100 PSIG @ 8692 Ft.
Original Produced Gas-Oil Ratio	600 SCF/Bbl
Production Rate	300 Bbl/Day
Separator Pressure and Temperature	200 PSIG. 75 °F.
Oil Gravity at 60° F.	°API
Datum	8000 Ft. Subsea
Original Gas Cap	No

WELL CHARACTERISTICS

Elevation	610 Ft.
Total Depth	8943 Ft.
Producing Interval	8684-8700 Ft.
Tubing Size and Depth	2-7/8 In. to 8600 Ft.
Productivity Index	1.1 Bbl/D/PSI @ 300 Bbl/Day
Last Reservoir Pressure	3954* PSIG @ 8500 Ft.
Date	, 19
Reservoir Temperature	217* °F. @ 8500 Ft.
Status of Well	Shut in 72 hours
Pressure Gauge	Amerada
Normal Production Rate	300 Bbl/Day
Gas-Oil Ratio	600 SCF/Bbl
Separator Pressure and Temperature	200 PSIG, 75 °F.
Base Pressure	14.65 PSIA
Well Making Water	None % Cut

SAMPLING CONDITIONS

Sampled at	8500 Ft.
Status of Well	Shut in 72 hours
Gas-Oil Ratio	SCF/Bbl
Separator Pressure and Temperature	PSIG, °F.
Tubing Pressure	1400 PSIG
Casing Pressure	PSIG
Sampled by	
Type Sampler	Wofford

REMARKS:

* Pressure and temperature extrapolated to the mid-point of the producing interval = 4010 PSIG and 220°F.

File RFL 76000

Company	Good Oil Company	Formation	Cretaceous
Well	Oil Well No. 4	County	Samson
Field	Productive	State	Texas

HYDROCARBON ANALYSIS OF Reservoir Fluid SAMPLE

COMPONENT	MOL PERCENT	WEIGHT PERCENT	DENSITY @ 60° F. GRAMS PER CUBIC CENTIMETER	° API @ 60° F.	MOLECULAR WEIGHT
Hydrogen Sulfide	Nil	Nil			
Carbon Dioxide	0.91	0.43			
Nitrogen	0.16	0.05			
Methane	36.47	6.24			
Ethane	9.67	3.10			
Propane	6.95	3.27			
iso-Butane	1.44	0.89			
n-Butane	3.93	2.44			
iso-Pentane	1.44	1.11			
n-Pentane	1.41	1.09			
Hexanes	4.33	3.97			
Heptanes plus	33.29	77.41	0.8515	34.5	218
	100.00	100.00			

VOLUMETRIC DATA OF Reservoir Fluid SAMPLE

1. Saturation pressure (bubble-point pressure) 2620 PSIG @ 220 °F.
2. Specific volume at saturation pressure: ft^3/lb 0.02441 @ 220 °F.
3. Thermal expansion of saturated oil @ 5000 PSI = $\frac{V\ @\ 220\ °F}{V\ @\ 76\ °F}$ = 1.08790
4. Compressibility of saturated oil @ reservoir temperature: Vol/Vol/PSI:

From 5000 PSI to 4000 PSI = 13.48×10^{-6}
From 4000 PSI to 3000 PSI = 15.88×10^{-6}
From 3000 PSI to 2620 PSI = 18.75×10^{-6}

Pressure-Volume Relations at 220 °F.

Pressure PSIG	Relative Volume(1)	Y Function(2)
5000	0.9639	
4500	0.9703	
4000	0.9771	
3500	0.9846	
3000	0.9929	
2900	0.9946	
2800	0.9964	
2700	0.9983	
2620	1.0000	
2605	1.0022	2.574
2591	1.0041	2.688
2516	1.0154	2.673
2401	1.0350	2.593
2253	1.0645	2.510
2090	1.1040	2.422
1897	1.1633	2.316
1698	1.2426	2.219
1477	1.3618	2.118
1292	1.5012	2.028
1040	1.7802	1.920
830	2.1623	1.823
640	2.7513	1.727
472	3.7226	1.621

(1) Relative Volume: V/Vsat is barrels at indicated pressure per barrel at saturation pressure.

(2) $$\text{Y Function} = \frac{(\text{Psat}-\text{P})}{(\text{Pabs})\ (\text{V/Vsat}-1)}$$

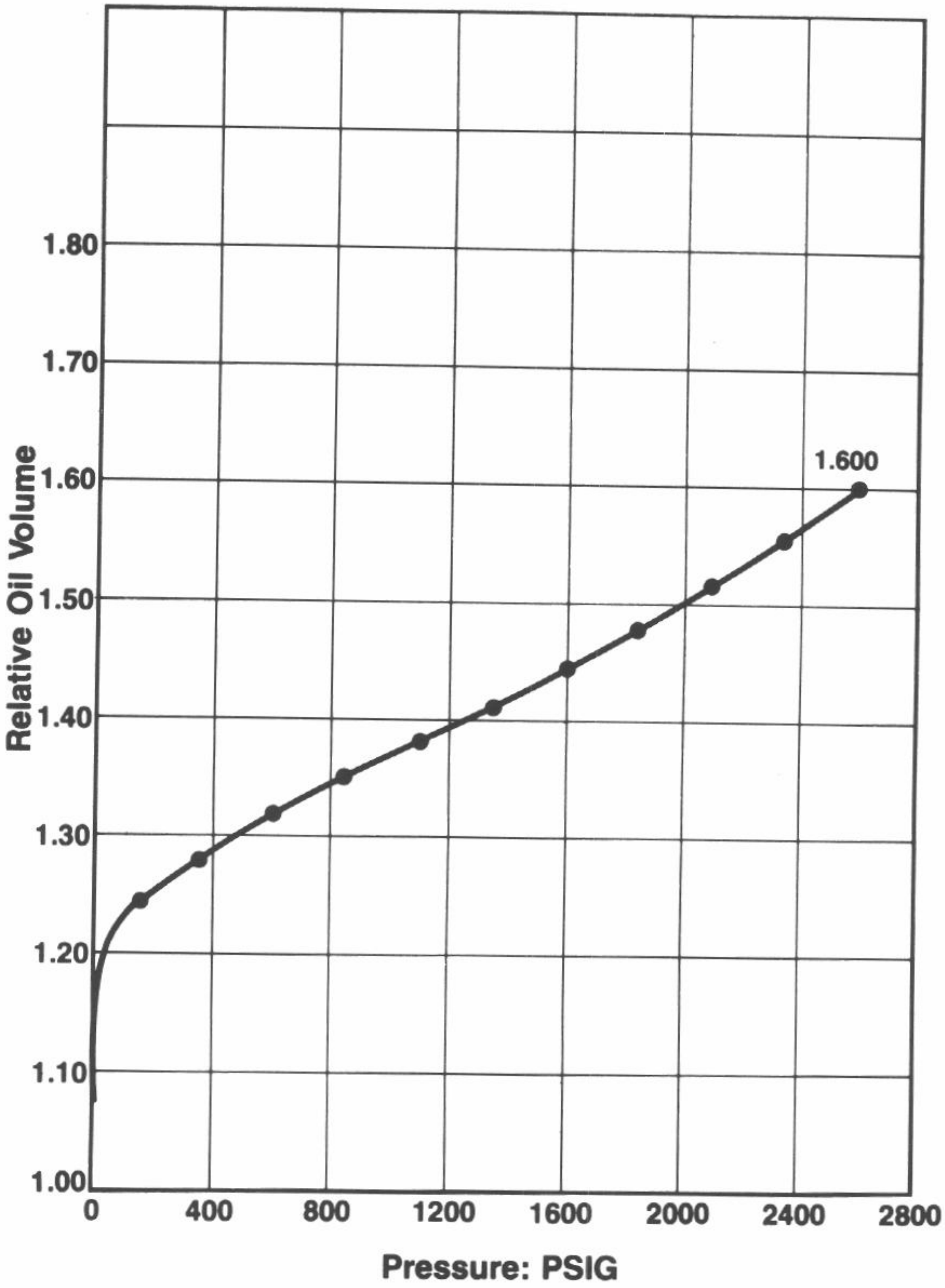
Differential Vaporization at 220 °F.

Pressure PSIG	Solution Gas/Oil Ratio(1)	Relative Oil Volume(2)	Relative Total Volume(3)	Oil Density gm/cc	Deviation Factor Z	Gas Formation Volume Factor(4)	Incremental Gas Gravity
2620	854	1.600	1.600	0.6562			
2350	763	1.554	1.665	0.6655	0.846	0.00685	0.825
2100	684	1.515	1.748	0.6731	0.851	0.00771	0.818
1850	612	1.479	1.859	0.6808	0.859	0.00882	0.797
1600	544	1.445	2.016	0.6889	0.872	0.01034	0.791
1350	479	1.412	2.244	0.6969	0.887	0.01245	0.794
1100	416	1.382	2.593	0.7044	0.903	0.01552	0.809
850	354	1.351	3.169	0.7121	0.922	0.02042	0.831
600	292	1.320	4.254	0.7198	0.941	0.02931	0.881
350	223	1.283	6.975	0.7291	0.965	0.05065	0.988
159	157	1.244	14.693	0.7382	0.984	0.10834	1.213
0	0	1.075		0.7892			2.039
		@ 60°F. = 1.000					

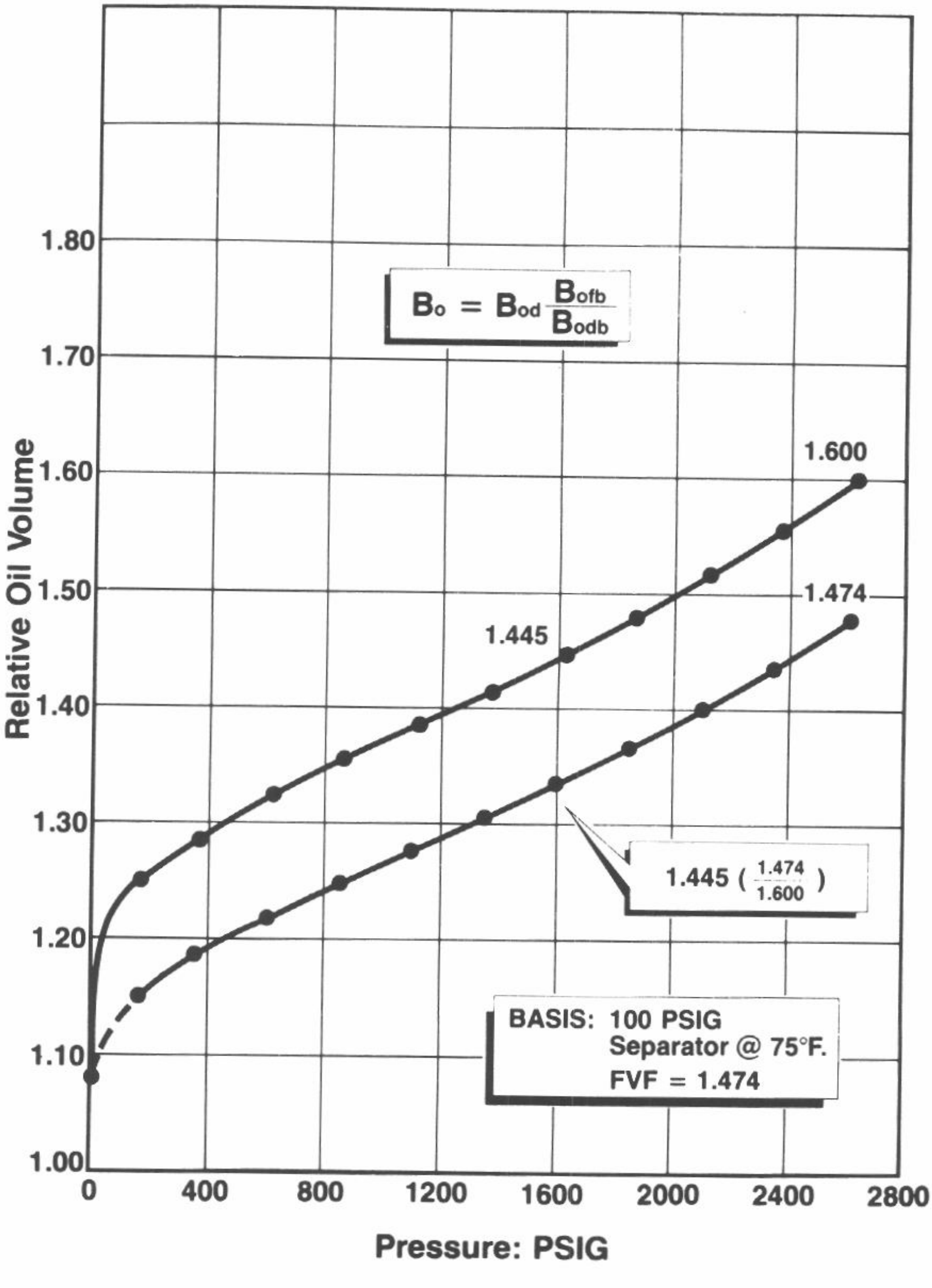
Gravity of residual oil = 35.1°API @ 60°F.

(1) Cubic feet of gas at 14.65 psia and 60°F. per barrel of residual oil at 60°F.
(2) Barrels of oil at indicated pressure and temperature per barrel of residual oil at 60°F.
(3) Barrels of oil plus liberated gas at indicated pressure and temperature per barrel of residual oil at 60°F.
(4) Cubic feet of gas at indicated pressure and temperature per cubic foot at 14.65 psia and 60°F.

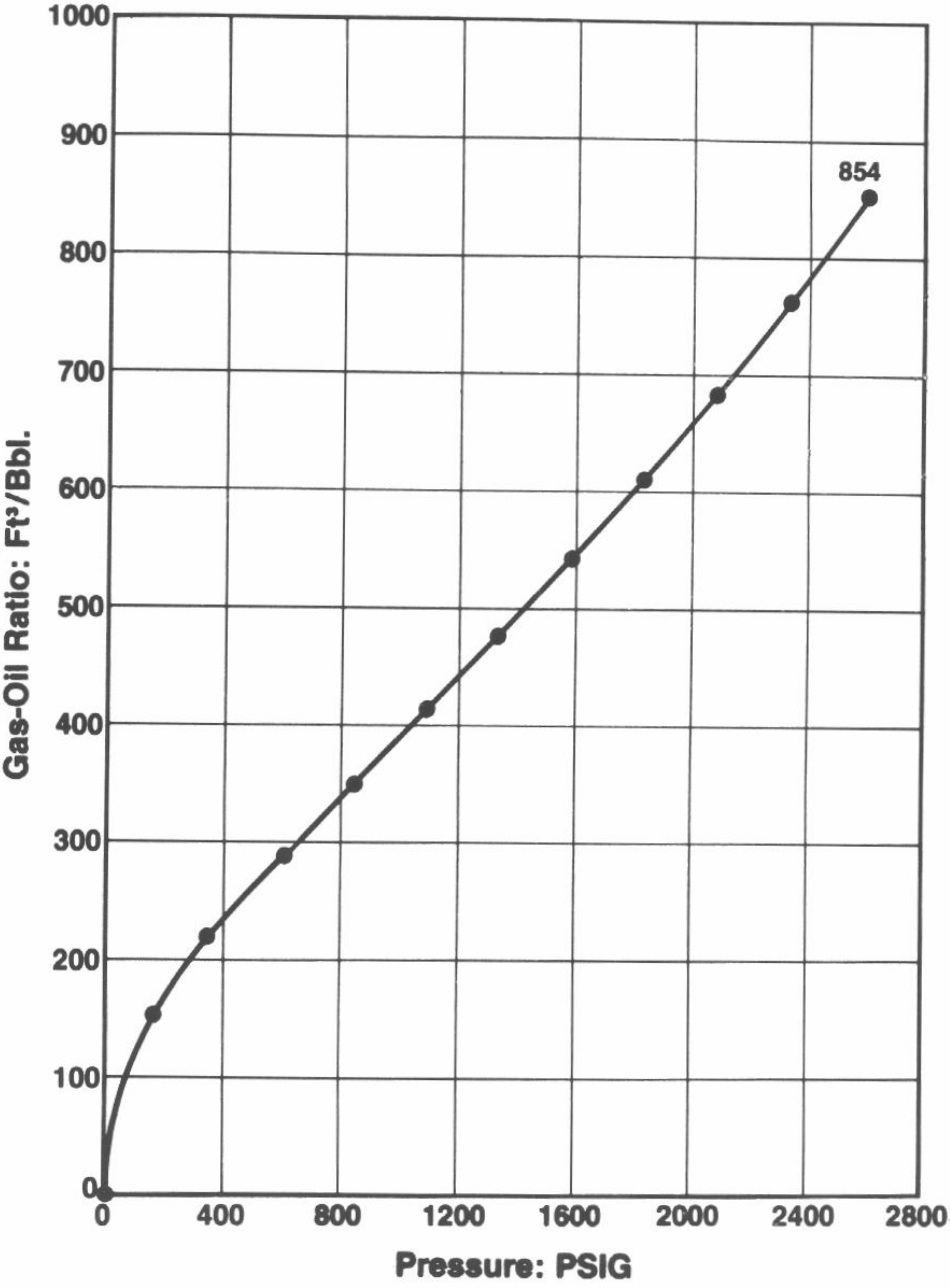
Adjustment of Oil Relative Volume Curve to Separator Conditions



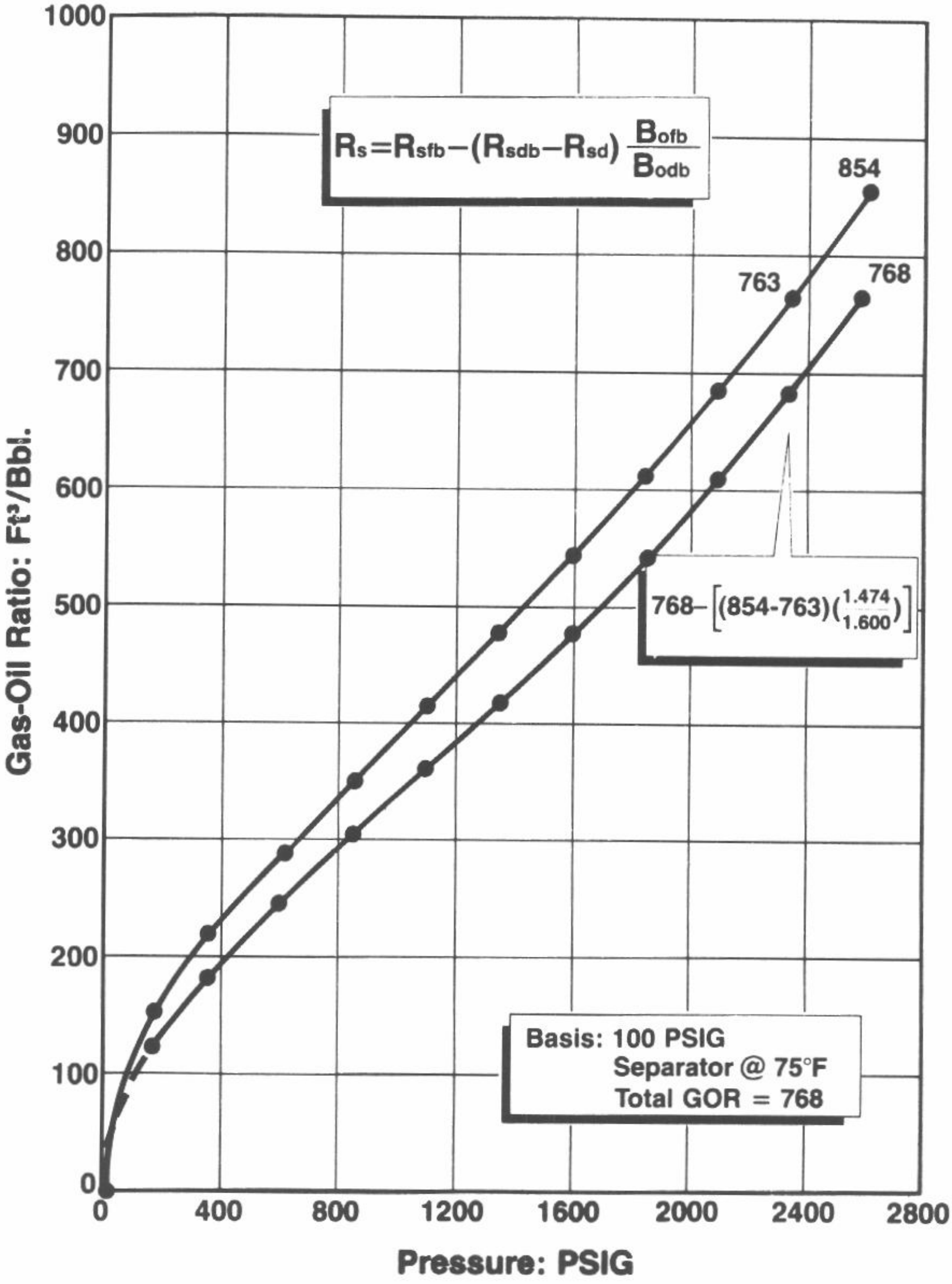
Adjustment of Oil Relative Volume Curve to Separator Conditions



Adjustment of Gas in Solution Curve to Separator Conditions



Adjustment of Gas in Solution Curve to Separator Conditions



File RFL 76000
Well Oil Well No. 4

Viscosity Data at 220 °F.

Pressure PSIG	Oil Viscosity Centipoise	Calculated Gas Viscosity Centipoise	Oil/Gas Viscosity Ratio
5000	0.450		
4500	0.434		
4000	0.418		
3500	0.401		
3000	0.385		
2800	0.379		
2620	0.373		
2350	0.396	0.0191	20.8
2100	0.417	0.0180	23.2
1850	0.442	0.0169	26.2
1600	0.469	0.0160	29.4
1350	0.502	0.0151	33.2
1100	0.542	0.0143	37.9
850	0.592	0.0135	43.9
600	0.654	0.0126	51.8
350	0.738	0.0121	60.9
159	0.855	0.0114	75.3
0	1.286	0.0093	137.9

File RFL 76000

Well Oil Well No. 4

SEPARATOR TESTS OF Reservoir Fluid SAMPLE

SEPARATOR PRESSURE, PSI GAUGE	SEPARATOR TEMPERATURE, °F.	GAS/OIL RATIO (1)	GAS/OIL RATIO (2)	STOCK TANK GRAVITY, °API @ 60° F.	FORMATION VOLUME FACTOR (3)	SEPARATOR VOLUME FACTOR (4)	SPECIFIC GRAVITY OF FLASHED GAS
50 to	75	715	737			1.031	0.840
0	75	41	41	40.5	1.481	1.007	1.338
100 to	75	637	676			1.062	0.786
0	75	91	92	40.7	1.474	1.007	1.363
200 to	75	542	602			1.112	0.732
0	75	177	178	40.4	1.483	1.007	1.329
300 to	75	478	549			1.148	0.704
0	75	245	246	40.1	1.495	1.007	1.286

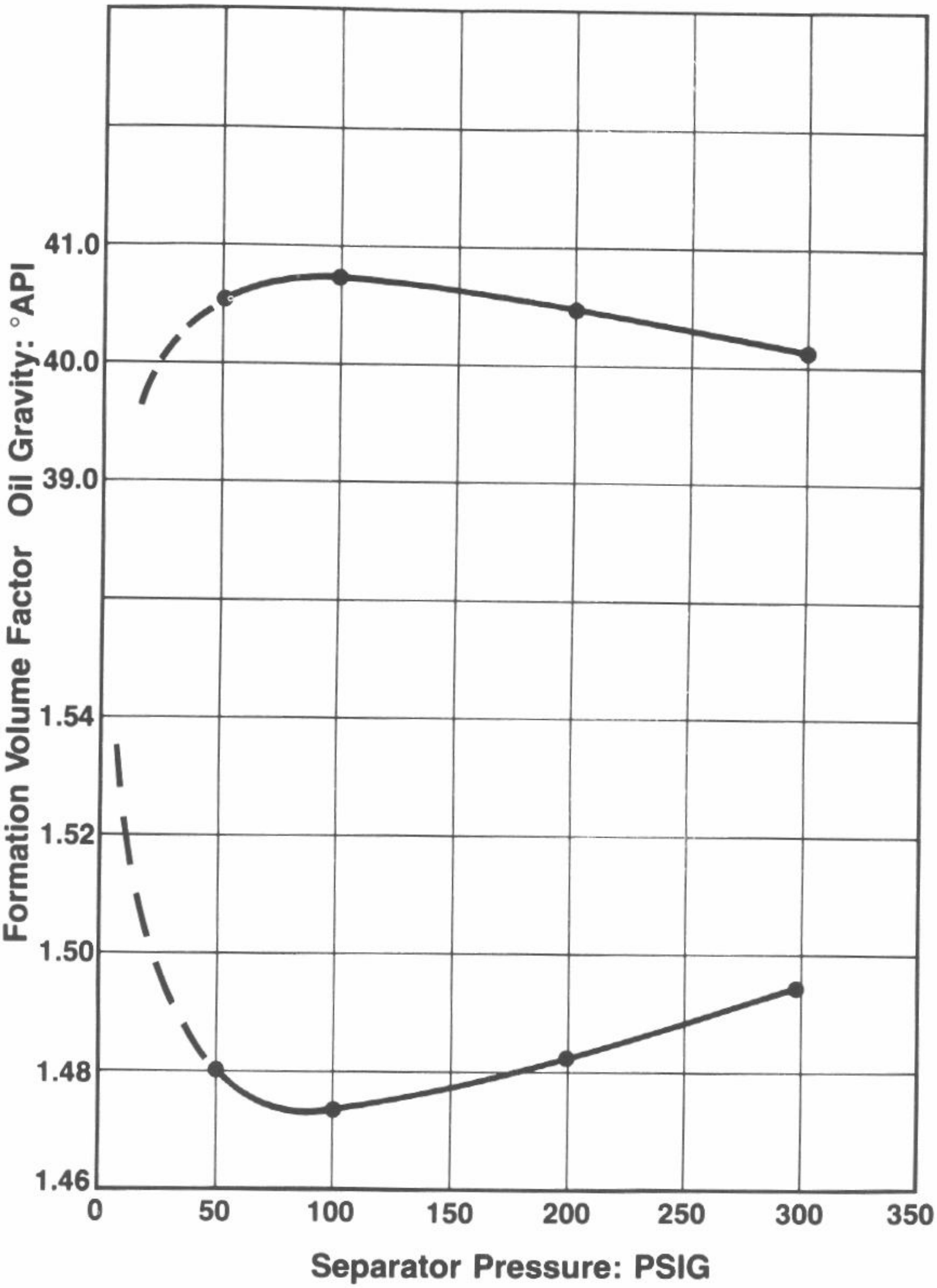
(1) Gas/Oil Ratio in cubic feet of gas @ 60° F. and 14.65 PSI absolute per barrel of oil @ indicated pressure and temperature.

(2) Gas/Oil Ratio in cubic feet of gas @ 60° F. and 14.65 PSI absolute per barrel of stock tank oil @ 60° F.

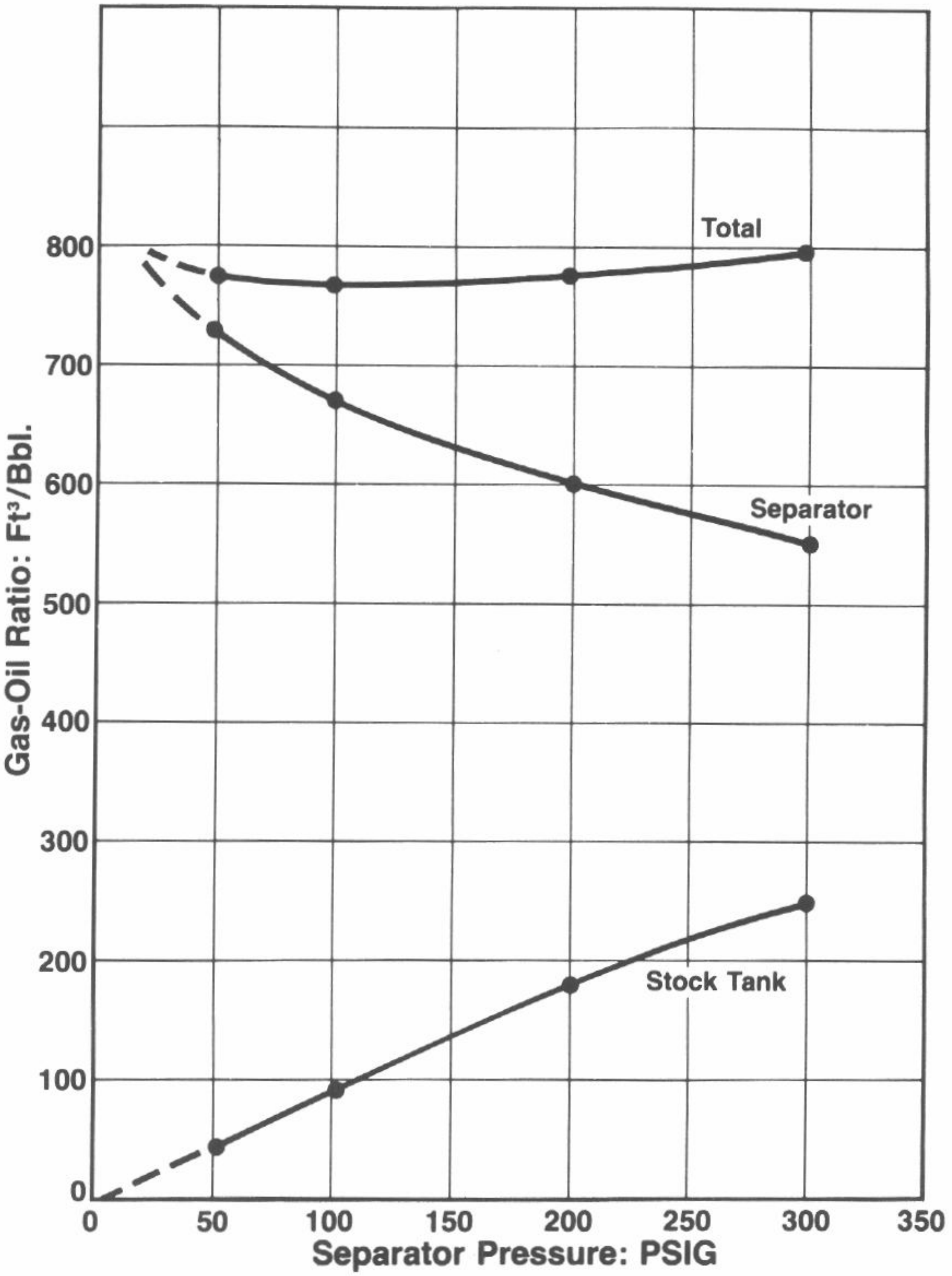
(3) Formation Volume Factor is barrels of saturated oil @ 2620 PSI gauge and 220 ° F. per barrel of stock tank oil @ 60° F.

(4) Separator Volume Factor is barrels of oil @ indicated pressure and temperature per barrel of stock tank oil @ 60° F.

Formation Volume Factor and Oil Gravity Vs. Separator Pressure



Gas-Oil Ratio Vs. Separator Pressure



Page 8 of 15

File RFL 76000

Company	Good Oil Company	**Formation**	Cretaceous
Well	Oil Well No. 4	**County**	Samson
Field	Productive	**State**	Texas

HYDROCARBON ANALYSIS OF Separator GAS SAMPLE

COMPONENT	MOL PERCENT	G P M
Hydrogen Sulfide	Nil	
Carbon Dioxide	1.62	
Nitrogen	0.30	
Methane	67.00	
Ethane	16.04	4.265
Propane	8.95	2.449
iso-Butane	1.29	0.420
n-Butane	2.91	0.912
iso-Pentane	0.53	0.193
n-Pentane	0.41	0.155
Hexanes	0.44	0.178
Heptanes plus	0.49	0.221
	100.00	8.793

Calculated gas gravity (air = 1.000) = 0.840

Calculated gross heating value = 1405 **BTU**
per cubic foot of dry gas at 14.65 **psia at 60° F.**

Collected at 50 **psig and** 75 **° F.** in the laboratory.

Page 9 **of** 15

File RFL 76000

Company	Good Oil Company	**Formation**	Cretaceous
Well	Oil Well No. 4	**County**	Samson
Field	Productive	**State**	Texas

HYDROCARBON ANALYSIS OF Separator GAS SAMPLE

COMPONENT	MOL PERCENT	GPM
Hydrogen Sulfide	Nil	
Carbon Dioxide	1.67	
Nitrogen	0.32	
Methane	71.08	
Ethane	15.52	4.127
Propane	7.36	2.014
iso-Butane	0.92	0.299
n-Butane	1.98	0.621
iso-Pentane	0.33	0.120
n-Pentane	0.26	0.094
Hexanes	0.27	0.110
Heptanes plus	0.29	0.131
	100.00	7.516

Calculated gas gravity (air = 1.000) = 0.786

Calculated gross heating value = 1321 **BTU**
per cubic foot of dry gas at 14.65 **psia at 60° F.**

Collected at 100 **psig and** 75 **° F.** in the laboratory.

File RFL 76000

Company Good Oil Company		**Formation** Cretaceous	
Well Oil Well No. 4		**County** Samson	
Field Productive		**State** Texas	

HYDROCARBON ANALYSIS OF Separator GAS SAMPLE

COMPONENT	MOL PERCENT	GPM
Hydrogen Sulfide	Nil	
Carbon Dioxide	1.68	
Nitrogen	0.36	
Methane	76.23	
Ethane	13.94	3.707
Propane	5.31	1.453
iso-Butane	0.57	0.185
n-Butane	1.21	0.379
iso-Pentane	0.20	0.073
n-Pentane	0.16	0.058
Hexanes	0.16	0.065
Heptanes plus	0.18	0.081
	100.00	6.001

Calculated gas gravity (air = 1.000) = 0.732

Calculated gross heating value = 1236 **BTU**
per cubic foot of dry gas at 14.65 **psia at 60° F.**

Collected at 200 **psig and** 75 **° F.** in the laboratory.

File RFL 76000

Company Good Oil Company **Formation** Cretaceous

Well Oil Well No. 4 **County** Samson

Field Productive **State** Texas

HYDROCARBON ANALYSIS OF Separator GAS SAMPLE

COMPONENT	MOL PERCENT	GPM
Hydrogen Sulfide	Nil	
Carbon Dioxide	1.65	
Nitrogen	0.39	
Methane	79.42	
Ethane	12.48	3.318
Propane	4.21	1.152
iso-Butane	0.43	0.140
n-Butane	0.90	0.282
iso-Pentane	0.15	0.055
n-Pentane	0.12	0.043
Hexanes	0.12	0.049
Heptanes plus	0.13	0.059
	100.00	5.098

Calculated gas gravity (air = 1.000) = 0.704

Calculated gross heating value = 1192 **BTU**
per cubic foot of dry gas at 14.65 **psia at 60° F.**

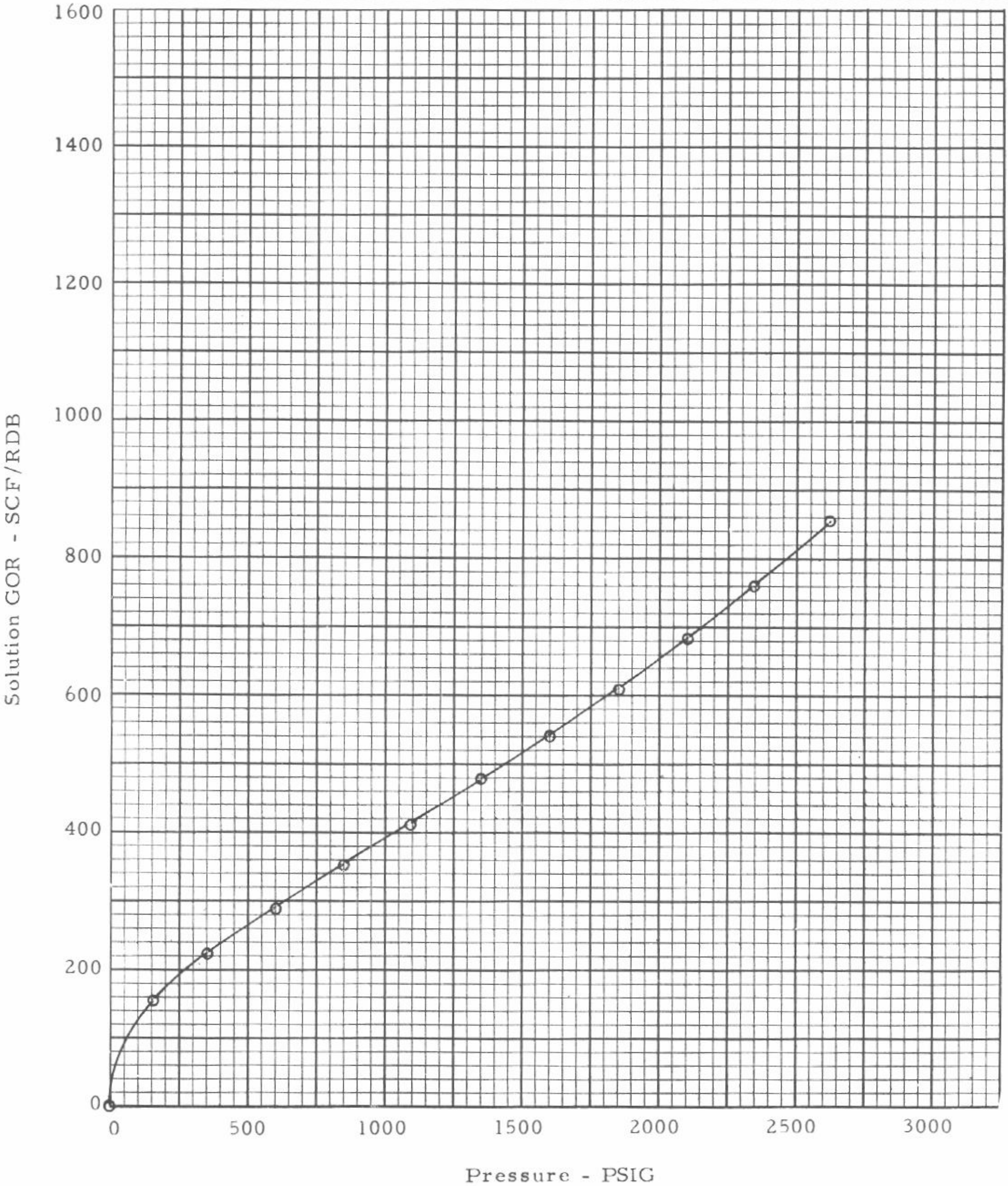
Collected at 300 **psig and** 75 **° F.** in the laboratory.

Core Laboratories, Inc.

Manager
Reservoir Fluid Analysis

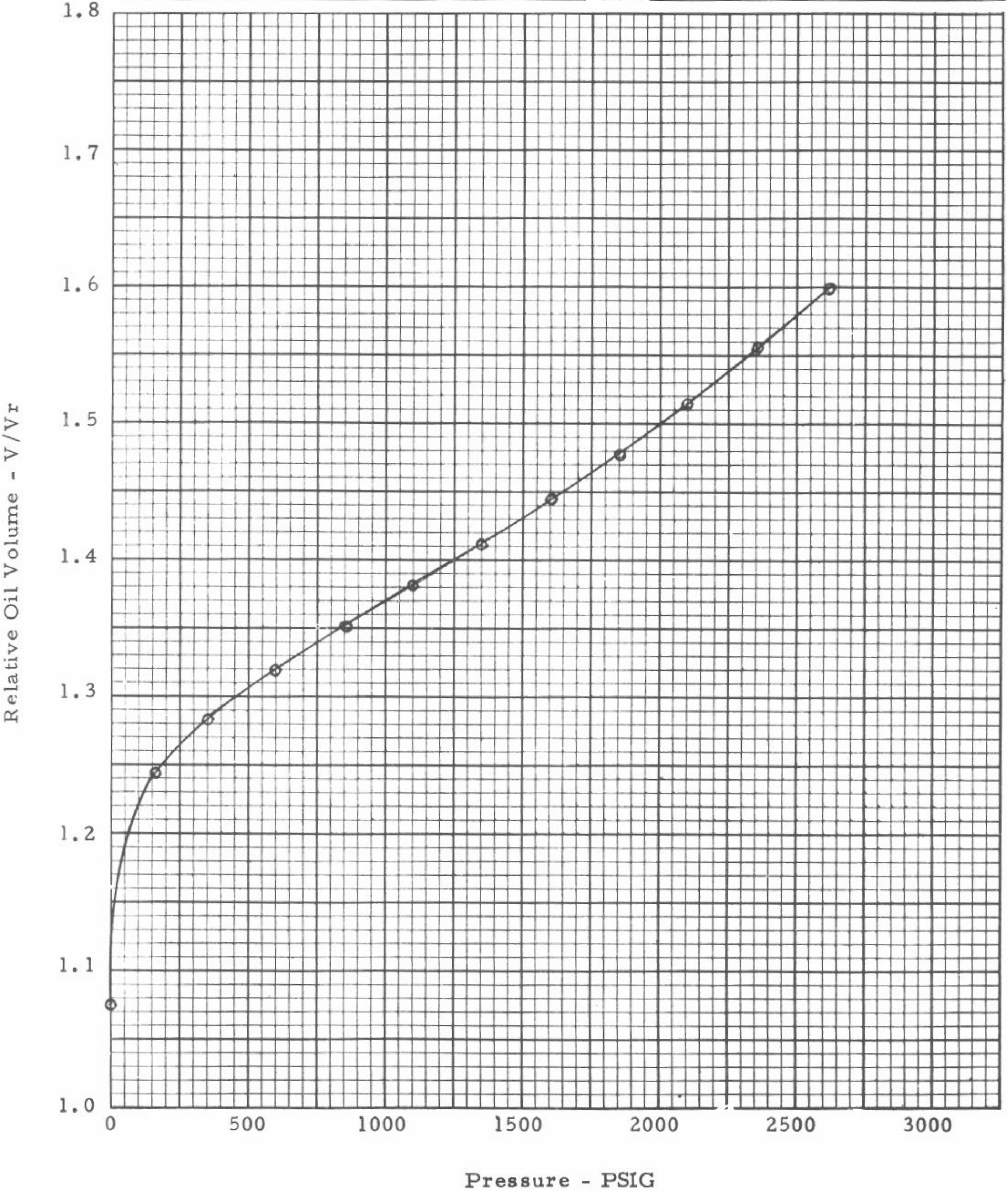
Solution Gas/Oil Ratio During Differential Vaporization

Company	Good Oil Company	Formation	Cretaceous
Well	Oil Well No. 4	County	Samson
Field	Productive	State	Texas



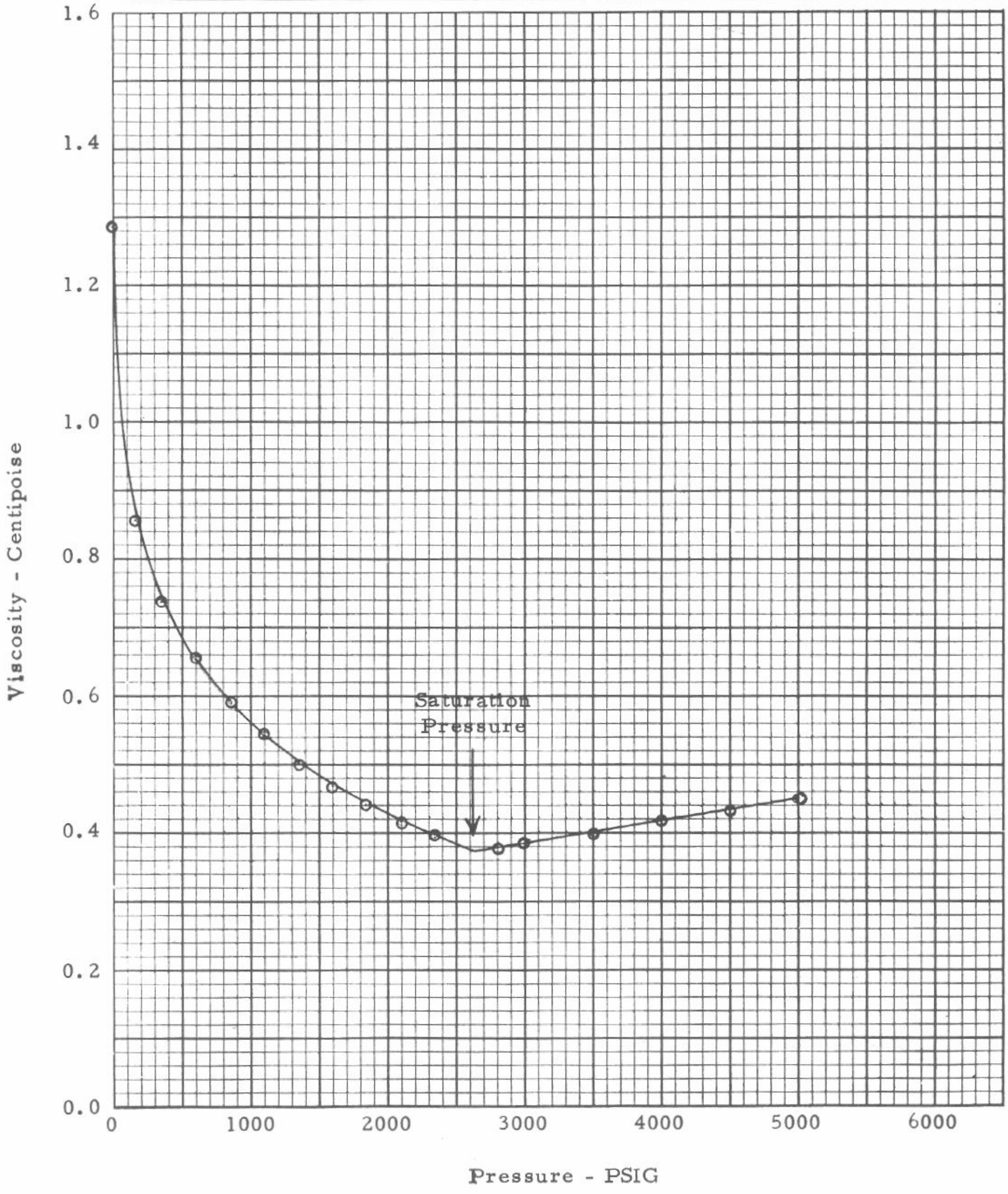
Relative Oil Volume During Differential Vaporization

Company	Good Oil Company	Formation	Cretaceous
Well	Oil Well No. 4	County	Samson
Field	Productive	State	Texas

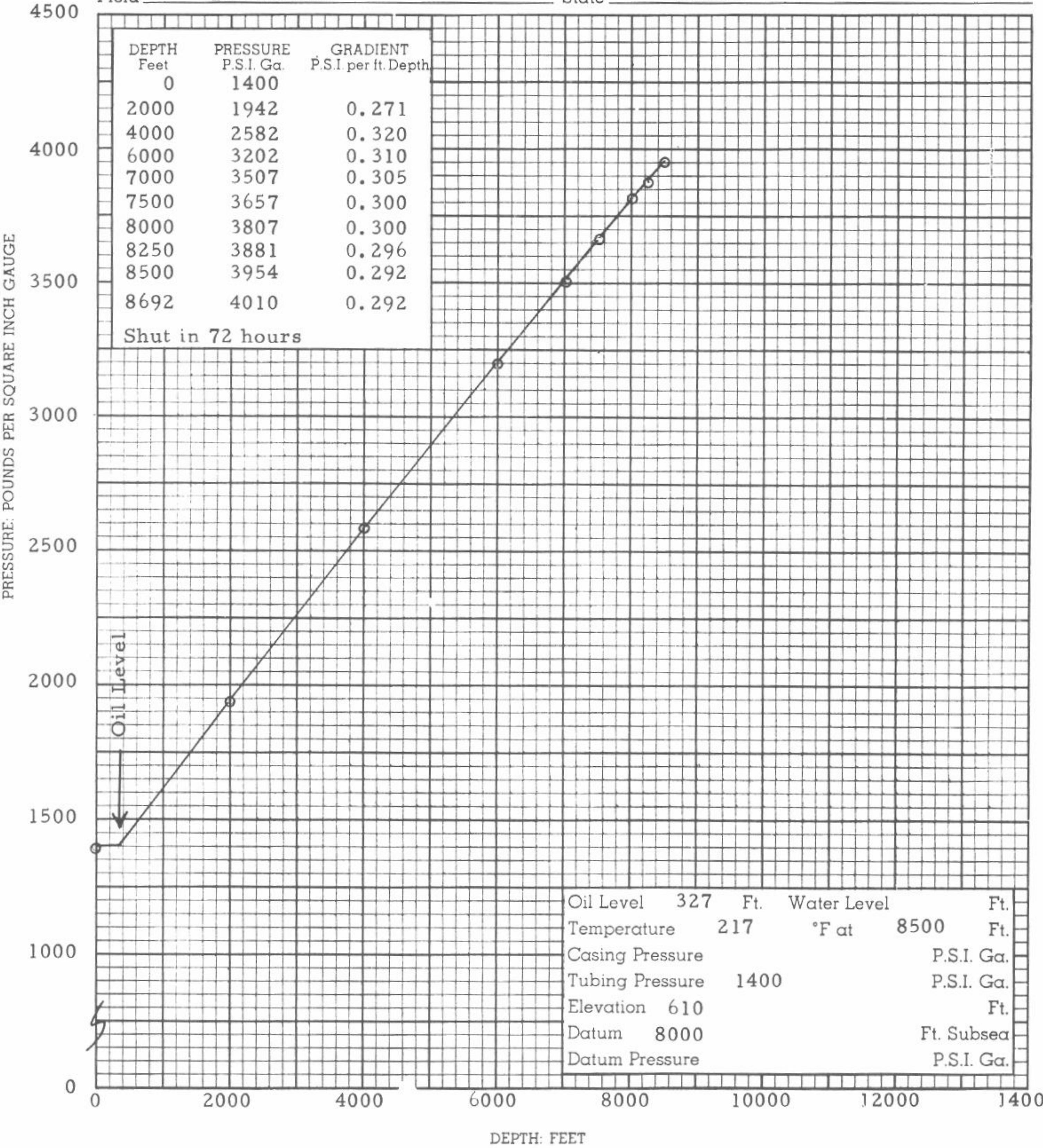


Viscosity of Reservoir Fluid

Company Good Oil Company
Formation Cretaceous
Well Oil Well No. 4
County Samson
Field Productive
State Texas



Company Good Oil Company
Well Oil Well No. 4
Field Productive
Formation Cretaceous
County Samson
State Texas



DEPTH Feet	PRESSURE P.S.I. Ga.	GRADIENT P.S.I. per ft. Depth
0	1400	
2000	1942	0.271
4000	2582	0.320
6000	3202	0.310
7000	3507	0.305
7500	3657	0.300
8000	3807	0.300
8250	3881	0.296
8500	3954	0.292
8692	4010	0.292

Shut in 72 hours

Oil Level 327 Ft. Water Level Ft.
Temperature 217 °F at 8500 Ft.
Casing Pressure P.S.I. Ga.
Tubing Pressure 1400 P.S.I. Ga.
Elevation 610 Ft.
Datum 8000 Ft. Subsea
Datum Pressure P.S.I. Ga.

CORE LABORATORIES, INC.
Reservoir Fluid Analysis

Reservoir Fluid Study

GOOD OIL COMPANY
Condensate No. 7 Well
Productive Field
Samson County, Texas

RFL 82000

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS 75207

RESERVOIR FLUID DIVISION

Good Oil Company
P. O. Box 100
Oil City, Texas 10010

Attention: Mr. John L. Jones

Subject: Reservoir Fluid Study
Oil Well No. 4
Productive Field
Samson County, Texas
Our File Number: RFL 76000

Gentlemen:

Duplicate subsurface fluid samples were collected from the subject well and these samples were submitted to our laboratory for use in a reservoir fluid study. Presented in the following report are the results of this study as requested by Good Oil Company.

As a quality check, the room temperature saturation pressure of each sample was initially determined. At 75°F., subsurface fluid sample Nos. 1 and 2 were found to have bubble point pressures of 1880 psig and 1885 psig, respectively. These values were considered to be in good agreement with one another and subsurface fluid sample No. 2 was selected for use in the reservoir fluid study.

The hydrocarbon composition of the subsurface fluid was determined by low temperature fractional distillation. The results of this distillation in terms of both mol percent and weight percent are presented on page two.

A small quantity of the reservoir fluid was charged to a high pressure windowed cell and thermally expanded to the reservoir temperature of 220°F. During a constant composition expansion at this temperature, the fluid was found to have a bubble point pressure of 2620 psig. The results of the pressure-volume measurements at reservoir temperature may be found on page four.

When subjected to differential pressure depletion at the reservoir temperature, the fluid evolved a total of 854 cubic feet of gas at 14.65 psia and 60°F. per barrel of residual oil at 60°F. The resulting relative oil with each displacement terminating at the original saturated volume. The well stream displaced at each displacement level was charged to low temperature fractional distillation equipment for volume measurement and compositional analysis. The results of the constant volume depletion at the reservoir temperature may be found on page four.

The smooth well stream compositions were then used with published equilibrium ratios to calculate the cumulative and instantaneous surface recoveries that may be expected during pressure depletion of the reservoir. The cumulative recovery calculations were based upon one MMSCF of original fluid and they are presented on page five. A summary of the instantaneous surface recovery calculations is given on page six.

Visual measurements of the retrograde condensate were performed at several points during the constant composition expansion and at each point during the constant volume depletion at the reservoir temperature. The maximum observed volume of retrograde condensate was 25.0 percent of the hydrocarbon pore space. A tabulation of the retrograde liquid measurements may be found on page seven; a graphical interpretation of these data is given on page twelve.

Thank you for the opportunity to be of service to Good Oil Company. Should you have any questions or if we may be of further assistance in any manner, please feel free to call upon us.

Very truly yours,

CORE LABORATORIES, INC.

Manager
Reservoir Fluid Analysis

CORE LABORATORIES, INC.

Reservoir Fluid Analysis

File RFL 82000

Company Good Oil Company
Date Sampled March 23, 1982
Well Condensate No. 7
County Samson
Field Productive
State Texas

FORMATION CHARACTERISTICS

Formation Name	Pay Sand
Date First Well Completed	February 20, 1982
Original Reservoir Pressure	7000 PSIG @ -11300 Ft.
Original Produced Gas/Liquid Ratio	SCF/Bbl
Production Rate	Bbls/Day
Separator Pressure and Temperature	PSIG °F.
Liquid Gravity at 60°F.	°API
Datum	11300 Ft. Subsea

WELL CHARACTERISTICS

Elevation	302 Ft.
Total Depth	12060 Ft.
Producing Interval	11547-11980 Ft.
Tubing Size and Depth	2-3/8 In. to 11411 Ft.
Open Flow Potential	MMSCF/Day
Last Reservoir Pressure	7000 PSIG @ -11300 Ft.
Date	March 25, 1982
Reservoir Temperature	256 °F. @ -11300 Ft.
Status of Well	Shut in
Pressure Gauge	Amerada

SAMPLING CONDITIONS

Flowing Tubing Pressure		780 PSIG
Flowing Bottom Hole Pressure (at -11300 Ft.)		1505 PSIG
Primary Separator Pressure		440 PSIG
Primary Separator Temperature		87 °F.
Secondary Separator Pressure		PSIG
Secondary Separator Temperature		°F.
Field Stock Tank Liquid Gravity		46.5 °API @ 60°F.
Primary Separator Gas Production Rate		869 MSCF/Day
Pressure Base	14.65 PSIA	
Temperature Base	60 °F.	
Compressibility Factor (F_{pv})	1.046	
Gas Gravity (Laboratory)	0.699	
Gas Gravity Factor (F_g)	1.1961	
Stock Tank Liquid Production Rate @ 60°F.		185 Bbls/Day
Primary Separator Gas/Stock Tank Liquid Ratio		4697 SCF/Bbl
or		212.9 Bbls/MMSCF
Sampled by		Core Laboratories, Inc.

REMARKS:

File RFL 82000

Well Condensate No. 7

HYDROCARBON ANALYSES OF SEPARATOR PRODUCTS AND CALCULATED WELL STREAM

Component	Separator Liquid, Mol Percent	Separator Gas Mol Percent	Separator Gas GPM	Well Stream Mol Percent	Well Stream GPM
Hydrogen Sulfide	0.00	0.00		0.00	
Carbon Dioxide	0.00	0.01		0.01	
Nitrogen	0.01	0.13		0.11	
Methane	10.76	83.01		68.93	
Ethane	6.17	9.23	2.454	8.63	2.295
Propane	8.81	4.50	1.231	5.34	1.461
iso-Butane	2.85	0.74	0.241	1.15	0.374
n-Butane	7.02	1.20	0.376	2.33	0.730
iso-Pentane	3.47	0.31	0.113	0.93	0.338
n-Pentane	3.31	0.25	0.090	0.85	0.306
Hexanes	8.03	0.21	0.085	1.73	0.702
Heptanes plus	49.57	0.41	0.185	9.99	6.006
	100.00	100.00	4.775	100.00	12.212

Properties of Heptanes plus	Separator Liquid	Separator Gas	Well Stream
API gravity @ 60°F.	39.0		
Density, Gm/Cc @ 60°F.	0.8293		0.827
Molecular weight	160	103	158

Calculated separator gas gravity (air=1.000) = 0.699
Calculated gross heating value for separator gas = 1230 BTU per cubic foot of dry gas @ 14.65 psia and 60°F.

Primary separator gas collected @ 440 psig and 87°F.
Primary separator liquid collected @ 440 psig and 87°F.

Primary separator gas/separator liquid ratio = 3944 SCF/Bbl @ 60°F.
Primary separator liquid/stock tank liquid ratio = 1.191 Bbls @ 60°F./Bbl
Primary separator gas/well stream ratio = 805.19 MSCF/MMSCF
Stock tank liquid/well stream ratio = 171.4 Bbls/MMSCF

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Well Condensate No. 7

PRESSURE-VOLUME RELATIONS OF RESERVOIR FLUID AT 256°F.
(Constant Composition Expansion)

Pressure, PSIG		Relative Volume	Deviation Factor, Z
7500		0.9341	1.328
7000	Reservoir Pressure	0.9523	1.264*
6500		0.9727	1.199
6300		0.9834	1.175
6200		0.9891	1.163
6100		0.9942	1.150
6010	Dew Point Pressure	1.0000	1.140**
5950		1.0034	
5900		1.0076	
5800		1.0138	
5600		1.0267	
5300		1.0481	
5000		1.0749	
4500		1.1268	
4000		1.2024	
3500		1.3096	
3000		1.4689	
2500		1.7169	
2100		2.0191	
1860		2.2747	
1683		2.5150	
1460		2.9087	
1290		3.3173	
1160		3.7153	
1050		4.1342	

*Gas Expansion Factor = 1.545 MSCF/Bbl.
**Gas Expansion Factor = 1.471 MSCF/Bbl.

DEPLETION STUDY AT 256°F.

Hydrocarbon Analyses of Produced Well Stream - Mol Percent

	Reservoir Pressure - PSIG							
Component	6010	5000	4000	3000	2100	1200	700	700*
Carbon Dioxide	0.01	0.01	0.01	0.01	0.01	0.01	0.01	Trace
Nitrogen	0.11	0.12	0.12	0.13	0.13	0.12	0.11	0.01
Methane	68.93	70.69	73.60	76.60	77.77	77.04	75.13	11.95
Ethane	8.63	8.67	8.72	8.82	8.96	9.37	9.82	4.10
Propane	5.34	5.26	5.20	5.16	5.16	5.44	5.90	4.80
iso-Butane	1.15	1.10	1.05	1.01	1.01	1.10	1.26	1.57
n-Butane	2.33	2.21	2.09	1.99	1.98	2.15	2.45	3.75
iso-Pentane	0.93	0.86	0.78	0.73	0.72	0.77	0.87	2.15
n-Pentane	0.85	0.76	0.70	0.65	0.63	0.68	0.78	2.15
Hexanes	1.73	1.48	1.25	1.08	1.01	1.07	1.25	6.50
Heptanes plus	9.99	8.84	6.48	3.82	2.62	2.25	2.42	63.02
	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Molecular weight of heptanes plus	158	146	134	123	115	110	109	174
Density of heptanes plus	0.827	0.817	0.805	0.794	0.784	0.779	0.778	0.837
Deviation Factor - Z								
Equilibrium gas	1.140	1.015	0.897	0.853	0.865	0.902	0.938	
Two-phase	1.140	1.016	0.921	0.851	0.799	0.722	0.612	
Well Stream produced- Cumulative percent of initial	0.000	6.624	17.478	32.927	49.901	68.146	77.902	

*Composition of equilibrium liquid phase.

File RFL 82000

Well Condensate No. 7

CALCULATED CUMULATIVE RECOVERY DURING DEPLETION

Cumulative Recovery per MMSCF of Original Fluid	Initial in Place	Reservoir Pressure - PSIG						
		6010	5000	4000	3000	2100	1200	700
Well Stream - MSCF	1000	0	66.24	174.78	329.27	499.01	681.46	779.02
Normal Temperature Separation*								
Stock Tank Liquid - Barrels	181.74	0	10.08	21.83	31.89	39.76	47.36	51.91
Primary Separator Gas-MSCF	777.15	0	53.18	145.16	283.78	440.02	608.25	696.75
Second Stage Gas - MSCF	38.52	0	2.26	5.17	8.03	10.51	13.21	14.99
Stock Tank Gas - MSCF	38.45	0	2.29	5.38	8.73	11.85	15.51	18.05
Total "Plant Products" in Primary Separator Gas-Gallons								
Ethane	1841	0	126	344	674	1050	1474	1709
Propane	835	0	58	163	331	526	749	873
Butanes (total)	368	0	26	73	155	256	374	441
Pentanes plus	179	0	12	35	73	122	177	206
Total "Plant Products" in Second Stage Gas-Gallons								
Ethane	204	0	12	27	42	55	70	80
Propane	121	0	7	17	27	36	47	54
Butanes (total)	53	0	3	8	13	17	23	27
Pentanes plus	23	0	1	3	5	7	10	11
Total "Plant Products" in Well Stream - Gallons								
Ethane	2295	0	153	404	767	1171	1626	1880
Propane	1461	0	95	250	468	707	979	1137
Butanes (total)	1104	0	70	178	325	486	674	789
Pentanes plus	7352	0	408	890	1322	1680	2037	2249

*Primary separator at 450 psig and 75°F., second stage separator at 100 psig and 75°F., stock tank at 75°F.

CALCULATED INSTANTANEOUS RECOVERY DURING DEPLETION

	Reservoir Pressure - PSIG						
	6010	5000	4000	3000	2100	1200	700
Normal Temperature Separation*							
Stock Tank Liquid Gravity, °API at 60°F.	49.3	51.7	55.4	60.4	64.6	67.5	68.6
Separator Gas/Well Stream Ratio, MSCF/MMSCF							
Primary Separator Gas Only	777.15	802.85	847.45	897.28	920.44	922.04	907.14
Primary and Second Stage Separator Gases	815.67	837.04	874.26	915.77	935.04	936.84	925.38
Separator Gas/Stock Tank Liquid Ratio, SCF/STB							
Primary Separator Gas Only	4276	5277	7828	13774	19863	22121	19475
Primary and Second Stage Separator Gases	4488	5502	8076	14058	20178	22476	19867
GPM from Smooth Well Stream Compositions							
Ethane plus	12.212	10.953	9.175	7.509	6.851	6.970	7.574
Propane plus	9.917	8.648	6.856	5.164	4.469	4.479	4.963
Butanes plus	8.456	7.209	5.434	3.752	3.057	2.990	3.349
Pentanes plus	7.352	6.158	4.437	2.800	2.108	1.959	2.171

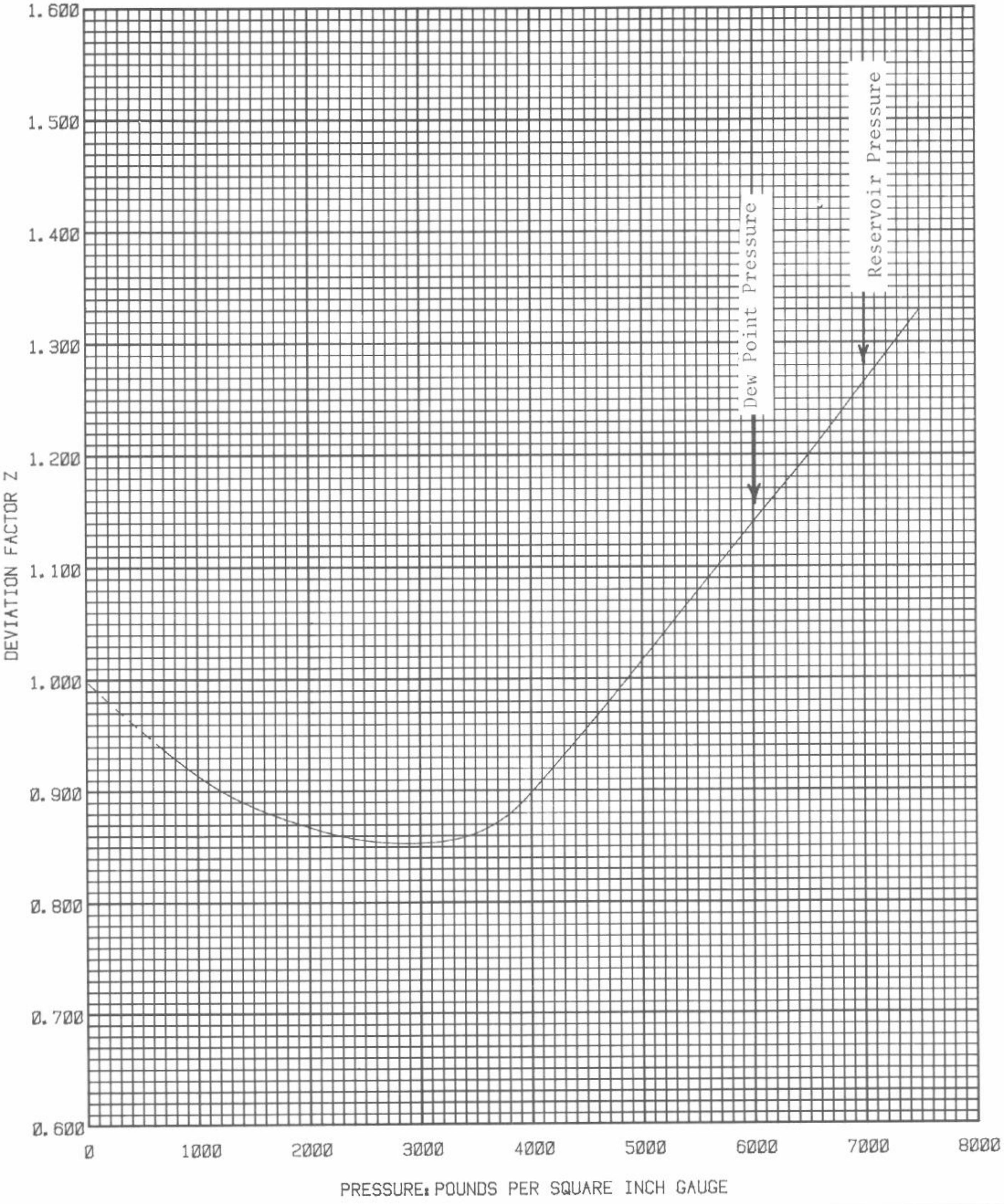
*Primary separator at 450 psig and 75°F., second stage separator at 100 psig and 75°F., stock tank at 75°F.

RETROGRADE CONDENSATION DURING GAS DEPLETION AT 256°F.

Pressure, PSIG	Retrograde Liquid Volume, Percent of Hydrocarbon Pore Space
6010 Dew Point Pressure	0.0
5950	Trace
5900	0.1
5800	0.2
5600	0.5
5300	2.0
5000 First Depletion Level	7.8
4000	21.3
3000	25.0
2100	24.4
1200	22.5
700	21.0
0	17.6

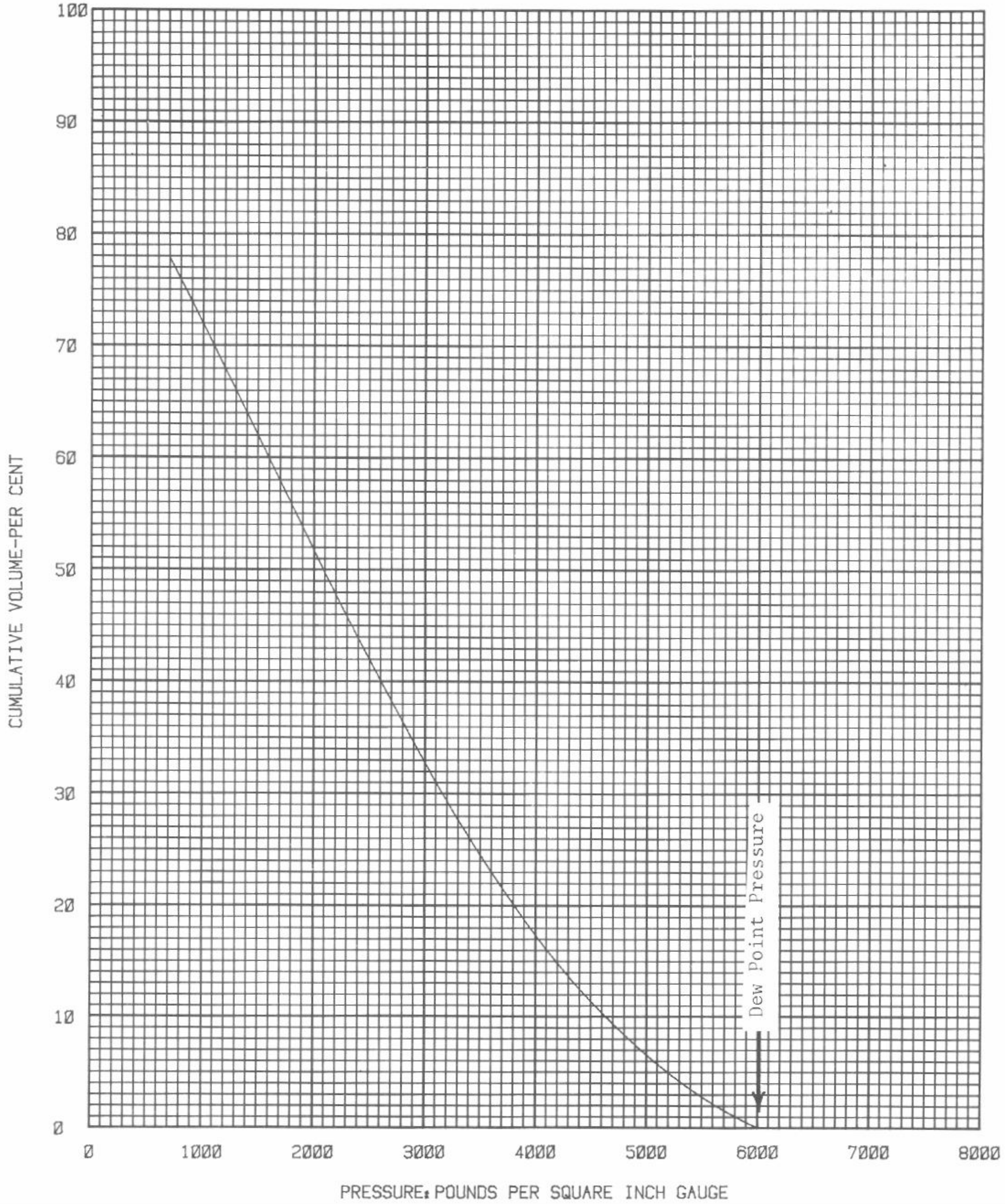
DEVIATION FACTOR Z OF WELL STREAM DURING DEPLETION AT 256 °F.

Company	GOOD OIL COMPANY	Formation	PAY SAND
Well	CONDENSATE NO. 7	County	SAMSON
Field	PRODUCTIVE	State	TEXAS



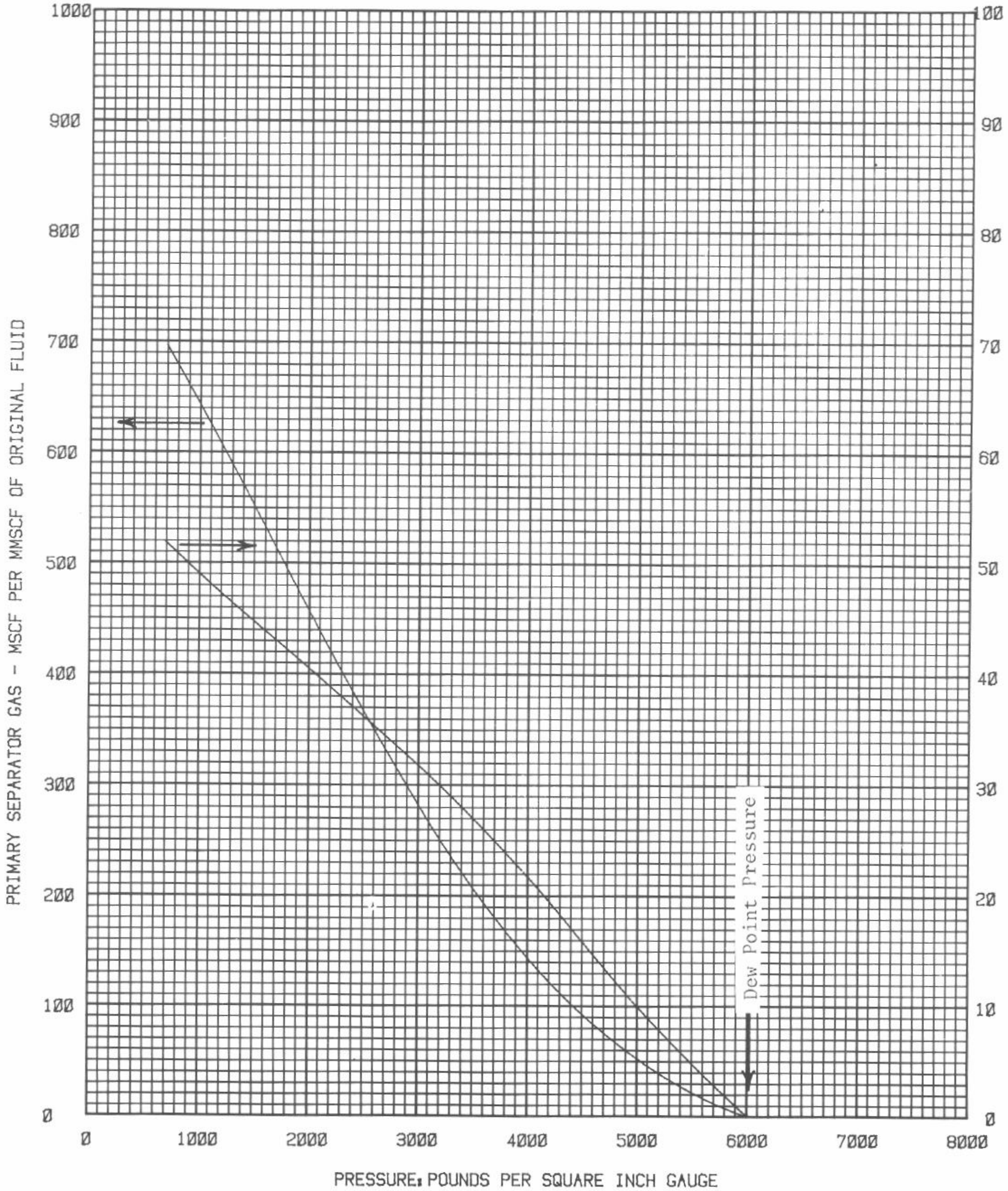
VOLUME OF WELL STREAM PRODUCED DURING DEPLETION

Company	GOOD OIL COMPANY	Formation	PAY SAND
Well	CONDENSATE NO. 7	County	SAMSON
Field	PRODUCTIVE	State	TEXAS



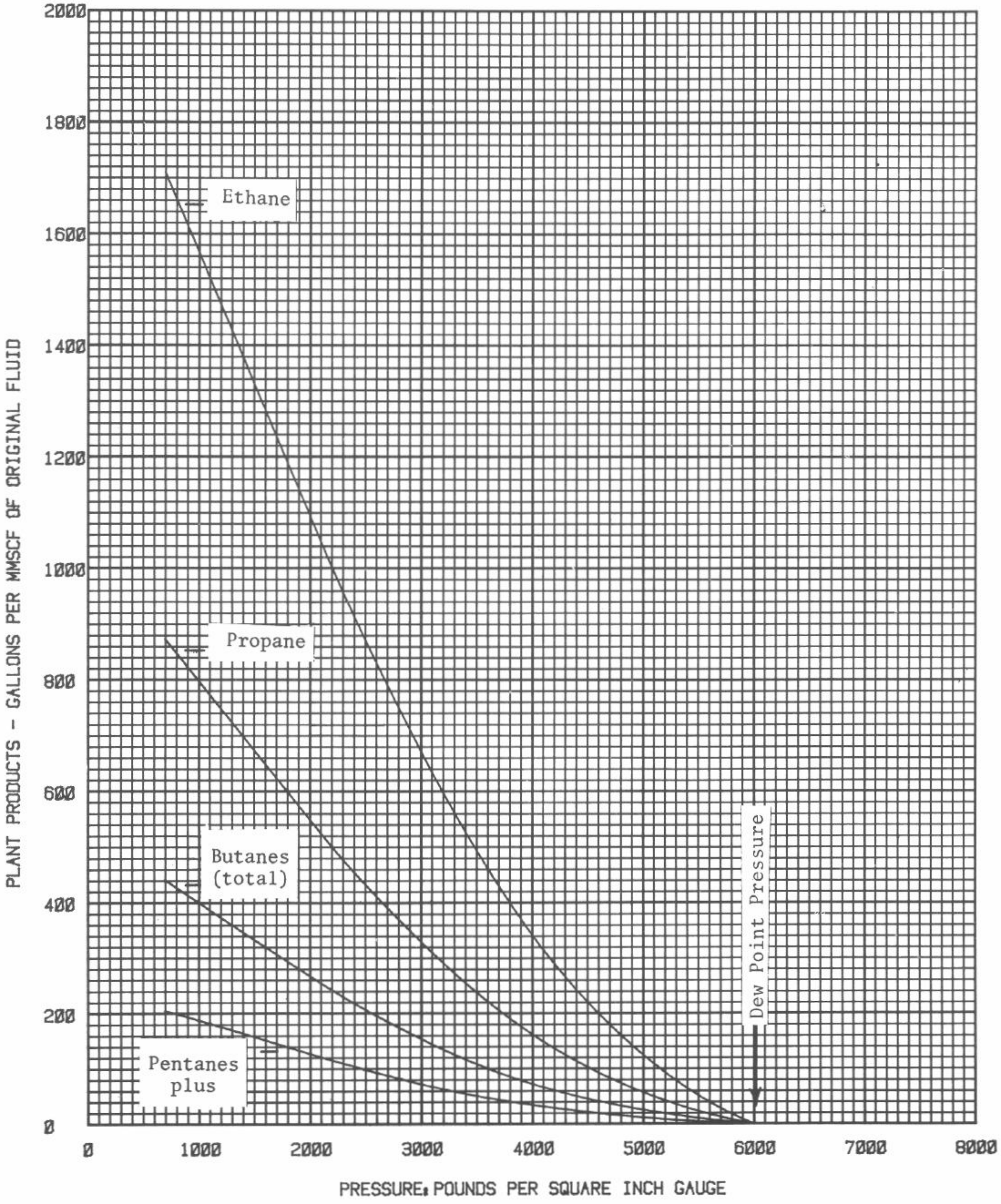
CUMULATIVE RECOVERY DURING DEPLETION

Company	GOOD OIL COMPANY	Formation	PAY SAND
Well	CONDENSATE NO. 7	County	SAMSON
Field	PRODUCTIVE	State	TEXAS



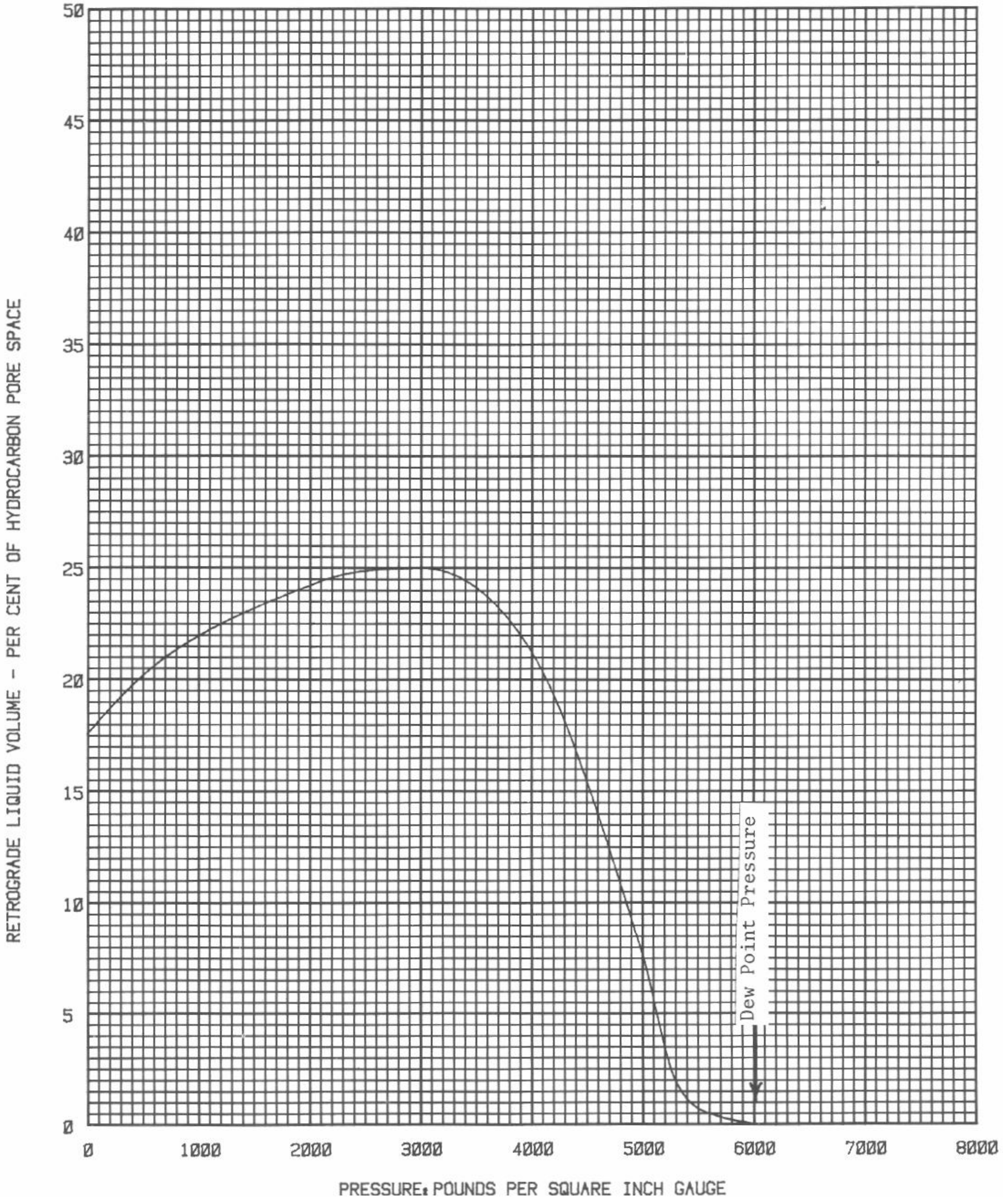
CUMULATIVE RECOVERY-PLANT PRODUCTS IN PRIMARY SEPARATOR GAS

Company GOOD OIL COMPANY
Formation PAY SAND
Well CONDENSATE NO. 7
County SAMSON
Field PRODUCTIVE
State TEXAS



RETROGRADE CONDENSATION DURING DEPLETION

Company GOOD OIL COMPANY
Formation PAY SAND
Well CONDENSATE NO. 7
County SAMSON
Field PRODUCTIVE
State TEXAS



Operating Quantities:

1. Reservoir pressure.
2. The instantaneous producing gas-oil ratio.
3. The cumulative stock tank recovery.
4. The cumulative gas recovery.

Equations:

Total gas recovered from reservoir = NR_p

$$N_pR_p = \frac{N(B_t - B_{tb}) - N_p(B_t - R_{si}\ B_g)}{B_g} \tag{1}$$

Another relation for total gas recovered:

$$N_pR_p = \int_o^t R \times d(N_p) \tag{2}$$

Combining equations (1) and (2) we have

$$\frac{N(B_t - B_{tb}) - N_p(B_t - R_{si}\ B_g)}{B_g} = \int_o^t R \times d(N_p) \tag{3}$$

$$R = \frac{kg}{ko}\frac{\mu o}{\mu_g}\frac{B_o}{B_g} + R_s \tag{4}$$

$$S_o = (1 - \frac{N_p}{N})\frac{B_o}{B_{ob}}(1 - S_{wi}) \tag{5}$$

The step-by-step utilization of Equations (3), (4) and (5) is summarized as follows:

I. Known data: Original value of reservoir pressure, reservoir temperature, the physical characteristics of reservoir gas and reservoir oil (including R_s, R_{si}, B_g, B_o, B_{ob}, μ_o, μ_g), connate-water saturation, the variation between gas/oil relative-permeability characteristics ratio, oil saturation, and reservoir volume.

II. Prediction:

1. Choose a value of pressure several hundred pounds below the original value and evaluate the fluid characteristics at this pressure. Choose a value of N_p. Substitute these values in the left-hand side of Equation (3). This will give a numerical value.

2. Using the chosen values of Step 1, substitute in Equation (5) values of N_p, S_{wi}, and fluid characteristics. Solve for S_o.

3. Using the value of S_o from Step 2, find a kg/ko value from the known relationship between kg/ko and oil saturation.

4. Substitute the kg/ko value from Step 3, along with fluid characteristics, in Equation (4). Solve for R.

5. Use the value of R from Step 4 and the chosen value of N from Step 2 to evaluate

   $$\int_o^t R \times d(N_p)$$

Since an integrated quantity is given; it is necessary to begin calculations for time equal zero and obtain the integral value, step by step. This can be done either graphically or by the simple approximation of averaging gas-oil values over small production intervals.

6. Equation (3) should now balance, i.e., the value in Step 1 for the left-hand side should equal that in Step 5 for the right-hand side, provided the chosen values of N_p and P are in agreement. If a balance is not obtained, choose a different N_p but not a new pressure, and repeats Steps 2 to 6 until a balance is reached.

   By the outlined procedure values of N_p and R which exist at the chosen pressure are obtained.

   A second pressure several hundred pounds below the first chosen can now be used to calculate a second trio of values. By a succession of such steps, the history of the internal gas-drive reservoir is predicted. In each successive calculation it is to be remembered that the integral quantity in Step 5 is evaluated from zero time onward.

NOMENCLATURE

N_p = Cumulative produced stock tank oil, barrels. This value is solved for in the prediction calculation.

N = Total barrels of stock tank oil originally in place.
= Total hydrocarbon volume of reservoir from routine and special core analysis, electric logs, etc., divided by the formation volume factor for the average field separator pressure. The formation volume factor, Bofb, is found in Column 6, Page 7 of the sample report.

B_t = Two-phase formation volume factor.

The two-phase formation volume factors may be calculated by multiplying the Relative Total Volumes, page 5, column 4 by the formation volume factor, Bofb, for the average field separator pressure, column 6, page 7, and dividing by the Relative Oil Volume factor at the bubble point, Bodb, found on page 5, column 3. The formation volume factor used for this calculation should be the same as the one used to calculate the oil in place, N.

$$B_t = B_{t}d \; \frac{(Bofb)}{(Bodb)}$$

B_{tb} = Value of B_t at saturation pressure.

R_s = Gas in solution, standard cubic feet per barrel of stock tank oil.

The gas in solution as a function of pressure may be calculated from the data found on page 5, column 2 using the following formula.

$$R_s = R_{sfb} - (R_{sdb} - R_{sd}) \; \frac{(Bofb)}{(Bodb)}$$

R_{sfb} is the sum of the separator gas and the stock tank gas, column 4 on page 7 of the sample report. Use the data for the average field separator as in the previous calculation. R_{sdb} is the gas in solution at the bubble point from the differential vaporization, column 2, page 5. R_{sd} is the gas remaining in solution at the pressure being evaluated taken from column 2, page 5. Bofb and Bodb are the same as those used to calculate B_t.

R_{sb} = Value of R_s at saturation pressure, standard cubic feet per barrel of stock tank oil.

Bg = Gas conversion factor, barrels in reservoir per standard cubic foot.

$$= \frac{Z(14.7)\ (Tr + 460)}{5.615\ (P + 15)\ (520)}$$

Where Z is deviation factor of the gas at the desired pressure. Z may be found on Page 5, Column 6 of the sample report.

Bg may also be calculated by dividing the gas formation volume factor from Page 5, Column 7 by 5.615. Tr is reservoir temperature, P is the pressure at which Bg is to be determined.

R_p = Net cumulative gas-oil ratio, standard cubic feet per barrel stock tank oil. Calculated from depletion calculations.

R = Instantaneous producing gas-oil ratio, standard cubic feet per barrel of stock tank oil. Calculated from basic data during depletion calculations.

B_o = Oil Formation volume factor.

B_o is calculated by the formula

$$B_o = Bod \frac{Bofb}{Bodb}$$

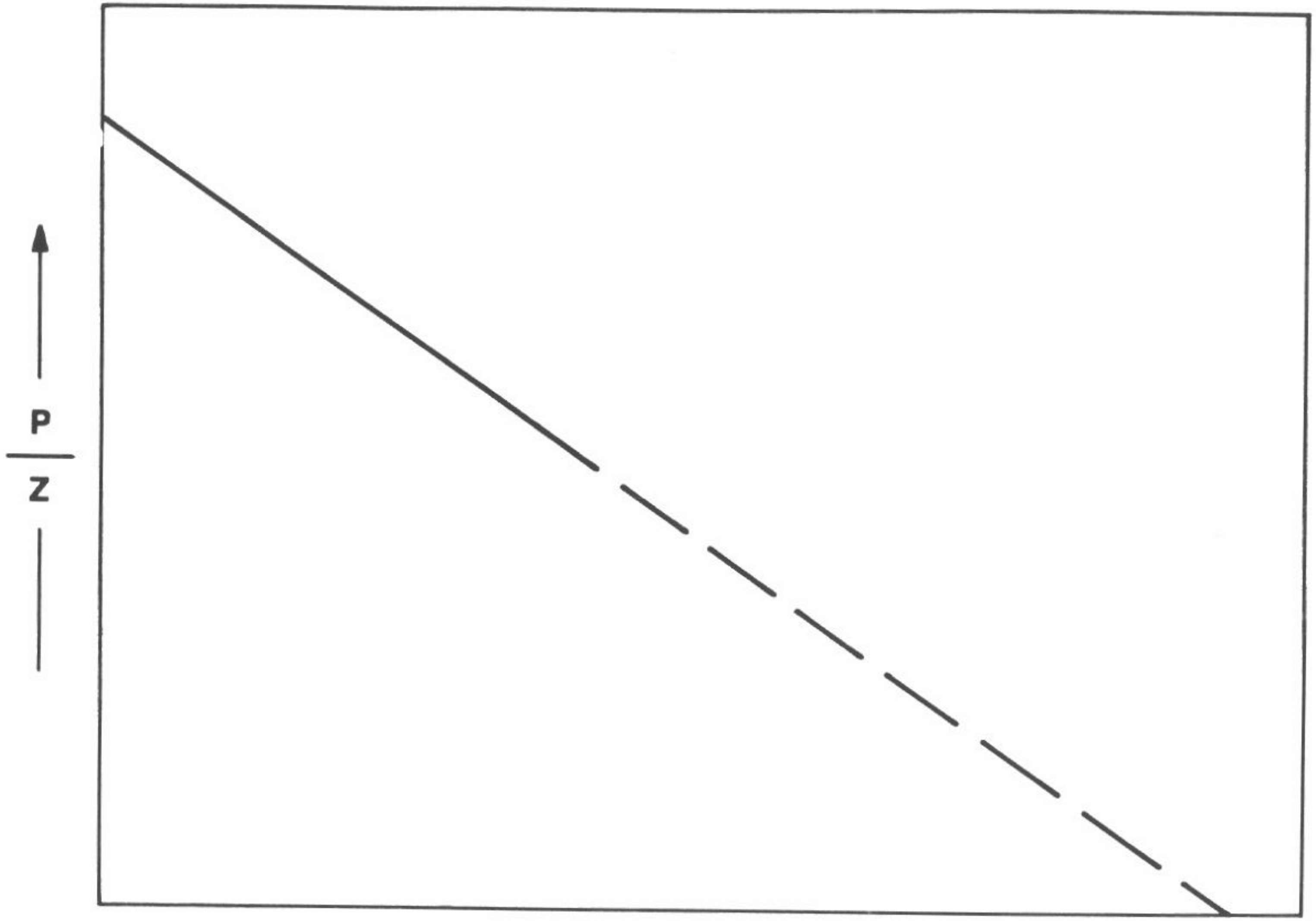
Bod are the Relative Oil Volumes found in column 3, page 5. Bofb and Bodb are the same values used in previous calculations.

B_{ob} = The value for B_o at saturation pressure.

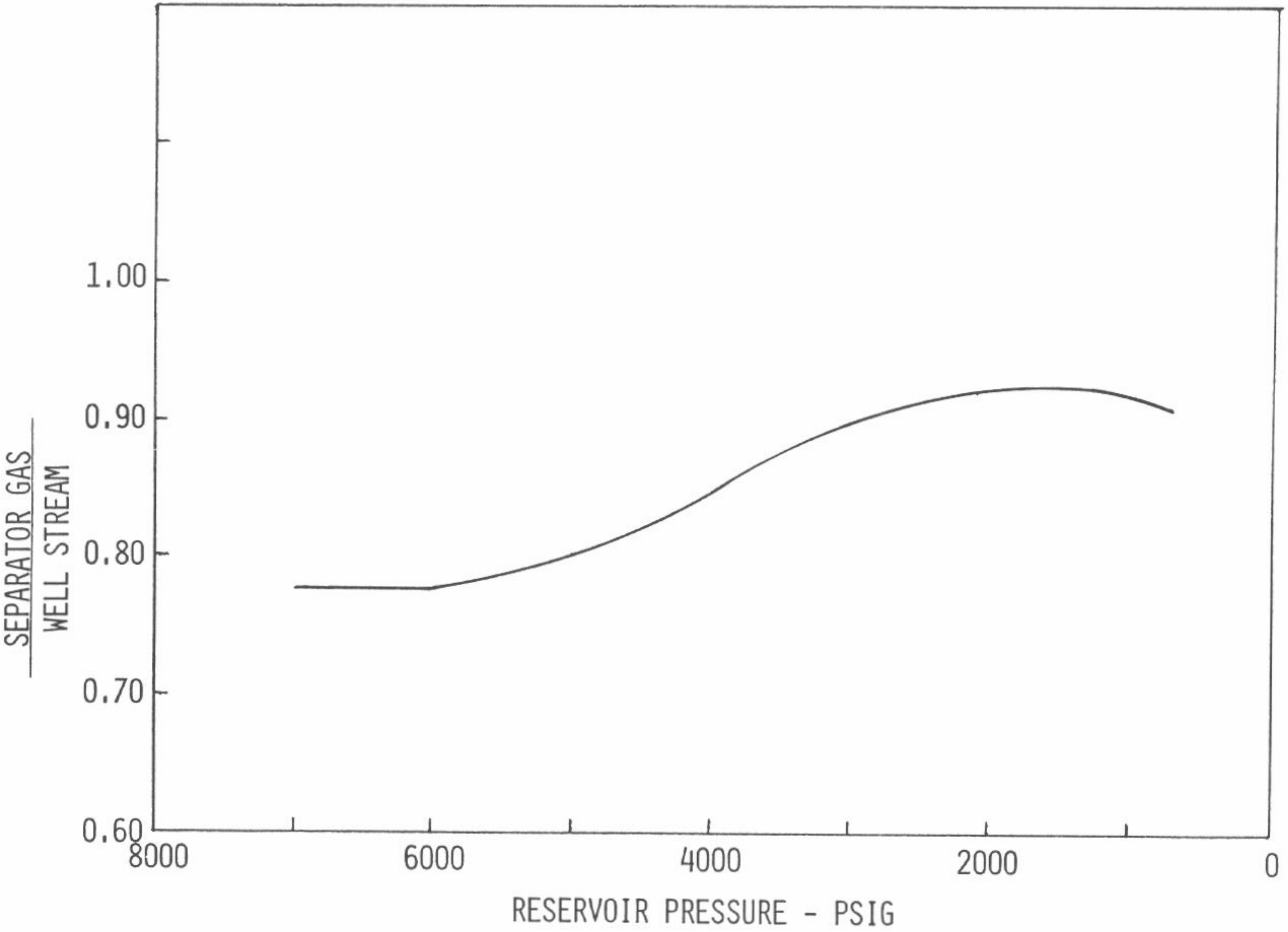
μo = Reservoir oil viscosity. Page 6, Column 2.

μg = Gas viscosity. Obtain the gas viscosity from Page 6, Column 3.

Pressure, PSIG	Two Phase Formation Volume Factor B_t	Gas in Solution R_s	Oil Formation Volume Factor B_o
5000			
4000			
4100			
4000			
3500			
3000			
2900			
2800			
2700			
2620	1.474	768	1.474
2350	1.534	684	1.432
2100	1.610	611	1.396
1850	1.713	545	1.363
1600	1.857	482	1.332
1350	2.067	423	1.301
1100	2.389	365	1.273
850	2.919	307	1.245
600	3.919	250	1.216
350	6.426	187	1.182
159	13.536	126	1.146
0		0	1.075



CUMULATIVE WELL STREAM PRODUCED


SEPARATOR GAS
WELL STREAM
1.00
0.90
0.80
0.70
0.60
8000
6000
4000
2000
0
RESERVOIR PRESSURE - PSIG