11th
TECHNICAL
CONFERENCE
ON PETROLEUM
PRODUCTION

In Co-operation With
The Pennsylvania Grade
Crude Oil Association

October 31 - November 1, 1947
STATE COLLEGE, PENNSYLVANIA

Contents

Foreword

THE PENNSYLVANIA STATE COLLEGE has three functions in the discharge of its obligations to the Commonwealth: resident instruction, extension and correspondence instruction, and research. The Eleventh Technical Conference on Petroleum Production, held in the School of Mineral Industries on October 31 and November 1, 1947, represents one means whereby the College accomplishes some of the purposes for which it was established.

Over one hundred representatives of the petroleum industry met with members of the staff of the Mineral Industries Experiment Station to hear reports on the extensive research in progress on petroleum production in general and secondary recovery in particular. These reports were followed by general discussion of the work in progress and of petroleum production problems. An opportunity was also afforded to the members of the conference to visit the various laboratories of the School of Mineral Industries and to discuss matters of mutual interest with the staff.

The importance of such a conference cannot be overestimated, since the opportunity it provides for exchange of ideas benefits the scientists and technologists at the School as well as the practical oil producers.

This bulletin has been prepared as the Proceedings of the Conference. The papers contained in it indicate the broad and coordinated effort being made by the Divisions of Geology, Mineralogy, Geophysics, and Petroleum and Natural Gas to advance the art of finding and recovering petroleum. The papers by Pirson, Swartz, and Krynine represent progress reports on an expanded program seeking a better delineation of the edge of the oil fields in Pennsylvania and a better understanding of the reservoir rock. This has been made possible through the support of the Commonwealth of Pennsylvania, the Pennsylvania Grade Crude Oil Association, and

the South Penn Oil Company, as well as through the co-operation of the United States Geological Survey and of many producers in Pennsylvania. The Mineral Industries Experiment Station gratefully acknowledges the assistance it has received from these agencies.

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Selective Plugging With Smoke

by

R. F. NIELSEN
DIVISION OF PETROLEUM AND NATURAL GAS

The possibility that smokes or "aerosols" might serve as selective plugging agents in air-gas drive just as "aquasols" have served in water flooding was suggested by Yuster and Calhoun [2] in a paper dealing with the general status of selective plugging. A report of experimental work on the use of smokes for selective plugging was given at the Ninth Annual Secondary Recovery Conference [1].

At that time three general methods of preparing smokes were mentioned: 1) mechanical dispersion of a fine powder in an air or gas stream; 2) quenching of the vapors of a volatile solid by a cold gas stream; 3) chemical reactions, such as the burning of a material or the combination of two gases such as ammonia and hydrogen chloride.

Plugging experiments involving the first two methods were described. In Method 1, the smoke or dust was passed slowly upward to allow settling of the larger particles. The resulting smoke, however, gave little or no plugging in laboratory experiments.

Various modifications of Method 2, the quenching of a vapor, were also described. These were found to give good selective plugging in the laboratory. Difficulties arose in field trials when it was found impossible to supply enough cooling of the vapors to obtain a large quantity of dry and stable smoke. The smoke pot described in that report has since been modified to provide thermally insulating rings between the top and bottom sections and to allow throttling of carbon dioxide directly from a cylinder into the top section. Even with these modifications the resulting smoke was either not dry or too thin to be effective.

The present paper is a report of experimental work done since that previously described. This work involves Method 3, chemical reactions, and also a fourth method, atomization of a solution of a solid in a volatile solvent, supplying sufficient air or gas to vaporize the solvent.

Among the chemical smokes tried were military smoke grenades, furnished from the army surplus. These were set off in an iron pot connected in the injection air or gas line. Both the white smokes, consisting mainly of zinc dust and hexachloroethane, and the colored smokes, consisting, except for the dyestuff, mainly of inorganic materials, were tried. The white grenades did not behave normally under confinement, and after they had been burning smoothly for a short while, a sudden reaction took place with a surge of pressure, resulting in large quantities of partially decomposed hexachloroethane being deposited on the pipes. The colored grenades behaved normally, but there was no appreciable plugging action although the cores were covered with a colored powder. There was also considerable deposition of the colored powder on the inside of the pipe.

The chemical smoke which has shown the most promise so far is ammonium chloride smoke. This has been made in three different ways. The first, which is not strictly a chemical method, consisted in quenching the vapors from the hot salt in a stream of cold air or gas. In the second method a stream of dry gas containing ammonia was continuously mixed with one containing hydrogen chloride. In the third method alternate slugs of dry air or gas containing ammonia and hydrogen chloride were run into the tubing, with a slug of dry air or gas between each slug of the reacting gases. With this last procedure there should be very little smoke formed in the pipe, but it would be formed opposite the sand face. In the laboratory the results by the three methods were about the same, fairly good plugging and selectivity being obtained[1].

Because of the tendency of this smoke to deposit on pipes, only the third method was tried in the field. Figure 1 shows the hook-up used. The amounts of the various gases were controlled

FIGURE I

ARRANGEMENT FOR ALTERNATE INJECTION OF AMMONIA AND HYDROGEN CHLORIDE INTO WELL
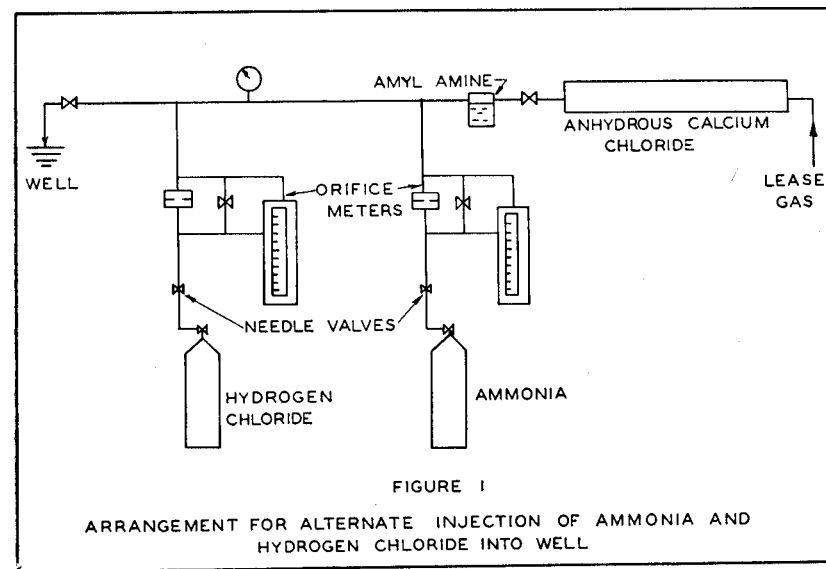
manually by needle valves with the aid of small orifice meters. About a minute elapsed between each change of mixture. To keep corrosion at a minimum, the gas was passed over amylamine, and the ammonia was always run in slightly in chemical excess over the hydrogen chloride. Since hydrogen chloride forms a mist with gas containing water vapor, the latter was removed by passing the lease gas through a piece of 4-inch pipe containing anhydrous calcium chloride.

Table 1 shows the results of the ammonium chloride injection, as determined by individual orifice meter readings. These show a definite reduction in intake rates. Figure 2 is a copy of the injectivity tests made by the Bureau of Mines Field Office in Franklin, Pa. These also show a definite reduction in intake rate, but it is seen that the plugging action was not permanent; that is, 21 days after the treatment there is some gain in injectivity and six months later the well is taking air as fast as before treatment. The ammonium chloride may have dissolved or may have been swept away mechanically. From the solubility and vapor pressure lowering of
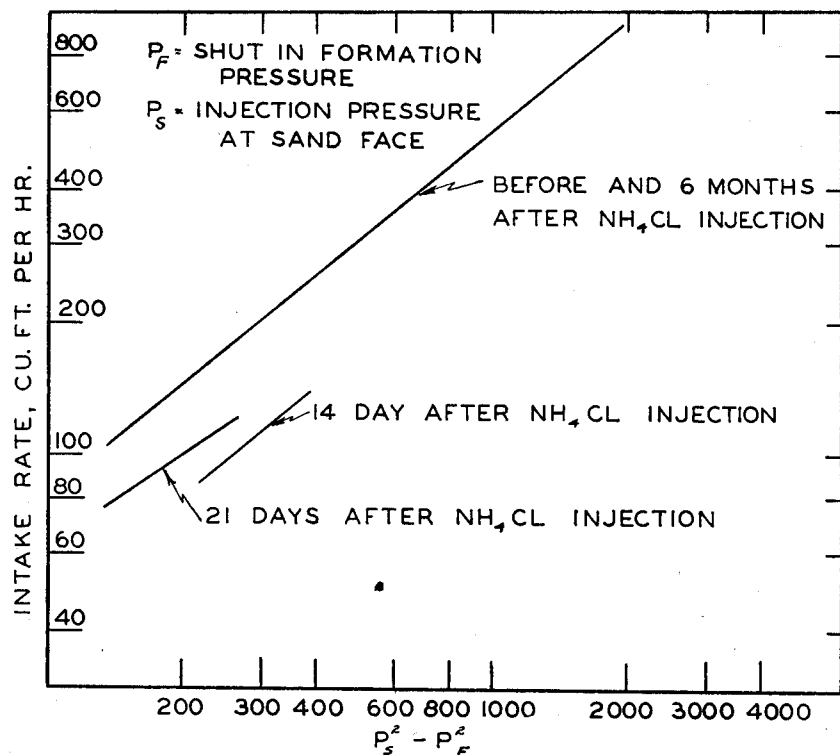
FIGURE 2

EFFECT OF NH₄CL SMOKE ON INJECTIVITY OF WELL
(BY PERMISSION OF BUREAU OF MINES)

ammonium chloride in water, it would pick up moisture from the injected gas if the gas were more than 70 per cent saturated at the pressure and temperature of the sand face. Since in this particular well the gas was throttled down a great deal from line pressure, it seems unlikely that the salt would pick up moisture from the gas except on a very warm day.

The preparation of ammonium chloride smoke by the above method had the disadvantages of being somewhat involved and of using corrosive chemicals.

TABLE 1

EFFECT OF AMMONIUM CHLORIDE SMOKE ON GAS INTAKE RATES

Date	Pressure psi gauge	Injection Rate C.F.D.	Conditions
September 18. 1946	19	7680	Before NH₄Cl Smoke
December 11, 1946	15	6000	Before NH₄Cl Smoke
December 11, 1946	15	2950	2/3 of Cylinders Used
December 12, 1946	15	4100	Next day before continuing
December 12, 1946	15	2800	All Chemicals In
December 19, 1946	14.5	2640	
December 26, 1946	17	3120	
December 26, 1946	15	2160	
January 2, 1947	13.5	1920	
January 2, 1947	15	2640	
July 8, 1947	15	6000	

The use of alternate slugs of reacting gases (separated by slugs of dry air) was also tried in the laboratory with certain chlorides which form a smoke by reaction of the vapors with moist air. The compounds tried were antimony pentachloride, tin tetrachloride, and titanium tetrachloride. A dry air stream passed over one of these liquids was alternated with an air steam passed over aqueous ammonia of such concentration as would give ammonia and water vapor in the proper ratio for chemical reaction. No appreciable plugging action was obtained with any of these three compounds, although the smoke appeared quite dense and a considerable amount of powder was deposited on the cores.

The fourth method, atomization of a solution of a solid in a volatile solvent, was tried both in the laboratory and in the field. The hook-up is shown in Figure 3. The nozzle was Spraying Systems Company's JNP-11 pneumatic type, requiring a pressure differential of about 20 to 30 psi for operation. In the laboratory the spray was directed into a 55-gallon drum, instead of the larger tank shown in the figure. The solutions used were paraffin in naphtha, paraffin in carbon tetrachloride, paraffin in liquid butane, and "Vinsol" in acetone. "Vinsol," a rosin derivative, was tried at the suggestion of the personnel of the Hercules Powder Company. The solutions
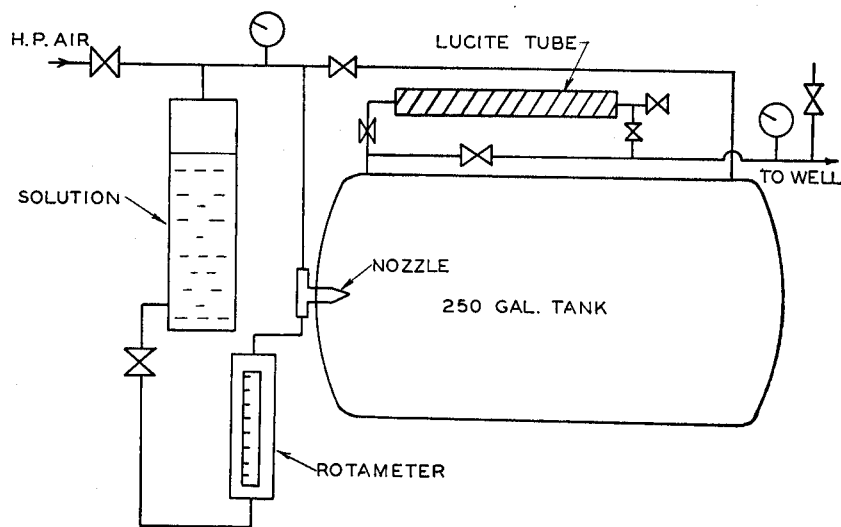
FIGURE 3
ARRANGEMENT FOR INJECTION OF SMOKE MADE BY ATOMIZING A
SOLUTION OF A SOLID IN A VOLATILE SOLVENT

generally contained from 10 to 20 per cent of the solid by weight, depending on solubility. It is necessary, of course, that the air or gas stream vaporize all the solvent, in order that the smoke may be dry. To do this usually more air was required than that supplied to the nozzle for atomization, hence the additional air line to the drum. The amounts of air theoretically required at various pressures and temperatures were calculated from thermal vapor pressure data, and at least a 50 per cent margin over the calculated air-liquid ratio was allowed. The purpose of the small Rotameter was to measure liquid rates, air rates being determined in the laboratory by a displacement meter and in the field by the known injectivity of the well.

A core holder large enough to hold six or eight radial cores of varying permeabilities was used in the laboratory experiments. Since some of the solutions were inflammable, nitrogen was used instead of air. Back pressure was provided by having the outlet under

about five feet of water. Fairly good selective plugging was obtained with all solutions in laboratory tests. The results are shown in Table 2. The smoke from the butane solution was not as fine as that from the other solutions and showed a little more tendency to stick to pipes. This may have been because the pressure in the drum was below the vapor pressure of butane, causing too rapid evaporation.

TABLE 2

PLUGGING OF LABORATORY CORES BY SMOKES MADE BY ATOMIZATION OF A SOLUTION OF A SOLID IN A VOLATILE SOLVENT

Solution	Perm. before Plugging md.	% Reduction
Paraffin in Naptha	260	41
" " "	170	72
" " "	65	62
" " "	15	5
Paraffin in Butane	310	44
" " "	260	71
" " "	220	41
" " "	160	66
" " "	105	28
" " "	15	9
"Vinsol" in Acetone	200	75
" " "	145	63
" " "	100	40
" " "	55	65
" " "	45	50
" " "	15	8

In the field tests attempts were made at first to employ the lease gas, but the high solubility of hydrocarbon gases in the solvents interfered both with proper atomization and with evaporation. Nitrogen was subsequently used, and finally air. The latter is, of course, hazardous with inflammable liquids, and proper precautions must be taken.

The well was the same as had been treated previously with ammonium chloride. It was taking about 6000 cu ft per day at 19 lb gauge. It is estimated that about 5 lbs of paraffin and 5 lbs of

Vinsol were sent down the well. About two months elapsed between the two treatments. Neither had any measurable effect on the gas intake rate. This result was somewhat disappointing, both in view of the laboratory data and inasmuch as the smoke, especially the Vinsol smoke, seemed to be perfectly dry and stable and of very small particle size. Since the question naturally arose as to whether the smoke actually got down the well, 850 feet of one-inch pipe was strung out on the ground. The Vinsol smoke was sent through it at about the same rate as it was sent down the well. As near as the eye could tell, the quantity of smoke was about the same at the end of the string of pipe as when bled off at the source. Also, practically no deposition could be observed on the pipe, although there was some at fittings and valves.

The results of these field tests cannot readily be accounted for if, as the test with the string of pipe indicates, the smoke reached the sand face. If there had been some small lowering of the intake rate, one would put the blame on an insufficient quantity of material. It is known that the average smoke particle size increases with time due to agglomeration. This may be one explanation for the difference between laboratory and field results when smoke is sent down the tubing. A possible remedy for this would be to inject at a greatly increased pressure in order to cut down the time of travel. The glistening appearance of the laboratory cores after plugging and the extremely small amount of material required for plugging indicate that the particle size was very small in the laboratory experiments. There is, of course, always the possibility that the particular well treated was not a fair test of the method. Perhaps a test on another well and with a higher injection rate would prove enlightening.

SUMMARY

1. The various methods of smoke generation were reviewed and the laboratory and field tests involving these methods were described.

2. While a number of methods gave fair selective plugging

in the laboratory, those necessitating passing the smoke down the tubing have not been successful in the field so far.

3. A method in which the smoke was formed at the sand face by alternate injection of ammonia and hydrogen chloride gave a reduction of about 50 per cent in gas intake rate, but the plug was not permanent.

REFERENCES

1. Nielsen, R. F., and Yuster, S. T., Selective Plugging by Smokes in Air-Gas Drives, *Proceedings of the Ninth Technical Conference on Petroleum Production, Mineral Ind., Exp. Sta. Bull.* No. 41, pp. 21-30

2. Yuster, S. T., and Calhoun, J. C., The Selective Plugging of Oil Sands, *Producers Monthly 8*, No. 7, 31 (May 1944)

Relative Permeability Studies

by

J. H. HENDERSON AND S. T. YUSTER
DIVISION OF PETROLEUM AND NATURAL GAS

A method of measuring relative permeabilities on small core samples was recently reported by this laboratory [4]. As a result, a number of inquiries have arisen regarding the experimental apparatus and the technique used. The purpose of this paper is to present briefly some theoretical implications of the method, to elaborate on the apparatus and the experimental procedure, and to present typical data collected to date.

INTRODUCTION

Various phases of the theory of petroleum production require data on relative permeability of the porous media to the flowing fluids. Comparatively simple laboratory techniques for obtaining this information on small core samples have not been available until recently. Moreover, most published data have been gathered using large core systems which often were not even oil sands. The method described herein uses sand samples obtainable by conventional coring methods and provides a wide range of conditions under which flow data may be gathered.

For the sake of clarity, certain terms used are defined as follows, using the nomenclature designated by A.P.I. Code No. 27 [1]. *Permeability* of a core will be understood to be determined with a single, homogeneous, liquid phase present. *Effective permeability* will refer to the permeability of the core to one phase when two phases are present. *Relative permeability* as applied to one fluid phase, at any definite percentage saturation of that phase, is the ratio of the effec-

tive permeability to the permeability and is given by the equation:

$$K_{ro\,(\%o,\%w)} = \frac{K_{o\,(\%o,\%w)}}{K}$$

Systems involving three-phase equilibrium are excluded from discussion in this work. Similarly, it is not within the scope of the report to deal extensively with the application of relative permeabilities once they are obtained. It will suffice to point out that in virtually every prediction of reservoir production behavior, some estimate must be made of the fractional permeability of the porous medium to the fluids present. Heretofore such prediction has been based largely on the air permeability of core samples in conjunction with often rather sketchy knowledge of past field performance. If reliable experimental relative permeability curves can be provided which are characteristic of a field or sector of a field, prediction of reservoir behavior will rest on a much firmer foundation than it has in the past.

The information which may be derived from the effective permeabilities at the equilibrium saturations is particularly interesting to those operating secondary recovery projects using a water drive. The data from a relative permeability test include the residual oil saturation expected of an efficient water drive, and the irreducible water saturation, which should be an indication of the original connate water saturation. These data in conjunction with good core analyses should permit accurate prediction of water intake and oil production rates. In addition, the method of measurement promises to provide more information on the flow behavior of fluids at or near the flood front, where essentially 100 per cent liquid saturation may be safely assumed. There is also the possibility that with the collection of data on many sands whose field performance under water drive is known, a reliable criterion of field responsiveness to water flooding may be developed.

THEORETICAL DISCUSSION

Briefly, the concept of relative permeability has given rise to

two major assumptions regarding multiphase simultaneous flow through porous bodies. These are the flow of a single phase through a given capillary of a series of capillaries at any one time and the simultaneous flow of two immiscible fluids through one capillary channel.

If the first condition holds and the system behaves as a bundle of parallel, disconnected capillaries, the fluid with which each is filled will depend upon the interfacial tension of the two fluids present, the diameters of the capillaries, and the preferential wettability of the surfaces for the fluids involved. Then it might be expected, as pointed out by Leverett [2], that the relative permeability curves will be straight lines, 45-degree diagonals on the conventional relative permeability plot of K_r vs S. The fact that the relative permeability curves for actual sands do not follow such a pattern is attributed to the action of interfacial forces active in the interstices of the sand.

In this connection it is interesting to note the work of Martinelli, Putnam, and Lockhart [3] who have published relative permeability curves for gas-liquid vicious flow in a single glass capillary. In this case it might be expected that the K_r curves would be 45-degree diagonals since there are no interstices to sidetrack any portion of the liquid and thus interfere with flow. Instead, the curves resemble the conventional curves presented by Wycoff and Botset [6] for consolidated and unconsolidated sands. Here, then, is a suggestion that placing the sole responsibility for the low effective permeability of a sand containing two immiscible phases on the trapping of a portion of fluid in the interstices may not be completely justified.

To return to the question of the flow picture, the second possible mechanism is that simultaneous flow of two immiscible fluids occurs in a single capillary. This, of course, can occur in two primary ways; i.e., flow of both fluids in parallel and perhaps annular paths, or some form of slug flow. The latter is virtually excluded because of the difficulty of initiating this type of flow by artificial means. The former is difficult to visualize as occurring

to any great extent in a natural sandstone, particularly of the consolidated type having very small interconnected pores.

A flow picture more compatible with our present knowledge of fluid behavior would be a combination of the two described above, with the former playing the major role. It is this type of flow pattern that the relative permeability apparatus is believed to provide.

For example, visualize an oil and water mixture under a given pressure in contact with the face of a water-wet sand. It seems logical that the water will penetrate the pores of the sand under a driving head of the applied pressure plus the capillary pressure of the sand. The oil will penetrate those pores whose openings at the sand face are of sufficient diameter to have a displacement pressure less than the applied pressure on the oil phase. Here, then, is a condition fulfilling the restrictions of the first possibility cited above; flow of the non-wetting phase in those capillaries of sufficient diameter to permit its entry, and simultaneous flow of the wetting phase in those capillaries of smaller diameter.

If this picture is projected a short distance into the body of the sand, could not a combination of the two be possible, with some of the capillaries which at the fluid source selectively permitted the flow of oil here discharging into capillaries containing brine, droplets of oil, or perhaps even a small stream of oil?
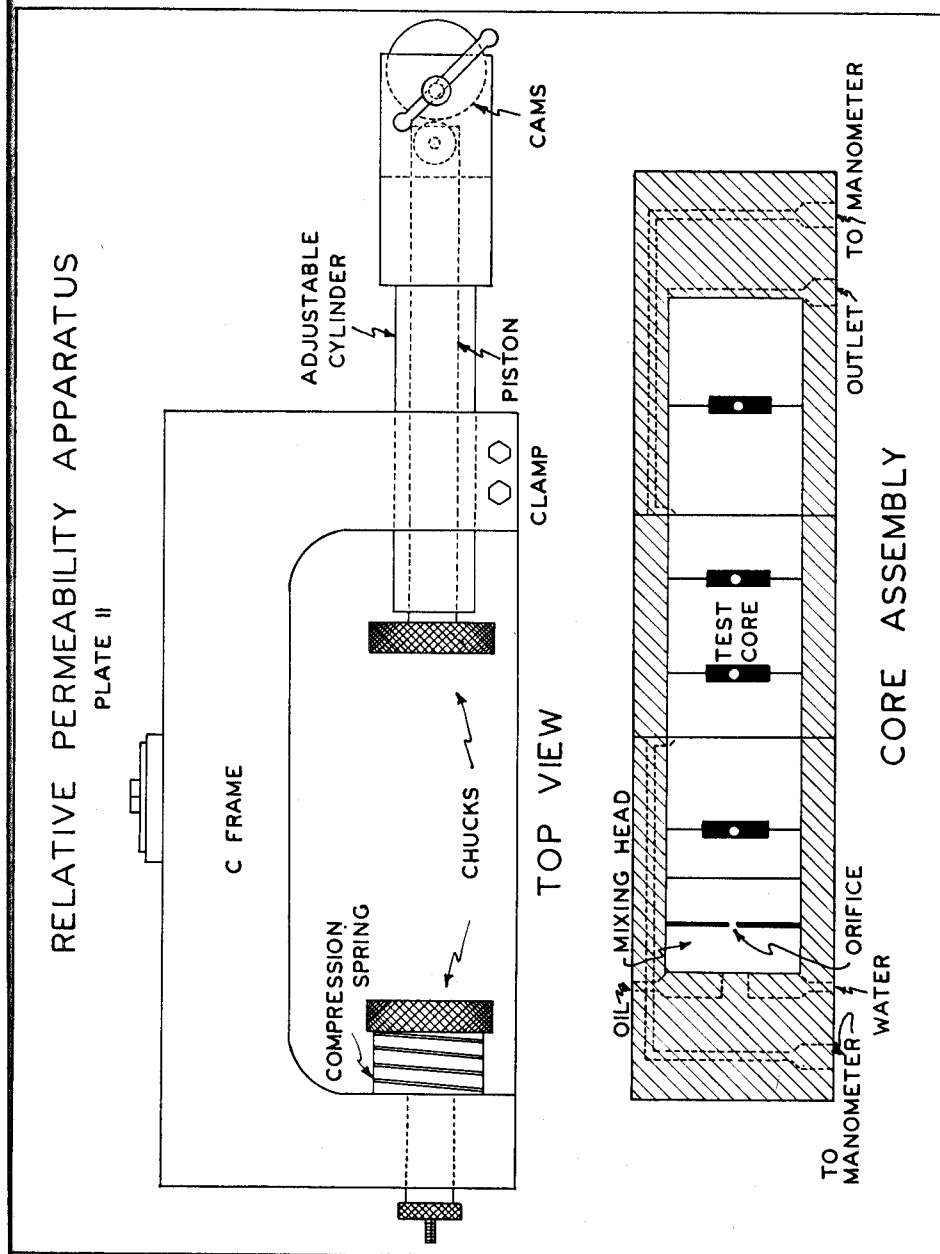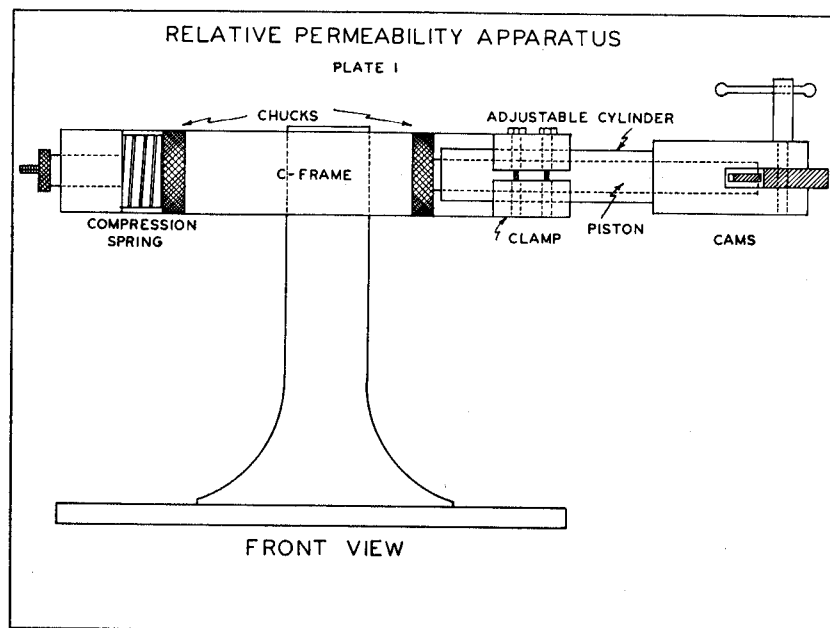
Similarly, it can be visualized that a capillary which, although permitting the entry of oil will not permit its flow past a point at which the diameter of the pore has diminished to such an extent that the applied pressure on the oil phase will not exceed the pressure drop across the brine-oil interface at the construction.

Any number of circumstances can be suggested as occurring within a nonhomogeneous porous medium. The above were cited only to emphasize the complexity of the physical analysis which will be necessary in any attempt to explain thoroughly the result of relative permeability measurements.

APPARATUS

The equipment used in the measurement of relative permeability meets three primary objectives: 1) It makes possible the use of small, consolidated core samples obtained by conventional coring methods. 2) Simultaneous flow of two fluids in various ratios may be maintained. 3) Necessary measurements of pressure drop, flow rates, and saturations are possible. In addition, and perhaps of equal importance, means are provided for determining the existence of steady-state conditions, eliminating the end effect, and providing for an even distribution of the multiphase complex throughout the core cross section.

Plates I, II, and III show in some detail the apparatus used. Plate I is a front view of the C-clamp used to hold the three core sections used. Plate II is a top view of the C-clamp and an enlarged view of the three core sections in the respective positions they occupy

RELATIVE PERMEABILITY APPARATUS
PLATE I

FRONT VIEW

RELATIVE PERMEABILITY APPARATUS
PLATE II

TOP VIEW

CORE ASSEMBLY

during test. Plate III is a diagram of the reservoir system from which the test fluids are injected into the core assembly.

Exclusive of the clamping device, the over-all picture of the apparatus is this: A reservoir system injects controlled ratios of test fluids into the mixing head of the core assembly, where they are evenly distributed through a section of the same sand as that being tested. The outlet face of the mixing head section is in intimate contact with the inlet face of the core section upon which permeability determinations are to be made. The outlet face of the test section in turn is in intimate contact with the face of the outflow section, also composed of sand from the same core sample.

The clamping device and the reservoir system need no explanation to supplement the diagrams. Embodied in the core assembly, however, are three features which have prompted consider-
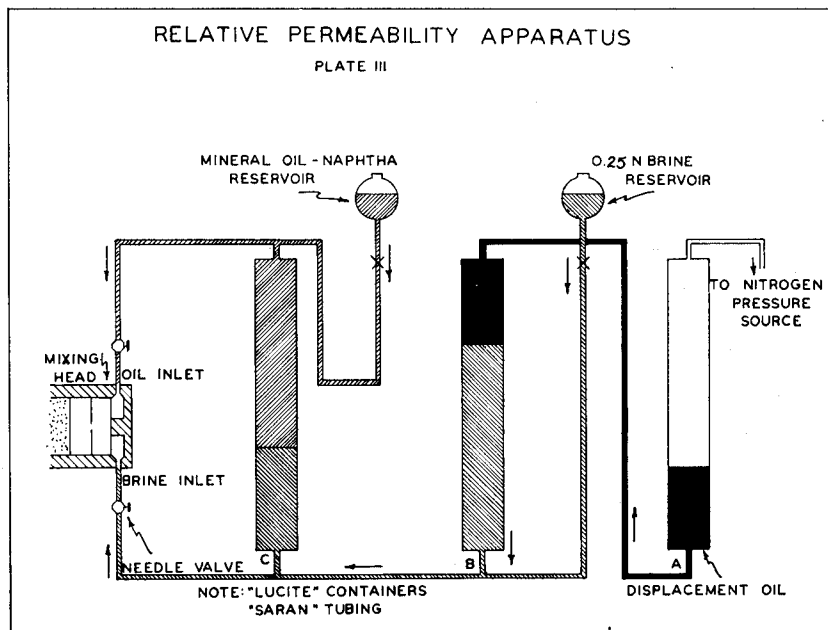
RELATIVE PERMEABILITY APPARATUS

PLATE III

NOTE:"LUCITE" CONTAINERS
"SARAN" TUBING

able inquiry. These are the mixing head assembly, the sand face contact with the Lucite-Lucite seal, and the method of measuring pressure-drop across the core.

Before discussing these topics in detail it may be well to point out the conditions to which the cores are subjected during the mounting procedure. All three sections of the core assembly are mounted in Lucite* by compression molding in a 1¼-inch diameter clyindrical mold. It has been found feasible to mount these cores using a pressure of 1500 psi and a temperature of 100° C. This has permitted mounting the most friable of the Bradford sands which heretofore have failed in compression under the higher pressures formerly used. No appreciable penetration of the Lucite occurs. The inlet chambers, shown in the diagram of the mixing head, and the outlet chamber were originally obtained by mounting a magnesium disc in the Lucite and subsequently dissolving it out with dilute acetic acid. In place of the magnesium, small discs of compressed salt are now used which are easily dissolved out with fresh water.

The mixing head in which the simultaneous flow of two fluids through the sand is established is shown in some detail in Plate II. The essential elements are the inlet chambers, the two synthetic sandstone discs separated by foil containing a 1/16-inch orifice, and the short section of the same sand as the test core. With this arrangement it has been possible to provide an even distribution of the two phases as they emerge from the mixing-head assembly and flow into the test core.

In the measurement of relative permeability on small core samples three major stumbling blocks occur: 1) assurance that the saturation is the same throughout the test core; 2) determination of the saturation of the test section after equilibrium conditions have been established; 3) measurement of the pressure gradient across the core due to the flow of the fluid.

The core assembly is designed to give an even saturation distribution throughout the test section with no end effects which might interfere with the rate of fluid flow. To accomplish this the core

sections are so prepared that they may be forced into such intimate contact with each other that the surface forces of the fluids will maintain a homogeneous saturation distribution from one core section to the adjacent section. There must be no pressure discontinuity in either phase due to the break in the sand body. In order to do this the cores are machined in the following manner: The sand face is first ground to a flat surface with a tool grinding attachment on a machine lathe, and the Lucite sheath is then machined until it protrudes past the sand face 0.00050 inches. Each of the four exposed sand faces is treated in this manner. Thus, to allow the sand surfaces to be in absolute contact, each pair of Lucite ends must compress a total of 0.0010 inches when placed under the compressive stress in the C-clamp. In addition to placing the sand surfaces in intimate contact, this method has provided a Lucite-Lucite seal which has proved leak proof under working pressures up to 45 psi.

The ideal apparatus would permit the accurate determination of spot saturations throughout the test section at any instant during a flooding test, without disturbing any portion of the apparatus. As an approach to this condition it was originally hoped that a method of measuring the resistance of the test fluids to the flow of an electric current would provide such a measure of core saturation. Wycoff and Botset [6] and Leverett [2] used a similar method of saturation determinations in their early work on relative permeability, using a calibration curve constructed from weight balance saturation determinations of a small sample of sand, independent of the sand body upon which flow tests were conducted. Unfortunately, this conductivity method of saturation determination did not prove feasible in the work on actual reservoir sands, as will be pointed out later. The actual saturations were determined by weighing the test section of core on an analytical balance. As is evident from a study of Plate II, the test section of the core may be removed from the system almost instantaneously by simply releasing the clamping device. This permits the core to be removed, weighed, and returned to the flow stream in a very short time.

The measurement of the pressure gradient across the core section has been accomplished in the following manner: A study of Plate 11 shows channels through the Lucite leading to the machined faces of the end core sections. Across these openings in the core mount a mercury manometer is connected using capillary tubing, and with water over the mercury transmitting the pressure fluctuations from the core assembly to the mercury column. Pressure pickup is assured at the core end of the leads by the following method: After the sand face has been ground, as described previously, a scratch is made around the circumference of the sand body adjacent to the Lucite sheath. This assures fluid continuity and takes care of any possible Lucite penetration that may block off the manometer lead from the fluids flowing through the sand body. A small channel cut in the machined Lucite surface of each end section connects this circumferential scratch with the manometer lead.

Much discussion has revolved around this method of pressure measurement because of its failure to employ diaphragms containing 100 per cent saturation of a given phase. Pressure-drop measurements using saturated porous diaphragms are, of course, intended to measure the pressure drop in one phase only. Presumably the advantage in measuring the pressure drop in each of the phases present is that it relieves the ambiguity in the present method of calculation, in which the same pressure drop across the core is used in the calculation of both the permeability to oil and the permeability to water.

To state that the pressure drop in the two phases is unequal, *assuming the medium to be homogeneous,* is tantamount to stating that the saturation ratio of the two phases varies from the inlet end to the outlet with the nonwetting phase being at its highest saturation at the inlet end of the test section and at its lowest at the outlet end. If the pressure drop in each phase is different, then perhaps a major requirement of a reliable apparatus has not been attained, which is that of homogeneous saturation distribution throughout the sand body. In the case of the apparatus described,

assuming the sand face contact serves the intended purpose of preventing a pressure discontinuity in a given phase across the break, then the only saturation gradient which occurs through a homogeneous core will be one from inlet to outlet due to the pressure drop across the core creating flow. That is, the nonwetting phase at the inlet end of the core, because of the higher absolute pressures existing there, may occupy pores of smaller size than at any point downstream, simply from a consideration of interfacial tensions and capillary radii.

It is difficult to visualize how a homogeneous saturation distribution can be obtained in a small core sample if on various points on the sand surface an arbitrary 100 per cent saturation of a given phase is imposed by the use of selectively-wet porous diaphragms. In a small core sample it is almost mandatory that these diaphragms occupy an appreciable proportion of the core surface. In fact, they often are placed on the face of the sand body through which flow must occur, where they certainly impose an artificial saturation distribution on the pore structure.

With the present setup, the likelihood of a discontinuity of saturation distribution due to the pressure taps is believed to be minimized. Contact of the manometer leads with the fluid in the core is through a very small cross section of free liquid. The manometer system involves no flow after equilibrium is established. The core itself has the freedom to determine which fluid, or ratio of fluids, shall exist in this pressure tap. Surely it will be one which will create a minimum of disturbance in the equilibrium of the saturation distribution.

There is undoubtedly a place in the academic development of relative permeability measurements and in the attempt to understand their significance completely for a single phase Δp measurement. If accomplished without severely disturbing the saturation distribution of the flowing system, it should provide important evidence regarding any possible saturation gradient in conjunction with the pressure drop due to flow.

TYPICAL TEST PROCEDURE

The procedures used in the actual test are largely a matter of laboratory technique. However, there are a few features which are of considerable importance. Among these are the initial saturation of the core sections, the sequence of flooding operations, and the saturation determinations themselves. It might also be well to mention here that the role of the machinist in the preparation of the core assembly is of the utmost importance. Carelessness in this phase of the preparation will result in an imperfect sand-sand, Lucite-Lucite contact which will necessitate regrinding of the sand surfaces.

Attaining a 100 per cent saturation of one liquid phase in initiating a test is of utmost importance. Any gas saturation will invalidate the subsequent weight-balance saturation determinations. The technique used in these tests is to clean thoroughly and to dry the core assembly to a constant weight, apply vacuum of 1 to 2 mm Hg. to the system, and with the vacuum pump still in operation inject the liquid into the core under a pressure of approximately 75 psi. When the liquid appears at the evacuated end of the core assembly the vacuum pump is removed and the system flowed under a back pressure until several pore volumes have been produced. The weight of the core is taken immediately after saturation and again after being in contact with the saturating fluid for a period of several hours. If water is the saturating liquid, as it usually is, the core will have gained several milligrams. This weight is used as the 100 per cent liquid saturated weight for subsequent saturation determinations, while the first weight of the saturated core is used in checking the pore volume. This gain in weight is accredited to the absorption of water by the Lucite cast. This effect has not been detected when oil is used as the saturating medium.

The following sequence in which the fluids are injected into the core has been used: Saturate 100 per cent with brine, determine the pore volume and constant saturated weight, flood the core with the oil phase to the minimum residual water saturation, repeat with a brine flood carried to the minimum residual oil saturation, then

determine the behavior, flowing various ratios of oil and brine at core saturations between the two equilibrium points. Variations of the flooding sequence has been tried, but the above brine-oil, brine-complex sequence has given the most trouble-free operation.

The saturation determinations themselves are largely a matter of operational skill. After equilibrium has been established (as indicated by a constant Δp across the test core and the constancy of the resistance reading of the conductivity bridge), the flow rates are measured, the C-clamp is released, the test section is quickly removed, weighed on an analytical balance, and returned to the flow stream. In the reinsertion of the test section into the flow stream extreme care must be exercised to make certain that no air is forced into the sand section.

DATA AND CONCLUSIONS

As stated previously, the conventional conductivity methods of determining saturations did not prove satisfactory. The reason for rejecting this method of saturation measurement is evident in Figures 1, 2, and 3, which present calibration curves of brine saturation versus relative electrical conductivity. Figures 1 and 3 each show two calibration curves for a single core, using air and oil as indicated for displacement of the brine. Visualize the results if the air-brine calibration curve is used for the saturation determinations during an oil-brine relative permeability test. Similar pairs of curves have resulted from all tests conducted on reservoir sands, and work by other investigators [5] has verified their existence for synthetic sandstone cores.

Figure 3 shows two oil-brine conductivity curves determined on the same core at two different applied pressures. In the test in question, the first curve was determined at an applied pressure of 21 psi. The applied pressure was then raised to 42 psi, resulting in a decided lateral shift. This is the first concrete evidence that the pressure drop across the test section may provide some sort of

FIG. 1
RELATIVE CONDUCTIVITY
VS. BRINE SATURATION
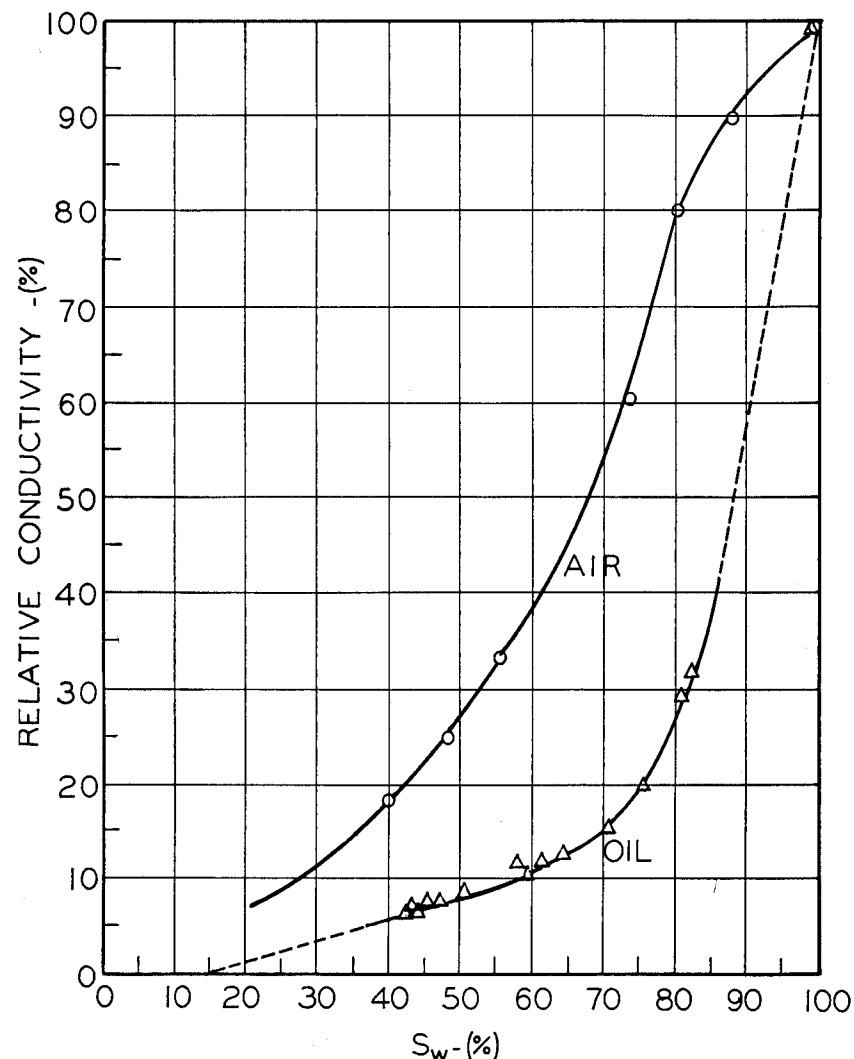BRADFORD CORE 27-BT-3

FIG. 2
RELATIVE CONDUCTIVITY
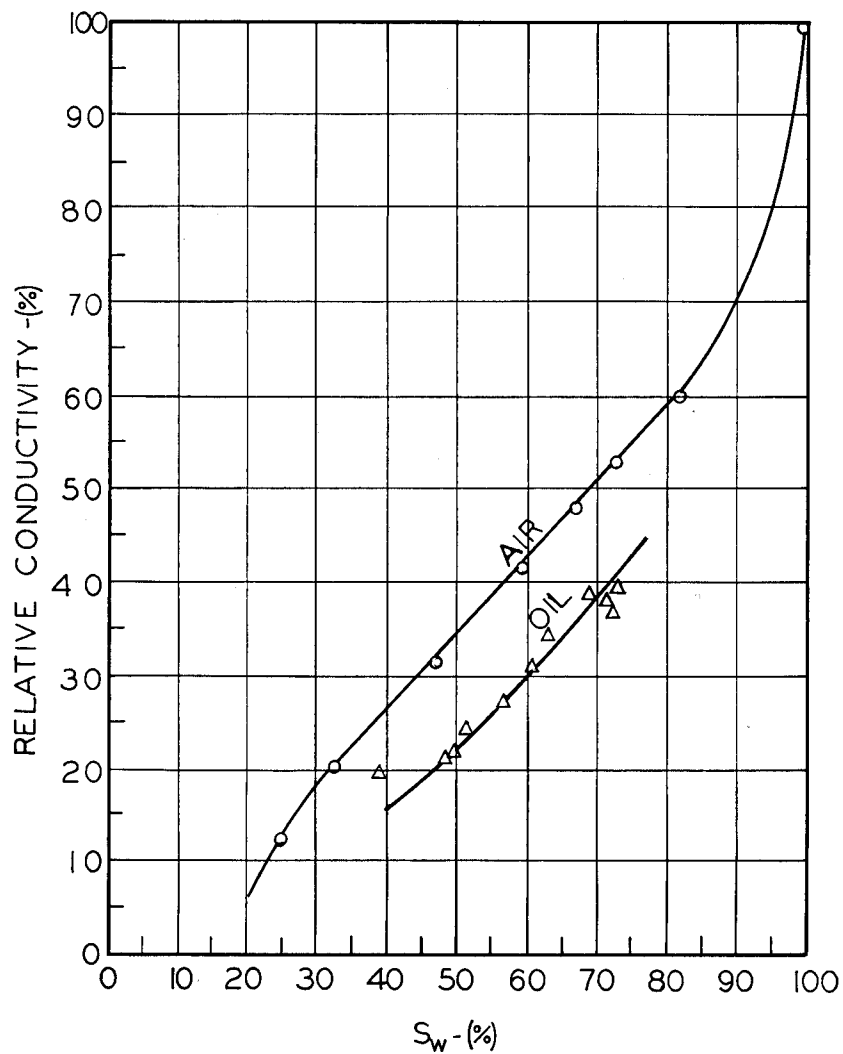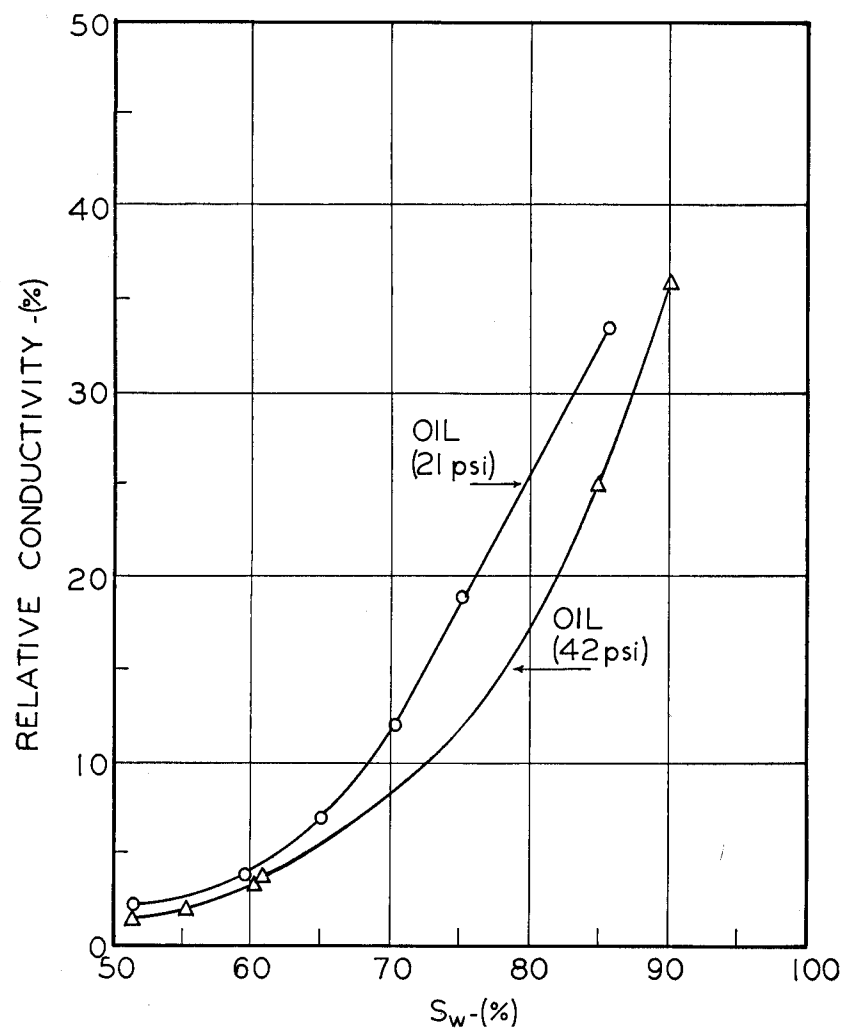VS. BRINE SATURATION
VENANGO CORE B-4-A

FIG. 3
RELATIVE CONDUCTIVITY
VS. BRINE SATURATION
BRADFORD CORE 9-KS-1

unique saturation distribution pattern, perhaps one similar to that suggested in the previous discussion. In general the shape of the relative conductivity curves is similar for all cores tested, although no two cores gave curves which could be termed "like." The conductivity measurements then serve the following purpose: A constant resistance reading during a flood is a valuable indication that steady-state conditions exist. Once a curve is established for given test conditions of temperature, applied pressure, and brine normality, the curve may be used for saturation determinations during that particular test only. It is emphasized that the curve must be well established by weight saturation determinations before this is possible.
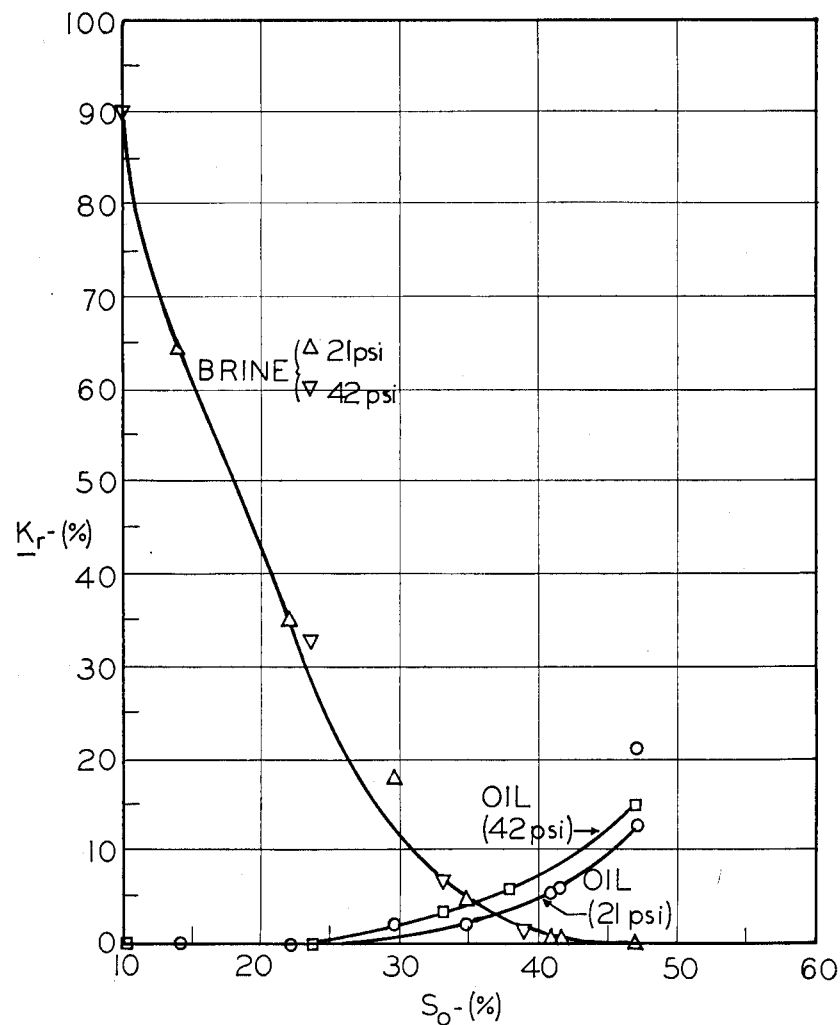
Relative Permeability Curves

Figures 4, 5, 6, and 7 show typical results of the relative permeability tests described above, on natural consolidated sand cores. Pertinent data for the cores are tabulated below.

Figure	Core Designation	Reservoir Sand	Permeability	Effective Porosity (%)
5	BT-27-3	B'fd 3rd	83md	20.2
6	BT-27-3 (acidized)	" "	105	22.4
4	9-KS-1	" "	105	23.0
7	B-4-A	Venango	148	20.2

Understanding the significance of the curves shown is difficult if the conditions imposed upon the core during the test are not known. For this reason each pair of curves will be discussed briefly to point out what are believed to be the notable features.

All the curves presented were determined by use of the flooding sequence described previously, in which the core is initially 100 per cent brine-saturated. This sequence of flooding has been found to be most satisfactory from a practical standpoint. Reversing the flood sequence—that is, flooding the dry core first with an oil phase—has not altered the type of curve materially. The maximum effect noted was a shift of the entire curve latterly approximately 4

FIG. 4
RELATIVE PERMEABILITY
BRADFORD CORE 9-KS-1
K_r vs. S_o

per cent along the saturation axis in a direction which increased the oil saturation for a given pair of K_r values.
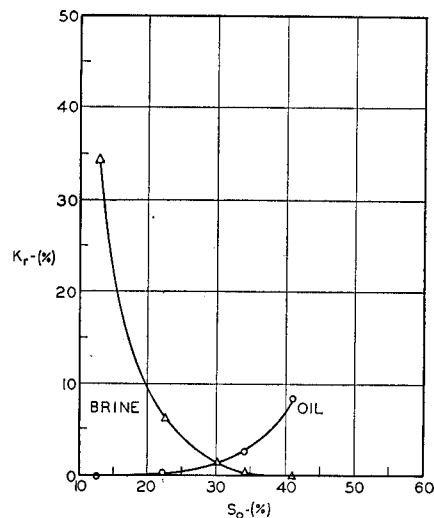
First consider the curves of Figure 5 on a Bradford sand of 83 millidarcies permeability. These curves show a residual oil saturation of 13.5 per cent and an irreducible brine saturation of 43 per cent. Two facts immediately attract attention: 1) the very high irreducible water saturation, and 2) the very low K_{ro} at this saturation. As subsequent figures show, all Bradford sands tested have shown these two characteristics. It was first thought that they were perhaps partially due to the fixed flooding history to which the cores were subjected. To check this the flooding sequence was reversed, the initial flood being 100 per cent oil. After the oil-brine complex was established in this manner, the same type of curves resulted as with the standard procedure described previously.

Figure 6 shows relative permeability curves determined on the same core as those of Figure 5 after treatment of the core with hydrochloric acid. The main feature to be noted here is the increased oil permeability and the decrease in the irreducible brine saturation by 15 per cent. In conjunction with this, the effect of the acid on the porosity and permeability of the core should be noted. The porosity was increased from 20.2 per cent to 22.4 per cent and the permeability from 83 md to 105 md. The purpose of acidification was to ascertain the effect of the acid on the wettability of the core. Apparently the effect was not great. At any rate no conclusive statements may be made from this one test.

FIG. 5
RELATIVE PERMEABILITY
BRADFORD CORE 27-BT-3
K_r vs. S_o

FIG. 6
RELATIVE PERMEABILITY
BRADFORD CORE 27-BT-3
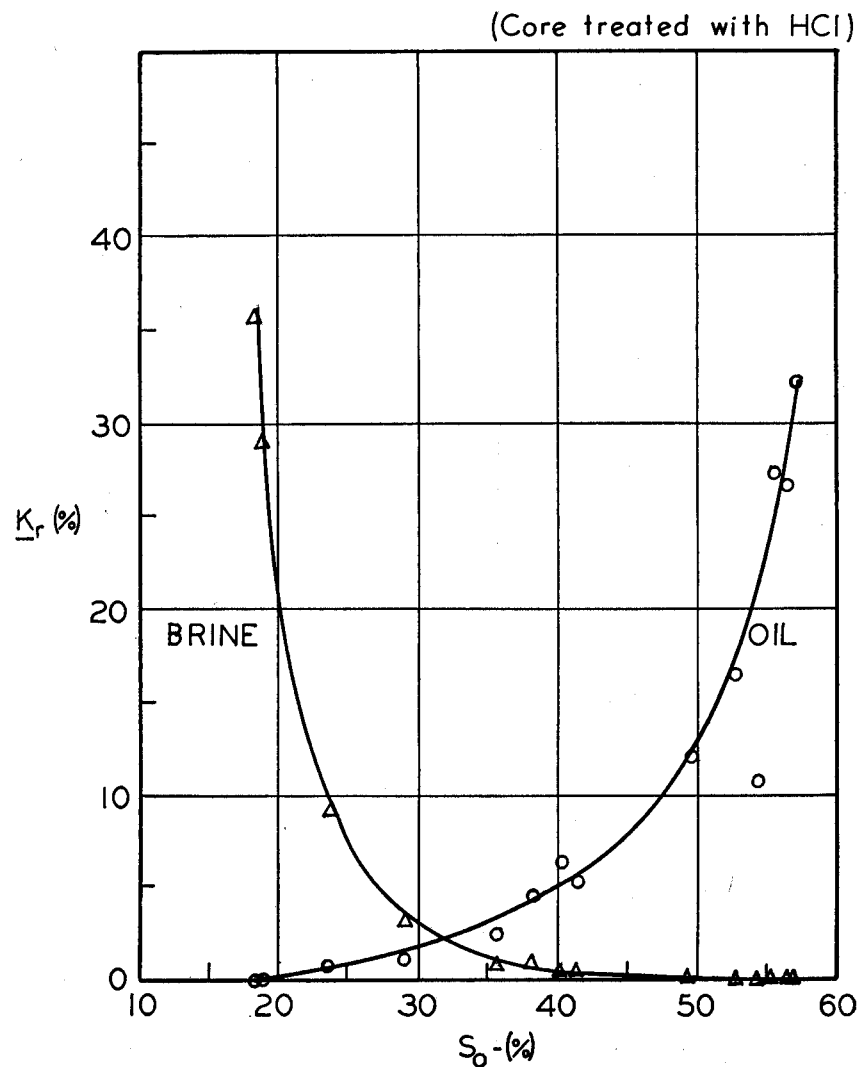K_r vs. S_o

(Core treated with HCl)

Figure 4 shows curves for a Bradford core on which tests were conducted under two different applied pressures. As was pointed out under a discussion of saturation determinations, the conductivity curves for the two pressures are different. Here it was suggested that perhaps the fluid distribution in the core might not be the same for two different applied pressures. There is a shift of the K_{ro} curve slightly upward with the higher applied operating pressure, but with the same irreducible water saturation maintained. Note that in this test the residual oil saturation is shown as 10 per cent, with a K_{rw} of 90 per cent. This saturation was obtained during the 42 psi test. During the low pressure test the oil saturation could be reduced to only 14 per cent with a corresponding K_{rw} of 62 per cent.

Figure 7 shows the results of an oil-brine test on a Venango sand sample. Note the reversed positions of the K_{ro} and K_{rw} curves as compared to those on all Brad-
ford sands. In this case the strik-ing feature is the very low brine permeability of 4 per cent at the highest brine saturation obtain-able; namely, 73.5 per cent. The marked difference in the type of curves obtained on the two sands presented suggests the possibility of determining an emperical cri-terion of whether or not a par-ticular sand will respond to water flooding. Obviously the data herein do not constitute any such standard. However, we know Bradford sands will re-spond to an artificial water flood. We know Venango sands, in

FIG. 7
RELATIVE PERMEABILITY
VENANGO CORE B-4-A
K_r vs. S_o

general, do not. Bradford sands to date have given a characteristic pair of curves in every test. Venango sands have given a radically different type of diagram. Correlation of field behavior and relative
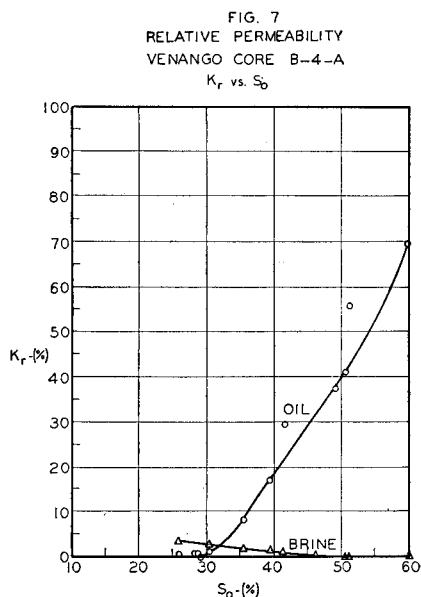
permeability curves on many different sands should prove very inter-esting in this respect.

Practical Significance of the Experiment

In discussing the significance of this study in secondary re-covery, it is desirable to summarize the over-all picture presented by the data gathered on Bradford sands. The residual oil saturation after a brine flood of an oil-brine complex is in every case very low. In Figure 4 note that the residual oil saturation is below 10 per cent of the pore volume. The pressure gradient across the core is fan-tastically great in comparison with field conditions (up to 130 pounds per square inch/foot), and the conditions of water injection are ideal (many pore volumes of brine being flowed through the core to attain the residuals shown). Herein may lie a clue to the reason for the higher residuals reported on field tests of sands subjected to floods. As was indicated previously, when a lower pressure gradient is used in the laboratory tests, the residual oil saturations are higher. If a gradient comparable to that used in actual flooding operations were used, it is conceivable that oil residuals comparable to field values would result.

Now consider the equilibrium saturations of the water phase. Here the results do not fit in so well with field behavior. The irre-ducible water saturations are very high in every case. The lowest obtained on a Bradford sand to date is 43 per cent brine, and this on an acidified core, which may have had the pore structure altered considerably. The more usual order of magnitude is from 50 to 55 per cent brine. These data do not substantiate core analysis data which place the original connate water saturation of the Bradford sand as being much lower. Neither do they help to clarify the high virgin oil saturations reported from portions of the field. At no time during any of the relative permeability tests has it been possible to force more than 57 per cent oil into a core after it had been brine-flooded. This is true of cores up to 105 md permeability, re-gardless of which phase constituted the initial saturation. Here is a

suggestion that pore size distribution may have an important bearing on the magnitude of the percentage of pore space into which oil may be forced under a given applied pressure. A test on a 5 md core (14 per cent porosity), using 45 psi applied pressure, resulted in an irreducible brine saturation of 70 per cent. This, taken in conjunction with the fact that the 30 per cent oil was very easily removed by subsequent brine flood, indicates a physical distribution of pores which presents very few capillaries of sufficient diameter to permit the entry of oil and many very fine capillaries saturated with the wetting phase, brine.

These results do not mean that either the laboratory or the field analyses are not reliable. Rather they serve to emphasize the importance of understanding the way in which the data are obtained and for what they may be used. Looking at the statistics alone, one might ask: How can the Bradford field have spot oil saturations of 50 to 60 per cent, if in the laboratory it is barely possible to force this quantity of oil into the sand? It must be remembered that the relative permeability tests are conducted with only two phases present. It is quite certain that if the water content is reduced below its equilibrium saturation with a gas drive, the core will accommodate a higher percentage of the oil phase. The behavior of these cores under two-phase saturation may also place some limitations on just what conditions existed when the oil now in the Bradford sand came into being. It is difficult to understand how it could have migrated into the sands in such quantities under conditions of 100 per cent liquid saturation. Such considerations suggest that the use of irreducible water saturations as a measure of the original connate water saturations of the Bradford sand may be in error.

Previous indications that the Bradford sand may be oil wet are not borne out by a consideration of the residual oil saturations obtained on a number of tests. Note that in the test data presented on Bradford cores, the residual oil saturations are low in every case —in one, only 10 per cent of the pore volume. On tests of Bradford sand of lower permeability than those shown the residuals have been

even lower. Another factor to consider in this respect is that in those tests in which oil was the initial saturating phase, the irreducible brine saturation was again very high. This would indicate that the brine had displaced most of the oil phase from the small interconnecting pore spaces.

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Effect of Water Injection in Gas Drive

by

D. E. MENZIE
DIVISION OF PETROLEUM AND NATURAL GAS

Secondary oil recovery by air-gas drive has been used in some Pennsylvania oil fields for a quarter of a century or more. During this time much scientific knowledge has been gained and put to use for increasing oil production. However, even today there remains the challenge for all oil producers to reduce the vast quantities of oil which by present methods are destined to remain as residual oil in the sands and to produce the amount of oil which can be obtained with minimum effort and cost. This paper is a brief discussion of the beneficial effects of water injections during an air-gas drive on long cores. Laboratory data and curves are presented to show the increased oil recovery as a result of these injections. The paper also attempts to show the added benefit of reduced air-oil ratios which result from water injections.

PREVIOUS INVESTIGATIONS ON WATER INJECTION IN AIR-GAS DRIVES

Many investigators have recognized the importance of the role of connate water in secondary recovery of petroleum [1] [3] [4]. This role is especially important in the air-gas regions, for the margin of profit of a lease may be regulated to a great extent by the amount and distribution of the connate water. Dickey and Bossler [2] point out that the saturations of liquids in the reservoir will be the controlling factor in the movement of air. It has been further stated that the lack of fluid saturation in a formation is responsible to a great extent for the excessive by-passing of air during a drive [6]. Krutter [3] found that during an air drive the greatest amount of oil,

expressed in terms of the per cent of original oil in the sand, is recovered when 30 per cent connate water is present in the sand. Yuster and Day [7] presented some laboratory experiments to show how water may substitute in part for the residual oil in the formation. These experiments led to a study which was reported at the Tenth Annual Secondary Recovery Conference last year [5].

This paper presents some advantages of water injections during an air drive as found by laboratory studies. Brief discussion is given on the possibilities of water injections being used in the field and their advantages with respect to increased oil recoveries with reduced amounts of air required.

CORE PROPERTIES AND METHODS

Core R-9, the first core used in these experiments, was obtained from a horizontally drilled section of the Cow Run sand in Ohio. This core is about 3 feet long and 2¼ inches in diameter, and it was coated with about 100 layers of colorless metal finishing lacquer. The average dry air permeability of the core was found to be approximately 800 md. A small plug was drilled from the input end of the long core and was used to obtain the capillary pressure curve which will be discussed later.

Core A-1 was obtained from the Franklin mine project. It is a Venango sand core approximately 4 feet long and about 2 inches in diameter. This core was mounted for these experiments with a layer of Lucite. The core was then divided into several sections to facilitate handling and to reduce the time required for each run. Three sections have been denoted as A-1-A, A-1-B, and A-1-C. Pertinent properties of each are given in Table 1. The fourth section of core A-1 was used to obtain a plug from which the capillary pressure curve for this core was made.

In each experiment the cores were extracted, dried, and saturated with the fluids used in the tests. When a core was saturated with liquid, a vacuum was drawn on one end and a pressure was

used to force the liquid into the core. After each run the core was extracted and returned to the original dry weight. All saturation percentages are based on total pore volume of the core.

WATER INJECTIONS IN THE COW RUN SAND

A series of experiments were performed on a long core of the Cow Run sand (Table 1) in which alternate air drives and water injections show their effects on cores 100 per cent saturated with close-cut Pennsylvania oil and degassed Venango crude. Figure 1 is a graph of oil saturations in per cent of the pore volume of the

TABLE 1

PROPERTIES OF CORES

Core	Type of Sand	Length Inches	Dia. Inches	Perm. Mds.	Poros-ity %	Pore Vol.cc.	Remarks
R-9	Cow Run	35.9	2.20	19.4	19.4	480	Coated with Lacquer
A-1-A	Venango	4.06	2.05	8.9	8.9	15.7	Coated with Lucite
A-1-B	Venango	4.29	2.05	9.2	9.2	21.3	Coated with Lucite
A-1-C	Venango	14.76	2.05	9.3	9.3	75.9	Coated with Lucite

core plotted against time of air drive in hours. The core had been 100 per cent saturated with a close-cut oil of .805 specific gravity and 2.3 centipoises viscosity. A 20 cm mercury air drive was imposed on the core. This amounts to a 1.29 psi per foot pressure gradient across the core. At the finish of the first air drive the saturation of the core had been reduced to 49 per cent oil. At this point the core was considered produced to an economic limit. To study the effects of water injections, a slug of water equal to 18.8 per cent of the pore volume of the core was injected into the input end. This water was forced into the core by applying the same amount of air pressure to the water slug as was used in the previous air drive. After this amount of water was injected, the core was allowed to stand for a period of time while the injected water distributed itself throughout the core. A second air drive of 20 cm mercury was then applied to the core; and as the curve in Figure 1 shows, the core

was reduced to 35.5 per cent oil saturation. This is an added 13.5 per cent of oil recovered by the injection of the slug of water. A second water injection of 19.2 per cent was added when the core was considered driven to an economic limit. A 20 cm mercury air drive was repeated on the core, and approximately 10 per cent more oil was recovered. A third water injection was performed and another air drive was imposed on this core, but only a trace of oil and some water was produced.

FIGURE 1
SATURATION VS TIME
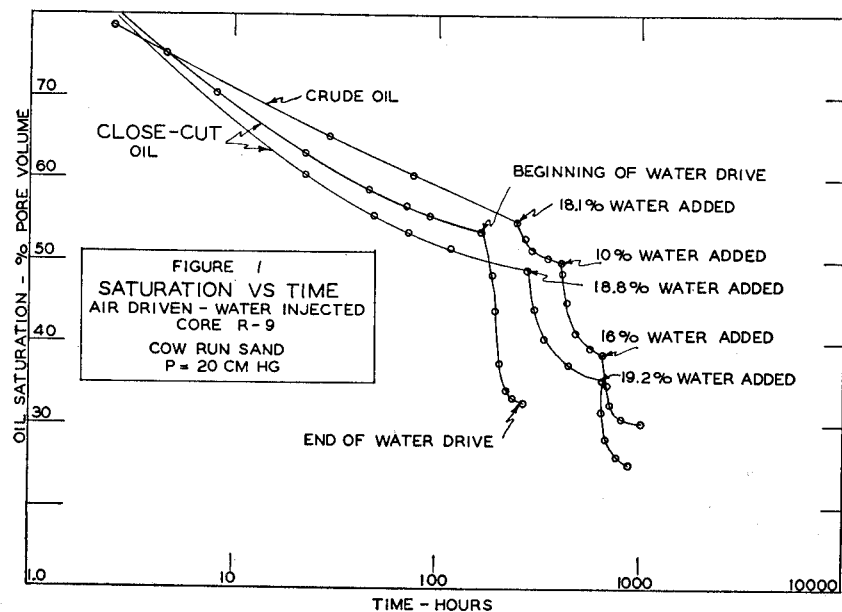AIR DRIVEN – WATER INJECTED
CORE R-9
COW RUN SAND
P = 20 CM HG

Figure 1 also shows a similar run on the same core except that a Venango crude oil (.82 specific gravity and 6.5 centipoises viscosity) was used during the experiments. The core was saturated with 85 per cent crude oil and 15 per cent water.* A 20 cm mercury air drive reduced the oil saturation to 55 per cent. An 18.1 per cent slug of water was added, and the 20 cm mercury air drive was

* The low water saturation of 15 per cent was obtained by evaporating water from the core.

repeated with a beneficial result of 5 per cent more oil produced. This procedure was repeated with a 10 per cent and a 16 per cent slug of water, and 11 per cent and 9 per cent more oil was produced. A comparison of the close-cut oil curve of Figure 1 and the crude oil curve shows that the beneficial effect of water injection holds true for both types of oil. Approximately 25 per cent more oil, based on the total pore volume of the core, was recovered in each case as a direct result of the slugs of water injected.

The main question concerning the theory behind the system of alternate water injections and air drives has been: Are we simply applying a water drive on the core and getting the same effects as would be obtained by imposing a regular water drive following an air drive? A curve in Figure 1 was obtained in an attempt to answer this question. The core was 100 per cent saturated with close-cut oil and driven as before with a 20 cm mercury air drive. This is the same procedure that was used in the initial close-cut oil curve. The core was produced to a 54 per cent oil saturation, at which time no more oil was being produced and the economic limit had been reached. The core was then given a 20 cm mercury water drive—the same pressure used in previous runs. The water drive produced 19 per cent additional oil but was not quite so efficient as the method of water injection by slugs. Approximately 6 per cent more oil was recovered when water was injected by slugs than when a complete waterdrive was imposed on the core. From this study it appears that to obtain maximum oil recoveries in the field, the water must be injected in the form of a slug.

In Figure 1 the last water injection during the close-cut oil test was a 19 per cent slug of water. To inject this percentage of water into a formation in a 300-foot five-spot with a 12 per cent porosity would require 363 barrels of water per foot of sand. This amounts to 9.3 barrels of water per acre per foot of sand for each per cent increase in water saturation. This is assuming that the

water is spread uniformly throughout the formation. The figure is given as a comparison of the volumes of water required in the field and in the laboratory water injections.

Figure 2 is a graph of oil saturation as per cent of pore volume of the core against the cumulative gas volumes in pore volumes through the core for the three runs previously discussed. The curves show that the effect of water injection on the amount of gas required is beneficial. A definite deflection of the gas volume curve for each water injection proves this point.
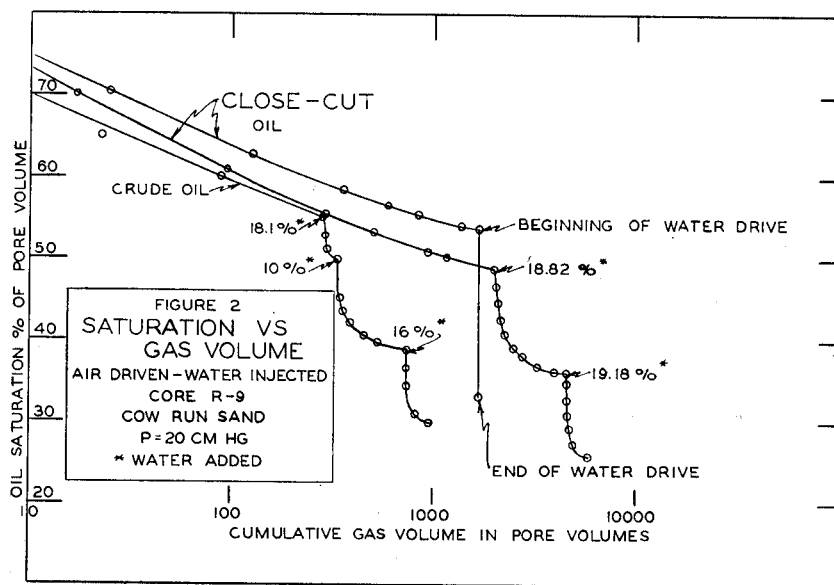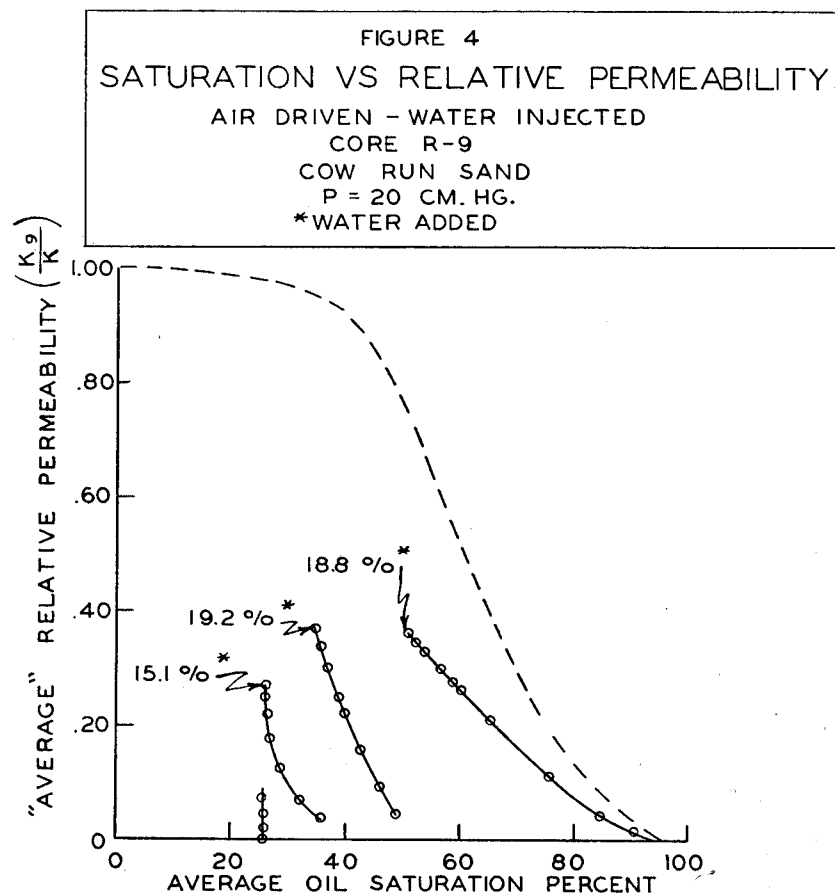

Figure 3 is a graph of oil saturation in per cent of pore volumes of the core versus calculated produced gas-oil ratios in cubic feet of gas per barrel of oil for the runs previously described. The calculated gas-oil ratios are extreme in some cases and not within the field limits; but this was more or less intentional, since all runs were continued as long as oil was being produced from the core. This fact will have no bearing on the trends of the curves. The close-cut
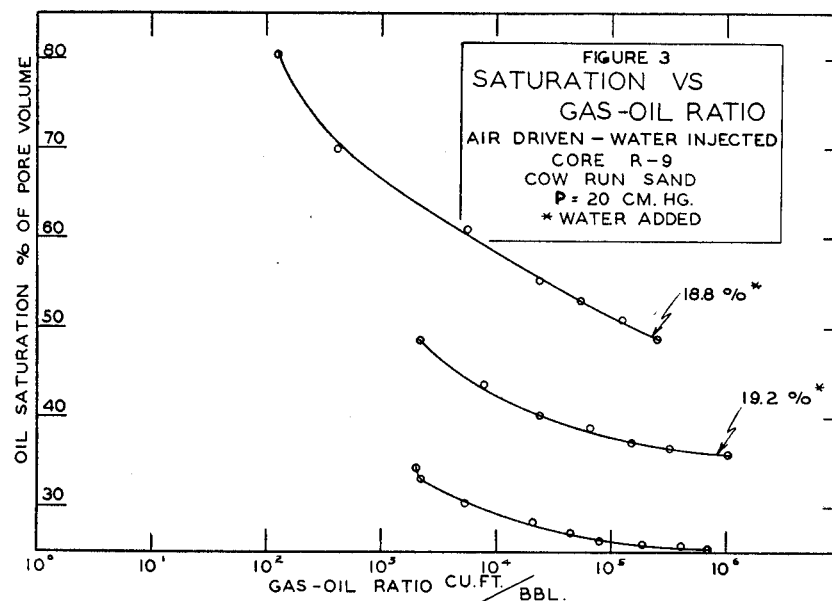
oil curve in Figure 3 shows that the gas-oil ratio increases rapidly prior to water injection. When the first slug of water is injected into the core, the gas-oil ratios are immediately cut back to 1/200 of the previous value. The second water injection results in an even larger reduction in the gas-oil ratio. These results are comparable to those of selective plugging in air-gas drive. The high permeability formations through which large amounts of air are being moved have been partially plugged with water. The plug is selective to a certain extent, for a greater amount of water enters the more permeable zones and thus tends to reduce the flow of air through those zones. This plug is not permanent, for as air pressure is applied behind the slug of water the liquid spreads before the air front. Eventually the liquid bank is exhausted and air begins to break through to the producing wells. The reduction in gas-oil ratios was approximately the same when crude oil was used, but to eliminate confusion the curve was not drawn on Figure 3.

FIGURE 4

SATURATION VS RELATIVE PERMEABILITY

AIR DRIVEN – WATER INJECTED
CORE R-9
COW RUN SAND
P = 20 CM. HG.
*WATER ADDED

The rates of flow of air during water injection studies may be further clarified by a study of the change in air permeability during these experiments. The relative permeability-saturation relationship contains the basic information required. Figure 4 is a graph of the "average" relative permeability to air (Kg/K) versus the average oil saturation throughout the core in per cent of pore volume of the core. This curve is plotted as "average" relative permeability because the calculations differ in several ways from the commonly accepted steady-state relative permeability curve. The laboratory curves are

from necessity based on the measured air produced from the end of the core over a period of time under changing conditions. A pile up of liquid at the producing end of a core or "end effect" is known to influence the rate of flow of gas from the core. The saturations as shown on Figure 4 are also from necessity only average saturations throughout the core, since individual oil saturations in each section could not be measured. The dashed curve† in this figure is the steady-state relative air permeability. Beginning at the 100 per cent oil saturation point and following the solid curve, a relative permeability (Kg/K) of .37 and 49 per cent average oil saturation was reached. The relative permeability to air was quite high, and as a result large volumes of air were injected into the sand. An 18.8 per cent slug of water was added to the core at this point. When the air drive was repeated, the relative permeability to air had been reduced almost to zero. As shown by the curves, each time a slug of water was injected the air permeability was reduced.

In connection with any study of the flow of air through a formation, the influence of the percentages of oil and water saturations must be recognized. The amounts of liquid in the formation will regulate to a great extent the permeability to air. The curves of Figure 5 have been drawn to illustrate this relationship. The ratio of the gas-liquid saturations within the core at any one time during the water injection runs has been plotted against the gas-oil ratio produced from the core. Since the core was 100 per cent oil-saturated at the beginning of the experiment, the gas-liquid ratio will be zero at the start. As liquid is produced from the core, both the gas-liquid and the gas-oil ratios increase. After the first 18.8 per cent water injection, the amount of liquid present in the core increased, and as a result the gas-liquid ratio decreased. The gas-oil ratio also decreased because of the reduced flow of air. Each water injection shows this general relationship; therefore in actual practice a high liquid saturation may be desirable as a means of reducing the amount of air through the formation. This high liquid saturation

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† Data by R. J. Day, Air-Gas Drive Research Program, The Pennsylvania State College.
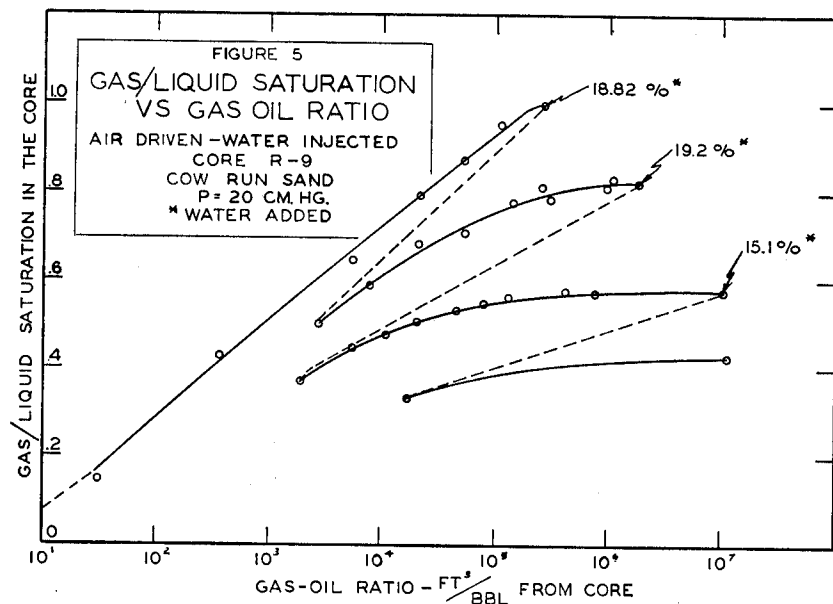
could be composed mostly of water, but the permeability of this water must not be too great, or excessive water-oil ratios will be produced. Also with high liquid saturations an increased effective pressure may be imposed on the low permeability formation.
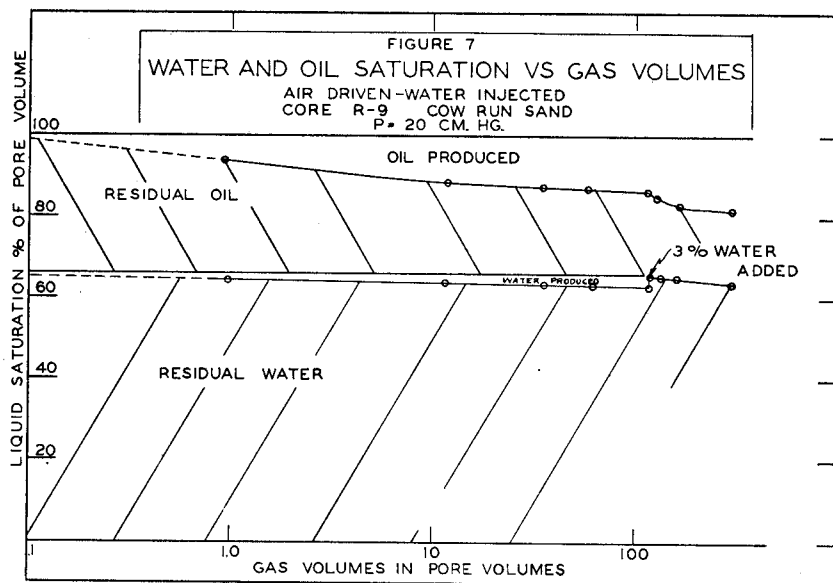
Until now the discussion has dealt with cores which have been 100 per cent or very nearly 100 per cent oil saturated, and the effects of water injection on these cores have been shown. It is also necessary to study the effect of high initial water saturations within the core prior to water injections. To prepare for such a test requires, first, that the core be 100 per cent saturated with water and, next, that an oil drive be imposed which reduces the water saturation and supplies the oil for the test. Such an experiment is illustrated in Figure 6. The core at the end of the oil drive was 100 per cent liquid saturated, as the figure shows; i.e., 66 per cent water saturated and 34 per cent oil saturated. A 20 cm mercury air drive was imposed on this core; and from Figure 6, which is a plot of per cent liquid saturation versus time of drive in hours, the oil saturation

was reduced from 34 per cent to 18 per cent in 145 hours. During this air drive the residual water saturation was reduced by only 4 per cent. After the core was considered at an economic limit, a 3 per cent slug of water was added. The core was again air driven, with
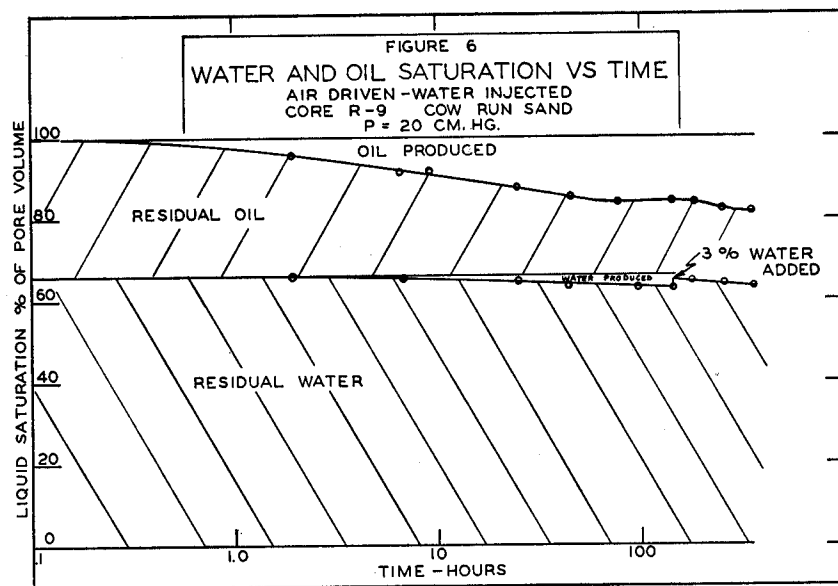
the result that 4 per cent additional oil (based on total pore volume) was obtained. Figure 7 is a graph of liquid saturation versus gas volumes through the core, and this curve shows the value of the water injection during this experiment. These figures point out the conditions under which water injections may be beneficial.

In the experiments represented by Figures 1 to 7 inclusive the amounts of water have been varied, and the resulting residual oil saturations after driving have been determined. Figure 8 is a general plot of the preceding experiments in which residual oil saturations in per cent of pore volume of the core are plotted against water saturations in per cent of pore volume. This data represents the saturations at the end of the individual air drives (dotted line shows

FIGURE 7
WATER AND OIL SATURATION VS GAS VOLUMES
AIR DRIVEN—WATER INJECTED
CORE R-9   COW RUN SAND
P = 20 CM. HG.

FIGURE 8
RESIDUAL OIL SATURATION VS
WATER SATURATION
AIR DRIVEN — WATER INJECTED
CORE R-9
COW RUN SAND
P = 20 CM. HG.

water produced during a single air drive). The curve shows that at zero water saturation (i.e., when the core has been 100 per cent oil saturated and then driven with air at 20 cm mercury), the residual oil saturation is found to be approximately 52 per cent. If 20 per cent water is added to the core, the residual oil saturation after an air drive is reduced to 41 per cent oil. If 40 per cent water is added, the residual saturation is reduced to 30 per cent oil. As the per cent water saturation is increased, the residual oil saturation is reduced. This statement is correct up to a certain water saturation, at which point the permeability to water increases to a value where water is produced from the core. Any additional water added to the core above this point will, in turn, allow water to be produced from the end of the core. The critical point was found to be about 55 per cent water saturation although, as Figure 8 shows, water injection was beneficial to oil production up to about 65 per cent water saturation without an excessive water-oil ratio. In other words, the relative permeability to water is insignificant below 65 per cent water satura-

tion. This is substantiated by both an air drive and an oil drive on the completely water-saturated core (See Figure 9), these drives also being at 20 cm mercury pressure differential. The capillary pressure curve given in Figure 10 indicates that the point for this core at which the water should flow is approximately 40 per cent. In actual experiments water was produced from the core at approximately 55 per cent water saturation.
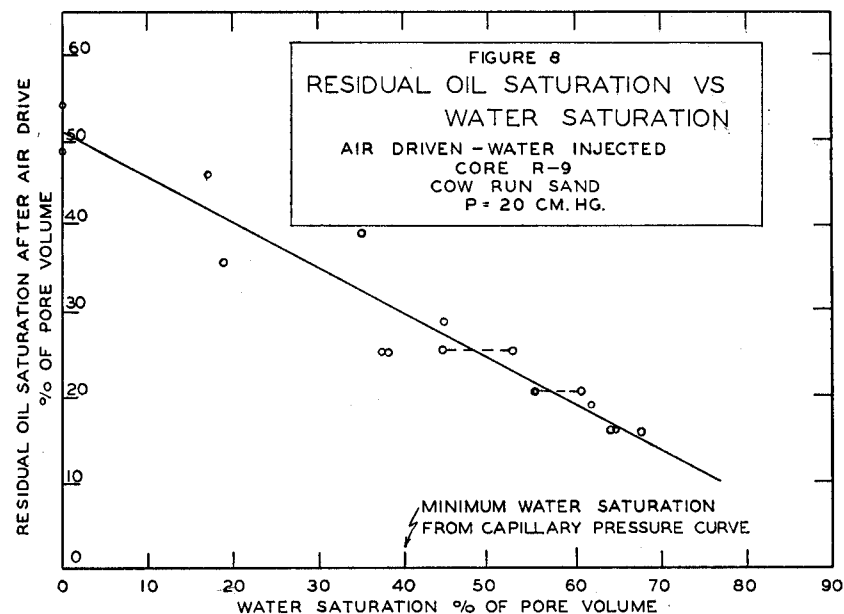
The curves of Figure 9 are a plot of water saturation in this core against the time of drive in hours. The air drive curve is a smooth line showing no great deflection at the point of air breakthrough. The ultimate saturation by the air drive is approximately 67 per cent water saturation. The oil drive curve shows a definite deflection when the oil breaks through at the producing end. The final residual water saturation of 66 per cent after the oil drive is

FIGURE 9
COMPARISON OF OIL AND AIR DRIVE
ON WATER SATURATED
CORE R-9
COW RUN SAND
P = 20 CM.HG.
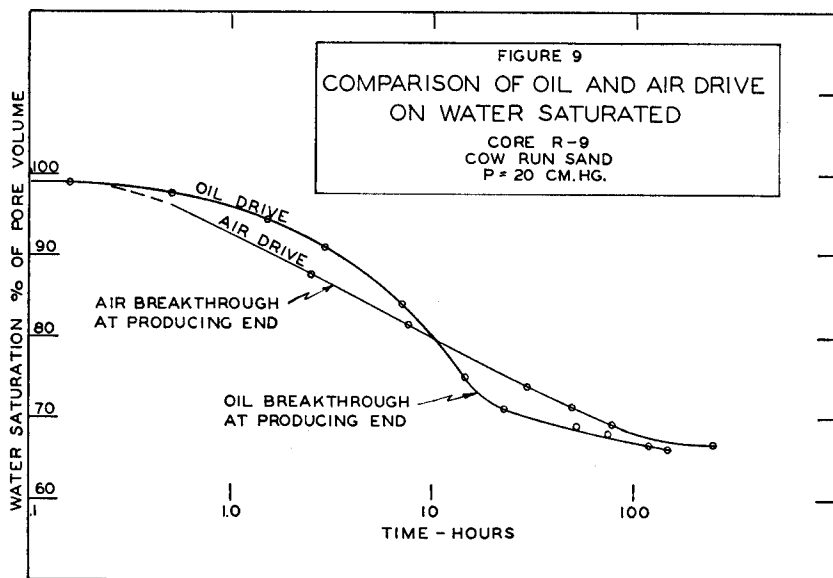
approximately the same as after the air drive. From these results it appears that a practical minimum water saturation is approximately 66 to 67 per cent. It is of interest to compare this with the irreducible minimum water saturation as found by the capillary pressure curve for a plug from the end of this core (Figure 10). The irreducible minimum water saturation by capillary pressure at 20 cm mercury was approximately 40 per cent. This discrepancy may be partially accounted for on the basis of "end effect" in the experiments, and partially on the basis of the low water permeability below 65 per cent water saturation.
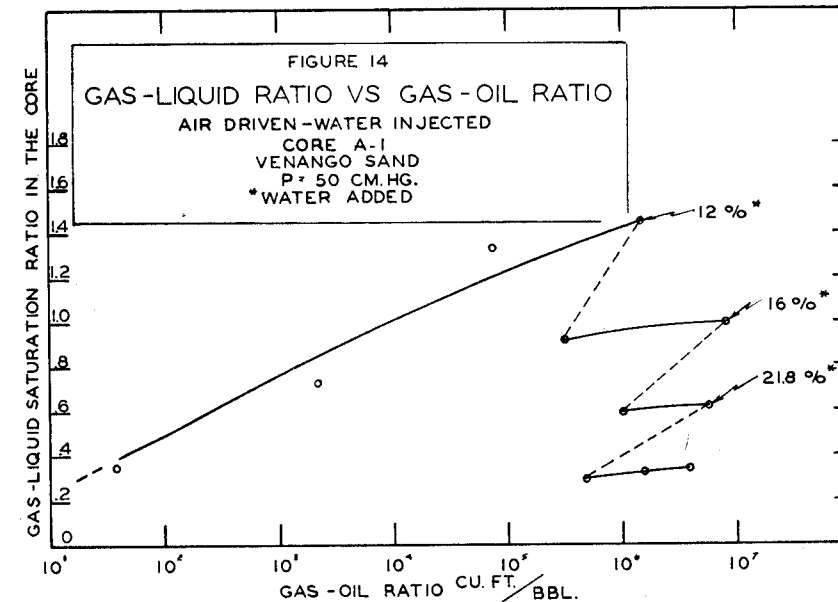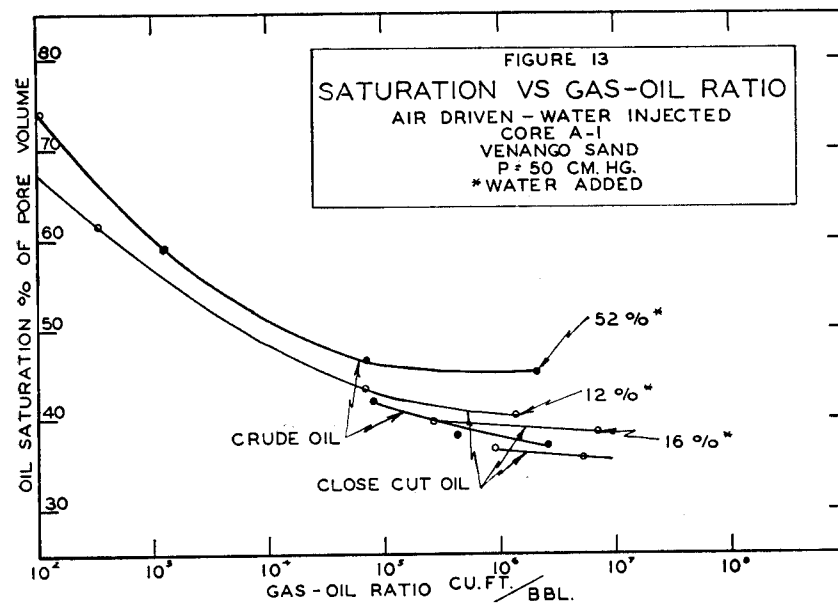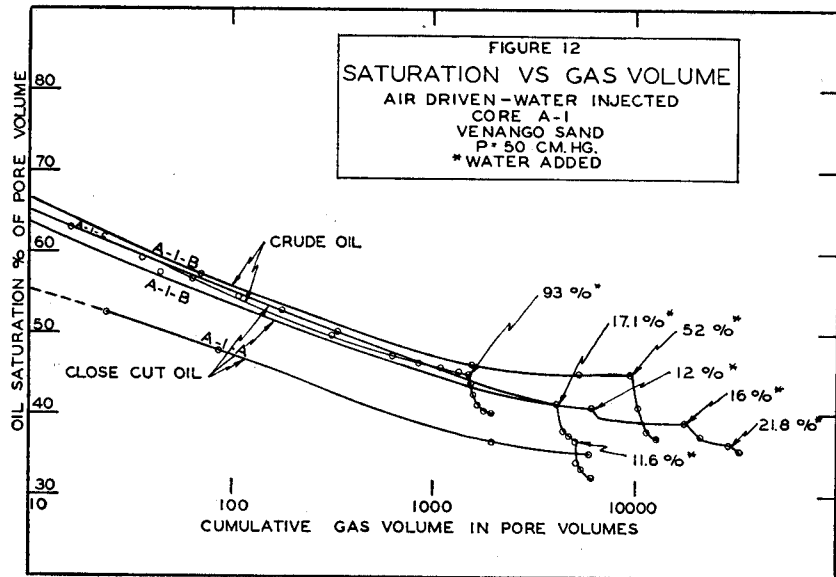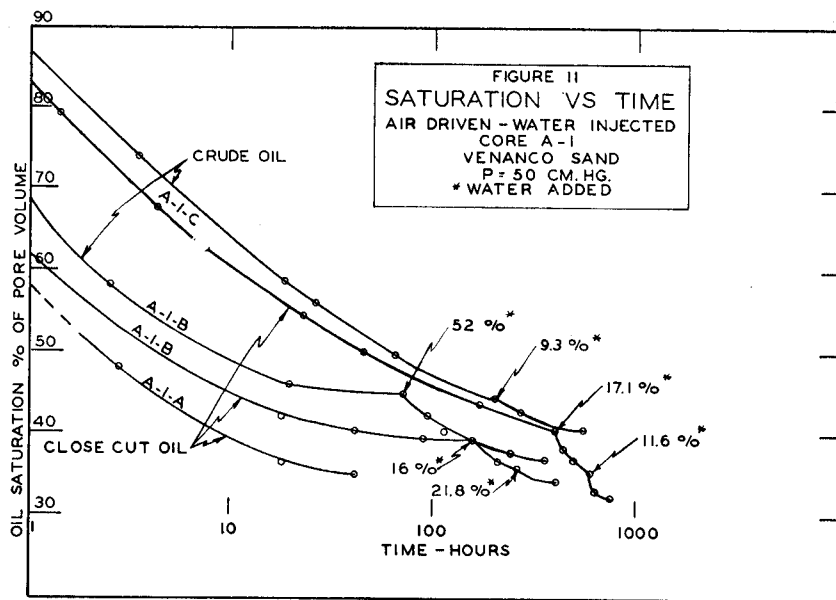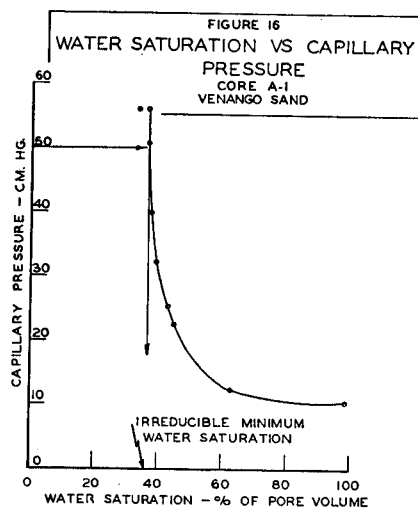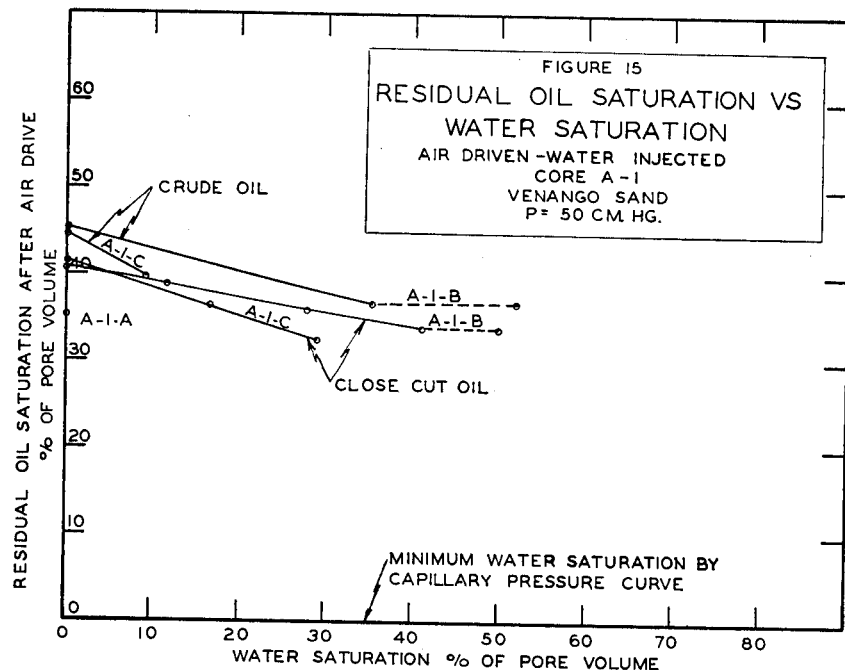
WATER INJECTION IN THE VENANGO SAND

The next study of water injection was an investigation of the effects of a change in sand characteristics and structure. For this work the cores of the A-1 series, the properties of which are given

FIGURE 10
WATER SATURATION VS
CAPILLARY PRESSURE
CORE R-9
COW RUN SAND
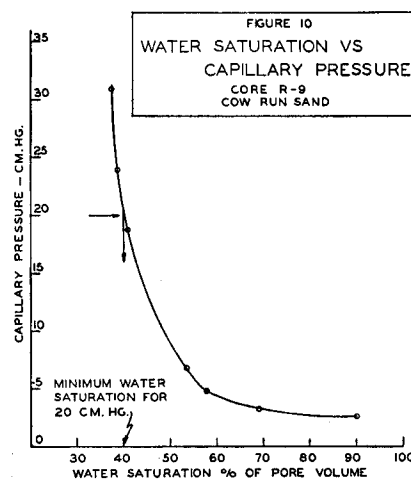
in Table 1, were used. Figure 11 is a curve of the oil saturations in per cent of pore volume versus time in hours for air drives and for alternate water injections on sections of this core. The increased oil recovered with both the close-cut and the Venango crude oil shows the beneficial effects of water injection in a Venango core. A pressure of 50 cm mercury was imposed on the water into the core during the water injections. The final residual oil saturation during these runs was approximately 34 per cent. Figure 12 is a series of curves of oil saturations versus gas volumes through the core for these same runs on the sections of the Venango core. These curves also show the reduced gas volumes required for the additional oil recovered by water injections. Figure 13 is a plot of per cent oil saturations against gas-oil ratios for these runs. The results for the Venango sand core are found to be, in general, the same as for the Cow Run core; i.e., the gas-oil ratio is greatly reduced when a slug of water is added between the air drives. Figure 14 shows the effects of water injections on the gas-oil ratio versus gas-liquid saturation ratio for the same core. This curve shows reduced gas-oil ratios as liquid saturations of the core are increased. Water injections will increase the liquid saturations and will cause less gas to blow through the core. Figure 15 is a summary of results of air drive experiments on the Venango core. The residual oil saturation after each air drive was plotted against the amount of water present in the core during the drive. As in the case of the Cow Run sand experiments, the residual oil saturation is reduced by increased water saturations in the core. At approximately 35 to 40 per cent water saturation the permeability to

FIGURE 11
SATURATION VS TIME
AIR DRIVEN – WATER INJECTED
CORE A-1
VENANCO SAND
P = 50 CM. HG.
*WATER ADDED

FIGURE 12
SATURATION VS GAS VOLUME
AIR DRIVEN – WATER INJECTED
CORE A-1
VENANGO SAND
P = 50 CM. HG.
*WATER ADDED

FIGURE 13
SATURATION VS GAS-OIL RATIO
AIR DRIVEN – WATER INJECTED
CORE A-1
VENANGO SAND
P = 50 CM. HG.
*WATER ADDED

FIGURE 14
GAS-LIQUID RATIO VS GAS-OIL RATIO
AIR DRIVEN – WATER INJECTED
CORE A-1
VENANGO SAND
P = 50 CM. HG.
*WATER ADDED

FIGURE 15
RESIDUAL OIL SATURATION VS
WATER SATURATION
AIR DRIVEN – WATER INJECTED
CORE A – 1
VENANGO SAND
P = 50 CM. HG.

FIGURE 16
WATER SATURATION VS CAPILLARY
PRESSURE
CORE A-1
VENANGO SAND

in the case of the Cow Run sand experiments, water injected in addition to the minimum water saturation resulted in more oil being produced.

SUMMARY

This paper has attempted to show the value of water injections during an air drive. The experiments show that:

1. Increased oil production resulted from water injection in a Cow Run core using a close-cut oil.

2. Approximately the same increase in production resulted when a Venango crude oil was used.

3. The additional oil recovered by water injections was greater when slugs of water were injected than when a regular water drive was imposed on the sand.

4. Reduced air volumes and therefore reduced gas-oil ratios were required to recover this additional oil.

5. Water injections help to reduce the amounts of air which are blown through the high permeability formations.

6. Increased oil recoveries resulted from water injections even when the connate water saturation was above the irreducible minimum water saturation.

7. Similar results to those given above for a Cow Run core have been observed in tests with a Venango core.

From the data offered it appears that under certain conditions water injections during an air drive will increase the oil recovery and decrease the air required for production.

ACKNOWLEDGMENTS

water was sufficient to allow water to be produced from the end of the core. This agrees with the minimum water saturation as found by the capillary pressure curve for core A-1, shown in Figure 16. The plug core used to obtain the data was drilled from the fourth section of long core A-1. An irreducible minimum water saturation of 36 per cent is indicated by the capillary pressure curve. This saturation may be the connate water saturation in the formation. As

edgment is made to S. T. Yuster, R. F. Nielsen, and other members of the staff of the Division of Petroleum and Natural Gas for their interest and help, and to members of the Pennsylvania Grade Crude Oil Association for their support of this work.

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Airborne Magnetometer Survey in Central Pennsylvania

by

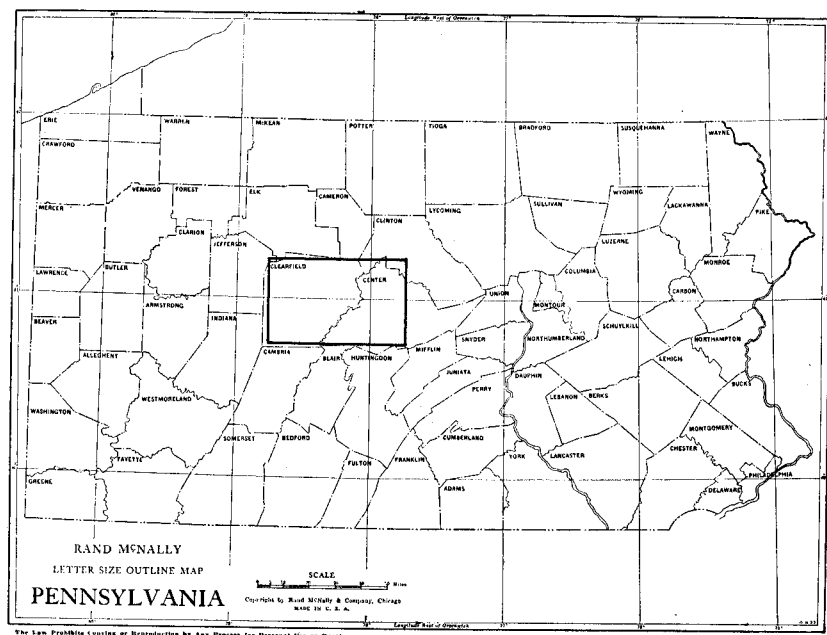SYLVAIN J. PIRSON AND LLOYAL O. BACON
DIVISION OF GEOPHYSICS
IN CO-OPERATION WITH THE GEOPHYSICS SECTION
OF THE U. S. GEOLOGICAL SURVEY

The magnetic survey of Central Pennsylvania was initiated for the purpose of finding out the possibilities of geophysically discovering deeply buried potential oil and gas structures within the Appalachian geosyncline.

Anomalies of the earth magnetic field or deviations from a normal magnetic field distribution over the earth are indicative of the basement complex topography with which the structures of deeply buried sediments are intimately related and associated. The relationship between magnetic anomalies and conditions favorable for the accumulation of oil and gas are therefore indirect.

The selection of the area for this study, shown in Figure 1, was based on the following considerations:

1. It seemed advisable to select an area of the Allegheny Plateau where sufficient geological information was at hand in order to correlate with magnetic anomalies. The geological features desired were: a) well-defined and long anticlines, b) a stratigraphy known from a number of deep wells drilled within the area, c) conditions similar to those expected at great depths within the Appalachian geosyncline. These requirements were obviously met by the area selected, inasmuch as the Chestnut Ridge, the Laurel Hill, and the Gatesburg anticlines were included in the area.

RAND McNALLY
LETTER SIZE OUTLINE MAP
PENNSYLVANIA
Copyright by Rand McNally & Company, Chicago
MADE IN U. S. A.
SCALE

The Law Prohibits Copying or Reproduction by Any Process for Personal Use or Resale.

One deep test, the Deemer Hilliard well in Bell Township, Clearfield County (still drilling beyond 8000 feet with Onondaga Lime at 7424 feet), gives an idea of the probable depth to the basement rock, estimated at about 15,000 feet on top of the Chestnut Ridge anticline.

2. It seemed further desirable to select an area which would include a small section of the highly folded Allegheny Mountains in order to ascertain any possible relationship between the geologic structures within the geosyncline and the mountain ranges. This requirement was met by covering the area of State College and Bellefonte.

3. It seemed desirable to ascertain in greater detail the effect of weathering on the magnetism of the Gatesburg formation, a potential reservoir rock within the Appalachian geosyncline. A reduction in magnetic susceptibility of the weathered Gatesburg had already

been observed by a reconnaissance survey. This requirement was fulfilled by covering the Gatesburg anticline west of Bellefonte and State College with a fairly detailed vertical magnetic survey as well as with the airborne instrument.

Preliminary magnetic work was done with an Askania Vertical Magnetometer. The magnetometer is of the uncompensated type with a temperature coefficient of 6.5 gamma per degree centigrade. In the regions surveyed, the earth magnetic field equals about 55,000 gammas (one gamma = 10^{-5} oersted). Sensitivity of the instrument was adjusted to 12 gammas per scale division.

The precision of the field measurements was of the order of ±4 gammas owing to the lack of temperature compensation.

In addition, the probable error of a single reading is considered rather large owing to possible presence of near surface magnetic disturbances along the highways used for traverse lines.

Five hundred and fifty magnetic stations were occupied at ¼-mile intervals along highways in the area, as shown in Map 1. The main traverse extended along Highways 322 and 153 from two miles east of Boalsburg, in the southeastern part of the area, to Penfield, in the northwestern part. Several other traverses were made in the area between Philipsburg and the Allegheny front, and a short traverse was run northwest of Karthaus.

Magnetic values for the stations were plotted on a map of the area and contoured. The widely separated traverses and the relatively few stations made it imperative to use broad interpolations in contouring the vertical anomaly map.

Significant features of this map are the positive anomaly in the Black Moshannon State Park area and the anomaly northwest of Clearfield.

MAP 1 can be found in a pocket on the inside back cover of this bulletin.

The Black Moshannon anomaly appears to have a probable closure on the north. However, on account of interpolation between widely separated points, this closure cannot be ascertained. The airborne magnetic map (Map 2) indicates a closure about a second order anomaly in this region; however, this closure is of much smaller magnitude than that of Map 1.

The anomaly northwest of Clearfield is quite large and shows a relief of about 140 gammas. This anomaly coincides quite well with the known geological axis of the Chestnut Ridge anticline and is the magnetic reflection of that structure, though it is considerably offset to the south of the axis determined from surface mapping of the structure by Cathcart [1].

In order to prepare for the airborne survey of the area, north-south flight lines were drawn at ½-mile intervals on topographic maps and aerial photographs of the area. The aerial photographs were used by the pilot and co-pilot for flight control, whereas the topographic maps were used in flight by an observer to plot reference points.

All air operations were performed by U. S. Geological Survey personnel using a specially equipped airplane. Total flight time was 34.5 hours, but due to poor flying weather the total time spent by the crew in the area was 16 days. During this time approximately 4000 miles of traverse were flown.

Computations on the airborne data were begun in December 1946 with the calculations on the base lines and computation of the closure area for the base line traverses. The closure error was very small, indicating the high precision of the airborne survey. Closure errors were computed for two closed traverses having one side in common. The error for the traverse around the northern half of the area was one gamma; the error around the southern half was 11 gammas. This is, however, a high degree of precision, for the error

MAP 2 can be found on the inside back cover of this bulletin.

of 11 gammas occurred in a traverse 170 miles long and is equivalent to a distributed error of about one gamma per 15 miles.

The total laboratory time required to complete the preliminary contour map of the area was four months, the laboratory force consisting of one geophysicist and one assistant. The laboratory work does not, however, end with the preparation of the preliminary map, and considerable time has been spent in studying the anomalies and in working out methods for their geological interpretation. The following conclusions were derived from the surveys.

A. *First Order Magnetic Anomalies*

1. North and west of the Allegheny Front there is generally good agreement between the known geologic structural axes and the observed magnetic axes. Hence it is concluded that the orogenic forces which wrinkled the nonmagnetic sedimentary formations also uplifted the magnetic basement rock as a core within the anticlinal axes. Accordingly, it is inferred that under the Allegheny Plateau the basement complex partook of the folding and uplifting of the mountains and anticlinal chains.

2. The agreement between magnetic and geological axes is strikingly disturbed in two regions. The broad magnetic high (some 20 miles in diameter) centered just south of Karthaus is located exactly on the axis of the magnetic high which reflects the Laurel Hill anticline. This high shows a striking northward spit crosswise to the general structural trend. Farther west, in the region between Mahaffey and Luthersburg, a smaller circular magnetic high appears associated with the Chestnut Ridge anticline and greatly obscures the trend of the latter in this region.

The hypothesis is submitted that these two polarization highs are the magnetic expression of igneous intrusions (probably somewhat basic) perhaps contemporaneous with basement deformation, intrusions which likely expanded from an underlying igneous and molten magma through faults within the basement rocks resulting from

orogenic stresses during mountain building to the southeast. The northward spit of the Karthaus high may be viewed as a wide igneous dike within the sediments. Possibly it is not out of place to speculate concerning the geological significance of these magnetic polarization highs. If the contention is correct that they are due to large scale igneous intrusions contemporaneous with the Appalachian revolution, it would be natural to expect that they might have given rise to mineralization within the overlying and deformed sediments. Surface evidences of such mineralization are not absent, though they are somewhat scanty; e.g., zincblende vein between Milesburg and Belle-fonte, barite vein in the Juniata formation west of State College at Skytop, zincblende and galena in Sinking Valley south of Tyrone, etc. It is noted that these mineralizations appear to be of hypogene origin by ascending hot mineralizing solutions. These mineralizations are located about 20 miles from the center of the Karthaus magnetic high which has a 10-mile radius. The mineralizations cited are also characteristic of the epithermal or low temperature zone which can be expected to have reached the reported mineralized regions from the intrusion. In view of the high degree of probability of the "zonal theory" of mineralization distribution around an igneous intrusion, the speculative views emitted here could be ascertained by means of an intensive geochemical exploration program of the region consist-ing of microchemical analyses of soils, plants, and ground waters for traces of mineral elements. One must not lose sight, however, of the possibility that the intrusion might be Pre-Cambrian and as such would have neither structural nor mineralizing significance. This point could be settled by a geothermal investigation of the high, as an intrusion contemporaneous with the Appalachian revolution would have a geothermal anomaly. Other observations point to the unlike-lihood of a Pre-Cambrian intrusion, i.e., the broadening of the sedi-mentary anticline in the region of Karthaus and the presence of radial and peripheral faults in the northwest of the Philipsburg quadrangle indicate that some abnormal subsurface forces were at play at time of folding.

3. A further striking observation is the rapid decrease of the earth magnetic field southeast of the Allegheny Front toward the area of intense folding. This must be interpreted as a thickening of the relatively nonmagnetic sediments covering the basement rock. In the region of State College and Bellefonte one should expect the Pre-Cambrian rocks to be at least 10,000 feet deeper than west of the Allegheny Front. Though the airborne survey covered but a small area of the strongly folded rocks, the conclusion expressed here is further borne out by a vertical magnetic profile measured in 1942 as far as the Seven Mountains to the southeast, which indicated a con-stant decrease of the vertical component of the earth magnetic field.

These conclusions are quite in keeping with the modern views on mountain building theories as propounded by Vening-Meinesz [9], Kuenen [6], Hess [4], Griggs [3], and others. According to these authors, mountain building chains result from the squeezing out under lateral compression of great and narrow oceanic troughs filled with relatively unconsolidated sediments. This theory preassumes the existence of a deepening trough within the igneous (usually acid) substratum which gradually fills up with sediments. The observed decrease in the magnetic field in the region of State College and Bellefonte is but a fossil witness of the mechanism which gave rise to the great Appalachian revolution. This is further substantiated by the large isostatic gravitational anomaly known to be centered around Harris-burg [7].

4. Further large-scale magnetic anomalies may be reported.

a. The complicated contours southwest of Houtzdale are interpreted as a possible shallow peridotite dike. This type of igneous activity is known to be common in Appalachian folds, the nearest being at Dixonville, Indiana County, just outside the area surveyed [5].

b. A small magnetic low north of Bellefonte is well evidenced, though its significance is not clear due to its cross trend.

c. Generally the known synclines are marked by magnetic lows, unless disturbed by the large intrusional highs.

B. *Second Order Magnetic Anomalies*

Second order or residual magnetic anomalies are those which are obtained after subtracting the first order anomalies. Procedures for such reductions have appeared in the literature [2]. Residual anomalies are those which have the most significance from the point of view of oil and gas accumulation. It is justified to assume that all small magnetic highs shown on the second order anomaly map (Map 3) correspond to structural highs within the sedimentary rocks, though allowance must be made for the structural crest offset owing to the magnetic field's inclination of 75 degrees.

It is advised, however, not to venture drilling on these magnetic highs in search for oil and gas unless their existence be substantiated and corroborated by independent geological evidences or geophysical measurements of a different nature; i.e., responding to a different physical property of the rocks, such as contrast in density, electrical conductivity, elastic modulus, etc.

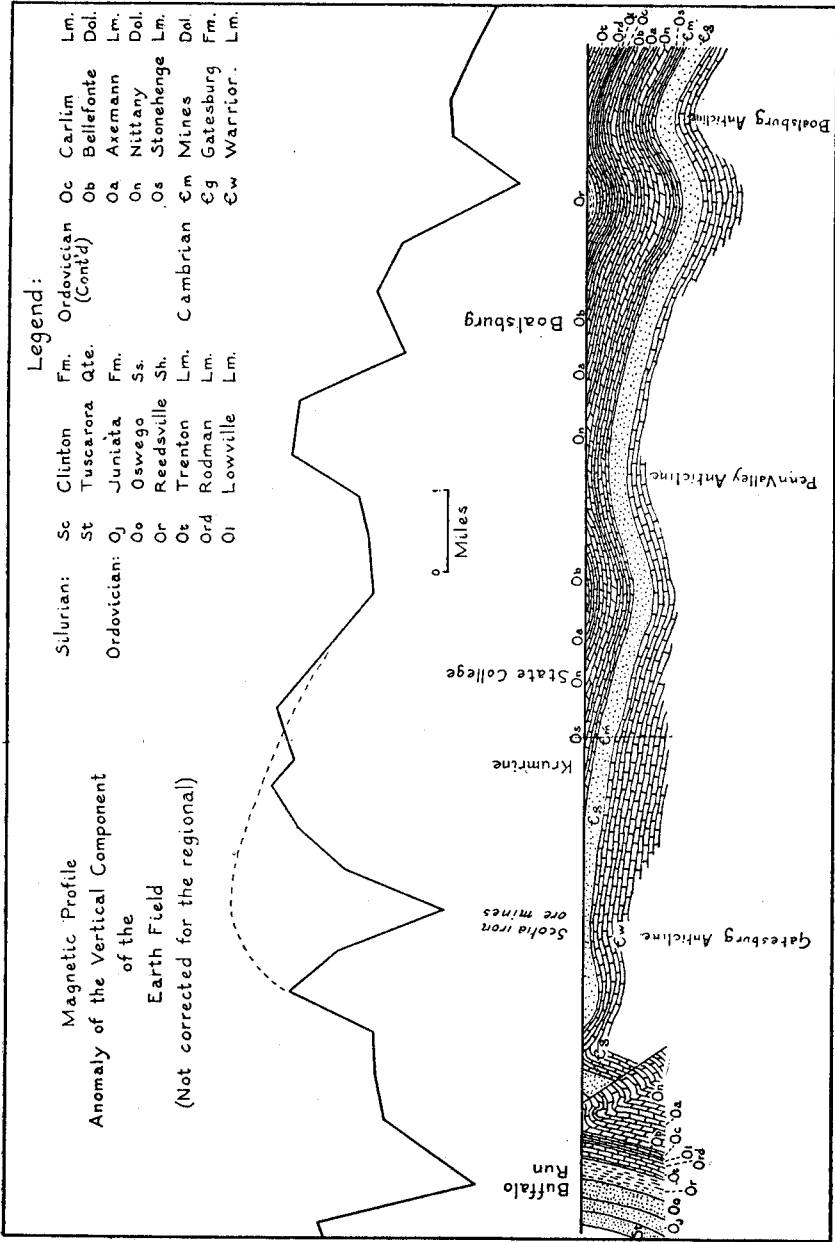## C. *Third Order Magnetic Anomalies*

Third order magnetic anomalies are those which are obtained after elimination of first and second order anomalies. Generally they are extremely difficult to recognize, and it is often difficult to distinguish between a second and a third order anomaly.

Third order anomalies have stratigraphic significance. They may be produced by a magnetic sediment or by the disappearance of magnetism from a normally magnetic sediment.

The only recognized magnetic sediment in the area is the Gatesburg formation which, when weathered, loses its magnetic susceptibility and becomes a fine potential reservoir rock for oil and gas.

The loss in magnetism is well illustrated over the Gatesburg anticline where normally a magnetic high is expected. It is noted,

Legend:

Silurian:
Sc Clinton Fm.
St Tuscarora Qte.

Ordovician:
Oj Juniata Fm.
Oo Oswego Ss.
Or Reedsville Sh.
Ot Trenton Lm.
Ord Rodman Lm.
Ol Lowville Lm.

Ordovician (Cont'd):
Oc Carlim Lm.
Ob Bellefonte Dol.
Oa Axemann Lm.
On Nittany Dol.
Os Stonehenge Lm.

Cambrian:
€m Mines Dol.
€g Gatesburg Fm.
€w Warrior. Lm.

Magnetic Profile
Anomaly of the Vertical Component
of the
Earth Field
(Not corrected for the regional)

Miles

Boalsburg Anticline
Boalsburg
Penn Valley Anticline
State College
Krumrine
Scotia iron ore mines
Gatesburg Anticline
Buffalo Run

however, that an airborne magnetic low is observed west of Bellefonte over the anticline. This relationship was already recognized in 1942 with the vertical intensity profile from Seven Mountain to Sandy Ridge, as shown in Figure 2, and was further verified during this survey, with both the vertical and the airborne methods.

Within the geosyncline, however, where the Gatesburg is buried under some 10,000 to 15,000 feet of sediments, the surface magnetic effect of an erosional feature associated with a possible late Cambrian unconformity would be a reduction in magnetic field intensity of but a few gammas.

Nevertheless, some of these seemingly third-order anomalies are observed on the flanks of first-order magnetic highs, notably between Clearfield and Penfield on the Chestnut Ridge, in two small areas just south of Luthersburg, and finally on the Chestnut Ridge north of Karthaus, at the intersection of the anticlinal axis with the postulated dike from the Karthaus high.

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Geologic Aspects of Petroleum Exploration in Pennsylvania

by

FRANK M. SWARTZ
DIVISION OF GEOLOGY

INTRODUCTION

Exploration to replenish the dwindling known reserves of oil and gas in Pennsylvania must be directed, first, toward discovery of heretofore undeveloped occurrences in Devonian and Mississippian strata that provide present production in the State and, second, toward search for supplies in geologically older and deeper horizons.

In response to an inquiry by A. E. Booth, the writer in 1944 prepared a stratigraphic chart (Figure 1) designed to give insight into oil and gas possibilities near Bradford, Pennsylvania, at horizons deeper than those reached by the deep test well at Derrick City. In this chart rock successions near Chambersburg and Bellefonte were plotted from the surface geological work of Stose [8] and Butts [4] respectively. The log for the Derrick City well was obtained from Fettke's report [5]. Subsurface sections near Niagara Falls and Boston, New York, were taken directly from Figure 4 in a paper by Torrey, Fralich, et al [11] on "The Geology of New York and Northern Pennsylvania." The section near Niagara Falls seems to be based on the Depew No. 2 well of Erie County, New York; deep horizons in the section near Boston apparently were generalized from the Depew No. 2, Bemus Pierce, and George Button wells of Erie County, since the New York Geological Survey has not reported wells drilled to the

FIGURE 1 can be found in a pocket on inside back cover.

Pre-Queenston near Boston. The chief inaccuracy resulting from use of the synthesized Boston section is the small value given for the Upper Cambrian "Potsdam" sandstones, which recently have been penetrated in much greater thickness in Wyoming County.

The 1944 chart represents a preliminary step in the geological approach to oil and gas possibilities of deep horizons in northern Pennsylvania. It employs the method of gathering stratigraphic information about strata in areas adjacent to the region of interest, to provide interpretations of likely progressive changes through the area of unproved subsurface occurrence. The chart suggests that the Bald Eagle-Oswego sandstones extend to a wedge-out somewhere near Bradford, and that they overlie a thick sequence of marine shales having promise as the source of petroliferous materials. The Trenton-Black River limestones can be expected between subsea depths of about 6500 and 7500 feet and are of interest because of productivity in New York, Ohio, and Indiana. The dolomites of the Beekmantown group, 3000 feet thick near Bellefonte, should thin out markedly toward Bradford but nevertheless may provide significant zones of porosity. Thinning of these and other strata presumably is in part a result of discontinuities in deposition, involving periods of emergence and leaching. The sandstones of the thick, Upper Cambrian Gatesburg formation of central Pennsylvania appear to continue northward into the so-called Potsdam sandstones reached in several deep wells in western New York, where their yield of salt water gives proof of porosity. Much of the thick Cambrian sequence found beneath Gatesburg horizons in central and southern Pennsylvania should progressively wedge out between Bellefonte and Bradford; their thinning, northerly remnants may nevertheless have served as source rocks for gas and oil.

It is thus clear that there are a number of Pre-Medina horizons in Pennsylvania that deserve consideration in plans for future deep tests near Bradford and in neighboring regions. Such strata merit fuller geological investigations of thickness distributions, paleogeography of deposition, and relation to crustal movements that oc-

curred both during and subsequent to sedimentation. Sandy and potentially sandy strata of near-shore marine sequences deserve first consideration because of likely porosity as well as association with favorable source rocks. Carbonate rocks made porous by leaching incident to emergence, or by the shrinkage of dolomitization, may furnish extensive porous zones; limestones and dolomites are important as reservoir horizons in parts of Texas and in some of the mid-continent oil fields.

Correlated with the stratigraphic-paleogeographic investigations, there is need for structural studies that will deal with relations of crustal movements to localization of textural and thickness changes of sediments, to regional and local dips affecting migration of oil and gas, to form of domes, and to deep structures involved in geophysical problems. Crustal warping active during sedimentation may have produced shallowed belts of the sea floor especially favorable to shoals with coarsened and well-winnowed sand. Uparched portions of surfaces of temporary emergence will tend to undergo more active leaching and solution. Both deformation and sedimentary convergence must be considered in studies of the form of domes and their changes in location and amplitude from ground level down to horizons of potential reservoirs and to levels involved in geophysical investigations. Compaction, cementation, and fracturing are all likely to have been influenced by crustal deformation as well as by weight of overburden.

A number of studies recently in progress in the Division of Geology bear upon these problems of the oil and gas possibilities of deeper horizons. Separate reports on most of these studies will eventually be published. The projects will be briefly outlined at this time to indicate their scope. Their subjects are: 1) surface structure in the area of the Philipsburg magnetometer survey and relation to geophysical data; 2) geologic usefulness of aerial photographs in western Pennsylvania; 3) structure and convergence in selected gas

fields in New York and Pennsylvania; 4) stratigraphy, convergence, and paleogeography of Trenton and sub-Trenton at their outcrop in Pennsylvania, Maryland, and New York.

SURFACE STRUCTURE IN AREA OF THE PHILIPSBURG MAGNETOMETER SURVEY, AND RELATION TO GEOPHYSICAL DATA

Interpretation of magnetic and other geophysical data requires full consideration of available geological information. Accordingly, a map (See Figure 2) showing structural features of the surface geology has been prepared by G. H. Crowl for use in conjunction with the airborne magnetometer survey of the Philipsburg region, conducted co-operatively in 1946 by the Divisions of Geophysics of the United States Geological Survey and of The Pennsylvania State College. In the southern tier of the eight quadrangles covered by the flights, structural contouring on the Upper Freeport coal in the Curwensville and Houtzdale quadrangles was obtained from publications by Ashley [1] and Ashley and Campbell [2] respectively. Similar data for part of the Philipsburg quadrangle were kindly furnished by the Pennsylvania Geological Survey from Dr. Ashley's unpublished work. Structural axes in the Bellefonte quadrangle were taken from Butts's [4] geologic map.

The four northerly quadrangles of the magnetic survey have not been remapped geologically since the days of the Second Pennsylvania Geological Survey. For these quadrangles Crowl obtained approximate strike-dip directions and locations of structural axes by stereoscopic studies of paired aerial photographs. Positions of the axes are believed to be reasonably correct. Supplementary field work would, of course, be required to determine changes in pitch of the axes and values of dips in the limbs of the folds.

FIGURE 2 can be found in a pocket on the inside back cover.

The structural map compiled by Crowl is shown in Figure 2 with an overlay of the isogam contours prepared by Pirson and Bacon from the airborne magnetometer survey, the results of which are discussed in full in the accompanying paper by Pirson and Bacon. In the following comments attention is directed to several geologic implications of the study.

Comparison of the geological and geophysical patterns of the map reveals major divergences between the surficial geologic structures and the magnetic reflections of deep geologic features. Whereas the surface geologic structure northwest of the Allegheny Front is dominated by a series of gentle anticlinal and synclinal folds that trend northeast-southwest, the major magnetic features are two rounded highs contrasting with two extensive lows that trend northwest-southeast. The major magnetic high, centering south of Karthaus, is represented by several concentric isogam contours, and has one spur extending to the northeast, one to the north. The surface axis of the Laurel Ridge anticline crosses the center of the Karthaus magnetic high, and the northeastern spur of the magnetic high is nearly coincident with the continuation of this anticlinal axis. The northern spur of the Karthaus magnetic high is directed across the surficial geological axes. The trend of the magnetic low that extends toward Clearfield from a point southeast of Houtzdale, and that reappears near Penfield, likewise diverges strongly from the axes of the surface folds. The magnetic high southwest of Curwensville is rounded rather than linear in form; its center lies well to the east of the surface axis of the Chestnut Ridge anticline and is nearer the surface axis of the Clearfield syncline.

Southeast of the Karthaus magnetic high, the magnetic intensity decreases continuously in value to and probably beyond the southeastern corner of the Bellefonte quadrangle. The Nittany Valley arch, though it is a dominant feature of the surface geology of the region, is reflected only by a terrace-like flattening of the magnetic

gradient. The Gatesburg and Buffalo Run anticlinal axes shown in Figure 2 together constitute the axial region of the Nittany Valley anticlinal fold.

Pirson and Bacon's suggestion that the large, roughly circular magnetic anomalies south of Karthaus and southwest of Curwensville probably reflect basic intrusive igneous bodies richer in magnetite than adjacent rocks, has considerable geologic plausibility. It is less clear whether such masses would more likely be elements of the Pre-Cambrian basement complex, or whether they may penetrate the deeper part of the Paleozoic sediments. Small faults have been recognized in the Philipsburg and Houtzdale quadrangles (See Figure 2). These so far as known tend to be roughly perpendicular to the axes of surface folds, and in view of their continuation southwestward along a belt paralleling the Allegheny Front, do not seem to have special relationship to emplacement of an igneous mass at the magnetic high near Karthaus. Peridotite dikes have been discovered in western Pennsylvania [5], and there are random small-scale mineralizations in central Pennsylvania that may have been derived from solutions of igneous origin. None of these can be connected directly with the possible deep intrusive masses near Karthaus and Curwensville, though they are suggestive of some limited but regional deep igneous activity.

The possibility that the magnetic highs may reflect concentrations of magnetite in Paleozoic sediments rather than in metamorphic and igneous rocks of the Pre-Cambrian basement cannot wholly be eliminated with present knowledge; there is, however, little evidence in favor of such an hypothesis.

Whatever their detailed cause, it seems reasonably clear from comparisons with the surface geology that the large magnetic highs south of Karthaus and southwest of Curwensville, and the major lows that contrast with them, reflect deep geologic features other than true domes and sags of the deep Paleozoic sediments and of the Paleozoic, Pre-Cambrian junction. Magnetic reflections of the fold

structures of the deep Paleozoics must, it appears, be sought in smaller features of the magnetic variations.

The essential coincidence of the northeasterly spur of the Karthaus high with the surface position of part of the Laurel Hill anticlinal axis suggests that this spur may represent the same arch as developed at depth. An elongated magnetic low northwest of the Karthaus spur lies along the Clearfield syncline, as does another small low south of Clearfield. The saddle between the magnetic lows respectively southeast and northwest of Clearfield is traversed by the surface axis of the Chestnut Ridge anticline.

Although this approximate geographic agreement of various secondary magnetic features with corresponding surface anticlines and synclines suggests structural interrelationship, the supposition that the magnetic variations reflect folds at the base of the Paleozoic sediments must be treated for the present as a fairly plausible hypothesis, needful of further proof. There are two sets of troublesome facts that must be given special consideration in this connection. In the first place, various other secondary magnetic features trend across the axes of the surface rock folds, although they seem comparable in form and amplitude to the anomalies paralleling the surface axes. In addition, the secondary magnetic features compared with gentle surface rock flexures to the northwest of the Allegheny Front are much stronger than the magnetic "terrace" associated with the major Nittany Valley arch.

With respect to the first of these questions, the magnetic spur extending northward from the Karthaus magnetic high is reasonably comparable in form, dimensions, and amplitude to the northeasterly spur; there is no direct reason except comparison with surface axes to suppose that the two magnetic spurs are fundamentally different in nature as is demanded by the hypothesis that one spur reflects deep folds of the Paleozoic sediments, whereas the other does not. If the Karthaus high actually represents a magnetite-rich intrusive igneous body, both of the spurs could represent igneous offshoots of

the main rock mass. The magnetic low near Penfield is comparable in geographic size, in general pattern, and, in a reverse sense, in amplitude to the spurs of the Karthaus high. Like the northerly spur it is transverse to the surface geologic axes.

The lack of appreciable magnetic reflection of the major Nittany Valley arch is one of the surprising results of the magnetic survey and raises significant problems about deep structures.

Geologic mapping in and near Nittany Valley gives measure to the magnitude of this arch and shows that if the surface of the Pre-Cambrian, Cambrian junction is reasonably concordant with surface structures it should rise more than 15,000 feet from the Allegheny Front to the vicinity of the axis of the Nittany Valley fold. If, on the other hand, the magnetic gradient truly reflects the slope of the surface at the base of the Paleozoics, then there is no such rise of the surface of the Pre-Cambrian rocks, but instead there is a descent of possibly 5000 to 10,000 feet; hence there would be a tremendous change in geologic structure from ground level to the base of the Paleozoics, and Early Paleozoic strata would have to be mashed together to fill the space between the Pre-Cambrian surface and the uparched strata exposed at ground level.

Considerable duplication of subsurface strata may occur where the Birmingham overthrust and several adjacent faults are strongly developed in Nittany Valley in and beyond the southwestern corner of the Bellefonte quadrangle; but even there it would be most surprising if the subsurface rock-squashing would cancel out the Nittany Valley arch before it reaches the upper surface of the Pre-Cambrian rocks. Near Bellefonte the Birmingham fault and other overthrusts are reduced to a minimum so far as has been detected in the surface geology. Lack of such collapse in the surface formations makes it seem unlikely that the subsurface strata could be mashed together in the degree required if there is at this place no appreciable rise in the Pre-Cambrian surface.

If, on the other hand, the surface of the Pre-Cambrian rocks

does rise in about the manner suggested by the surface geology, then the variation in magnetic susceptibility from the Paleozoics to those Pre-Cambrian rocks flooring the Nittany arch must be small. The magnetic gradient instead of reflecting surface features of the Pre-Cambrian basement would result presumably from changes taking place within, and perhaps deep within the Pre-Cambrian rocks themselves. It might further be expected that, since the Nittany Valley arch produces so small a magnetic anomaly, the northeasterly spur of the magnetic high near Karthaus is too great in amplitude to be caused by the gentle Laurel Hill anticline with which it is geographically associated.

The magnetic survey provides data of great interest. It requires review of the whole problem of subsurface geologic structure in central Pennsylvania. Interpretations of the deep geology of the region must satisfy the facts both of the magnetic anomalies and of surface geology. Interpretation of deep structures of the region is still in the stage of speculation. Additional types of geophysical data, such as a gravimetric survey, may prove helpful.

GEOLOGIC USEFULNESS OF AERIAL PHOTOGRAPHS IN WESTERN PENNSYLVANIA

Stereoscopic examination of aerial photographs throughout the northern half of the area of the airborne magnetometer survey of the Philipsburg region has provided a considerable test of the usefulness of this technique in Pennsylvania. The photographs used were obtained from the United States Department of Agriculture. The United States Geological Survey has sponsored aerial photographing of some parts of Pennsylvania, generally during periods of sparse vegetation so that geologic features are better shown.

Where topography is fairly rugged in western Pennsylvania, traceable benches are generally recognizable on the hill slopes. (See

Figure 3. AERIAL PHOTOGRAPH SHOWING WELL DEFINED BENCHES FORMED BY GENTLY DIPPING STRATA, IN AREA 6 TO 8 MILES SOUTHEAST OF TYLER, CLEARFIELD COUNTY, PENNSYLVANIA.

Figure 3.) Since these benches follow crops of particular strata, they yield much geologic information. Where the surface is flatter, benches become more obscure and geologic results of photographic studies may be few.

The stereoscopic method has proved reasonably satisfactory for rapid reconnaissance of larger structural features. Its proper role, however, lies in its use directly in conjunction with field work. Taken to the field base, the photographs and stereoscope can provide very valuable tools for interpretation and projection of day-by-day geologic work. During the past summer a co-operative Pennsylvania Geological Survey and Pennsylvania State College field party employed steroscopes with gratifying success. Mirror stereoscopes are much more helpful than simpler types.

STRUCTURE AND CONVERGENCE IN SELECTED GAS FIELDS IN NEW YORK AND PENNSYLVANIA

Insight into the nature of domes and folds in northern Pennsylvania and southwestern New York can be considerably advanced by further studies of depths and thicknesses of rocks penetrated by drilling. Some work of this type has been published by Bradley and Pepper [3] and by Robinson, Jones, and Gaddess [7]. Additional investigations are needed and should consider such problems as the nature and origin of the folding or doming stresses, the relation of asymmetry to the manner of application of folding stresses, the question of activity of the arch during the time of sedimentation, and the role played by regional and by local convergence.

The writer has co-operated in a discussion of these problems as they affect the Wayne-Dundee gas field of New York [10]. This fold was selected for initial study because it has been extensively drilled so that good geological records are available, and because it has not been much affected by faulting. Full consideration of fold forms and origins in northern Pennsylvania and southwestern New York must deal with the faults that in some instances are strongly developed.

However, such faults not only complicate observation of the form of the fold, but also obscure the effects of convergence and early warping.

In the Wayne-Dundee field, as discussed separately by L. F. Adams and the writer, there is evidence that the fold was active during the deposition of the sediments in which it occurs. Studies of additional domes are much needed to determine whether this was a regional phenomenon in western Pennsylvania and western New York. The axis of the Wayne-Dundee fold trends almost due east-west and nearly parallels the direction of westward convergence of the sediments. In folds farther south and southwest, the trend of the fold axes is more nearly perpendicular to the direction of sedimentary convergence, and the role of convergence in form of fold will correspondingly be modified.

The form of folds, changes in location and amplitude of the fold at depth, and relation of activity of the fold during sedimentation to porosities of coarsened textures and of leaching, have much significance in problems of exploration for oil and gas by geological and geophysical means, as well as upon general questions of oil and gas migration and accumulation.

STRATIGRAPHY, CONVERGENCE, AND PALEOGEOGRAPHY OF TRENTON AND SUB-TRENTON IN OUTCROP AREAS IN PENNSYLVANIA, MARYLAND, AND NEW YORK

By invitation of the Pittsburgh Geological Society, the writer contributed a discussion of the stratigraphy, convergence, and paleogeography of deposition of Trenton and sub-Trenton sediments of the outcrop areas in Pennsylvania, Maryland, and New York for the May 1947 symposium dealing with oil and gas possibilities of these rocks in central and eastern parts of the United States. The Pennsylvania Geological Survey co-operatively furnished support for continuation of this project during the past summer.

In the course of this study, a series of stratigraphic charts were

prepared that summarize the lithologic characters, thicknesses, and lateral changes in Lower Cambrian, Middle and Upper Cambrian, Lower Ordovician, and Middle Ordovician sediments where they are exposed in central Maryland, central and southeastern Pennsylvania, and eastern and northeastern New York. The stratigraphic information has in each instance been used to draw preliminary convergence or isopachous maps to show the trends of the deposits. The stratigraphic charts and isopachous maps together serve as a basis for considering the paleogeography of deposition of the sediments, and thus for providing insight into the source relations of the clastic materials, and their directions of transport. Such data provide the groundwork for attempts to outline subsurface distribution of the sediments, changes in lithology and clastic textures, and effects of crustal activity and emergence, needed in geological planning for future deep exploration.

Briefly, the Lower Cambrian sediments reach their maximum known thickness for the area in southcentral Pennsylvania and central Maryland, where they include thick and widespread sandstones. It is expected that these deposits thin out northwestward in such fashion that they will not be very important in regions of present oil and gas interest. On the other hand, the Upper Cambrian strata of central Pennsylvania contain sand interbeds that wedge out in equivalent sediments to the southeast. The geography of these deposits suggests that the sands were derived from the north; these sands, though deep for exploration in northern Pennsylvania, have promise as reservoir horizons because of probable persistence, thickness, and porosity. The Lower Ordovician is composed in central Pennsylvania of a thick carbonate sequence with only one sand body that is at all significant. Thick dolomite members furnish possibility of dolomite porosities, and unconformities with associated zones of leaching are likely to increase in number and significance in the thinning northerly subsurface extensions. The Middle Ordovician limestones of central Pennsylvania in part pass eastward into clayey and some sandy sediments. In northern and western Pennsylvania and in southwestern New York the

oil and gas possibilities of the Middle Ordovician limestones presumably depend upon leached and cavernous horizons associated with unconformities.

The proceedings of the Trenton, Sub-Trenton symposium are to be published by the American Association of Petroleum Geologists.

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Petrologic Aspects of Prospecting for Deep Oil Horizons in Pennsylvania

by

PAUL D. KRYNINE
DIVISION OF MINERALOGY

INTRODUCTION

The present paper is to be considered as a preliminary progress report on work carried out since the spring of 1946 by the Division of Mineralogy. The amount of accumulated material so far is extremely large, and publication of quantitative data and final interpretation is reserved for a series of final reports on the various phases of the problem.

The purpose of the present report is to acquaint the oil industry of the Commonwealth with the basic problems that will have to be solved if new oil fields are to be discovered in the Appalachian region and to present a review of the fundamental research methods that are being used in the solution of these problems.

Prospecting for new oil fields in the Appalachian region involves fairly expensive drilling through rather hard rocks. Since the oil industry in Pennsylvania is in the hands of a large number of relatively small independent companies with limited capital, it follows that before drilling any expensive wildcats great care should be taken in their location to avoid unnecessary money losses and discouragement.

The location of a wildcat well, like any other scientific or technological problem, can be solved directly — with luck — through the use of the time-honored, but rather expensive, trial and error method, generally based upon the use of geological analogies.

However, it might be a good idea first to make a thorough analysis of the principles of oil finding as applied to the peculiar conditions of the Appalachian province in order to discover which prospecting method, concept, or tool would best fit the conditions.

At present all methods of oil findings are based essentially upon the interpretation of indirect evidence and consist in observing and measuring some conspicious geological or physical property which is thought to be connected with the occurrence of an oil pool. In order to test the validity of the extrapolation of such secondary characteristics through the method of analogies, it is necessary to see how these secondary properties are related to the basic primary feature—namely, the occurrence of an oil field, which in its turn is nothing but a rock reservoir filled with oil that can be extracted at a profit. In a nutshell — no reservoir, no oil pool.

WHAT IS AN OIL RESERVOIR?

An oil reservoir can be defined pragmatically as possessing the following characteristics:

1. Adequate porosity to store fluids in general (P).

2. Adequate porosity to store oil preferentially against water (P$_o$).

3. Adequate permeability to allow flow of oil to a well (K).

4. Adequate yield—i.e., the property of maintaining sufficient permeability for adequate periods of time (K$_y$).

5. Proper type of fluid reactivity during drilling and production (R).

P and P$_o$ are almost absolute; i.e., they are not essentially affected by drilling and exploitation methods. On the other hand, K and K$_y$ are relative; i.e., they are to a large extent a function of the reaction of the rock with introduced fluids. The introduced fluids may come from the well, or they may be connate water from other portions

of the reservoir that is set in motion when fluid circulation begins toward the well. Hence, K and K$_y$ are dynamic and changeable figures and R controls the measures of such possible changes.

These economically valuable mass properties (P, P$_o$, K, K$_y$, R) which pragmatically define an oil reservoir are determined by the interplay of many petrographic variables in the solid reservoir phase (the rock itself) either alone or in conjunction with a series of reactions with the liquid phase.

These petrographic variables which control porosity, permeability, and yield are together known as pore pattern. This term includes pore size, pore density, capillary size, capillary density, mineral lining of capillaries, and reactivity of the minerals which form the walls of the said pores and capillaries.

It is impossible to give one single, unique quantitative definition of these petrographic variables, since in the sandstones alone there are three major series of rocks—namely, the arkoses, graywackes, and quartzites—all of them vastly different in composition and texture and hence possessing vastly different reservoir characteristics.

At present all the production of the Appalachian region comes essentially from sandstones of the graywacke type which are either not too well sorted ("dirty" sands), such as the Bradford sand, or somewhat better sorted ("clean" sands), such as the Venango sands. Preliminary work on graywackes shows apparently that an adequate oil reservoir in a sandstone of the graywacke class may be limited by certain quantitative values. These values involve "visible" porosity, or the amount of large pores easily observable under the microscope, and "residual or capillary" porosity, which refers to the network connecting the larger pores.

Quantitatively these limiting values seem to be as follows:

A. Visible porosity
   Pore size_____45 microns or more
   Pore density_____Over 5% of the rock

B. Capillary or residual porosity

Capillary size	⎱_____⎰No adequate quantitative
Capillary density	⎰	⎱data available
Lining of capillary walls___Less than 50% of wall area

These are very preliminary figures based on limited work and at present can be considered to be indicative at best of orders of magnitude only.

This pore pattern in its turn is only a derived property and is a function of certain fundamental features of the basic petrographic makeup of a sand which is expressed in terms of composition and texture. These fundamental petrographic properties are:

Grain size
Grain shape
Amount of matrix (fine clayey or silty material)
Degree of sorting
Character of the distribution of the fine material between
	the sand grains
Mineral composition of the grains
Mineral composition of the fine matrix
Amount, distribution, and composition of the chemical
	cements

In evaluating a sand it is necessary to differentiate between *sandiness* (ratio of sand grains to fine matrix, a property expressed on a field scale by the sand : shale ratio) and *coarseness* (the mean diameter of grade size of the sand grains themselves). Usually there is a relation between coarseness and sandiness, just as there is a relation between porosity and permeability, but this relationship is not necessarily direct nor absolute.

The relation between pore pattern on the one hand and composition and texture on the other, and also the mutual relations between porosity and permeability, pore pattern and petrographic makeup, are at present rather tentative and qualitative at best. However, it seems possible that one of the most fundamental properties of an oil reservoir, namely P_o, preferential porosity for oil, is a function

of a pore pattern which may in time be directly expressed in terms of grain size. On the basis of the work done by Illing and especially by J. C. Griffiths (personal communication based on unpublished work), it appears that as a whole gas sands, oil sands, and water sands fall roughly in the following classes:

Gas sands	— Over 250 microns in diameter
Oil sands	— Between 74 and 250 microns in diameter
Water sands — Below 88 microns in diameter

This is shown graphically in Figure 1 (largely compiled by J. C. Griffiths). These values refer to sandstones showing some degree of consolidation. In the case of completely loose sands a somewhat lower limit for oil sands may be possible.

In the case of nonuniform heterogeneous sand lenses such selective segregation of oil against water in the relatively coarser lenses may take place regardless of any hydrostatic or gravity control.

Hence changes in the fundamental petrographic makeup as reflected by changes in the pore pattern will lead to considerable alteration in the physical mass properties of a reservoir rock. In all cases such a favorable reservoir pattern represents a selective concentration of favorable petrographic features which *normally are not present in the average sand.* Such a favorable selective concentration transforms the rock from an ordinary sandstone into an actual or potential oil reservoir. Hence oil reservoirs can be considered as slightly abnormal sedimentary concentrates; they can be compared to placers, and they bear to the normal barren sandstone the same relationship that metallic ore deposits bear to the normal, barren, igneous rock.

The presence of an adequate reservoir is the absolute prerequisite for an oil field. If such a favorable reservoir happens to be homogeneous over a fairly extensive horizontal distance, then very late structural changes may cause the oil to move up-dip for some distance, and hence result in lateral migration. This, as everyone knows, has been the basis of the anticlinal theory which is the cornerstone of the "structural" or garden variety of oil finding. How-

ever, in the case of limited horizontal homogeneity (meaning sand lenses or even pronounced textural variations within *one* sand layer) the differentiation between oil sands and water sands may not depend so much upon late structural movements. This happens to be true for "Stratigraphic Traps," which includes practically every oil field in the Appalachian region.

ORIGIN OF OIL RESERVOIRS

Oil reservoirs are abnormal sedimentary concentrates and essentially represent some break in an otherwise uniform sedimentary cycle. These abnormal conditions tend to impose upon the sediment a pore pattern that will make it possible to store oil. The basic petrographic setup (composition-texture) which determines whether a rock is a potential reservoir or not may be established very early in the life of a sediment (primary, early sedimentary, depositional or syngenetic), or it may be subsequently superimposed upon the sediment (secondary, intrastratal, post-diagenetic, epigenetic).

Sedimentary or primary breaks in the normal process of deposition resulting in the formation of porosity may be based upon the removal of fine-grained material (clay) due to the "winnowing" of an otherwise "dirty" sand. This is produced through a process of selective sorting, operating over a fairly long period of time within the sand bars, beaches, or other sandy bodies; such conditions run along shore lines which have ceased to subside and remain stable for a certain length of time, thus interrupting the continuous process of normal mixed sedimentation of sand and clay. In the case of "clean," clay-free sands (quartzites), which are usually cemented by carbonate or silica cement, primary porosity may be due to an inadequate amount of cement; this in its turn may be due to a decrease in precipitation of cementing material from sea water, relative to the amount of physical detritus which is concomitantly mechanically dumped into the basin of deposition simultaneously.

Secondary or geochemical porosity, on the other hand, is pro-

duced by changes that leach, reprecipitate, or recrystallize chemically favorable constituents along zones of weathering or lines of underground fluid circulation controlled by so-called thermal, chemical, pressure, or saturation gradients.

Very little sedimentation takes place under static conditions and very little differentiation, either primary or secondary, takes place under conditions of prolonged equilibrium (either static or dynamic). Hence, all interruptions of normal sedimentary processes or disruptions of established intrastratal equilibrium mean some sort of structural deformation. However, this structural deformation, in order to be effective in producing porosity, must be early rather than very late. This means that porosity itself is a measure of structural deformation and that the location of oil reservoirs depends upon structure. The factors involved are much more complex than the mere shifting of oil within the reservoir to the structurally highest point. In order to be effective in controlling porosity (rather than initiating late migration), structural deformation must be early, in which case it may not be reflected at all on the surface of the ground; conversely, structural conditions within the region *after the formation of the reservoir,* as observed from surface geology, may be quite ineffective in determining the location of the reservoir.

Regardless of the origin of the porosity, be it primary or secondary, oil may tend to collect in the reservoir as it passes through it during the true process of vertical migration. On the basis of the experimental work done by Illing and of the tabulation of field data done by J. C. Griffiths of the Division of Mineralogy, it seems that there may be a definite preferential collecting of oil within sands that have a certain porosity pattern. On the other hand, water and gas seem to collect in sands that are respectively finer or coarser grained. Finally, in addition to this preferential saturation by oil, there may be an additional gravity separation of the conventional type into gas-oil and water with possibly considerable lateral migration if the reservoir is homogeneous in porosity and permeability. However, such lateral migration in Pennsylvania is hardly to be

expected in the very heterogeneous Devonian or Ordovician sediments, and in these primary preferential oil concentration is probably the rule. Nevertheless, in the potential, deep, orthoquartzite horizons of the Cambrian, considerable lateral migration may take place.

All selective or differential sedimentary or geochemical processes, which develop in porosity, since they are the result of structural deformation, are naturally related to a variety of other secondary features (geological or geophysical), which, if properly understood, may be used as landmarks of geological and geophysical exploration. Anticlines are the simplest and most obvious examples of secondary features that are related to primary oil producing fundamentals; namely, the possibility of late lateral migration toward a structural high. However, anticlines do not "work" in Pennsylvania. What is more, in the Appalachian region we are after the identification of early structural deformation that caused porosity (rather than lateral migration), and hence other secondary features useable for exploration must be found.

RECOGNITION AND DISCOVERY OF OIL RESERVOIRS

In order to tell a possible oil reservoir rock from one that is not, it is necessary first of all to establish what the differences between them are and then, if possible, to work out transitional gradients between the two; gradients that can be followed through the use of appropriate exploration techniques. For instance, in prospecting in the Devonian of Pennsylvania it would be necessary to learn first the differences that exist between the Bradford sand and the barren portions of the Chemung which at many places also carry sands. Also, when prospecting in "clean" sands of the Oklahoma Wilcox type, it may be necessary to establish what differences exist between those parts of the Wilcox that are "loose" and those that are tightly cemented and not porous. After such differences have been established, the occurrence of reservoir rocks should be related to some secondary features susceptible of discovery by surface or subsurface geological or geophysical methods.

The present work of the Division of Mineralogy is aimed at the establishment of such basic petrographic relationships which eventually can be applied in the Appalachian region.

On a regional scale two basic criteria can be used for a general delineation of fundamentally favorable or unfavorable regional areas:

1. A favorable region should show nonuniformity in the deposition of thick sediments, in order to make possible the existence of interruptions of the shore line type that may result in adequate loci of primary porosity. This excludes from consideration certain sedimentary types; for example, high rank graywackes which, regardless of their extreme sandiness, will probably never show any adequate porosity. This also, naturally, excludes all large non-sandy shale bodies.

2. There should be a favorable, or at least innocuous, secondary history of the region, meaning no metamorphism, no effective structural fissuring and rupturing (a somewhat relative concept), and no large-scale igneous intrusions.

On a local scale the delineation of favorable areas where oil sand may be expected will essentially comprise finding the loci of reservoir formation (either of primary or of induced porosity type). In addition to the well-known conventional methods of always looking for a structural high regardless of its relative age, a method that has spectacularly failed in most of the Appalachian province, two theoretical approaches can be used for such exploratory work:

1. The application of sedimentary gradients pointing from barren to reservoir rocks on the basis of petrographic analysis of surface and subsurface samples. The character and nature of such possible petrographic gradients are being theoretically studied at present by the Division of Mineralogy.

2. The correlation of such possible porosity loci with paleogeographical and structural features that can be studied by geological and geophysical methods. The most promising, at least theoretically,

line of approach in this connection is the concept that since reservoir rocks are the product of structural deformation at an early date during sedimentation itself, and since such oil sands tend to recur on top of each other, it follows that probably in the Appalachian province, at least, such structural deformation may recur along the same structural zones. This appears to represent within the sediments a reflection of movements along zones of weaknesses in the Pre-Cambrian basement, and hence the study of active structural lines within the Pre-Cambrian basement seems to be the most promising immediate line of attack. The present work will show whether such a theoretical tie-up between the deformation of the Pre-Cambrian basement and the early "structural" porosity in the sediments above is possible in practice on the basis of the prospecting tools available at the moment.

SPECIFIC PROBLEMS OF THE APPALACHIAN REGION

On the basis of stratigraphic and paleogeographical data available it seems that possible new oil reservoirs (or at least favorable zones of porosity) may be developed in Pennsylvania outside of the present producing areas, in four different ways:

1. Lateral extension eastward of the Devonian and other Upper Paleozoic oil sands.

2. Occurrence within the Upper Ordovician Oswego graywacke of sand bodies, essentially similar to those within the Devonian.

3. Occurrence in the Upper Cambrian (Gatesburg-Potsdam) orthoquartzites of sands of an entirely different type, probably analogous to the Mid-Continent Wilcox sand.

4. Occurrence of limestone porosity in the Middle Ordovician.

Evaluation of the relative potentialities of each of these four possibilities, and prospecting for definite drilling locations within each one, will have to be carried out in each case by entirely different methods.
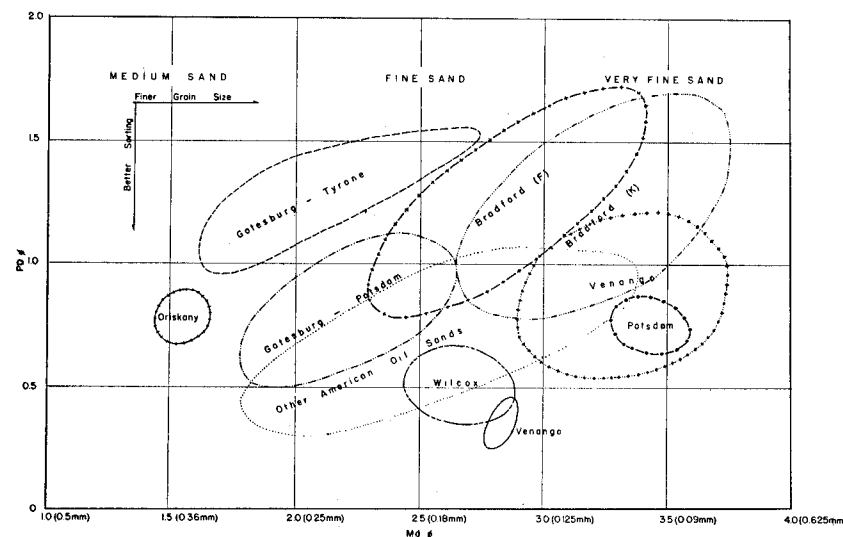
Figure 1. PLOTTING OF THE MEDIAN DIAMETERS AGAINST SORTING CO-EFFICIENTS OF MANY WELL KNOWN OIL SANDS ON THE BASIS OF KRUMBEIN'S PHI SCALE.

THE FIELDS BETWEEN 2.0 AND 3.5 PHI UNITS (0.250 TO 0.088 MM.) ARE NORMALLY OCCUPIED BY OIL SANDS. CONCEPT DEVISED BY J. C. GRIFFITHS.

1. An extension of the graywacke type of oil fields of the Devonian, or the evaluation and prospecting of the essentially similar Upper Ordovician possibilities, will have to be preceded by a tabulation of all the physical and petrographic properties of the producing portions of the Bradford, Venango, and other Paleozoic oil fields. Much of this work has been completed and either has been published or is in the files of the Division of Mineralogy.

These results should be compared with those obtained from a study of the barren portions of the same formations, first in the immediate vicinity of the oil fields themselves and second from a somewhat wider region, in order to discover the variables and establish a series of gradients showing how these variables change as an oil field is being approached. This fundamental work is now being

carried on on the basis of information obtained both from deep wells and from surface outcrops. Putting this data into usable shape will take some time. When compiled, the data will include sandiness, grain size, character of cements, pore patterns, density, and porosity. This type of fundamental work, apparently of no immediate practical significance, is nevertheless the type of research that must be carried on for any successful future exploration activity. Unfortunately until now such work has been neglected. In brief, this work should make it possible to differentiate potential reservoir areas from unfavorable regions mainly on the basis of sandiness and primary porosity.

2. In addition to this, a general evaluation of the regional background and, specifically, of the secondary history of all the possibilities located either east of the present oil fields, or at much greater depths below the present producing oil horizons, will have to be made. The objective of this work would be to give a rigorous test to the carbon ratio theory which until now has acted as a veritable bugbear in preventing any kind of large-scale exploratory work outside of the shallow Western Appalachian oil region proper.

In order to test the possibility of unfavorable lateral geographic changes when going from west to east, it will be necessary to make a traverse under strictly controlled geologic and petrographic conditions (to be absolutely certain that all examined specimens are comparable in lithology, mineral composition, grain size, and primary cementation) and to study whatever changes in density and porosity may take place along such a traverse. It is the intention of the Division of Mineralogy to make such a traverse in northern Pennsylvania in the not-too-distant future. Published data on the carbon ratio theory and reports on density and porosity changes in rocks from west to east in the Appalachian region, when critically analyzed, show that the compared rock specimens not only do not belong to identical rock types, but frequently belong to entirely different formations, and hence these results to a large extent are valueless.

In order to test the effect of compaction at depth and static load in the Lower Paleozoic, it will be necessary to make similar vertical traverses within deep wells. At present the Division of Mineralogy is engaged in a study of a series of deep wells that penetrate the Oswego and in determining the density and porosity of drill cuttings within these wells. On the basis of all the work completed so far, it appears somewhat doubtful whether the relatively great hardness and consolidation of the Appalachian sediments is the result of profound secondary changes as postulated by the carbon ratio theory. It appears at least equally possible that much of this well-known induration may be of primary origin, since the Appalachian geosyncline during the period of deposition of Paleozoic sediments was essentially a so-called "closed" geosyncline, abutting against a chemically charged epicontinental Mid-Continent sea, thus producing high initial supersaturation and fairly important early cementation. On the other hand, most of the Tertiary and Recent geosynclines are of the "open" type, abutting against deep oceanic waters, and hence as a whole show a much less intensive chemical cementation than that found in the Paleozoic sediments.

This again shows the necessity of a critical and completely objective evaluation of the possible late changes in porosity that may have been produced by static (load) or dynamic pressure, in order to show whether such differences indeed exist, and hence may be detrimental to porosity outside of the present oil producing areas, or whether they are wholly fictitious.

3. As a last step, a study is now in progress to compare and relate the occurrence of potentially favorable petrographic variables (See paragraph 1) to the occurrence of controlling paleogeographical features with the purpose of elucidating whether these controlling paleogeographical factors can in turn be reasonably and practically tied up with some second order geologic structural or geophysical properties susceptible of actual measurement and study by such prospecting tools as we have available. As stated before, the most promising

theoretical concept is the relationship between possible oil fields and recurrently active Pre-Cambrian zones of weakness, and the resulting possibilities of searching for these structural lines with the magneto-meter and gravimeter. The immediate obstacle is, of course, the necessity of interpreting exactly in these paleogeographical terms what the magnetometer or gravimeter will reveal.

4. In the potentially favorable zones of the Upper Cambrian orthoquartzites (Gatesburg and Potsdam formations) a similar study and tabulation of the relations existing among porosity development, favorable controlling petrographic criteria, and related paleogeo-graphical factors should be made and compared this time against the productive and nonproductive areas of the analogous Mid-Continent Wilcox sand.

Since the problem of evaluating and discovering Upper Cambrian reservoirs appears to be susceptible of an easier solution than that of the Oswego, and since the Potsdam is already known to be porous in many places (where it carries salt water), the major effort of the present petrologic studies is directed toward the study of the Gatesburg-Potsdam. Considerable data have been accumulated cover-ing sandiness, grain size, degree of cementation, and relative thickness of these possible Cambrian reservoirs. Detailed interpretation is now in progress. This work has been carried on in the field from the out-crops in New York State around Potsdam clear to the exposures in southern Pennsylvania on the Turnpike around Everett, and has also included a study of all the Potsdam and Gatesburg samples avail-able in deep wells drilled both in New York State and in Penn-sylvania. The work has shown that the greatest thickness of the sand is in the north and northwest and that two favorable types of porosity may exist in these orthoquartzites as follows:

a. Primary porosity due to insufficient cementation of the sand either by carbonate and/or silica during deposition. This type of porosity is analogous to certain reservoir zones within the Wilcox.

b. Secondary porosity developed in the Gatesburg by leaching

of the carbonate cement during uplift and weathering some time after deposition. This phenomena, which produces a beautifully porous sand analogous in all respects to the Wilcox sand of the Oklahoma City oil field, can be seen in outcrops around State College where it is the result of Tertiary and Recent weathering. However, petro-graphic work done by the writer has shown that such uplifting and leaching of the Gatesburg also took place in Lower Middle Ordo-vician time when erosion of such a zone of weathering produced, in the Ordovician Bellefonte formation, a sandy body (the Bellefonte sandstone) which can be shown to consist of reworked and weathered Gatesburg. The persistence of the Bellefonte sandstone suggests that this Lower Middle Ordovician area of uplift accompanied by weathering of the Upper Cambrian may have been extensive; and, on the basis of preliminary and at present incomplete data, the locus of a possible uplift is tentatively placed to the northwest of State College at a distance that may have ranged anywhere from 50 to 125 miles. These zones of sandy Mid-Ordovician leaching of Upper Cambrian rocks, if preserved after being covered with Upper Ordovician sediments, would indeed make possible the occurrence in central and northwestern Pennsylvania of an entirely new type of reservoir rock essentially the same as in the Oklahoma City oil field. Study of the respective geophysical reactions of fresh and weathered Gatesburg in central Pennsylvania may well give the clue to a possible prospecting method for this type of porosity.

ACKNOWLEDGMENTS

Water Flood Spacing

by

S. T. YUSTER

DIVISION OF PETROLEUM AND NATURAL GAS

INTRODUCTION

Determination of the optimum well spacing in a given area for secondary recovery by water flooding is, in general, based upon the experience in that area and may involve fairly costly errors before arriving at correct spacing. In some cases the optimum spacing may not be used, since the field experimentation required to determine it is costly and it is simpler to apply the experience gained in other areas—even though this may be unwarranted because of differences in conditions. Since field experimentation is costly, it would be highly desirable to have available a method based upon knowledge of the reservoir and its fluid contents, which would enable an operator to calculate the optimum spacing.

The purpose of this paper is to consider the different factors which affect spacing and to attempt to combine them mathematically to arrive at some quantitative answer. In view of the complexity of the problem because of the large number of variables involved, it is necessary to make certain simplifying assumptions which will be indicated as the discussion develops. Because of these assumptions the result may be an approximation, but one based upon the reservoir properties and therefore fairly close to the optimum.

While certain geological factors are very important in spacing considerations, some must be disregarded because it is not possible to place them upon a quantitative basis. For example, the presence of lenses of sand within the reservoir, which are sealed off from

the main sand body by impervious or relatively impervious boundaries, will result in loss of oil if the horizontal dimensions of such lenses are less than the order of the distance from input to producing well. However, the dimensions of such lenses would not be constant and would be unknown before wells are drilled, so that they could not be taken into consideration in determining spacing. For the purpose of analysis it is necessary to assume that the reservoir is of constant thickness, of uniform character, and continuous from well to well.

The spacing in a water flood development should be chosen to yield the maximum profit; and all variables, both controllable and uncontrollable, should be considered toward this end. Since the problem is chiefly economic, it is a matter of income versus expenditures. The chief factors to be considered are ultimate oil recovery, time limit for flood completion, and development and operating costs.

ULTIMATE OIL RECOVERY

The ultimate yield of oil from a given area is a measure of the income derivable from it, and consideration should be given to the effect of a change in spacing on this factor. The possible effect of spacing on lensing resulting in loss of oil has already been mentioned, but since it cannot be evaluated it will not be considered. The effect of spacing on ultimate oil recovery in a uniform sand should be considered. Work on the flooding of cores in the laboratory and the analysis of field data have indicated divergent effects with respect to higher flooding pressures. In some instances no improvement in recovery over that at low flooding pressures is shown, while in others there is a beneficial effect. The process does not seem to be understood very well, and in view of its controversial nature recovery will be considered to be independent of spacing in this analysis.

It is necessary to know the recoverable oil from the area, and

to arrive at this figure the saturation prior to flooding and after flooding is needed. In regions where the sand permeability is relatively low, such as the Bradford field, coring makes possible a determination of the oil in place. With higher permeabilities, the core may be flushed to various degrees by the drilling water so that oil saturations have very little meaning. One approach to obtaining such data is based on the following assumptions:

1. The reservoir was originally 100 per cent liquid saturated.

2. The connate water content can be determined (a) by coring with an oil base mud, (b) by measurement of the irreducible minimum saturation by the capillary pressure technique, or (c) from the equilibrium water saturation on relative permeability tests.

3. Fairly accurate oil production figures are available for the area, and these can be calculated back to the original reservoir conditions. •

4. The areal extent, thickness, and porosity of the reservoir are known.

With the above information a material balance computation can be made to give the oil saturation of the reservoir.

The residual saturation to be attained at the end of the water flood can be obtained from the results of floods in an area either by a calculation or from a core obtained in a flooded-out area. If these data are not available, a flood pot test should be made at a high pressure gradient, preferably on a virgin core from the area or on a core artificially saturated with brine and crude oil. The residual oil saturation obtained can be assumed to be the oil saturation after a field flood. The equilibrium oil saturation obtained from relative permeability data may also be used in some cases.

The difference between the oil content prior to and after water flooding is obviously the oil recovery. It should be calculated in barrels per acre foot or barrels per acre.

DEVELOPMENT COST

In this study the development cost covers the expenditures for drilling, completing, and equipping both the input and the producing wells. The average cost of a water input well includes its proportionate share of the distribution system but does not include any portion of the water pressure plant or water supply system. The average cost of a producing well includes its proportionate share of all pumping equipment, oil and gas lines, and any other equipment required to operate these wells.

From a study of data obtained from several companies operating water floods in the Bradford area, it was found that the well cost data could be broken up approximately into a fixed charge plus a cost based upon footage. The range of footage was fairly small, but in the absence of better data it will be assumed to hold in these studies. However, the development and completion methods used in other areas may change these figures to a great extent, and this must be kept in mind in applying the method. Average costs were used in all cases.

The average cost of a water injection well was found to be

1. $C_w = 1500 + 1.45 \, L$

where L is the depth of the well in feet. For example, the average cost of a 2000-foot water well would be $4400.

The average cost of an oil producing well was found to be

2. $C_o = 3000 + 1.5 \, L$

Using the above equation, a 2000-foot producing well should average $6000.

If the well pattern to be used in the development is the five-spot, the arithmetic average of the cost of the input and producing well can be used as the cost per well, since there would be one input well for each producing well. With other patterns the average cost per well would be weighted by the ratio of input to producing wells.

In some cases old wells are used in the pattern, which would

reduce the average cost per well. One difficulty with considering the possible use of old wells in the development is that the average well cost must be considered in determination of the well spacing, and fitting of old wells into a pattern requires knowledge of the spacing. This is equivalent to requiring an answer to the problem in order to determine the answer. A trial and error method must be resorted to.

If N equals the number of new wells needed in an area and O is the number of old wells which can be adapted to the pattern, then

$$3. \quad C = \frac{C_n N + C_r O}{O + N}$$

where C_n and C_r are the average cost of the new wells and the average cost of rehabilitating the old wells respectively.

OPERATING COST

The operating cost in this analysis is made up of two items: the cost of water delivered to the input well and the lifting costs. While cost data for both items are available, it is difficult to choose an average value in view of the large variation possible between different areas.

In water costs the type of water, the distance of water source from the pressure plant, the pressure of injection, and other factors must be considered. For purposes of simplification the water cost was broken into two parts, the first being the cost of producing and treating the water and the second the cost of delivery to the input well under the required pressure [1] [3]. The equation for the delivered cost of water to the injection well per barrel is

$$4. \quad D = 0.012 + 0.00000445 \, P$$

where P is the well head injection pressure. The first term on the right-hand side of the equation is the water producing and treating cost; the second is the injection cost. The latter item assumes an over-all efficiency of 68.5 per cent and a power cost equivalent to one per cent per kilowatt hour, which is the same as that assumed by Simmons [3].

The average lifting cost is based on a per barrel of oil produced and is the average for the life of the property. It therefore includes the cost of lifting the water which accompanies the produced oil. This average lifting cost is one of the most difficult factors to determine, and the value given here should be considered only as an estimate, even though it represents the average of values from several companies. Based upon a barrel of oil produced, it is

$$5. \quad B = 0.00042 \, L$$

The average lifting cost per barrel of oil is proportional to the well depth.

BREAK-EVEN SPACING

If it is assumed that pressure gradient and spacing have a negligible effect on the ultimate oil recovery, it is possible to calculate a spacing in which costs are just balanced by income. This is a minimum spacing. The calculation is based upon a five-spot development, but the method with other patterns will be similar.

The number of acres in a five-spot is its area in square feet divided by 43,560 or $W^2/43,560$, where W is the water to water well distance. Since there are two wells (one input and one producer) on the average in a five-spot the

$$6. \quad \text{Number of wells per acre} = \frac{2 \times 43,560}{W^2}$$

If the average cost of a well is C, the

$$7. \quad \text{Well cost per acre} = \frac{87,120 \, C}{W^2}$$

The average good flood will require about 15 times as much water over its life as oil to be produced over the same period. Because of the increase in price of crude in recent years the above factor in some cases has approached a value of 20 since the abandonment time has been prolonged. If R is the average oil recovery per acre foot, h

is the producing sand thickness, equation 4 gives the water cost per barrel, and the factor of 15 given above holds, the

8a.   Water cost = Rh (0.012 + 0.00000445 P)

If the flooding pressure to be used is to be the maximum (prior to parting the formations), and assuming one psi downward pressure for every foot of overburden, the safe surface pressure, P would be equal to 0.57 L. Substituting this in 8a gives

8b.   Water cost = 15 Rh (0.012 + 0.00000253 L)

The lifting cost based upon a barrel of oil produced is given by equation 5, and multiplying this by the recovery per acre will give the total lifting cost, or

9.   Lifting cost = 0.00042 L R h

The total development and operating costs per acre would be the sum of the well cost, water cost, and lifting cost, or

10.   Total cost

$$= \frac{87,120\ C}{W^2} + 15\ Rh\ (0.012 + 0.00000253\ L) + 0.00042\ LRh$$

$$= \frac{87,120\ C}{W^2} + Rh\ (0.18 + 0.000458\ L)$$

To "break even" the above figure should equal the total income derived from the sale of the crude oil. If M is the market value of a barrel of crude oil and there is a one eighth royalty on the production, the

11.   Total income = ⅞ M R h

This does not consider the present worth of future production since the production as a function of time is needed to make such an evaluation. By equating 11 and 10 the break-even conditions will be obtained.

12. $0.875\ M\ R\ h = \dfrac{87,120\ C}{W^2} + Rh\ (0.18 + 0.000458\ L)$

Solving for W gives the break even or minimum spacing

13. $W = \sqrt{\dfrac{87,120\ C}{Rh\ (0.875\ M - 0.18 - 0.000458\ L)}}$

In a five-spot development, the number of input wells should equal the number of producers. The average cost per well in such a development would be the average cost of an input and producer. By averaging equations 1 and 2 the average cost should be obtained, or

14.   C = 2250 + 1.475 L

It should be kept in mind that the cost data given here are averages for the Bradford area and may be quite different for other areas. Substituting 14 in 13 gives

15. $W = \sqrt{\dfrac{87,120\ (2250 + 1.475\ L)}{Rh\ (0.875\ M - 0.18 - 0.0000458\ L)}}$

This gives the spacing in terms of the well depth, recovery per acre, and selling price of the crude. Equation 13 states that the spacing varies directly as the square root of the well cost and inversely as the square root of the recovery per acre. Qualitatively this appears to be in the correct direction. For example, at greater depth, well costs are greater and spacing should be increased (all other factors being kept constant) to counteract the increase in cost. If well costs were to increase fourfold, then the spacing should be increased twofold; or in order to maintain a constant spacing the recovery per acre would have to increase to fourfold.

FLOWING PRODUCTION

The analysis so far assumes that all production will be pumped. It would be of interest to consider the case when the production is flowed. There will be no lifting costs and the last term of equation 10 drops out, which will make a corresponding correction in equation 13. Since the producing wells will be completed like input wells,

the well cost will be given by equation 1. Making these corrections gives an equation for the break-even or minimum spacing for flowing, or

$$16. \quad W = \sqrt{\frac{87,120 \, (1500 + 1.45 \, L)}{Rh \, (0.875 \, M - 0.18 - 0.000038 \, L)}}$$

A comparison will be made of the break-even spacing for flowing and pumping of production under Bradford conditions and also for mid-continent conditions. It will be assumed that the well depth is 2000 feet, the recovery per acre foot is 200 barrels, and that there is 25 feet of productive sand. The price of Bradford crude is $4.50 per barrel, and it will be assumed that the price per barrel in the mid-continent area is $1.80. Substituting these quantities into equations 15 and 16 gives the results shown in Table 1.

TABLE 1

COMPARISON OF "BREAK-EVEN" SPACING FOR DIFFERENT CONDITIONS

Area	Mode of Production	"Break-Even" Spacing
Bradford	Pumping	178 feet
Bradford	Flowing	144 feet
Mid-Continent	Pumping	430 feet
Mid-Continent	Flowing	240 feet

Because of the higher price for Bradford crude oil a considerably closer spacing is possible than in the mid-continent area. Qualitatively this is to be expected. However, the surprising result is the great difference in spacing between a pumping and a flowing operation in the mid-continent.

Both equations 15 and 16 can be put in logarithmic form so that the log of the spacing is a linear function of the recovery per acre with all other factors held constant. Figures 1 and 2 give the break-even spacing for a pumping operation as a function of the recovery per acre for $4.50 and $1.80 oil, respectively, with well

FIGURE I
"BREAK-EVEN" SPACING VS. RECOVERY
FOR PUMPING OPERATION AND $4.50 OIL
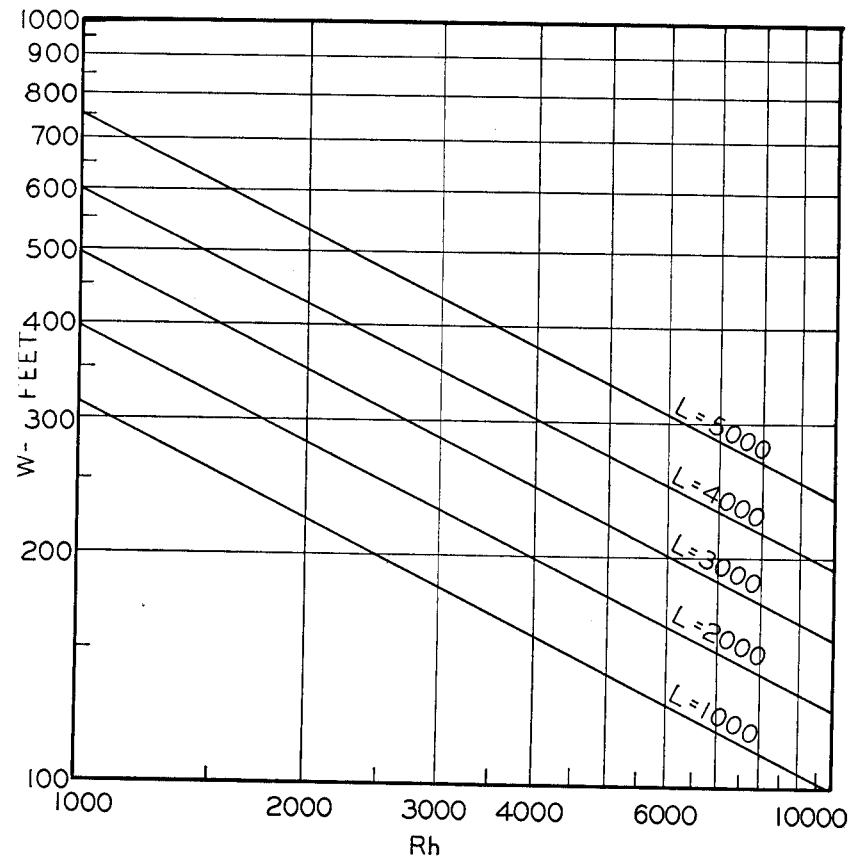
depth as a cross variable. Figures 3 and 4 represent a similar analysis for a flowing operation. For both Bradford and mid-continent conditions there is an apparent advantage to a flowing operation. This does not consider recovery rate and the economic factors which it controls. These will be considered later in the discussion.

FIGURE 2
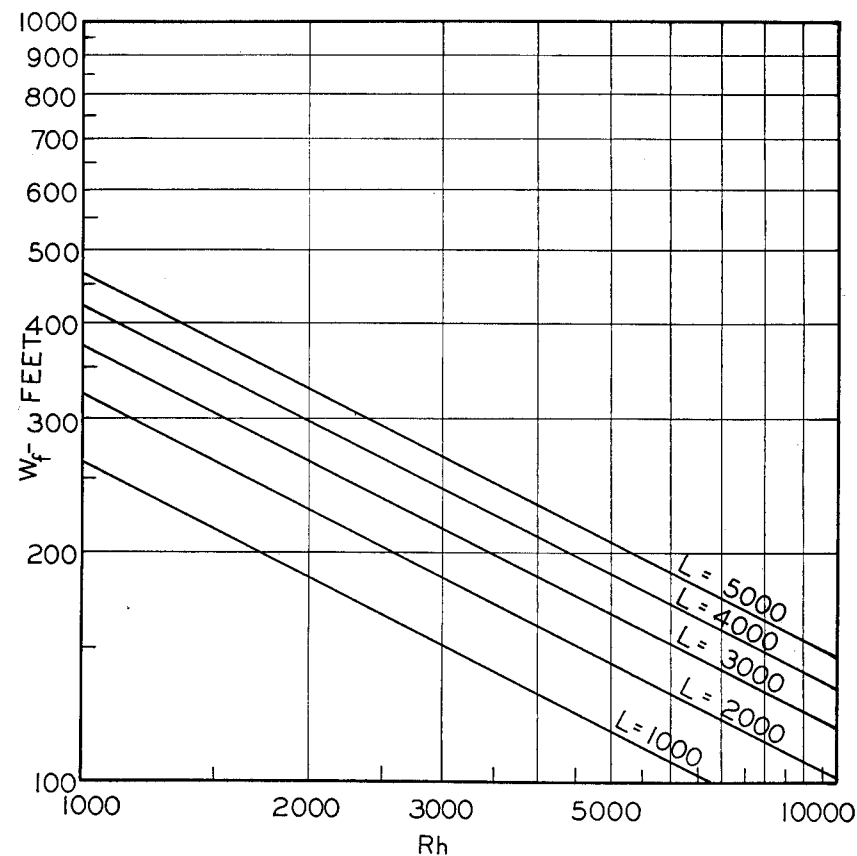"BREAK-EVEN" SPACING VS. RECOVERY
FOR PUMPING OPERATION AND $1.80 OIL

FIGURE 3
"BREAK-EVEN" SPACING VS. RECOVERY
FOR FLOWING OPERATION AND $4.50 OIL
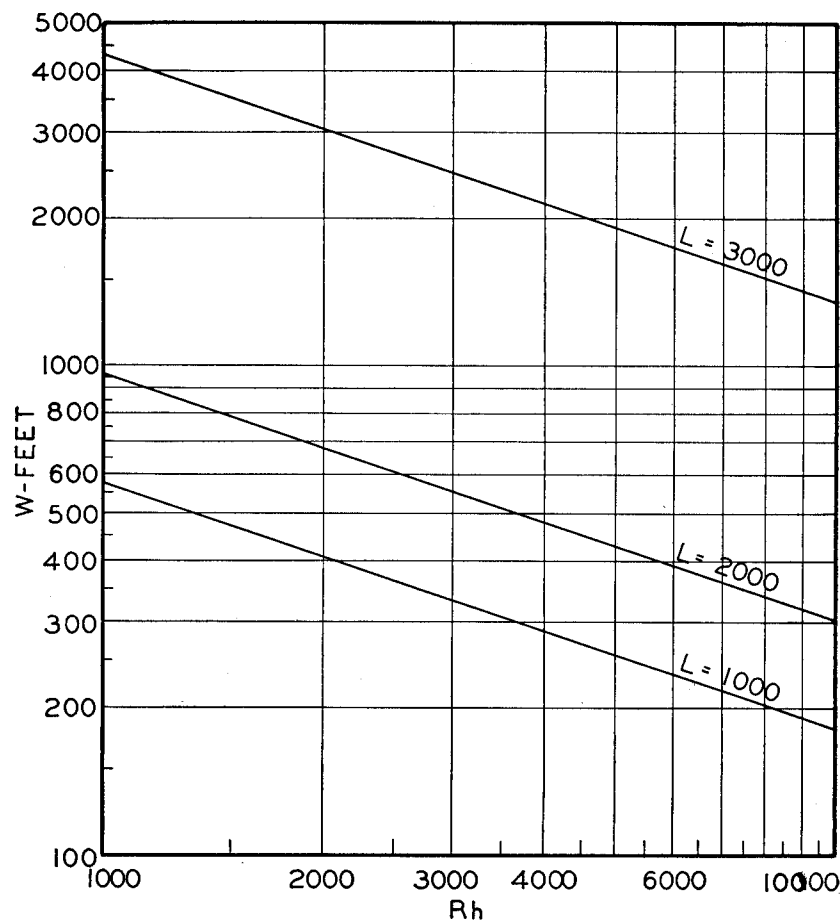
By dividing equation 16 into 15 it is possible to obtain the ratio of the pumping to flowing spacing.

$$17. \quad \frac{W}{W_f} = \sqrt{\frac{(2250 + 1.475\,L)\,(0.875\,M - 0.18 - 0.000038\,L)}{(1500 + 1.45\,L)\,(0.875\,M - 0.18 - 0.000458\,L)}}$$

This ratio is independent of the recovery per acre since it was assumed that the ultimate recovery would be independent of method of production. The ratio is plotted as a function of the well depth with the price of crude as a cross variable in Figure 5. The higher this ratio, the less favorable the pumping operation as compared to the

FIGURE 4

"BREAK-EVEN" SPACING VS. RECOVERY

FOR FLOWING OPERATION AND $1.80 OIL

FIGURE 5
FLOWING - PUMPING
SPACING RATIO
VS. WELL DEPTH
AND OIL PRICE
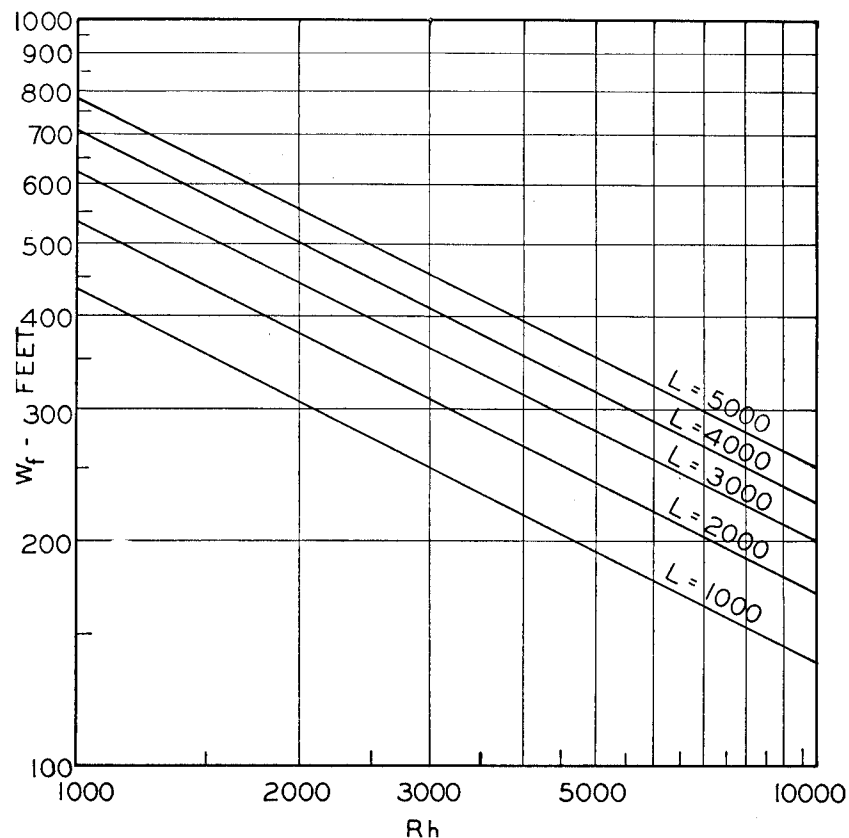
flowing operation. Under the assumptions made, flowing will always be more economic than pumping; but Figure 5 indicates that at lower oil prices and greater well depth (equivalent to less income and greater costs), the flowing operation is especially advantageous. This presupposes that the formation will have sufficient permeability to give an economic rate of production.
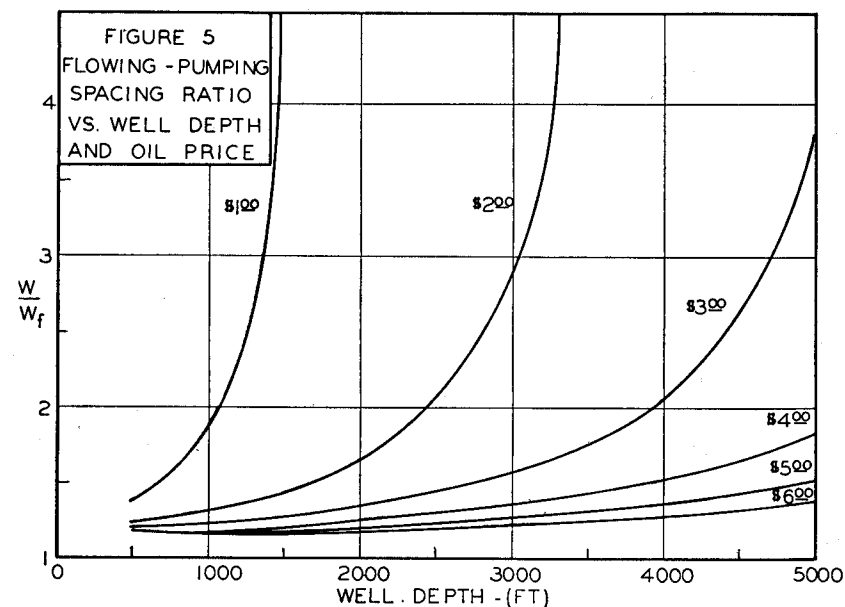
LIMITING CONDITIONS FOR FLOODING

If the parenthetical term in the denominator of the fractions under the vinculum in equations 15 and 16 becomes zero, the spacing would become infinite. Obviously such a condition is absurd, but it would represent a theoretical limiting condition on a development. By setting the parenthetical expressions equal to zero, a limiting value of the well depth would be obtained as a function of the price of crude. This theoretical limiting depth for a pumping operation is obtained from equation 15.

18. $L_{lp} = 1910 \, M - 393$

The corresponding equation for a flowing operation is obtained from equation 16.

19. $L_{lf} = 23,000 \, M - 4750$

It should be pointed out again that these results are the theoretical

maximum and the actual would be somewhat less. They also hold for the cost data and other conditions assumed.

Since equations 18 and 19 apply to the condition of infinite spacing, it is equivalent to having no wells on the property. The economic balance would then involve income from oil versus cost of water delivered to the injection well and lifting costs. The parenthetical expressions upon which equations 18 and 19 are based represent such cost data per barrel of oil recovered. This would be the cost data for the water flooding of an old property in which no new wells are drilled and no money is spent on the rehabilitation of old wells. This is certainly the lower limit for development cost. An examination of equation 19 shows that for oil as cheap as $1 per barrel the theoretical limiting depth is almost 20,000 feet, indicating the advantage of a flowing operation. The theoretical limiting conditions for a pumping operation as given by equation 18 are plotted
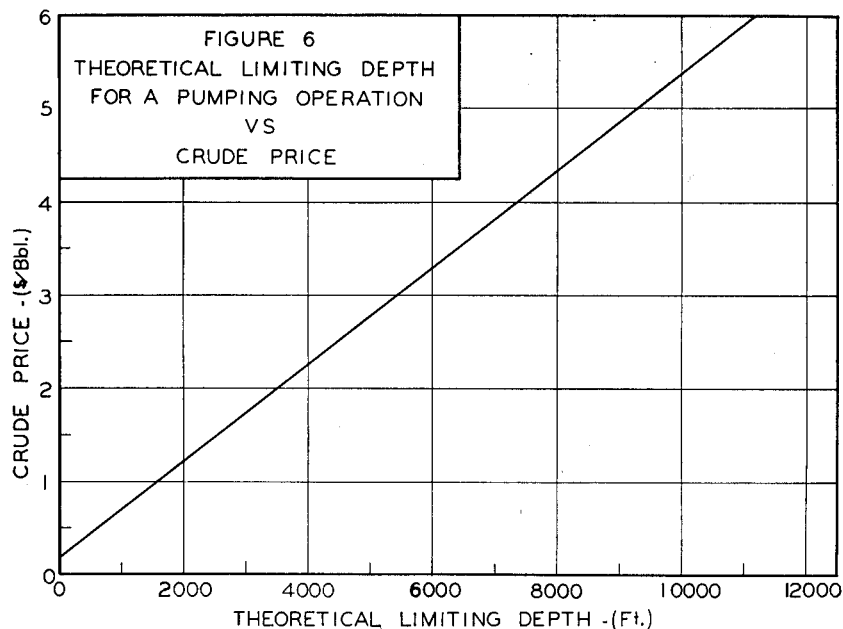
in Figure 6. This gives a maximum theoretical depth at which a property can be water flooded under the conditions assumed. For example, at $1 oil the maximum depth for water flooding would be about 1500 feet.

FIGURE 6
THEORETICAL LIMITING DEPTH
FOR A PUMPING OPERATION
VS
CRUDE PRICE

FIGURE 7
"BREAK-EVEN" SPACING FOR PUMPING
VS
RECOVERY AND CRUDE PRICE FOR 2000' WELL
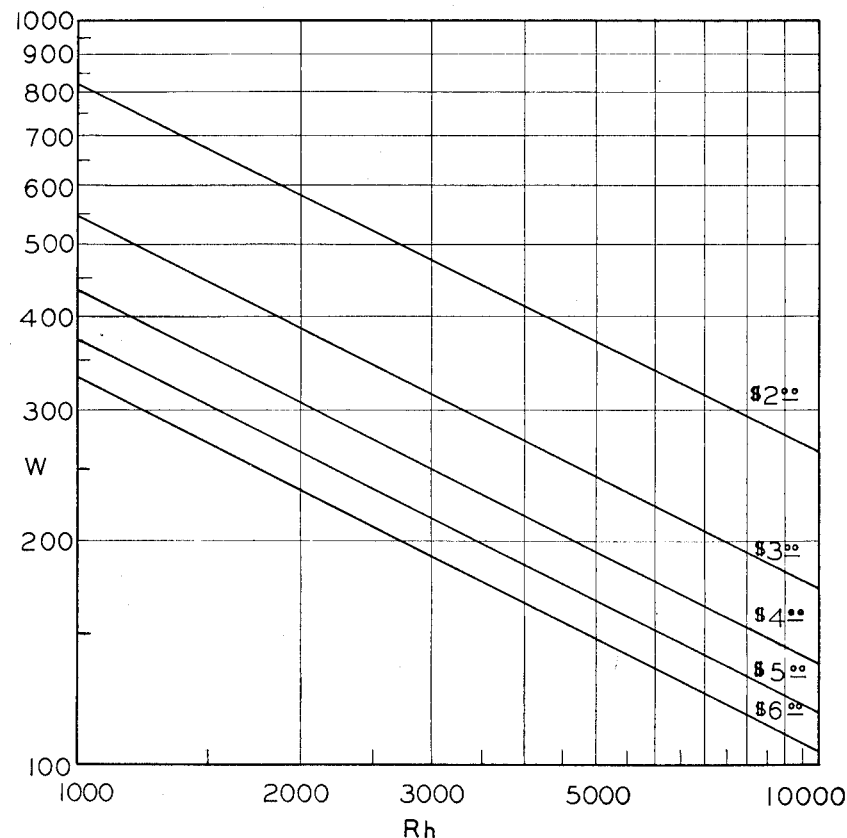
DEVELOPMENT OF MARGINAL AREAS

Using equations 15 and 16 it is possible to determine the effect of recovery per acre and the price of crude oil on the break-even spacing holding the well depth constant. It will be assumed that the well depth is 2000 feet. Figures 7 and 8 give the pumping and flowing spacing respectively as a function of recovery per acre and the price of crude oil. In a 300-foot five-spot pumping operation (Figure 7) the recovery per acre for break-even at $2, $3, $4, $5, and $6 oil is 7500, 3300, 2200, 1550, and 1220 barrels respectively. This indicates the marked effect of price on the quality of property which can be developed. Since the total recovery is the product of the recovery per acre foot and the number of feet of sand, the break-even spacing can be correlated with the minimum number of feet of sand which can be developed. In a 300-foot five-spot flowing operation (Figure 8) the recovery per acre for break-even at $1, $2, $3, $4, $5, and $6 oil is 7000, 2850, 1800, 1325, 1020, and 880 barrels respectively. The advantage of flowing is obvious under the conditions assumed and providing the rate of production is sufficiently rapid. At $2 oil the poorest recovery under pumping conditions which can be handled in a 300-foot five-spot at 2000 feet is 7500 barrels per acre. The corresponding value for flowing is 2850 barrels per acre. At $4.50 oil under corresponding conditions the minimum economic recovery per acre for pumping is 1750 barrels as against 1150 for flowing. The relationships given imply that the well cost in a given area will be unaffected by the crude price. This is not true since some direct correlation does exist. However, since the relationship is not known quantitatively, this factor must be disregarded. Because of the possible economic advantages of flowing it would appear that this method of production may bring certain marginal areas into consideration and thereby increase our petroleum reserves.

The discussion so far has assumed that the maximum flooding pressure to the point of parting the formations will be used in these

FIGURE 8
"BREAK-EVEN" SPACING FOR FLOWING
VS
RECOVERY AND CRUDE PRICE FOR 2000' WELL
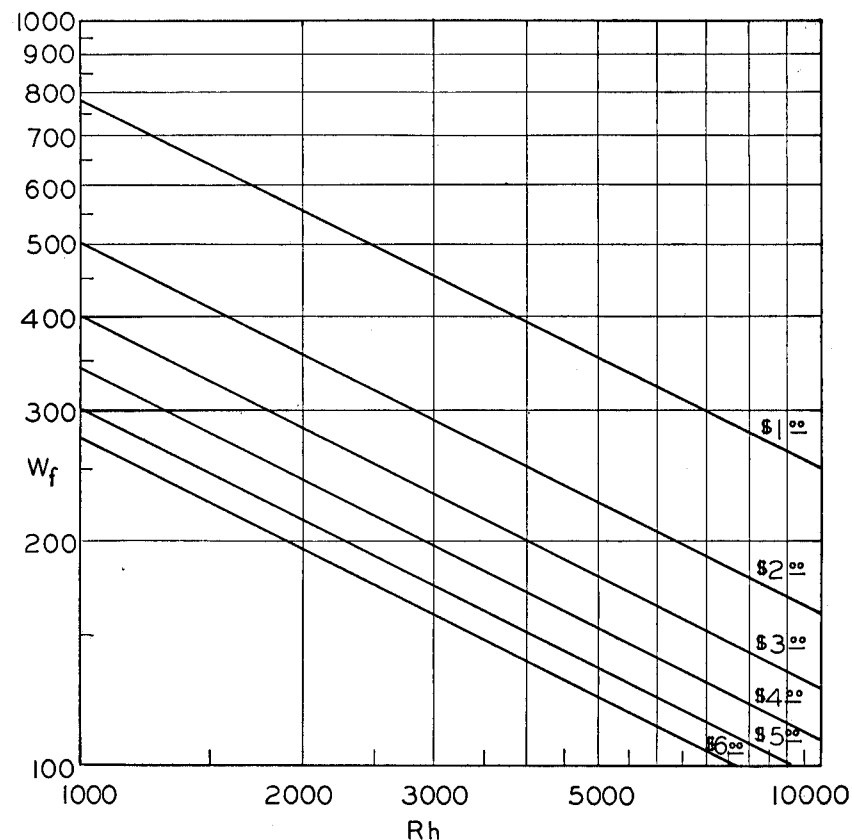
operations. In some areas such high pressures are not used because of the high permeability of the sand. In these cases the water cost equation 8a is used with no substitution of 0.57L for P. The equations corresponding to 15 and 16 then become

20. $$W = \sqrt{\frac{87,120\,(2250 + 1.475\,L)}{Rh\,(0.875\,M - 0.18 - 0.0000668\,P - 0.00042\,L)}}$$

21. $$W_t = \sqrt{\frac{87,120\,(1500 + 1.45\,L)}{Rh\,(0.875M - 0.18 - 0.0000668\,P)}}$$

Again it should be repeated that these relationships hold only under the conditions assumed, and proper corrections should be made for other conditions. At best the results given are approximations and should not be considered otherwise.

FLOOD-OUT TIME

The equations given so far have been based upon certain economic factors, but no consideration has been given to rate of flooding or its equivalent, the flood-out time. Obviously an increase in spacing will bring with it the disadvantage of a longer flood-out time along with certain advantages of lower development and operating cost. However, the spacing cannot be made too great since it will require too long a period of time to complete the production. In the intensive floods in the Bradford area, it is usually planned to complete the operation in about 10 years, or at the most 15 years. Ten years is more desirable in that equipment repairs and other maintenance costs will be at a minimum. This time limit is used in the analysis.

It was assumed previously that the total water required to complete the flooding operation would be 15 times the recoverable oil. Since the water required per acre would be 15 Rh and the number of acres per five-spot is $W^2/43,560$, the product of these would be the water required per five-spot, or

22. Total water per five-spot $= \dfrac{Rh\,W^2}{2900} = 0.000345\,RhW^2$

The steadied rate of water input in barrels per day into a five-spot is given by the equation

23. $$Q_5 = \frac{0.00154\,k\,h\,P_b}{\mu\,(\log W/r_w - 0.420)}$$

where k is the effective permeability of the formation to the flood waters in millidarcies. P_b is the sand face input pressure, μ is the viscosity of the injected water in centipoise at the formation temperature, and r_w is the effective well radius in feet. If the production is by flowing, the surface injection pressure, P, should be substituted for P_b.

Dividing the total water needed by the rate per day will give the number of days necessary to complete the flood. Since the time specified was 10 years, the spacing must be so adjusted that the required amount of water will flow into the formation during the time interval chosen. Equation 22 divided by 23, set equal to 10×365, and simplified gives

24. $$W^2\,(\log W/r_w - 0.420) = \frac{16,300\,k\,P_b}{\mu\,R}$$

This gives the spacing as a function of the factors controlling a 10-year flood-out time. The deriviation has assumed a steadied rate of water input which is not the true situation but will be sufficiently accurate to approximate the spacing. Unfortunately, W cannot be solved for directly, but a trial and error solution must be resorted to. In general, it will be simplest to substitute definite values of W into the equation and evaluate the left-hand side. The variables on the right-hand side can then be determined.

In order to use equation 24, it is necessary to know what r_w and k will be. The first is a controllable variable within limits which is determined by shooting or possibly by acidizing. The second is an uncontrollable variable which is a function of the fluid saturations in its simplest terms. The effective radius of the wells, r_w, requires a knowledge of the shot responsiveness of the sand in a given area

and the size of shot used. This can be obtained only by experience in an area. No adequate quantitative test has yet been developed in the laboratory for testing sand samples for their shot responsiveness. The field method requires that several shots of varying concentration be made on a given sand and the water input data be analyzed by a method described in the literature [4]. This same method also gives the effective permeability of the sand to the advancing flood waters. A laboratory method has recently been described for obtaining effective permeabilities on small core samples [2], and this can be used if field data are not available.

If the sand is made up of several strata of varying permeability, which is usually the case, some method of averaging must be used. Ideally each permeability should have its own spacing; but since this is impossible, the various strata should be weighted according to effective permeability, since permeability controls rate. Spacing should also be weighted according to recovery, since recovery controls the volume to be injected as specified in the initial assumptions. An additional reason for weighting the recovery is that the operator is chiefly interested in this factor and conditions should be chosen to favor the richest stratum. Accordingly the following weighting equation is recommended for obtaining an average k to use in equation 24:

$$25. \quad \frac{\Sigma\, khR}{\Sigma\, hR} = \bar{k}$$

In order to indicate the effect of the variables in equation 24 on the spacing, Figure 9 was plotted with the spacing versus permeability and the recovery per acre foot as a cross variable. A sand face pressure of 2000 psi, a viscosity of one centipoise, and an effective well radius of 15 feet were assumed.

It would be of interest to apply the graph to Bradford conditions and determine the spacing. Assuming the permeability to be 5 md and the relative permeability to be one tenth, the effective permeability would be 0.5 md. Let the recovery per acre foot be 200 barrels. The spacing under these conditions should be about

300 feet which is of the order of magnitude used in Bradford. If the recovery had been 100 barrels per acre foot, the spacing would have been 400 feet.

For higher permeabilities the spacing is correspondingly increased. For an effective permeability of 10 md and the same conditions as given previously, an 1100-foot spacing appears to be in order. This is considerably above what is used for these conditions in the mid-continent area. One reason is that lower pressures are used in order to hold down the volume rate of injection. According to equation 24, a reduction in flooding pressure will require a reduction in spacing in order to attain a 10-year flood-out time. The substitution of a shorter spacing and lower flooding pressure for the maximum spacing and maximum flooding pressure may be valid for holding to a 10-year flood-out time, but it may not be advisable economically. The cost of the additional wells necessary with a reduced spacing will more than offset the saving involved in injecting water at lower pressures.

FIGURE 9
SPACING FOR 10 YEAR FLOOD-OUT
VS
PERMEABILITY AND RECOVERY
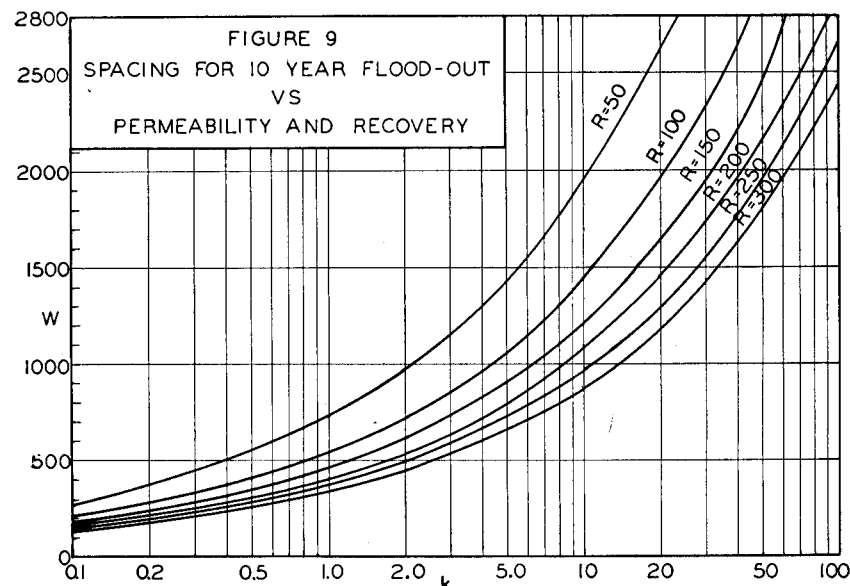
Since the cost calculations on water injection are based on well head pressures, it will be necessary to substitute the sum of the well head pressure and hydrostatic head for the sand face pressure in equation 24.

$$26. \quad W^2 (\log W/r_w - 0.420) = \frac{16,300 \, k \, (P + 0.43 \, L)}{\mu \, R}$$

The approximate maximum value for P is 0.57 L to prevent pressure parting.

If the flood-out time is to be for some period other than 10 years, equation 26 becomes

$$27. \quad W^2 (\log W/r_w - 0.420) = \frac{44.6 \, Yk \, (P + 0.43 \, L)}{\mu \, R}$$

where Y is the flood-out time in years.

In order to show the effect of well radius on spacing, calculations were made assuming a 2000 psi flooding pressure and a recovery of 200 barrels per acre foot. The results are given in Figure 10, in

FIGURE 10
SPACING FOR 10 YEAR FLOOD-OUT
VS
WELL RADIUS AND PERMEABILITY
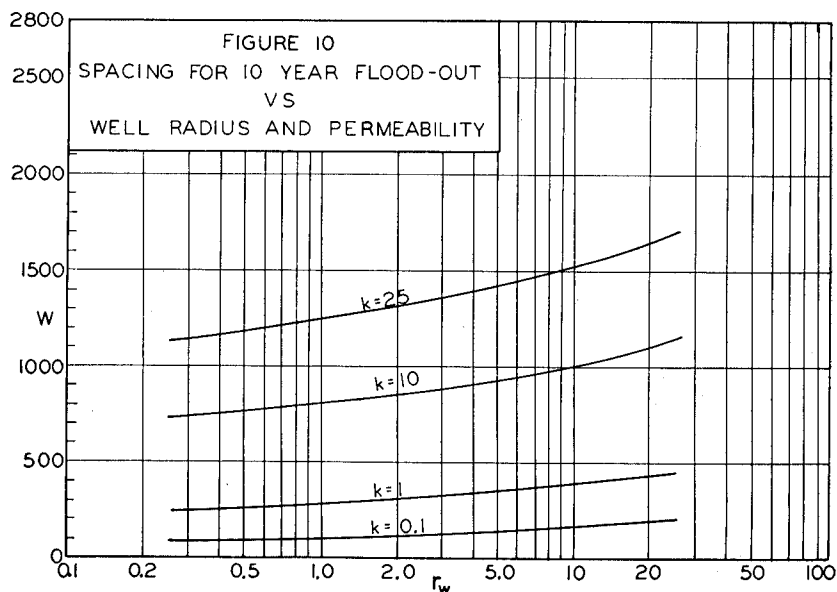
which spacing is plotted against well radius with effective permeability as a cross variable. The range of well radius values goes from 0.25 feet (an unshot well) to 25 feet for a heavily shot well. This upper value has been found in the analysis of some field data from the Bradford area. For a sand having an effective permeability in the range of 0.1 md to 1 md the spacing variation is approximately 440 feet. The expense of the shot is small as compared to the added cost for additional wells needed when they are unshot.

An examination of equation 24 shows that all of the independent variables other than r_w are on the right-hand side of the equation as a product quotient combination. Since the viscosity of the injected water is fairly close to one, it should be possible to plot the ratio $k \, P_b/R$ versus W with r_w as a cross variable. This has been done in Figure 11. By computing the ratio and choosing the proper value of r_w, the 10-year flood-out time will be obtained. Assume that a property is to be flooded at 1000 psi pressure, the recovery will be

FIGURE 11
MASTER GRAPH FOR DETERMINING
SPACING FOR TEN YEAR FLOOD-OUT
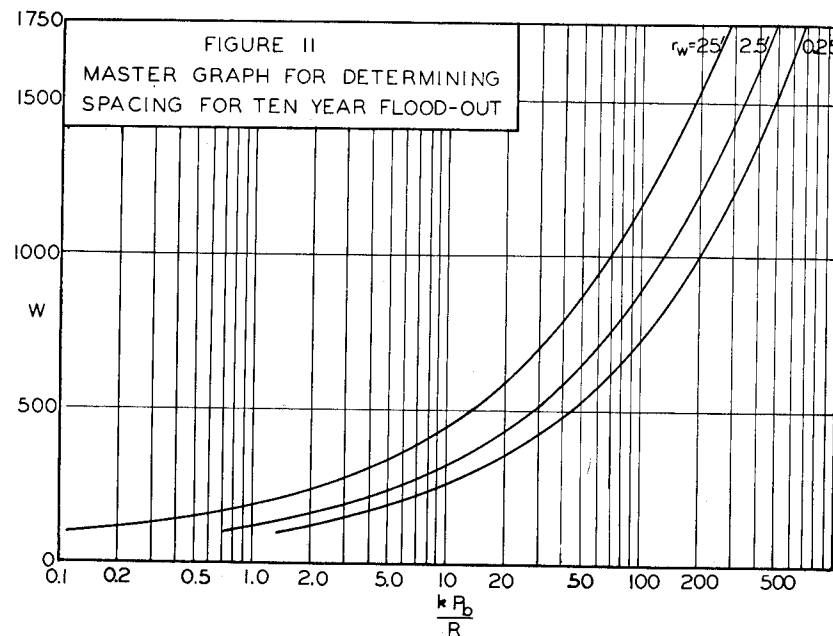
200 barrels per acre foot and the effective permeability is 2 md. What will be the spacing if the wells are unshot? If the wells are shot to an effective radius of 25 feet? The ratio $k P_b/R$ is $2 \times 1000/200$ which is equal to 10. From Figure 11 the spacing for unshot wells should be about 250 feet, while that for a 25-foot well radius would be about 430 feet. It may not be possible to shoot a well to a 25-foot radius; therefore the shooting limitation in a given area must be known before these calculations can be made.

It would be of interest to compare the 10-year flood-out spacing for flowing with that for pumping. In the example just considered, let it be assumed that the 1000 psi flooding pressure was the maximum possible on the property. The well depth was then approximately 1000 feet. The back hydrostatic pressure on the producing well would be 434 psi. The effective flooding pressure would then be the well head pressure at the injection well or 566. With this pressure, the ratio $k P/R$ is $2 \times 566/200$ or 5.66. Referring to Figure 11 for an unshot well gives about 200 feet, and for a heavily shot well the value is 350 feet.

Figure 11 can be used to determine graphically the pressure correction necessary in order to compensate for unshot wells while still maintaining a constant spacing. If a sand has an effective permeability of 2 md, will yield 200 barrels of oil per acre foot, and is being flooded at 1000 psi, the ratio $k P_b/R$ is 10. For a heavily shot well the spacing would be 430 feet. In order to maintain this spacing, what must the pressure be to complete the flood in 10 years if the wells are unshot? Figure 11 indicates that the ratio $k P_b/R$ at a 430-foot spacing on the $r_w = 0.25$ foot curve is 23. This is 2.3 times the previous ratio, or the pressure must be increased to a value 2.3 times the original to complete the flood in the allotted time. This is beyond what can be accomplished actually; and if it were possible, the additional cost involved in injecting the water would be greater than the cost of shooting.

GROSS PROFIT CONSIDERATIONS

The discussion so far has concerned itself with two spacings: a break-even spacing which gives no consideration to rate of recovery or time limit for completion of the flood, and a spacing based on a definite flood-out time but which does not consider costs. If the break-even spacing is greater than that for a 10-year flood-out, the application of the former will probably result in equipment repairs which would be costly, and the operation would result in a loss. If the two spacings are the same, it will be a break-even operation. If the 10-year flood-out spacing is greater than the break-even spacing, the property should operate at a profit.

Equation 12 modified to give the water cost in terms of the surface injection pressure will be

28. $$0.875\,MRh = \frac{87{,}120\,C}{W^2} + Rh\,(0.18 + 0.0000668\,P + 0.00042\,L)$$

This equation is for a pumping operation since it contains the cost of lifting the fluids from the producing well. If it is to be used for flowing, the term containing L should be dropped. The left-hand side of the equation represents the gross income on the property with no corrections for the present worth of future production. The right-hand side of the equation gives a summation of the development and operating costs. The spacing W is the dependent variable which is adjusted to make the two sides equal. If W is different from the break-even spacing, the difference between the gross income and the expenditures should give the gross profit per acre or

29. $$G = Rh\,(0.875M - 0.18 - 0.0000668P - 0.00042L) - \frac{87{,}120\,C}{W^2}$$

(Note that for flowing, the term containing L should be dropped.) The use of equation 26 or Figure 11 will give the 10-year flood-out spacing, and this substituted in equation 29 with the other variables will yield the gross profit.

In order to illustrate the application of equation 29 a com-

parison is made of the gross profit which can be derived from a pumping and flowing operation. The examples cited previously are used: 2 md effective permeability sand, 1000 feet deep and the maximum flooding pressure used, sand thickness 25 feet, 200 barrels per acre foot recovery, and an effective well radius of 25 feet are assumed. The crude price is assumed to be $2, the average well cost in pumping is given by equation 14, and that for flowing is equation 1. Table 2 gives a summary of the results. The advantages of flowing over pumping under the conditions assumed are quite obvious.

TABLE 2

COMPARISON OF PUMPING AND FLOWING OPERATIONS

Type of Production	Ten-Year Flood-out Spacing	Gross Profit per Acre
Pumping	430 feet	$3650
Flowing	350 feet	$5400

Similar calculations to those already discussed can be made over a wide range of conditions. If the assumptions made do not hold for a given area, the appropriate changes must be made in the relationships given. The results obtained will be approximations but will allow for a semiquantitative approach to a solution of the problem of well spacing in water flooding.

SUMMARY

1. An analysis has been made of the problem of water-flood spacing and equations for two different types of spacing derived. The first is based on an economic break-even of income versus cost. The second considers the conditions necessary for flood-out in a given time.

2. The break-even spacing analysis balances gross income from sale of oil against well cost, water cost, and lifting cost. It was assumed that the average flood would require 15 times as much water as oil to be produced.

3. The flood-out time analysis is based on the total water requirements and a steadied rate of water injection.

4. The break-even spacing can be obtained as a function of well depth, recovery per acre, price of crude, and the surface flooding pressure.

5. The flood-out time spacing can be obtained as a function of the effective well radius, the effective permeability of the sand, the recovery per acre foot, the well depth, and the applied surface pressure.

6. A relationship was obtained for computing the gross income on a development.

7. If the flood-out time spacing is greater that the break-even spacing, there will be a gross profit on the operation.

8. Applying the spacing relationships to a comparison between pumping and flowing of the production indicates a considerable advantage of the latter.

9. From the results summarized in Item 7 it would appear that some water flood projects may be underspaced, and an increase in gross profit would be possible with an increase in spacing.

10. The substitution of a decreased spacing for pressures below the maximum may result in a reduction in gross income.

11. The substitution of decreased spacings and/or increased pressures (which are limited) for shooting appears in general to be uneconomic.

12. The use of the flowing method of production using the maximum possible economic flood-out times should be given consideration in the development of marginal areas. It is believed that the technique will increase the reserves of oil available by water flooding.

13. A relationship was derived for approximating the maximum depth at which water flooding can be carried out.

ACKNOWLEDGMENTS

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(1.) Jones, J. P., and Rich, Hugh, Practical Economic Problems in Secondary Recovery, *Producers Monthly 10,* No. 5, 18 (March 1946)

(2.) Morse, R. A.; Terwilliger, P. L.; Yuster, S. T., Relative Permeability Measurements on Small Core Samples, *Producers Monthly, 11,* No. 10, 19-25 (August 1947)

(3.) Simmons, A. C., Fundamental Procedures in Estimating Costs for Secondary Water Flood Recovery of Petroleum, *Producers Monthly 8,* No. 7, 38 (May 1944)

(4.) Yuster, S. T., Field Effective Permeabilities and Shot Well Radii, *Producers Monthly 10,* No. 1, 31-37 (November 1945)

PUBLICATIONS OF THE MINERAL INDUSTRIES
EXPERIMENT STATION

Research results of the Experiment Station are disseminated through the following publications: (1) Bulletins, which present the proceedings of technical conferences and the detailed results of the experimental studies of a problem which may be more comprehensive than a single project; (2) Information Circulars, which present in nontechnical language the results of studies which are given in greater detail in other publications, and statistical data or pertinent information gathered from other sources; (3) Technical Papers, consisting of bound copies of papers published in scientific journals (reprints), of progress reports, and of results of experimental studies which represent isolated phases of research and which will be summated later in bulletin form.

A few of the publications are listed below. These may be obtained from the Director of the Mineral Industries Experiment Station, The Pennsylvania State College, State College, Pennsylvania, at the price quoted.

BULLETINS

33. Proceedings of the Tenth Pennsylvania Mineral Industries Conference, Petroleum and Natural Gas Section in co-operation with The Pennsylvania Natural Gas Men's Association, The Pennsylvania Grade Crude Oil Association, and the Bradford District Pennsylvania Oil Producers' Association, held at The Pennsylvania State College, May 2-3, 1941. **Price, 50 cents.**
38. Commemorating the Tenth Anniversary of the Establishment of the Research Program on Secondary Recovery by the Bradford District Research Group at The Pennsylvania State College, 1943. **Free.**
39. Proceedings of the Eighth Technical Conference on Petroleum Production, October 27-28, 1944. **Price, 50 cents.**
41. Ninth Technical Conference on Petroleum Production, November 2-3, 1945. **Price, $1.**
45. Tenth Technical Conference in Petroleum Production, November 1-2, 1946. **Price, $1.**
46. Report of Progress in Research for Biennium, 1945-47. **Free.**

TECHNICAL PAPERS

103. Pressure Parting by S. T. Yuster and J. C. Calhoun Jr. 1945. **Price, 25 cents.**
120. The Clay Content of Oil Sands by T. F. Bates, R. M. Gruver, and S. T. Yuster; and Gas Requirements in Gas Drive Recovery by S. T. Yuster and R. J. Day. 1947. **Price, 50 cents.**
124. Relative Permeability Measurements on Small Core Samples by R. A. Morse, P. L. Terwilliger, and S. T. Yuster. 1947. **Price, 25 cents.**

CIRCULARS

17. Careers and Mineral Industries. 1944. **Free.**
20. Opportunities for Productive Work Through Mineral Industries Research. 1945. **Free.**
26. Mineral Industries Extension Services. 1946. **Free.**
28. Mineral Industries Correspondence and Extension-Class Instruction. 1947. **Free.**
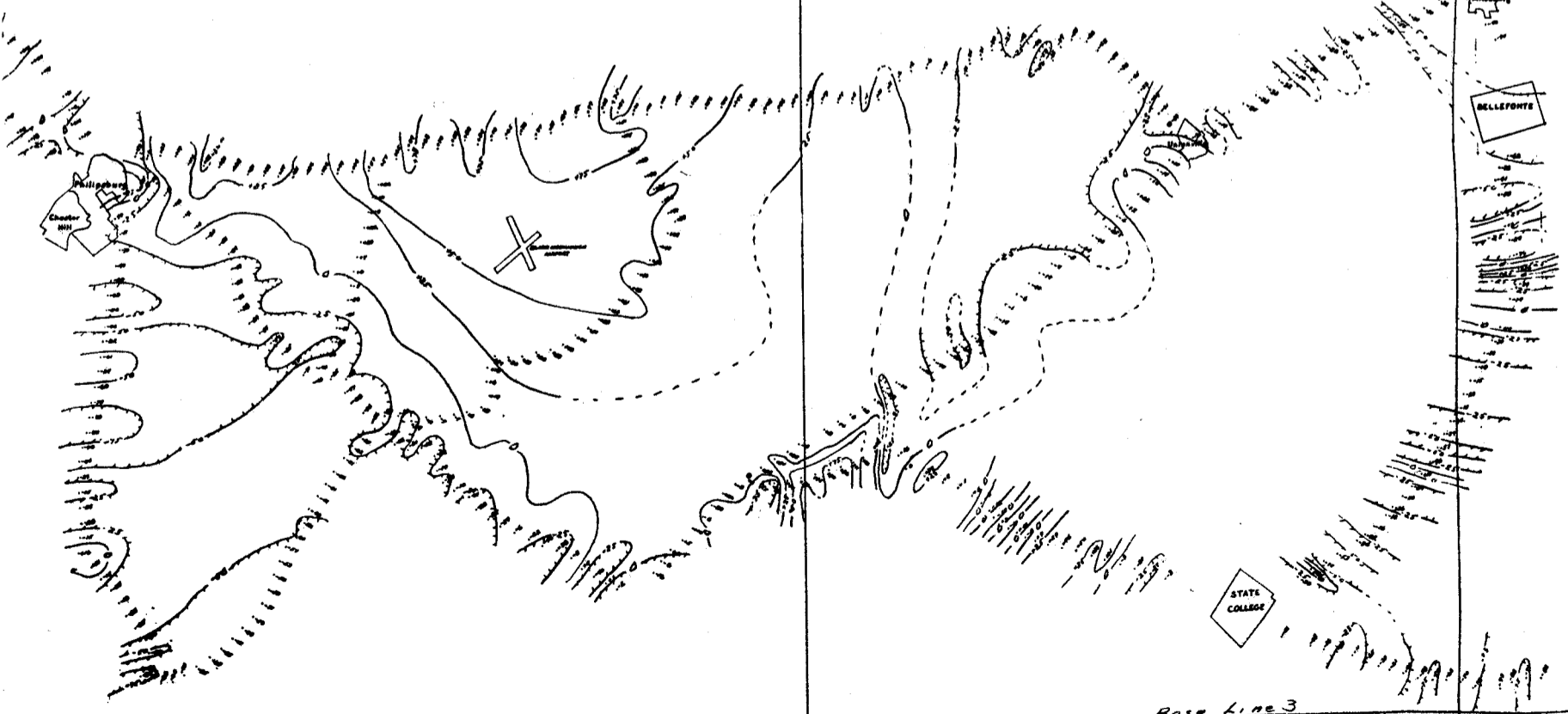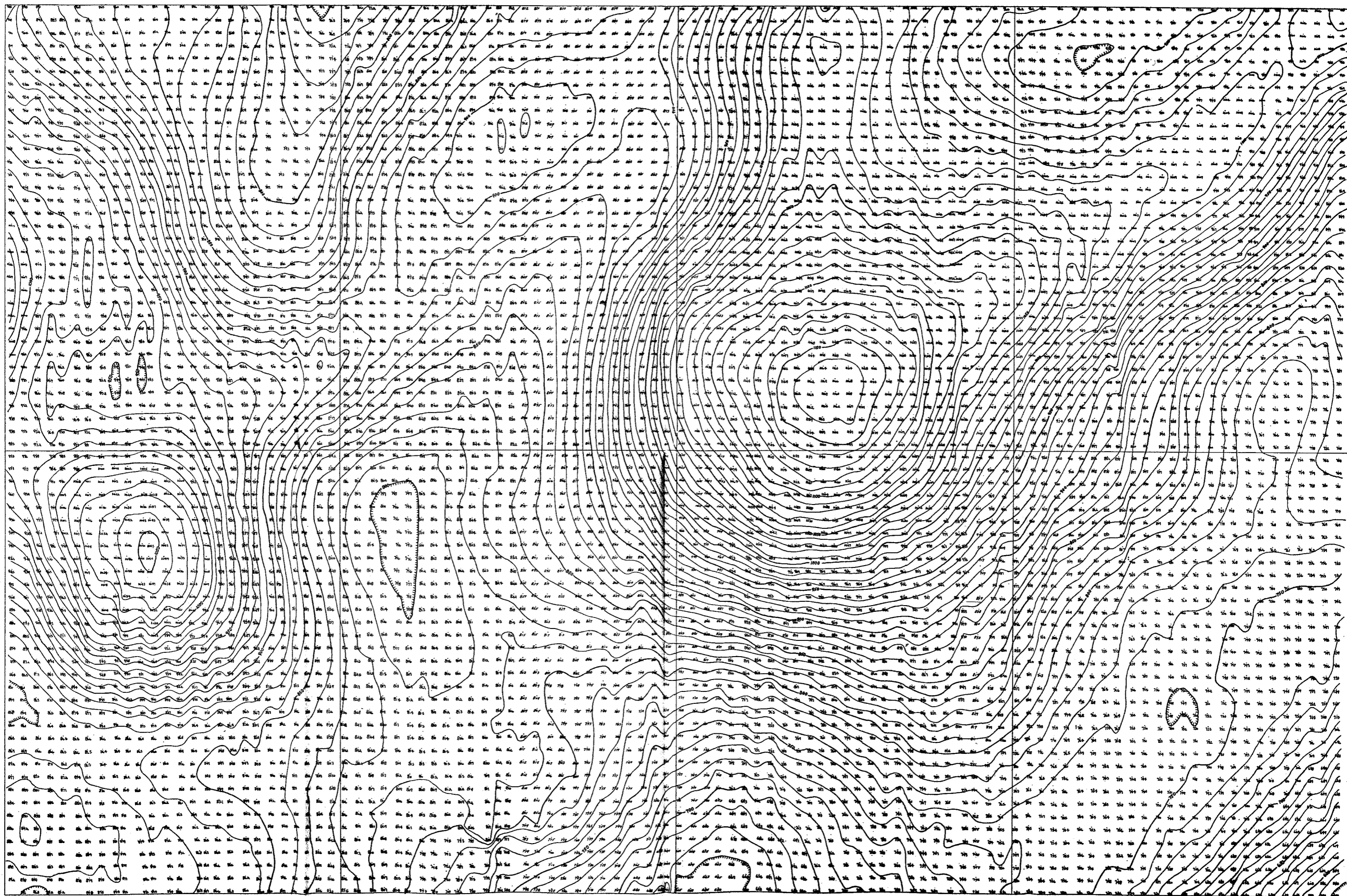
Base Line 5

Base Line 4

CLEARFIELD

Curwensville

Grampian

Base Line 3

PRELIMINARY MAGNETIC MAP
OF PART OF
CENTRE AND CLEARFIELD
COUNTIES

SHOWING VALUES FROM
GROUND SURVEY
AND
BASE LINES OF AIRBORNE
SURVEY

Base Line 5

Base Line 2

Snow Shoe

Base Line 4
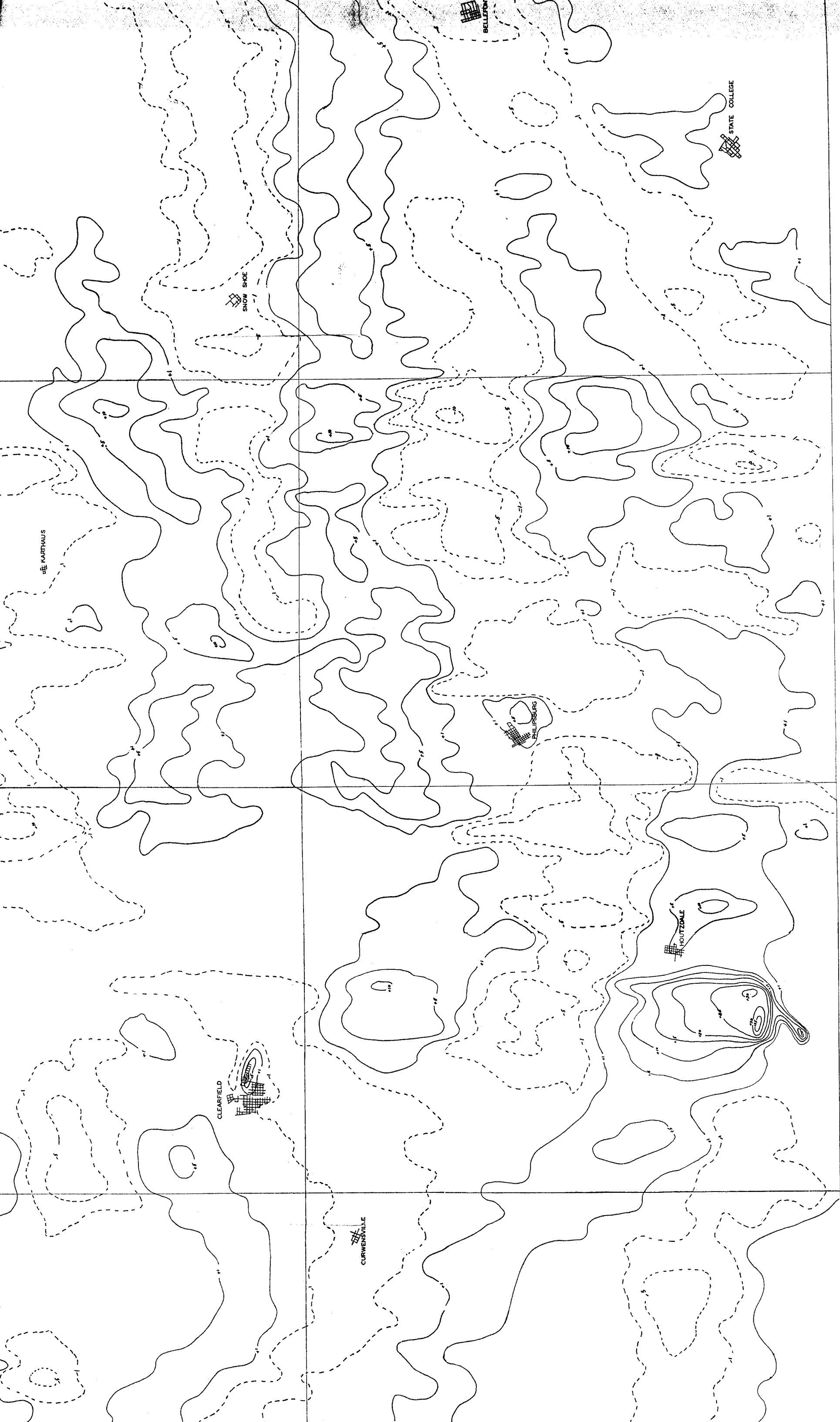
Milesburg

BELLEFONTE

Phillipsburg

Chester Hill
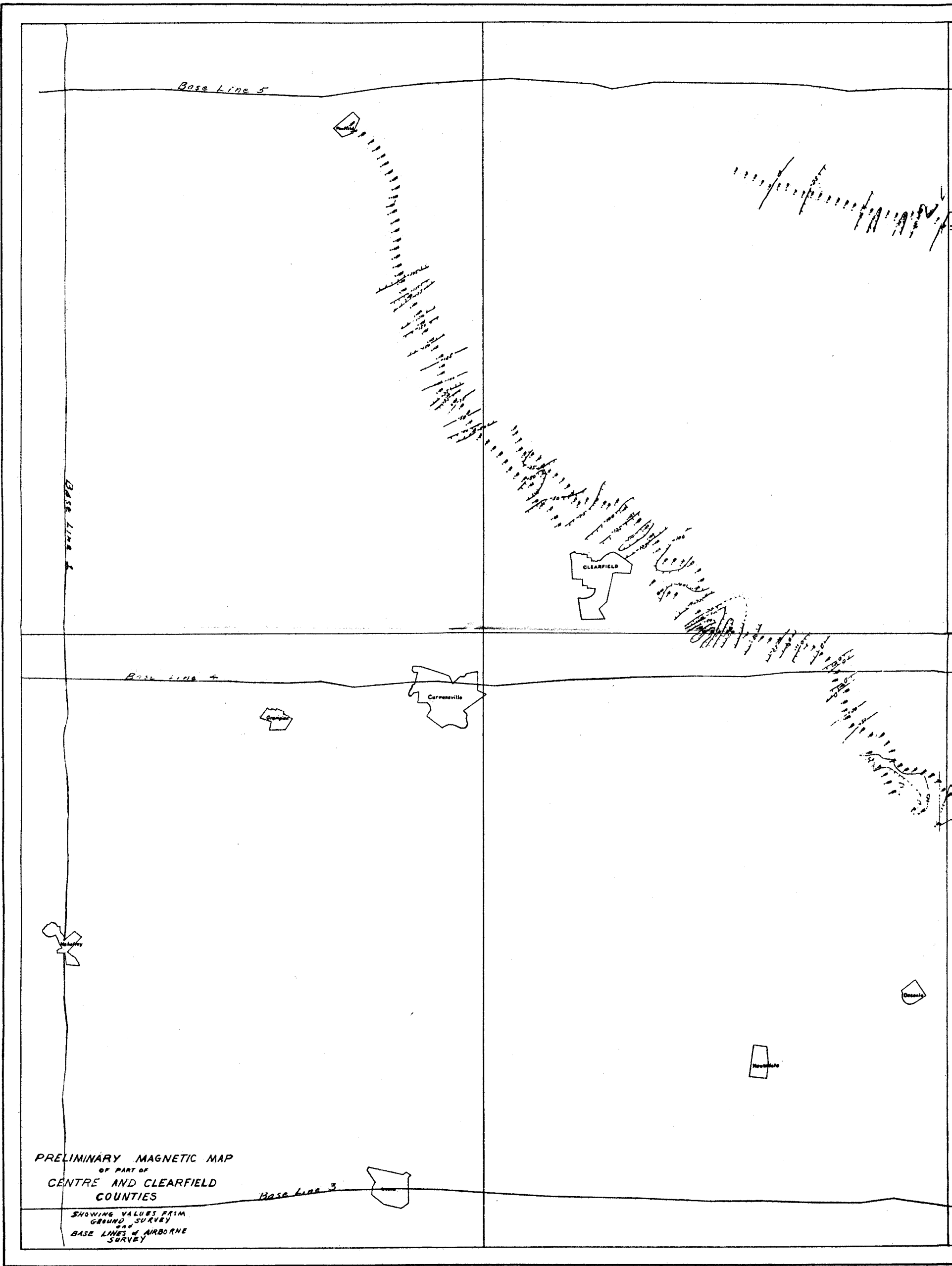
STATE COLLEGE

Base Line 3

Map 2. Preliminary Total Intensity Aeromagnetic Map of part of Centre and Clearfield counties, Pennsylvania. Contour interval—10 gamma. Scale—1 inch = 1 mile.

MAP 3

AEROMAGNETIC SECOND ORDER ¿ ANOMALY MAP

OF PART OF

CENTRE AND CLEARFIELD COUNTIES PENNSYLVANIA

SCALE — 1/ 62500
CONTOUR INTERVAL = 5 GAMMA

BELLEFON

STATE COLLEGE

SNOW SHOE

KARTHAUS

PHILIPSBURG

HOUTZDALE

CLEARFIELD

CURWENSVILLE
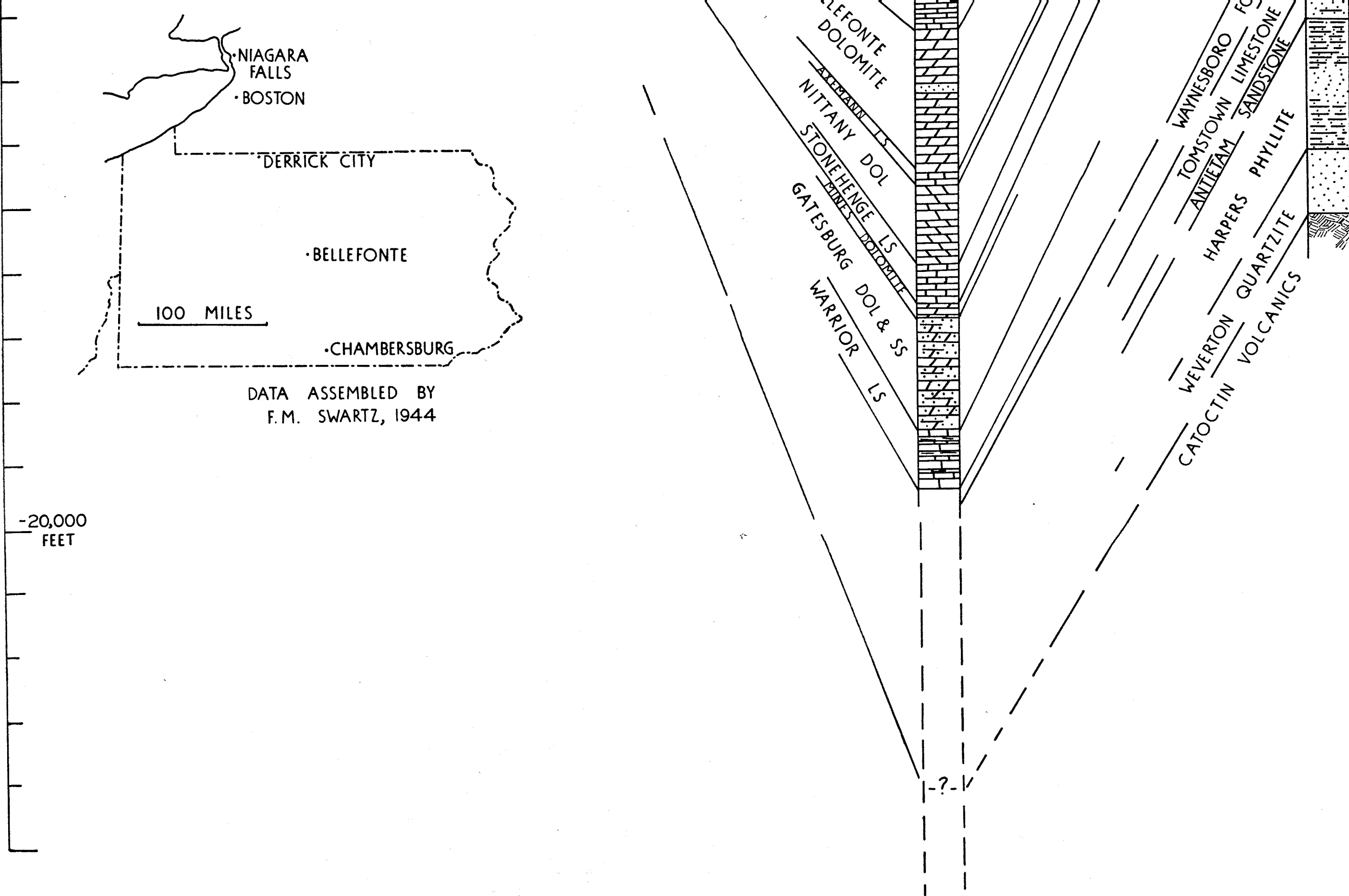
Figure 1. EXPECTED DEEP GEOLOGY NEAR BRADFORD, PENNSYLVANIA. SECTIONS NEAR BELLEFONTE AND CHAMBERSBURG ARE BASED ON SURFACE GEOLOGY AFTER BUTTS [4] AND STOSE [8] RESPECTIVELY. NIAGARA FALLS AND BOSTON SECTIONS ARE FROM TORREY, FRALICH, ET AL [11]; THE PRE-QUEENSTON PORTION OF THE "BOSTON" SECTION SEEMS TO BE GENERALIZED FROM THE DEPEW NO. 2, BEMUS PIERCE, AND GEORGE BUTTON WELLS OF ERIE COUNTY, NEW YORK. DERRICK CITY WELL TO TOP OF QUEENSTON IS FROM FETTKE [5]. PRE-QUEENSTON STRATA ARE PROJECTED TO THE DERRICK CITY AREA ON THE BASIS OF REGIONAL CHANGES IN THICKNESS AND CHARACTER.

NIAGARA FALLS   35 M.   "BOSTON"   50 M.   DERRICK CITY   85   M.   ALLEGHENY FRONT WEST OF BELLEFONTE   75 M.   SYNCLINAL AXIS WEST OF CHAMBERSBURG

SEA LEVEL

POCONO SS

BRADFORD SAND

CATSKILL RED BEDS

CHEMUNG SHALE

GENESEE

HAMILTON SHALE

SALINA SHALES

NAPLES GROUP

BRALLIER SHALE

LOCKPORT DOLOMITE

ALBION SANDSTONES

QUEENSTON RED BEDS

MARCELLUS BLACK SHALE

ONONDAGA

HAMILTON SHALE

HARRELL

OSWEGO SS

LORRAINE - UTICA SHALES

CRISKANY

KEYSER LS

TONOLOWAY LS

WILLS CREEK SHALE

MCKENZIE SH & LS

ROSE HILL SH

MARTINSBURG SHALE

TRENTON - BLACK RIVER LIMESTONES

"BEEKMANTOWN"

"POTSDAM"

CLINTON GROUP

TUSCARORA SS

JUNIATA RED BEDS

OSWEGO - BALD EAGLE SS

REEDSVILLE SHALE

CHAMBERSBURG LIMESTONE

STONES RIVER LIMESTONE

BEEKMANTOWN LIMESTONES

STONEHENGE

BASE OF TRENTON - BLACK RIVER SHOULD LIE AT ABOUT -7500 FEET IN BRADFORD AREA. DEPTH OF BASE OF CAMBRIAN LESS CLEAR; MAY BE ABOUT -9000 TO -10,000 FEET

TRENTON LIMESTONE

BLACK RIVER - CHAZY LSS

BEEKMANTOWN GROUP

BELLEFONTE DOLOMITE

CONOCOCHEAGUE LIMESTONE

ELBROOK LIMESTONE

-10,000 FEET

NIAGARA FALLS

BOSTON

DERRICK CITY

AXEMANN LS

NITTANY DOL

STONEHENGE

GATES

WAYNESBORO FORMATION

TOMSTOWN LIMESTONE

ANTIETAM SANDSTONE

HARPERS PHYLLITE

Figure 2. STRUCTURAL GEOLOGY AND MAGNETIC ANOMALIES OF PHILIPSBURG AREA. QUADRANGLES ARE AS FOLLOWS, BEGINNING AT UPPER LEFT: PENFIELD, CLEARFIELD, KARTHAUS, SNOWSHOE, CURWENSVILLE, HOUTZDALE, PHILIPSBURG, AND BELLEFONTE. ISOGAM CONTOURS ARE FURNISHED BY PIRSON AND BACON. STRUCTURAL GEOLOGY OF NORTHERN TIER OF QUADRANGLES AND PART OF PHILIPSBURG QUADRANGLE IS BASED ON STEREOSCOPIC STUDIES OF AERIAL PHOTOGRAPHS BY G. H. CROWL. STRUCTURAL CONTOURING OF CURWENSVILLE AND PART OF PHILIPSBURG QUADRANGLE IS FROM G. H. ASHLEY (1), AND ON HOUTZDALE QUADRANGLE FROM ASHLEY AND CAMPBELL (2). STRUCTURAL AXES OF BELLEFONTE QUADRANGLE ARE FROM CHARLES BUTTS (4).