PETROLEUM BRANCH, AIME
Fidelity Union Building
Dallas, Texas

PAPER NUMBER 410 - G

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The Role Of Bubble Formation In Oil Recovery By Solution Gas Drives In Limestones

By

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ABSTRACT

Laboratory data show that the gas-oil ratio performance of non-uniform porosity limestones produced by solution gas drive is sensitive to producing rate and to fluid properties. Non-uniform porosity limestones are those for which laboratory solution and external gas drive tests yield considerably different relative permeability ratio characteristics.

The oil recovery performance by solution gas drive depends directly on the number of gas bubbles formed. Laboratory rates of pressure decline, which are 100 to 10,000 times greater than normal field rates, cause the formation of an unusually large number of gas bubbles. This results in abnormally high oil recovery efficiencies. Since it is impractical to reproduce the number of bubbles formed under field conditions, laboratory solution gas drive data on non-uniform porosity limestones are therefore not directly applicable to field operations. However, certain laboratory data can be used to make a conservative estimate of field performance.

The concepts presented in this paper indicate the possibility that increased field oil recoveries may be obtained from non-uniform porosity limestones by rapidly reducing reservoir pressure for a short interval of time. It has yet to be established that significant improvements in oil recovery from such reservoirs can be realized by varying the pressure decline rate within limits possible in the field. However, the possibility that recovery may be increased in this manner warrants further study.

References and illustrations at end of paper.

INTRODUCTION

Limestone reservoir rocks can be divided into two general classes according to the nature of their pore space. One class has a comparatively uniform pore system composed mainly of voids between grains of the rock (intergranular type porosity). The other class, in addition to having intergranular porosity, has a secondary pore system composed of combinations of solution cavities, fractures, etc., and is considered to have non-uniform porosity.

It has been shown in a previous publication [1] that the laboratory measured gas-oil flow behavior of uniform type porosity limestones is essentially the same for a test simulating a field

BEFORE THE
OIL CONSERVATION COMMISSION
Santa Fe, New Mexico

Case No. 11798 (De Novo) Exhibit No. 15

Submitted by: Collins & Ware, Inc.

Hearing Date: August 14, 1997

solution gas drive as for one simulating an external gas drive. For non-uniform porosity type limestones a significant difference in gas-oil flow behavior was found on the same rock. More efficient behavior was observed during a solution gas drive test. This difference in oil displacement behavior was attributed to the complex nature of the pore space and to the fact that the source of gas in the two displacement operations is not the same. That is, in a solution gas drive the gas is evolved from oil within the pores of the rock itself, while in an external drive the gas is injected from an outside source.

Experimental work beyond that previously published shows that the laboratory solution gas drive behavior of non-uniform porosity limestones is not unique. Differences in oil recovery up to twofold, at the same flowing gas-oil ratio, were found by varying the test conditions. A variation in results on uniform porosity type rocks was also observed. However, the variation in flow behavior of one core under different test conditions was small and of the same magnitude as the observed differences between results of identical tests on separate cores of the same rock material.

For the non-uniform porosity limestones, the laboratory solution gas drive relative permeability characteristics were found to be affected by:

1. rate of pressure decline
2. original bubble point pressure of the gas-oil solution
3. oil viscosity
4. gas solubility characteristics.

Two examples of the variation observed on non-uniform porosity limestones are shown in Figures 1 and 2. The data in Figure 1 were measured on a West Texas Reef sample and those in Figure 2 on a Mid-Continent limestone sample. The data for curve B in each figure were obtained using a gas-oil solution having an initial bubble point pressure of 1000 psi. The initial bubble point pressure for tests A was 200 psi. In addition, the pressure decline rates for tests B were faster than for tests A.

The data of Figures 1 and 2 are quite typical of those obtained on non-uniform porosity limestones, and no satisfactory explanation has been heretofore published. The purpose of the studies reported in this paper was therefore: (1) to determine the reason for the observed variation in results of laboratory solution gas drive tests; (2) to design a laboratory test which would provide data for predicting field performance; and (3) to determine if special production practices in certain oil fields could result in improvements in oil recovery. The answer to the first question has been obtained. These studies offer only an insight into the possible means for answering the second and third questions.

FORMATION OF GAS SATURATION IN POROUS MEDIA

During all laboratory solution gas drive tests it has been observed that the oil is in a supersaturated state.[1] That is, the oil contains more dissolved gas than would be predicted from PVT relationships. In terms of pressure, the degree of supersaturation is expressed as the difference between the bubble point pressure of the oil and the actual pressure. Some degree of supersaturation is always observed to exist throughout the entire pressure depletion life of solution gas drive tests. It is noted, in fact, that the supersaturation history of a test actually is closely related to the measured flow behavior. In general, the higher the degree of supersaturation, the greater is the displacement efficiency of oil by gas.

By experience, it is known that supersaturation results in the formation of bubbles in a gas-oil solution. One might conclude, therefore, that the manner in which bubbles form and subsequently grow controls the displacement of oil during any solution gas drive. Since not all rocks exhibit unusual laboratory solution gas drive performance, the pore geometry probably also plays an important role.

A study of results such as are presented by Figures 1 and 2, and visual studies of non-uniform porosity limestones indicate that only a part of the total gas saturation is responsible for the observed gas-oil ratio performance. This implies that part of the porosity of these non-uniform rocks does not contribute to gas permeability. Nevertheless, if the saturation existing only in the conductive regions could be correlated with the flowing gas-oil ratios, it is believed that the differences exhibited in solution drive behavior would be resolved into one basic flow relationship. At present no way of obtaining such a correlation is apparent for naturally occurring rocks.

The above considerations indicate the influence of (a) the formation of gas bubbles, and (b) the displacement of oil by expanding gas bubbles on depletion characteristics of non-uniform porosity rocks.

A. FORMATION OF GAS BUBBLES

Kennedy and Olson[2] have shown that the rate at which gas bubbles form in a gas-oil solution is a function of the supersaturations. This in turn depends on the rate of pressure reduction. The higher the supersaturation, the greater is the rate at which gas bubbles form. Since in laboratory solution gas drive tests the supersaturation histories were different, it was logical to conclude that the oil displacement behavior was affected by the rate of bubble formation, and hence by the number of gas bubbles formed.

Information in the literature [3,4,5], together with data obtained at the Stanolind Research Center on gas bubble formation, were used to predict the total number of bubbles which might form under various rates of pressure decline. Although the details of this study are beyond the scope of this paper and will be covered in a future publication, an example of the results can be shown here. The predictions were made using different assumptions than were made by Kennedy and Olson [2]. Nevertheless, the agreement with their predictions on the number of bubbles formed is satisfactory, considering that both methods give only order of magnitude values.

The theoretical supersaturation history as well as the cumulative number of bubbles formed are shown in Figure 3 for a gas-oil solution undergoing constant rates of pressure decline of 1000, 100, 10, 1, and 0.1 psi per day. These rates of pressure decline cover the range of importance in field and laboratory solution gas drives. It must be emphasized that the results of Figure 3 apply only to a specific system. However, the effect of rate of pressure decline on the number of bubbles formed is the same for all systems; namely, an increase in the rate of pressure decline by a factor of ten results in about ten times as many bubbles being formed.

The significant information shown in Figure 3 is that the higher the rate of pressure decline, the greater is the total number of bubbles formed in a system. Also, essentially all of the bubbles are formed throughout a relatively short time interval during the pressure depletion life. From Figure 3 it can be estimated that in usual laboratory tests the number of bubbles formed is 100 to 10,000 times greater than the number formed under normal field conditions.

B. DISPLACEMENT OF OIL BY EXPANDING GAS BUBBLES

It is reasoned that the number of gas bubbles formed during the pressure depletion of a gas-oil solution in a porous material will have an effect on the oil displacement behavior. In this type of recovery method, oil is pushed out of a pore by the evolution of a gas bubble within this pore or by the intrusion of gas from another pore.

A gas bubble grows in two ways; namely, by the addition of gas which diffuses from adjacent oil and by expansion due to pressure reduction. As it grows it will invade the network of pores which offers the least resistance. This bubble will unite with others, eventually forming a continuous gas phase which extends to the exit of the porous body. After this occurs, gas flowing in this connected network of pores will be less effective in displacing oil from other pores. However, isolated gas bubbles will still be present, and will continue to displace oil with the maximum efficiency until they join the continuous gas phase. The more bubbles present, the greater will be the displacement of oil from regions not invaded by the conductive gas saturation. Figures 1 and 2 provide examples showing the effect of the number of bubbles on recovery. The approximate number of bubbles formed in each of these tests has been calculated using methods referred to in the previous section. The calculations show that about ten times as many bubbles were formed in the B tests as were formed in the A tests reported in each of the figures. This is in agreement with the concepts outlined above.

The amount by which bubble formation and the growth of bubbles affects flow behavior in a solution gas drive on uniform porosity type rocks has been found to be small, except in the early stages of depletion. In this type of rock all of the pores act as fluid conductors as well as fluid storage spaces. Displacement of oil from a specific pore or from a group of pores does not require the formation of a gas bubble in it. The reason is that gas evolved upstream can enter and thereby displace oil from any pore.

This is not the situation in non-uniform porous materials as is suggested above. In these, some pores act as fluid conductors as well as storage spaces while others are essentially storage spaces. In other words, comparison of the oil recovery performances calculated from laboratory solution and external gas drives indicates the presence of pore space which is not entered by an immiscible, non-wetting, displacing fluid (such as gas) during an external drive. These pores, or clusters of pores, have capillary pressure-saturation characteristics which are different from the "conductor" pores comprising the rest of the pore space. Recovery of oil from these "storage" pores by an external gas drive can be accomplished only at high gas-oil ratios. However, in this type of pore, or cluster of pores, the formation of a gas bubble during a solution gas drive can result in the displacement and recovery of this oil when the system is producing at a relatively low gas-oil ratio.

The above discussion explains why a laboratory solution drive recovers more oil than does an external gas drive at comparable flowing gas-oil ratios. It also offers an explanation for the variations in oil recovery observed in solution gas drives. To summarize, recovery of oil from these "storage" pores can only result from the formation of bubbles therein. If the number of bubbles formed during a solution drive varies, the recovery of oil from these pores will vary also. Where the volume of these pores comprises a high percentage of the total volume of the rock, these variations will be significant.

It was shown previously that at field rates of pressure decline the number of gas bubbles formed is small compared to the number formed in laboratory tests. This can be taken qualitatively to mean that laboratory solution gas drive tests will yield a higher oil displacement efficiency from a non-uniform limestone rock than should be expected in the field.

To confirm further the ideas expressed above, several solution drive tests were conducted under special conditions. The following section describes apparatus and general experimental techniques used in these tests. A description of the special test conditions employed is given in a later section, together with a discussion of the objectives of the experiments and of the results obtained.

DESCRIPTION OF APPARATUS AND PROCEDURE

The core samples used in this work were selected from producing sections in oil reservoirs and also from outcrop formations. All samples were cylindrical in shape and ranged from 2-1/2 to 4-1/2 inches in diameter. These samples varied from 6 to 11 inches in length with one exception. This exception was a specially prepared 6-foot long core. The apparatus and technique of mounting and testing these samples from 6 to 11 inches long have been described in a previous publication.[1]

The 6-foot long core sample was prepared from a piece of Cordova shellstone which outcrops near Austin, Texas. This core sample had a uniform diameter of 4-1/2 inches for five feet of length. The diameter was then reduced uniformly over a 3-inch long section, and the remaining nine inches of the core were shaped into a square cross section, one inch on a side. The core was prepared in this manner to minimize effects of boundary conditions on flow test results. In the flow tests this reduced section formed the downstream end of the core. At a point one foot from the downstream end of the core a small diameter tube was attached for pressure measurement. Fluid gathering plates were attached to each end of the rock and the assembly was surrounded by a thermosetting plastic. The plastic-sealed core was then placed in a steel cell, and the space between the inside of the cell and the outside of the core was pressured to 400 psi.

The technique of saturating the 6-foot long Cordova shellstone core differed from that used on the smaller samples. The large core was first saturated with a gas-free relatively pure hydrocarbon in the range of C_{10}-C_{12}. Next, methane gas was injected and oil produced until the average gas saturation reached approximately 30 percent pore space. The injection pressures were very close to the bubble point pressure of the methane-C_{10}-C_{12} solution to be used in the flow tests. After flow was terminated, methane gas was injected into the core through a regulator set to operate at the intended bubble point pressure. After various intervals of time the core was shut off from the methane supply, and the gas phase pressure change with time was observed. When the gas phase pressure drop became negligible for an interval of several hours, the residual oil was considered to be substantially at equilibrium with the gas present.

The gas phase was then removed by the injection of 200 psi bubble point oil, first at an injection pressure slightly above the bubble point pressure, then later at an injection pressure of 300 psi. The extent of liquid saturation was determined by both material balance and fluid compressibility checks. It was found that two pore volumes of oil were sufficient to remove the gas and thus completely saturate the core.

In addition to the previously[1] described apparatus, a special constant rate pump was used in the tests where a constant rate of pressure decrease or increase was used. This pump was powered by a constant speed electric motor working through a machine lathe gear train. The pump was connected to a back pressure regulator. Depending on the manner of connecting the pump, the pressure could be either increased or decreased at a constant rate.

RESULTS AND DISCUSSION

A. SHORT CORE TESTS

The usual laboratory solution gas drive test involves a pressure depletion time of hours compared with years for an actual reservoir. The laboratory pressure decline rates are accordingly orders of magnitude greater than field rates. Under such conditions the number of gas bubbles formed in a laboratory test is likewise much greater than the number formed in the reservoir.

The most direct method for reducing the number of bubbles formed during laboratory tests is to use slower rates of depletion. However, it is impractical from the standpoint of time alone to perform laboratory tests at field rates. There is also another serious objection to reducing laboratory depletion rates. A decrease in the rate of pressure decline also means a decrease in the pressure drop across the system and an increase in the "end effect", or liquid pile-up at the downstream end of the core. If this "end effect" is appreciable, it becomes impossible to obtain reliable gas-oil relative permeability data. These two factors militate against the direct laboratory measurement of correct solution drive gas-oil relative permeability characteristics. Nevertheless, laboratory tests described in the following paragraphs have been made to show the effect of bubble formation on oil recovery efficiency. These tests actually allowed measurement of the amount of oil produced solely as a result of the formation and growth of gas bubbles in the storage pores of a non-uniform porosity limestone sample.

Two nearly identical tests were performed on a single reservoir sample. The main feature of each test was the execution of a solution gas drive after the initial establishment of a high gas saturation (the necessity for the gas saturation will be explained later). The two solution gas drives were performed at greatly different rates, so that in one test few, if any, bubbles would be formed, whereas in the other test, many bubbles would be formed.

In order to form essentially no bubbles during a depletion test, it is sufficient to maintain supersaturation at a low value, such as 15 psi or less. The amount of supersaturation which will exist in a core subjected to a given rate of pressure decline depends, of course, on how fast the dissolved gas can diffuse out into the connected gas phase. Since it was desired to use reasonable rates of pressure decline in the tests, it was therefore necessary first to establish a high gas saturation prior to the solution gas drive.

Figure 4 is an example of results of diffusion tests on a sample of non-uniform porosity limestone. Although these data were not actually obtained on the Reef sample, they serve as an excellent example of the characteristics of such rocks. As can be seen from Figure 4, at high gas saturations the maximum rate of pressure decline which can be maintained without exceeding a given degree of supersaturation increases rapidly with increasing gas saturation. A solution gas drive in which no bubbles are formed cannot, therefore, be carried out at reasonable laboratory rates unless a high gas saturation is first established.

A further reason for initially driving the cores to a high gas saturation was to insure that any oil produced during the subsequent depletion test could come only from pores not normally emptied during an external gas drive, i.e., from the storage pores. Actually, the solution drives were also followed by final external gas drives to recover any newly released oil which might have been held back by end effect during the depletion process.

The two nearly identical experiments were performed on a single sample of the previously mentioned Reef limestone. In each of the two tests, the sample was saturated with gas-free C_{10}-C_{12}. Following this, the initial external gas drive was applied with a pressure differential sufficiently high to overcome end effect. This drive was terminated at 57 percent pore space average gas saturation. After establishing the gas saturation, the core was pressured to 1000 psig with gas until the residual oil was substantially at equilibrium at this pressure. At this point the core was depressured at a controlled rate of pressure decline. At the end of the pressure depletion a final external gas drive was applied at the same pressure conditions as were used for the initial external drive.

The two series of experiments were identical except for the rate of pressure decline during the depletion process. The two rates used during the solution drives were 38 and 2100 psi per hour. The 38 psi per hour rate was chosen on the basis of a calculation which indicated that the degree of supersaturation attained at this rate would not exceed 15 psi, and thus no bubbles would form. The 2100 psi per hour rate was the maximum rate attainable. A special bubble formation calculation indicated that even at the existing high gas saturation (57 percent), many bubbles would be formed at this rate of pressure decline.

The results of these tests are given in Figure 5. The data are presented as the flowing gas-oil ratio for the external drives versus the oil recovery as percent pore space. The effect of bubble formation on oil recovery for this non-uniform porosity limestone sample can be measured by comparing the performance of the two final external gas drives. The shift to the right for the gas drive which followed the rapid rate of pressure decline shows the increase in oil recovery due to bubble formation. This increase is appreciable in spite of the initial high gas saturation. The gas drive following the slow rate of pressure decline shows no significant increase in oil recovery. Identical tests on a sandstone core sample (uniform porosity) showed no effect of bubble formation on oil recovery.

The significant difference between the limestone core tests, therefore, is the increased oil recovery resulting from the formation of a large number of bubbles during the 2100 psi per hour pressure decline solution gas drive. For the other case, where very few bubbles were formed the performance is a continuation of the normal external gas drive behavior. On the basis of the above results, there is reason to believe that similar behavior should be observed at lower gas saturations. This would mean that in the field, where a small number of bubbles are formed, the oil recovery performance under a solution gas drive might approach that predicted from the flow characteristics measured in the laboratory by an external gas drive.

B. LONG CORE TESTS

The preceding tests substantiate the theory concerning the role of bubble formation on the recovery of oil from non-uniform porosity limestones. However, a field begins its producing history with no gas saturation, and the previous tests began with a connected gas saturation initially much greater even than the final gas saturation in a depleted reservoir. This difference is believed to be irrelevant with respect to the conclusions already reached. On the other hand, the actual establishment of the initial flowing gas saturation in a reservoir is a complex process. To bridge this gap between field conditions and the tests described to this point, experiments have been made in which no initial gas saturation was present, and in which bubble formation rates approached those for reservoir conditions.

The first consideration in selecting the operating conditions for such a test was to decide on the minimum practical rate of pressure decline. Obviously, a rate of 0.1 to 1 psi per day was unsatisfactory from the time standpoint alone. A decline rate of 10 psi per day was selected. This value was not considered too high, and it probably represents the maximum rate under which a reservoir might be produced even for a short interval of time.

The selection of a 10 psi per day rate of pressure decline presented a real problem with regard to end effect. At such a low rate of decline the pressure drop across a core is usually negligible, and end effect renders gas-oil relative permeability data meaningless. However, by a special core design this difficulty could be obviated. By increasing the flow resistance of the system, it was possible to operate at higher differential pressures with the same rate of pressure decline. The increase in the flow resistance of the system was accomplished in two ways. First a practical maximum length of core was used; namely, six feet. Secondly, additional resistance without a change in important capillary characteristics was obtained by reducing the cross-sectional area of the downstream end of the core. Because it was impractical to obtain an oil field core of the desired size, an outcrop (Cordova shellstone), was selected for these tests. The manner in which the core was shaped has already been described.

An external gas drive and two solution gas drives at widely different rates of pressure decline were performed on this large core sample. The results of these tests are presented by Figures 6 through 8. Figure 6 shows for these three tests the relationship between the gas-oil relative permeability ratio, k_g/k_o, and the gas saturation in percent pore space. The divergence noted between the laboratory external and solution gas drives indicates that this rock has a non-uniform porosity.

The rates of pressure decline for the two solution gas drive runs were 10 psi per day and 230 psi per day. The reliability of the k_g/k_o data from the standpoint of end effect can be evaluated from the history of the pressure drop across the reduced section of the core and from gas-oil capillary pressure data. Capillary pressure characteristics indicated that end effect would be negligible as long as the pressure drop across the reduced section exceeded 1 psi. Figure 7 presents the pressure drop history for the 10 psi per day run and shows that the test was not detrimentally influenced by end effect. The amount of end effect was, of course, even less with the fast decline rate.

The results of the two individual solution gas drive tests show a difference in recovery efficiency. At pressure depletion, the 10 psi per day decline rate test resulted in an oil recovery of 22 percent pore space. This may be contrasted with the 36 percent recovery achieved in the test carried out at the higher rate. This 64 percent increase in oil recovery is attributed to an increase in the number of bubbles formed during the faster run.

Figure 8 shows the wide variation in supersaturation which existed for the two individual solution gas drive tests. A calculation of the number of bubbles formed indicates that at the fast rate of pressure decline test there were about 100 times more bubbles than at the slower rate. The effect which this increased number of bubbles had on the efficiency of oil recovery was not apparent until an average gas saturation of approximately 17 percent pore space was reached. Beyond this saturation the difference in oil displacement efficiency for the two tests increased as depicted by the position of the separate k_g/k_o curves.

The increased number of bubbles formed during the rapid decline test does not explain the relative positions of the two solution drive curves of Figure 6 in the range from 0 to 17 percent gas saturation. Their relative positions can, however, be explained by visualizing the variation in extent of the connected gas saturation as a function of time. Since the pressure is always lowest at the downstream end of the core, the gas phase develops to a greater extent and becomes connected first in this part of the system. The connected portion of the gas phase then progresses upstream. This will result in the measurement of higher k_g/k_o values at a given average gas saturation than would exist if the connected portion of the gas phase was distributed uniformly throughout the core. This result is also evident at low gas saturations as can be seen in Figures 1 and 2.

The differences in the depletion rates and the measured pressure drops across the system for the two runs of Figure 6 show that the above explanation is probably correct. For the test carried out with a pressure decline rate equal to 10 psi per day there was no measurable pressure drop (0.5 psi could have been detected) across the 4-1/2 inch diameter section, and a maximum pressure drop across the reduced section of 12 psi. For the fast rate of pressure decline the pressure drops were 4 to 6 psi and 220 psi, respectively. This indicates a definite possibility of progressive gas phase development during the fast pressure decline test. If the rate of progression of conductive gas saturation had been the same in the two tests, it can be reasoned that the measured relative permeability curve for the faster test would be to the right of the curve for the slower test throughout the entire range of gas saturation.

C. SIGNIFICANCE OF STUDY IN REGARD TO RESERVOIR PERFORMANCE

One objective of this study was to design a laboratory test which would give results applicable to the prediction of field solution gas drive performance. Figure 3 shows that the number of bubbles formed under field rates of pressure decline (0.1 to 1 psi/day) would be less than 100 bubbles per cubic foot of reservoir rock. The exact number of bubbles would depend upon the rock and the fluids involved. Nevertheless, the value is an order of magnitude less than the number of bubbles calculated to have been formed in the 10 psi per day test discussed above.

On this basis it may be concluded that the results obtained from the above test do not represent normal field solution gas drive performance. It may be concluded from the above tests, however, that a decrease in the rate of pressure decline (at least throughout the range investigated in the laboratory) results in a lower efficiency of oil displacement from non-uniform porosity limestones. It may be proposed again that a limiting value on reservoir performance would be that predicted by the laboratory external k_g/k_o relationship, with the possibility that the field solution drive behavior would be somewhat more efficient. At least, the use of the external gas drive characteristics should give a conservative estimate of reservoir solution drive behavior.

In laboratory solution gas drives on non-uniform porosity limestones, oil recovery efficiency is seen to be improved appreciably by increasing rates of pressure decline. In the field the usual rates of pressure decline are 100 to 10,000 times slower than are practical in the laboratory. It has yet to be established that significant differences in oil recoveries from non-uniform porosity limestone reservoirs can be realized by varying the pressure decline rate within this lower range.

However, we cannot discount the possibility that unconventional production practices might be devised to yield recoveries approaching those obtainable in the laboratory. To achieve this goal would require a pressure decline rate of at least several psi per day. Nevertheless, it is possible that such a rate would need to be maintained for only a few days. The reason is that at any particular rate of pressure decline, the majority of bubbles are formed in a short time. For example, at about 10 psi per day pressure decline rate nearly all the gas bubbles are formed within three days. Of course, the most suitable time to subject the reservoir to such a fast decline rate would be when the reservoir pressure is near the bubble point. At this stage of depletion the gas-oil ratio is low, permitting maximum liquid withdrawal rates. Since the productivity of the wells would control pressure decline, the use of deep penetrating fractures would probably be indicated. Although these latter conclusions must, at present, be classed as speculative, their significance is great enough to demand further study.

CONCLUSIONS

1. The laboratory solution gas drive oil recovery efficiency of non-uniform porosity limestones increases with an increase in the number of gas bubbles formed. Pressure decline rate is the important factor in establishing the number of gas bubbles formed.

2. No practical test is available to measure in the laboratory the solution gas drive oil recovery performance at field rates of pressure decline. It is postulated that laboratory external gas drive data can be used to make a conservative prediction of field solution gas drive performance for non-uniform porosity limestone reservoirs.

3. The concepts presented in this paper indicate the possibility that increased field oil recoveries may be obtained from non-uniform porosity limestones by rapidly reducing reservoir pressure for a short interval of time. It has yet to be established that significant improvements in oil recovery from such reservoirs can be realized by varying the pressure decline rate within limits possible in the field. However, the possibility that recovery may be increased in this manner warrants further study.

ACKNOWLEDGMENT

The authors wish to express their appreciation to Mr. Herman Teel for his assistance in gathering the data for this paper.

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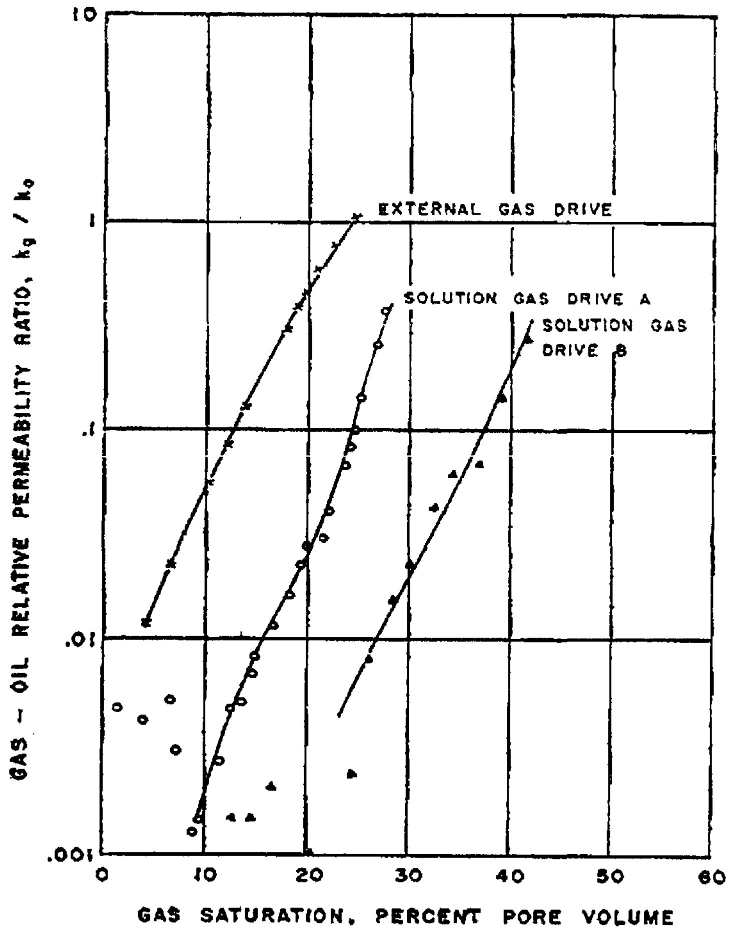


FIG. 1 - RELATIVE PERMEABILITY CHARACTERISTICS OF WEST TEXAS REEF LIMESTONE CORE.

Permeability = 21 mds.; Porosity = 20 percent
Curve A: Methane and C_{10}-C_{12}, bubble point pressure = 200 psig
Curve B: Nitrogen and C_{10}-C_{12}, bubble point pressure = 1000 psig.

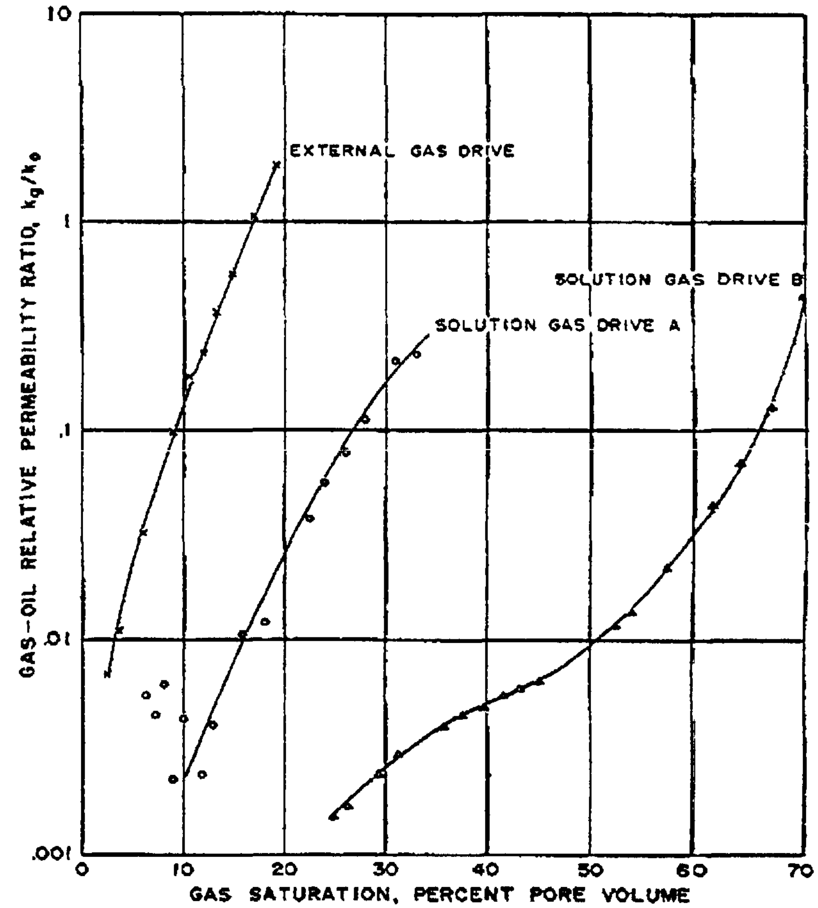


FIG. 2 - RELATIVE PERMEABILITY CHARACTERISTICS OF MIDCONTINENT LIMESTONE CORE.

Permeability = 1 mds.; Porosity = 30 percent
Curve A: Methane and C_{10}-C_{12}, bubble point pressure = 200 psig
Curve B: Methane and C_{10}-C_{12}, bubble point pressure = 1000 psig.

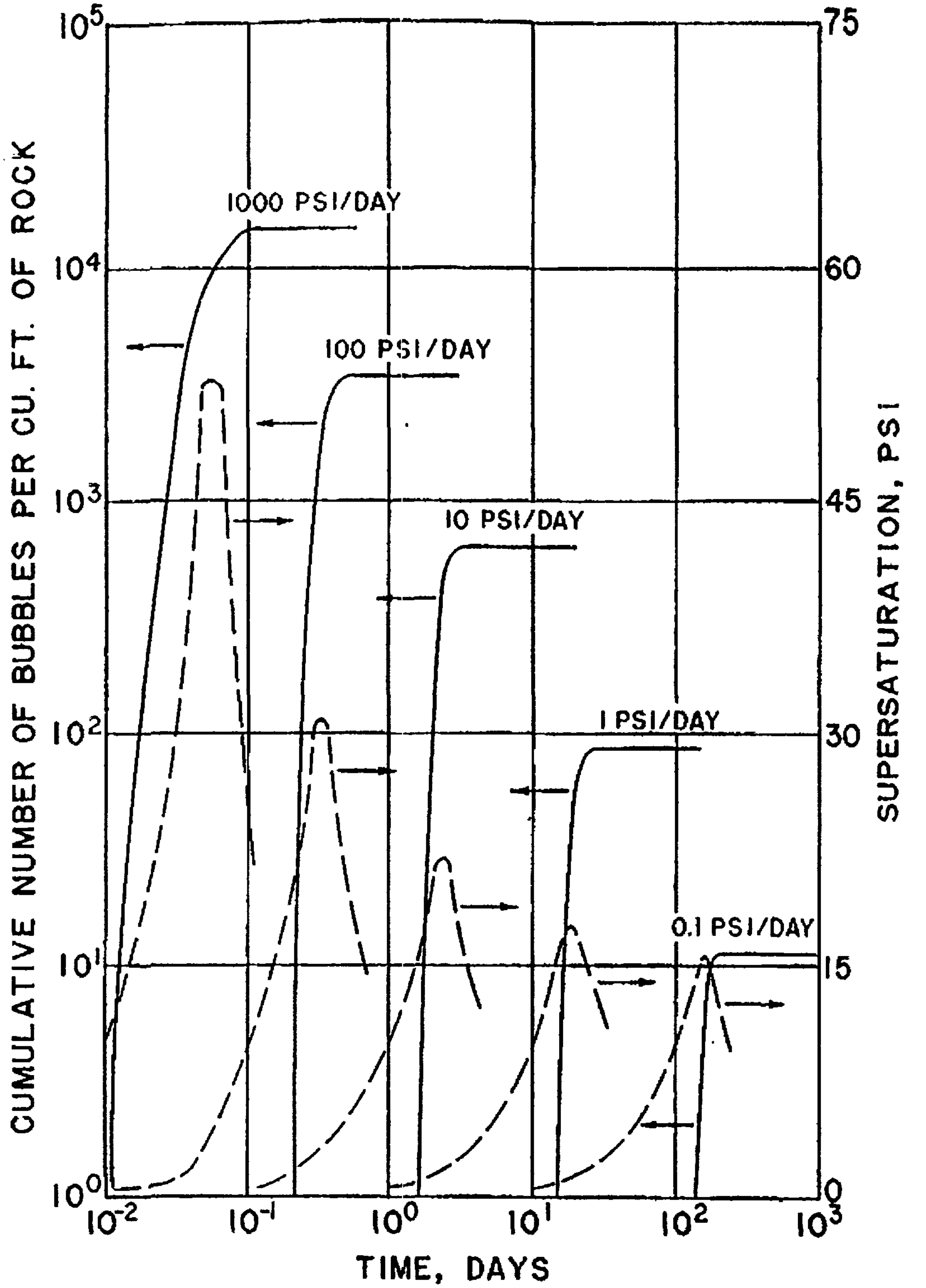


FIG. 3 - CALCULATED SUPERSATURATION AND BUBBLE FORMATION HISTORY WITH VARYING RATES OF PRESSURE DECLINE.

Values shown apply to a hypothetical system, however, the relative values apply to any system, e.g., a 10-fold increase in rate of pressure decline results in a 10-fold increase in the number of bubbles formed.

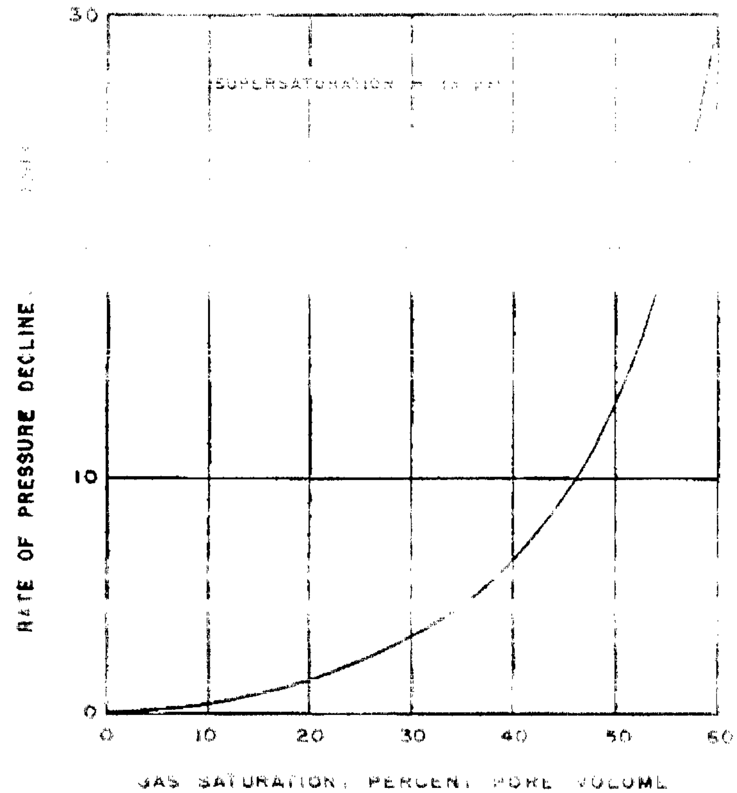
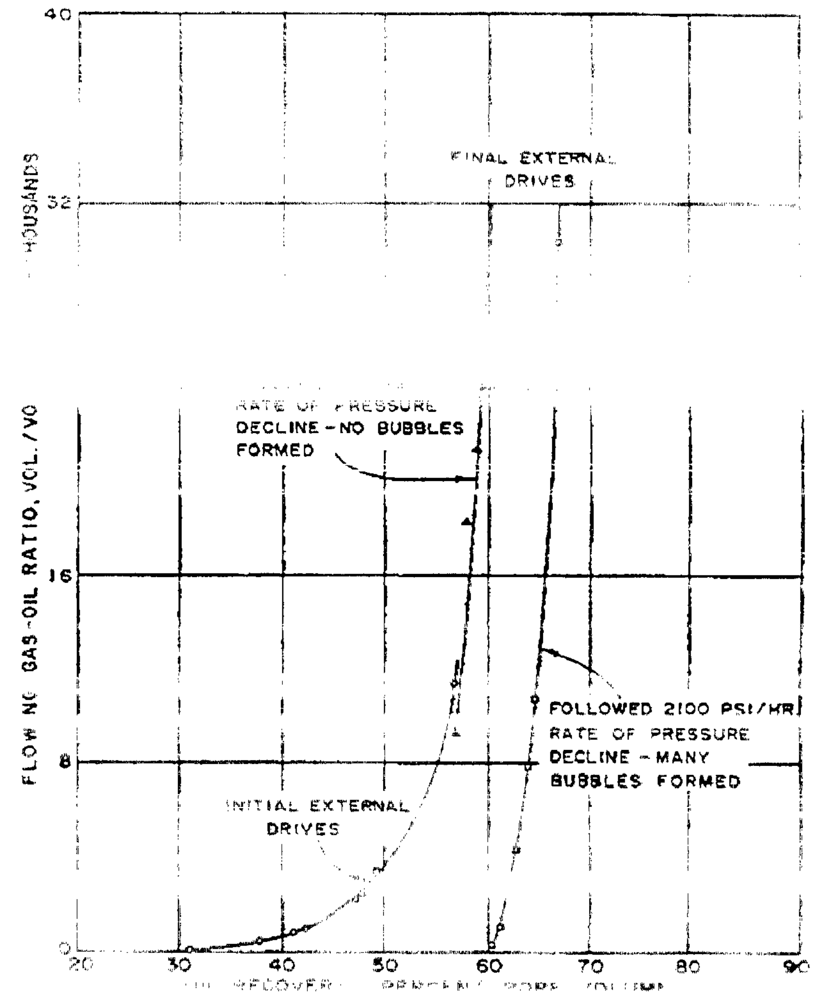


FIG. 4 - RELATIONSHIP BETWEEN PRESSURE DECLINE RATE AND GAS SATURATION WITHOUT BUBBLE FORMATION FOR CORDOVA SHELLSTONE.



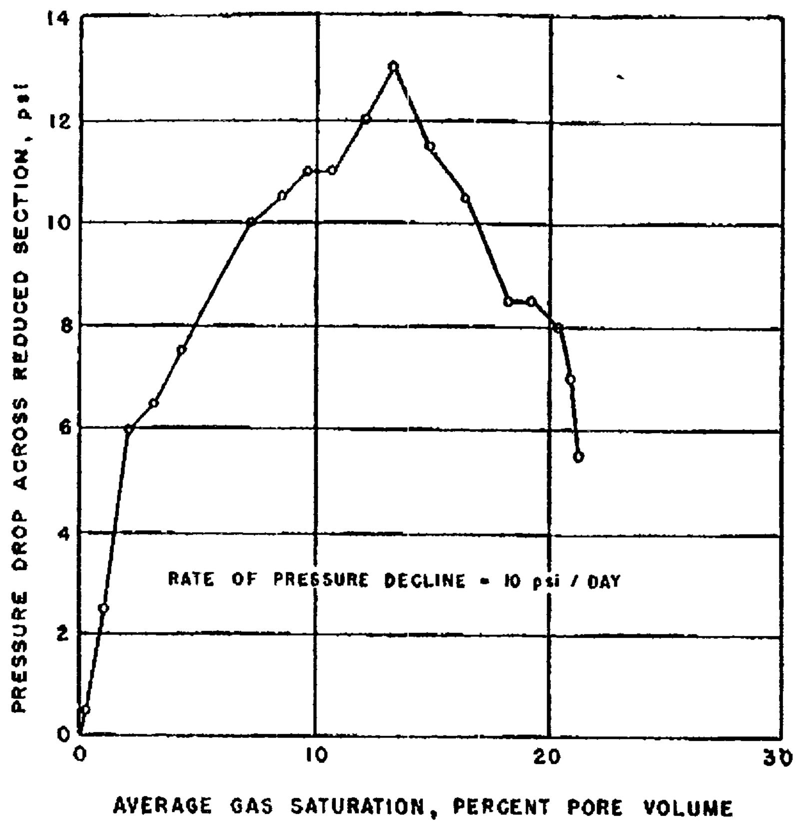


FIG. 7 - PRESSURE DROP PERFORMANCE ACROSS REDUCED SECTION OF CORDOVA SHELLSTONE.

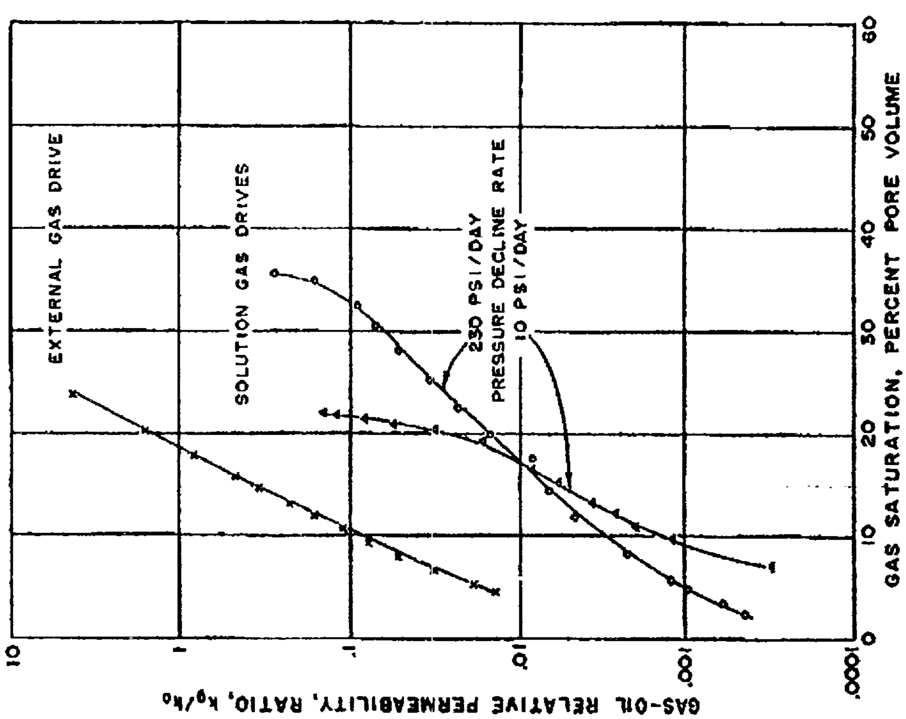


FIG. 6 - RELATIVE PERMEABILITY CHARACTERISTICS OF CORDOVA SHELLSTONE.

Permeability = 200 mds.; Porosity = 25 percent
Solution gas drives used a 200 psig bubble point solution of methane and $C_{10}-C_{12}$.

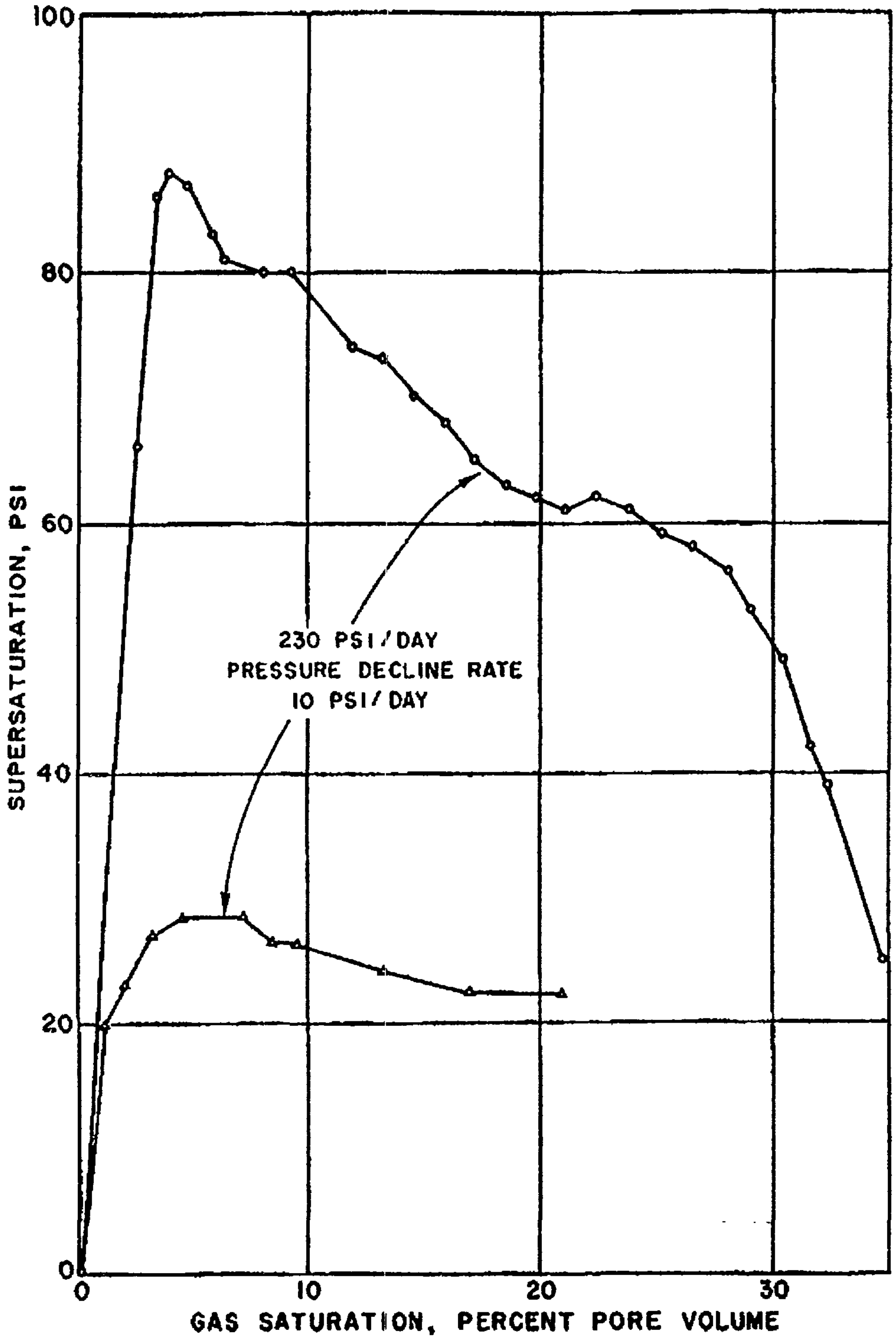


FIG. 8 - LABORATORY SUPERSATURATION PERFORMANCE OF CORDOVA SHELLSTONE.

Initial bubble point pressure in each test was 200 psig using a solution of methane and C_{10}-C_{12}