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UNITED STATES
Department of the Interior
Harold L. Ickes, Secretary

BUREAU OF MINES
R. R. Sayers, Director

REPORT OF INVESTIGATIONS

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By C. J. Wilhelm,[2] Sam S. Taylor,[3] W. C. Holliman,[4] and E. O. Owens[5]

INTRODUCTION

Brine produced from subsurface formations may be employed successfully instead of fresh water as a flooding medium in the secondary recovery of oil. The feasibility of this substitution has been proved in the shallow "shoestring" area of eastern Kansas and northeastern Oklahoma, where the supply of fresh water often is limited. In this procedure all brine produced with the oil is returned to the formation and thus is prevented from contaminating streams and fresh-water supplies.

This report includes a detailed description of a "flood project" in eastern Kansas studied by the Bureau of Mines. In an attempt to determine whether brine, when handled properly, can be used as effectively as fresh water in flooding oil from partly depleted formations, an analysis was made of all known conditions that influence flooding.

From the time water flooding was begun on this project the operator has considered it as a "pilot plant" or "experimental flood" to assist him in outlining expansion of the present project and initiating new projects. As a result records are more complete than those from a normally operated flood property. As the project has been operated experimentally its development and operation should not be used as a model for other flood projects, even if conditions appear to be similar. Careful study of the detailed data, however, may suggest how brine can be used as a flooding medium.

ACKNOWLEDGMENTS

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[1] The Bureau of Mines will welcome reprinting of this paper, provided the following footnote acknowledgment is used: "Reprinted from Bureau of Mines Report of Investigations 3573."
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engineer, Petroleum Experiment Station, Bureau of Mines, Bartlesville, Okla., and under the direct supervision of Ludwig Schmidt, senior petroleum engineer, Bureau of Mines, Bartlesville, Okla.

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The special analyses for the salt content of the produced oil were made by J. W. Horne, associate petroleum engineer, and L. F. Christianson, junior chemical engineer, Bureau of Mines. The illustrations were prepared by John Trevorrow, Bureau of Mines, and R. M. Himmelright, formerly with the Bureau of Mines.

HISTORY OF DEVELOPMENT

The present study of water[6] flooding as a method of increasing the ultimate recovery of oil was made on four leases in the McCune field, Crawford County, Kans. Figure 1 is a map showing the relative position of the surface equipment on the leases under flood. The oil is obtained from a shallow "shoestring" sand in which the depth of the wells ranges from 300 to 350 feet. This sand, known locally as the McCune, is one of the lenticular sands in the Cherokee shale of Pennsylvanian age. The total productive area of the four leases is approximately 47 acres.

The discovery well in this section of the shoestring was drilled in on lease D, January 12, 1932. This well soon was plugged and abandoned as it was not a commercial producer. In December 1932 well 1, now 1C, on lease A was completed as a producer. The drilling program initiated at that time was continued until there were 28 oil-producing wells on the four leases when water flooding was begun. When first completed, some of the wells flowed 100 barrels of oil per day for a short time; however, the wells were equipped with pumps, and central power plants were installed as soon as they were drilled. When the water-flooding project was begun the average production of oil per well had declined to approximately 1/2 barrel per day.

6/ The term "water" is used in this report when the significant factor is the type of fluid. The term "brine" is used when the presence of dissolved salts in the water is the significant factor.

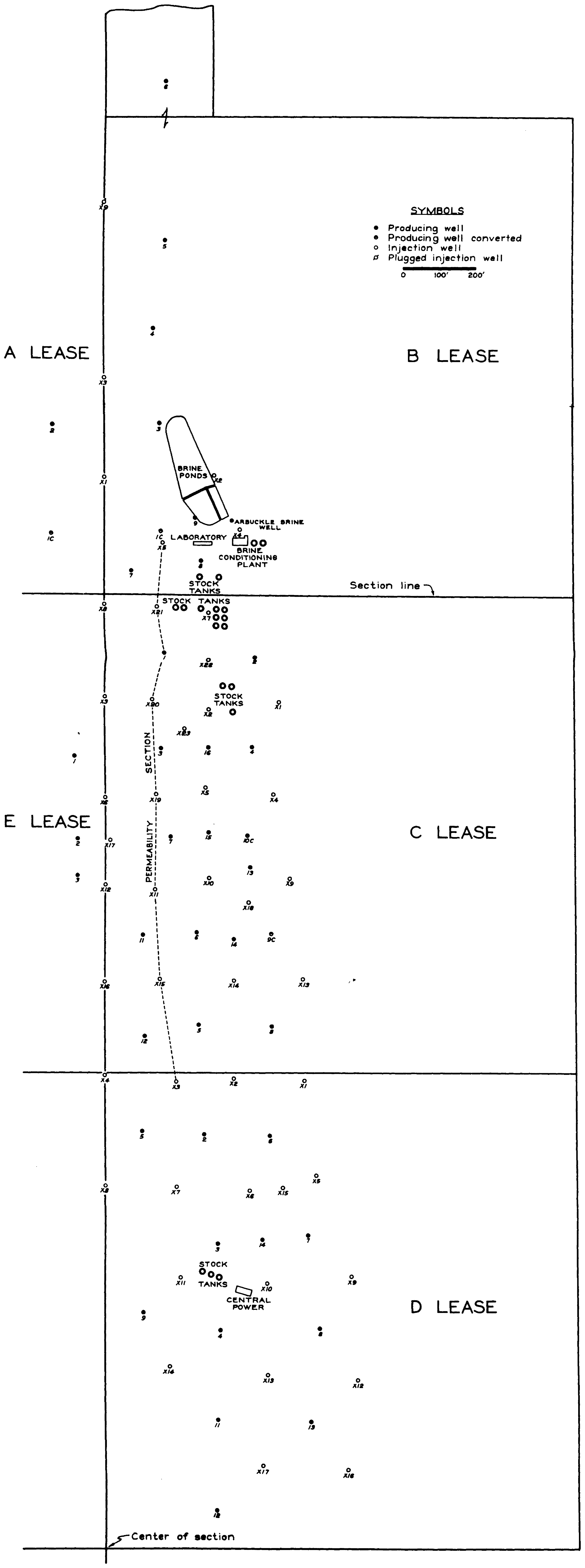


FIGURE 1.-MAP SHOWING DEVELOPMENT OF A WATER-FLOOD PROJECT, McCUNE FIELD, CRAWFORD COUNTY, KANS.

Because of the rapid decline in output of oil, vacuum was applied to the producing formation early in the life of the field. Vacuum was released on leases B and C in June 1937 and on lease D in June 1938, when water flooding was extended to include that property. The vacuum was released from the producing formation by opening the wellheads to the atmosphere.

The drilling of water-injection wells was begun in May 1937 with well X1, lease B. On all leases under flood, 14 injection wells were drilled in 1937, 25 in 1938, and 9 in 1939.

In the development of the property for water flooding the original oil-producing wells were continued in use, and water-injection wells were drilled around them. Several additional producing wells were drilled, and a few of the old oil-producing wells were converted to injection wells. As the original oil wells were not drilled on a standard pattern, the water-injection wells could not be drilled on a regular pattern.

Flooding operations were begun on lease C with the original eight producing wells (1, 2, 3, 4, 7, 10C, 6, and 9C) forming the pattern around which the water-injection wells were spotted. Drilling of additional injection wells extended the flood area to include old producing wells 5 and 8. Upon completion of injection wells X3 and X4, lease D, and X12, X15, and X16, lease C, additional producing wells 11 and 12 were completed on lease C (August 1938).

In 1939 a program was adopted for drilling producing and injection wells on inside locations, but the rapid decline in production forced abandonment of the program.

DESCRIPTION OF PROPERTY

The extent of the property under flood (see fig. 1) includes leases A, B, C, and D, operated by one company. Another company operates lease E and is not cooperating in the water-flooding project. All oil produced on leases A, B, C, and D is collected in stock tanks near the property line between B and C leases, whence it is transported to pipe-line stations or refineries by truck.

Oil-Producing Wells

The oil wells were drilled with cable tools, and all were completed in approximately the same manner at a total depth of 300 to 350 feet. The general procedure was to set a short string of 6-5/8-inch surface pipe to protect subsurface fresh-water horizons. An 8-inch bit was used in drilling the well to the point at which the 6-5/8-inch pipe was set. The wells were completed in the producing formation with 6-inch bits, then the oil string (4-7/8-inch casing) was set through the "Second Lime" at a depth of approximately 250 feet. Neither string of casing was cemented. Because of this casing program some wells had 150 feet of open hole.

The wells were placed on production after being shot with nitroglycerin. The size of the shots was varied according to the number of feet of producing sand. The largest shot recorded during early development of the leases was 100 quarts of nitroglycerin.

Four of theoil wells on lease D flowed oil for the first 24 hours after completion. The standard practice was established of running the 2-inch tubing as soon as a well was completed; then the pumping equipment was installed and the well placed on production. Central power units were employed for pumping the wells until 1938 when the gas-engine-driven units were replaced by electric-driven pumping units. In 1940 some of the pumping wells were converted to flowing wells.

Water-Injection Wells

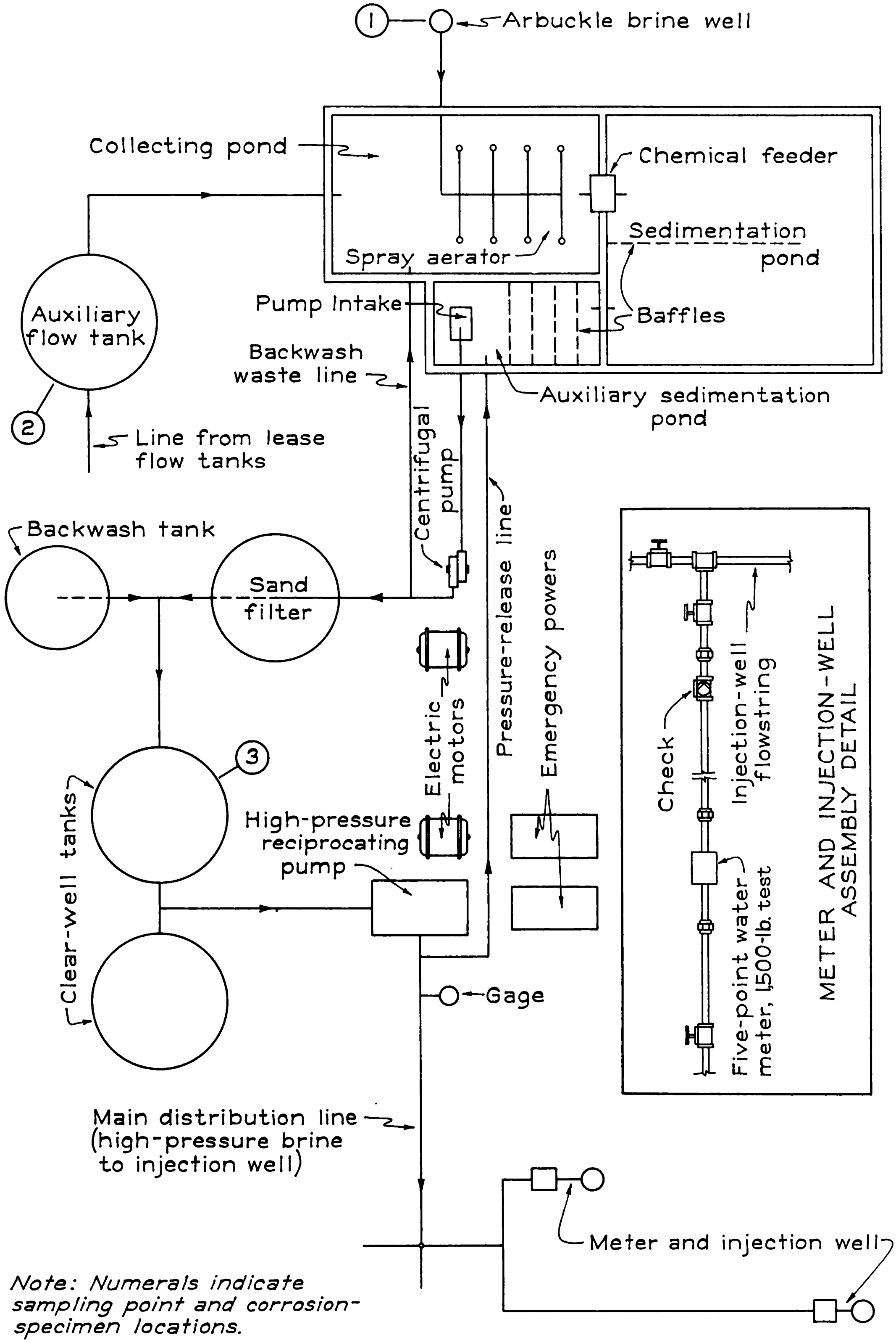
The injection wells also were drilled with cable tools. Completion of these wells differed from that of the oil wells in that a packer was run on 2-inch tubing and set at the top of the producing formation. All of the packers were "loaded" with several sacks of cement and mud extending to the surface of the ground to prevent bypassing of the injected brine. A "back-off" joint was placed in the tubing string above the packer to facilitate pulling the tubing if necessary. The injection wells were completed in the producing formation with 6-inch bits. Several injection wells were cored with a cable-tool core barrel to obtain data on the producing formation.

The procedure used in shooting the oil formation in the injection wells was varied considerably, as the operator thought that some of the early shooting technique had not been suitable for the type of formation. The general procedure was to employ a heavier shot in the less permeable part of the sand. The injection wells drilled in 1937 were shot with 10 to 55 quarts of nitroglycerin, depending on the thickness of the producing sand. The average shot was 1.6 quarts per foot of sand. The shots were increased to an average of 2.4 quarts per foot on wells drilled during 1938 and to 2.6 quarts per foot on wells drilled during 1939.

Experience with the injection wells shot with light and heavy charges showed that the amount of channeling or bypassing of the brine from the injection well to the producing well was independent of the size of the shot. In shooting wells drilled before 1940 the results probably were influenced by the fact that the shots were not "tamped" with sand or water. Moreover, the operators believed that some of the injected brine bypassed between several of the injection and producing wells through broken-sand sections above the producing sand.

Brine-Conditioning System

The water used for repressuring was a mixture of the brines produced with the oil and brine obtained from a well drilled to the Arbuckle limestone formation. Initially, most of the water injected was from the water well; however, as the flood progressed more brine was produced with the oil and less "make-up" water was required.



Note: Numerals indicate sampling point and corrosion-specimen locations.

FIGURE 2.-FLOW DIAGRAM OF BRINE CONDITIONING AND DISTRIBUTING SYSTEM.

Briefly, the general lay-out of the water-conditioning system was as follows: The brine produced on several leases drained through a gravity gathering system to the initial collecting pond. The "make-up" brine from the Arbuckle brine well was sprayed into the initial collecting pond, as illustrated in figure 2, and the treating compounds were added to the mixture of brine produced with the oil and Arbuckle brine as it passed into a large sedimentation pond. From the large sedimentation pond the brine flowed into an auxiliary sedimentation pond, where it was picked up by a pump, forced through the filter to the clear-well tank, then pumped through the distributing system to the injection wells.

The three ponds used for mixing and conditioning the brines were of earthen construction, and their depth ranged from 5 to 8 feet. The surface soil was a clay that permitted little brine to seep through the dikes. A fence was built around the dikes to prevent cattle from getting into the ponds.

The direction of flow of brine through the conditioning system is shown in figure 2. The brine produced with the oil and the Arbuckle brine were mixed in the initial collecting pond, which had a capacity of approximately 5,000 barrels. From the collecting pond the brine passed under a baffle through a trough into the large sedimentation pond. The coagulating chemical was portioned into the brine as it passed through the trough. The sedimentation pond had a capacity of approximately 15,000 barrels, and a wooden baffle extended through the center of the pond (from the end at which the brine entered) to within 90 feet of the opposite end to increase the retention time of the brine in the pond. The brine then passed under a baffle from a large retention pond into the auxiliary sedimentation pond, having a capacity of approximately 1,400 barrels, whence it was picked up by a centrifugal pump and forced through the pressure sand filter. From the filter the brine was forced into the clear-well tanks where it was picked up by the positive-displacement pump and forced through the distribution pipe-line system into the brine injection wells.

The 2-inch centrigugal pump for forcing the brine through the sand filter was driven by a 3-hp., 1,750 r.p.m. induction motor. The positive displacement pump was driven by a 15-hp., 1,200 r.p.m induction motor. All power was transferred by V-belts. The triplex, single-stage displacement pump had 4-inch pistons that were "metallized" with stainless steel to reduce corrosion. Two standard automobile engines were used for emergency power if the electric power failed. The two clearwell tanks shown in the flow diagram (fig. 2) were wood-stave tanks having a capacity of 100 barrels each.

The sand filter was a standard commercial pressure filter approximately 6 feet in diameter and 6 feet in height. At an average filtration rate of slightly more than 2.5 gallons a minute per square foot of filter-sand surface, the filter had a daily capacity of 2,500 barrels. The filter was backwashed daily with filtered brine from a 40-barrel tank 16 feet above the base of the filter. The difference in elevation between the tank and the sand bed in the filter provided enough head to back-wash the sand bed at an average rate of approximately 12.5 gallons per minute per square foot of filter-sand surface.

As shown in figure 2 the chemical feeder was between the initial collecting pond and the large sedimentation pond at thepoint where the brine entered the large pond. The feeder was of the electric-driven, dry-feed type.

Arbuckle Brine Well

The Arbuckle brine well was drilled to a total depth of 930 feet and completed in a water sand 10 feet thick at 915 to 925 feet. The 6-1/4-inch casing was set at 562 feet. The well was completed by shooting the water-bearing formation with 15 quarts of nitroglycerin. It was equipped with a centrifugal pump, vertical-shaft-driven by a 7 1/2-hp., 1,750 r. p. m. induction motor. The capacity of the pump was 2,000 barrels per day through the 3-inch tubing with the pump intake placed at a depth of 210 feet. The initial static fluid level of the brine was approximately 180 feet below the surface.

Chemical Characteristics of Brine Before and After Treatment

The brine produced from the Arbuckle well had some hydrogen sulfide and some sulfates in solution, but the total solid content was relatively low. Brine in the oil formation contained a much higher proportion of total solids and considerable iron but no hydrogen sulfide or sulfates. Upon mixing these brines the principal chemical reaction apparently was precipitation of iron as iron sulfide.

Table 1 gives some typical analyses of brine samples collected in 1938, including one sample from the Arbuckle brine well, two from producing wells, and one from the clear-well tank. The sample from well 13, lease D, is believed to be representative of the original brine in the oil-producing formation; the analysis shows that the injected brine had not reached this producing well at the time of sampling. Undoubtedly the sample from well 4, lease C, was mostly injected brine mixed with some formation brine.

Apparently several chemical reactions took place while the brines were being collected and conditioned for injection into theproducing formation. As the produced brine was drained into the collecting pond it was exposed to the atmosphere, resulting in precipitation of part of the iron. When the Arbuckle brine was sprayed into the collecting pond, it lost hydrogen sulfide; part passed directly into the atmosphere and part formed free sulfur. Then, upon mixing the produced brine and the Arbuckle brine in the pond a reaction took place between the iron compounds and hydrogen sulfide remaining in the two brines. The alum that was added to the mixed brines as they flowed into the large sedimentation pond acted as a coagulant for the finely divided materials in suspension in the brine. The net effect of aerating the two brines, mixing them, and adding a coagulant are shown in the analysis of the sample from the clear-well tank. This analysis indicates that the treatment reduced the iron, hydrogen sulfide, and bicarbonate content and increased the content of dissolved oxygen over that to be expected by mere dilution of cycled brine by Arbuckle brine. The quantities of certain ions, such as magnesium, sodium, sulfate, and chloride, are affected little, if any, by the treatment, being governed by the ratio of cycled brine to Arbuckle brine.

TABLE 1.- Chemical characteristics of several brine samples, McCune field, Crawford County, Kans. 1/

Mineral Analyses

Radical or compound	Arbuckle well, p. p. m.	Lease D, well No.13, p. p. m.	Lease C, Well No.4, p. p. m.	Clear-well tank, p. p. m.
Total solids	1,522	24,400	9,650	5,855
Iron	.5	26.0	8.5	.1
Calcium	79	356	176	129
Magnesium	35	200	86	62
Sodium	467	8,000	3,372	2,068
Carbonate	-	-	-	-
Bicarbonate	382	544	534	403
Sulfate	107	0	33	139
Chloride	660	13,225	5,425	3,260
Special Tests				
Reducing compounds as hydrogen sulfide	26.0		2.5	3.8
Oxygen	.4		5.0	7.1
Bicarbonate as calcium carbonate	354		484	356
Total iron	1.0		6.0	.4

1/ Mineral analyses by the Kansas State Board of Health. Special tests were made at the point of sampling by the authors.

To date organic growths have been controlled successfully in the surface ponds by periodic batch treatment with copper sulfate. Treatment for organic growths was begun in the latter part of 1938 after inspection disclosed growths in the filter and brine distribution lines. The growths in the filter had coated the sand grains and had caused the grains to adhere to one another to such an extent that the filter was ineffective in removing suspended matter in the brine. The accumulation of growths in the filter sand was not affected by back-washing, therefore the filter sand was removed and replaced with graded building sand. Evidently the organic growths in the distributing lines and in the injection wells were removed by batch treatments of copper sulfate and by "back-flowing" the injection wells, since recent inspection showed that no growths were present in the lines. As surface waters often carry organic growths, dikes were built around the ponds to eliminate surface drainage into them.

CORE ANALYSES

During early development of these leases the wells were completed without taking cores of the producing formation. When the flood project was begun cores were taken in most of the new producing and injection wells. The operator established a laboratory on the lease and analyzed the cores for permeability and water and oil saturation. The core analyses furnished the authors were on individually plotted core graphs.

The procedure used in determining the oil saturation and porosity of the cores is described by Barnes.7/ The oil content was determined by the retort method and theporosity, with a Washburn-Bunting porosimeter of the one-chamber type. The method employed for determining permeability was similar to that described by Johnson and Taliaferro,8/ except that a positive-displacement meter was used to measure the flow of air. The water content was determined by the procedure outlined by Taliaferro and Spencer.9/

The values obtained for oil saturation include a correction factor for the oil lost in the retort method of analysis because of cracking and for the oil remaining in the condenser. The correction factor was determined by retort analyses of oil-free unconsolidated sand, saturated with measured volumes of produced oil, and by noting the difference in the volume of oil charged and the volume recovered. The volume of charged oil covered the range of recoveries expected from the analyses of actual core samples. The operator concluded from these analyses that 2 cubic centimeters of oil should be added to the volume recovered in the analysis for losses caused by cracking and incomplete drainage of the analytical equipment. No correction was applied for the loss of oil during sampling of the formation, as very little gas was present originally and the formation had been subjected to standard pumping and pumping under a vacuum for several years.

7/ Barnes, Kenneth B., Porosity and Saturation Methods: Am. Petrol. Inst., Drilling and Production Practice, 1936, pp. 191-203.

8/ Johnson, T. W., and Taliaferro, D. B., Flow of Air and Natural Gas Through Porous Media: Bureau of Mines Tech. Paper 592, 1938, 55 pp.

9/ Taliaferro, D. B., and Spencer, G. B., A Method for Determining the Water Content of Oil Sands: Bureau of Mines Rept. of Investigations 3535, 1940, 11 pp.

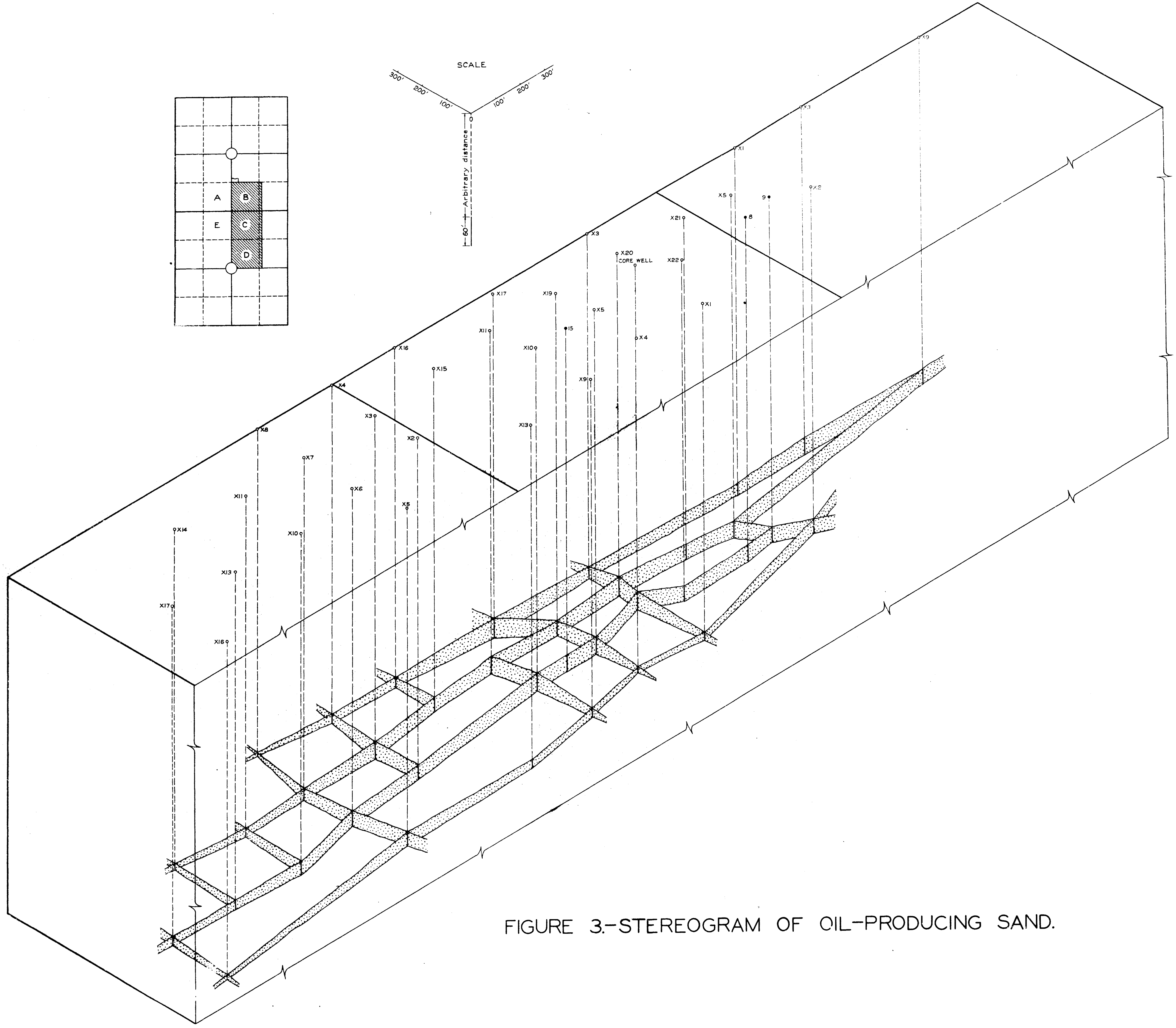


FIGURE 3.-STEREOGRAM OF OIL-PRODUCING SAND.

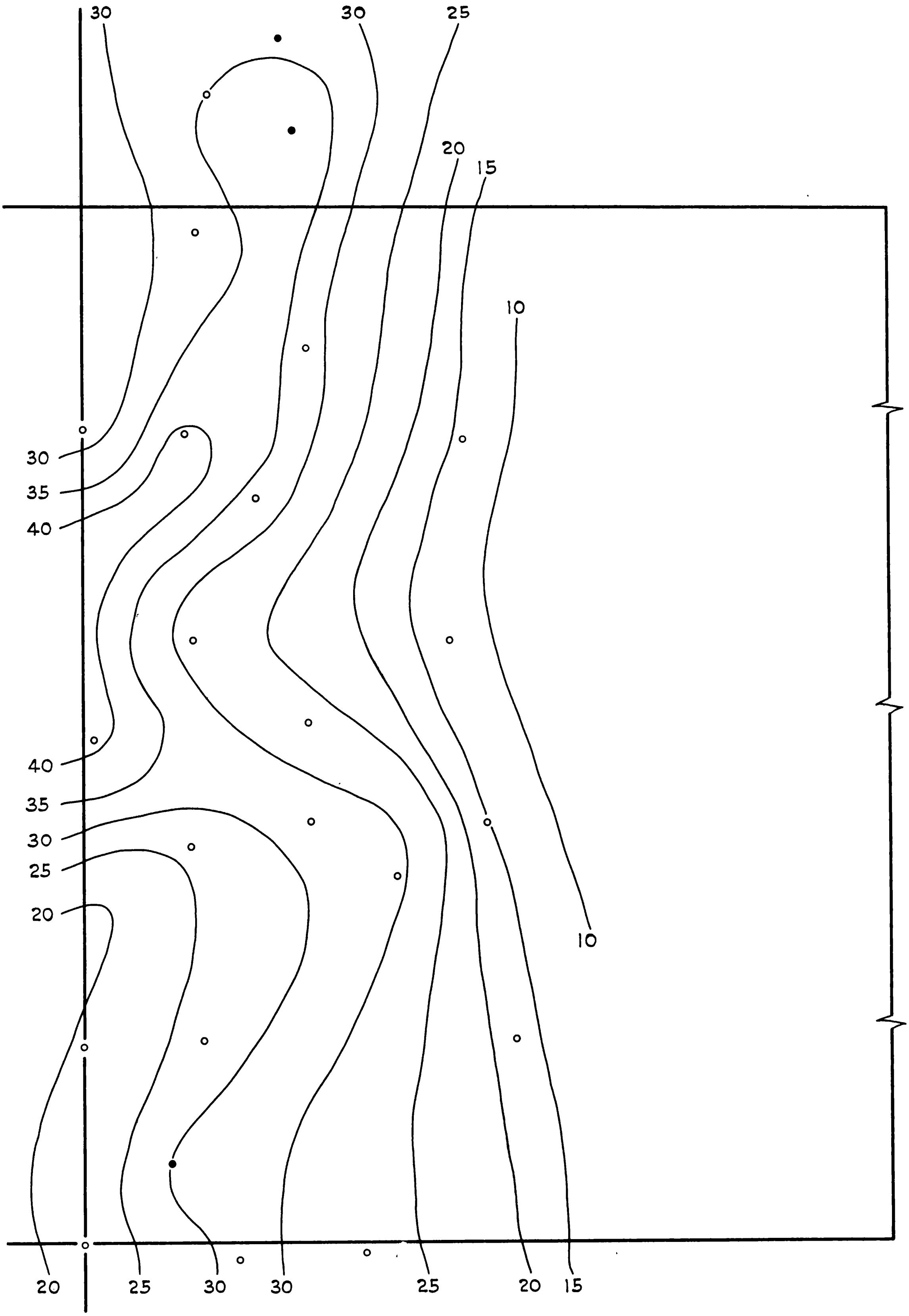


Figure 4.—Isopachous map of oil sand on lease C.

SUMMARY OF CORE DATA

The core analyses were employed in the construction of a three-dimensional drawing or stereogram (fig. 3) to illustrate the general contours of the sand body on leases B, C, and D. The upper surface in the illustration is a horizontal plane showing the relative position of the various wells on which core data were obtained. The thickness of the sand in the various wells is shown in the lower part of the figure; the elevation of the wells and depth to the sand body indicate the position of the sand sections of the various wells in relation to each other. In this way the general trends of the sand body can be visualized.

Core Data on Lease C

Of the analyses of cores taken on lease C, 17 were considered representative of the condition of the producing formation. Several cores were taken from wells drilled after the flooding project was in operation; however, only these analyses were used that compared favorably with analyses of cores from wells drilled when the project was begun. A few core analyses, which showed definitely that some fluid had been displaced where the cores were taken because of flooding, were not used in calculating the oil and water content.

An isopachous map (fig. 4) was drawn of the oil sand on lease C from information furnished by the core graphs of 19 wells drilled on lease C, 2 on lease D, and 3 on lease B. In constructing the map total thickness of sand was considered, including minor shale lenses that were indicated on some of the core graphs.

A planimeter was used on the map to determine the areas between the various contour lines, and from these data the total volume of the sand body under flood in lease C was calculated; this volume was approximately 424 acre-feet. The analyses of 17 cores from wells on lease C show that the sand contained approximately 678 barrels of oil per acre-foot and approximately 622 barrels of water per acre-foot. The assumed average porosity of 20 percent.[10] indicates approximately 1,550 barrels of pore space per acre-foot; therefore, the average oil saturation of the sand was 43.7 percent, the average water saturation was 40.1 percent, and the total fluid saturation was approximately 83.8 percent at the time the cores were taken.

Production records show that approximately 27,500 barrels of oil had been produced from the lease before water flooding. Assuming that the oil saturation of 678 barrels per acre-foot was representative of the formation at the time flooding was begun, then the total quantity of oil in place in the formation before development of the property approximated 315,000 barrels. This saturation indicates that initially the pore space was approximately 48 percent filled with oil.

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[10] From a large number of analyses the operator concluded that the porosity of the sand body averaged approximately 20 percent.

Available information was not complete enough to include several factors that might influence the estimate of the original volume of oil in the formation. Data were not available to correct for the shrinkage in volume of the oil due to gas escaping from solution during production. Moreover, no correction was made for the effect of the temperature of the formation on the volume of the oil. Calculation of the saturations of the cores and the volume of oil produced is based upon a temperature of 60° F.; however, the original temperature of the formation was approximately 70° F.

HISTORY OF OIL PRODUCTION AND BRINE INJECTION

The production of oil from leases C and D before water flooding totaled approximately 45,000 barrels.[11/] The yearly output reached a peak of 19,941 barrels in 1934 for 20 wells, or a daily average of approximately 2.7 barrels of oil per well. By February 1937 production had declined to a daily average of 0.44 barrel of oil per well.

Figure 5 presents graphically the average daily production by weeks of individual leases B, C, and D, and of the three leases combined, since water flooding was begun. The production from lease A was not included as it was negligible. The curves for the production of oil on leases B, C, and D were begun when the production increased owing to the injection of brine. The breaks in the curves during the 34- to 36- week interval in 1939 were caused by a 2-week shut-down of all producing oil wells in Kansas ordered by the Kansas Corporation Commission.

The curves showing the decline in production of the leases are not indicative of the decline in output of individual wells, as the drilling program of both producing and injection wells was continued throughout the period. Fifteen injection wells were drilled in 1937, 22 injection and 2 producing wells were completed in 1938. During 1939 seven injection and six producing wells were drilled, and during the first 6 months of 1940 three injection wells were completed.

Water flooding was begun in June 1937 by loading the bore of the injection wells with brine. Brine did not enter the formation owing to the hydrostatic pressure of the fluid column in the well, therefore pump pressure was applied. During the first week the pump pressure was increased gradually to approximately 275 pounds per square inch, at which time the volume of brine injected into several wells had increased to an average of 20 barrels per day. The pump pressure of 275 to 300 pounds was maintained until December 1939 when it was increased to approximately 315 pounds; at that time approximately 48 barrels of brine per well was injected daily. The injection pressure necessarily is limited by the relative shallowness of the producing formation.

The total volume of brine that was injected on the entire flood project to November 1, 1940, was approximately 1,960,000 barrels. The ratio of the volume of brine injected to the volume of oil produced was 20 to 1 in 1937, 13 to 1 in 1938, and 17 to 1 in 1939. It averaged 13.5 to 1 from the time

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11/ Figures were not available for oil production before flooding on leases A and B. Moreover, production figures from leases C and D were not available from April to September 1937.

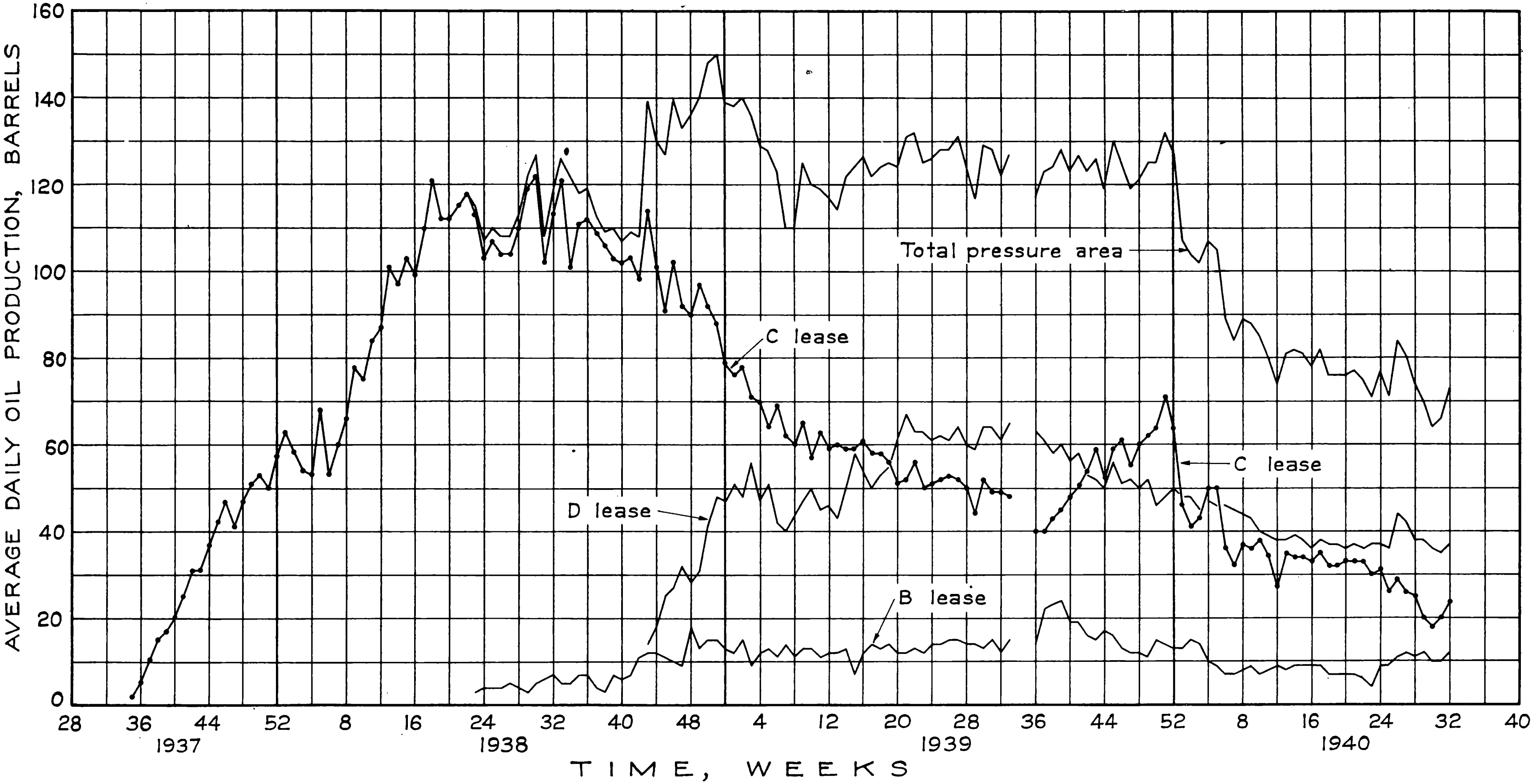

FIGURE 5.-OIL PRODUCTION CURVES OF FLOOD AREA IN McCUNE FIELD, CRAWFORD COUNTY, KANS.

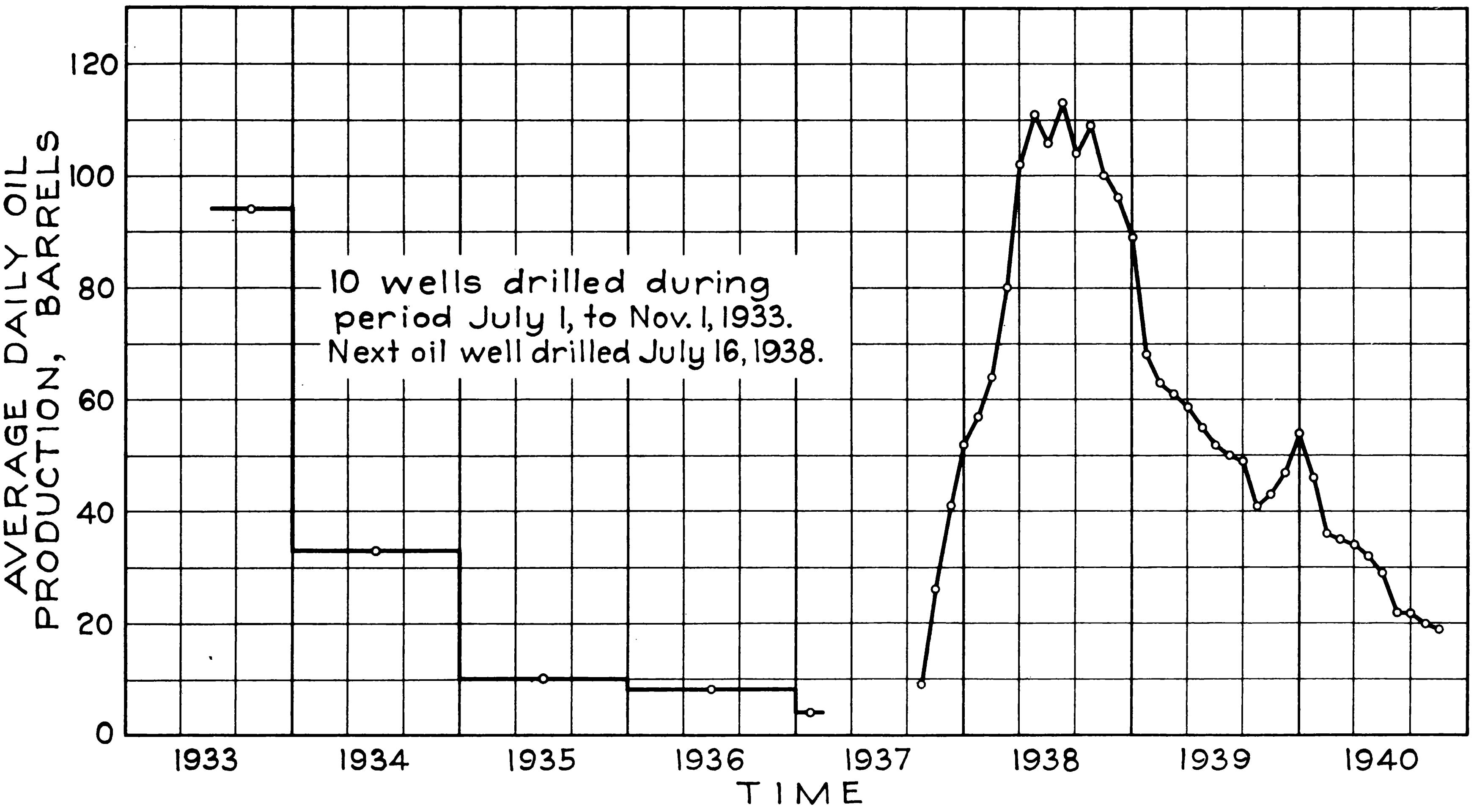

FIGURE 6.–OIL-PRODUCTION CURVE OF LEASE C.

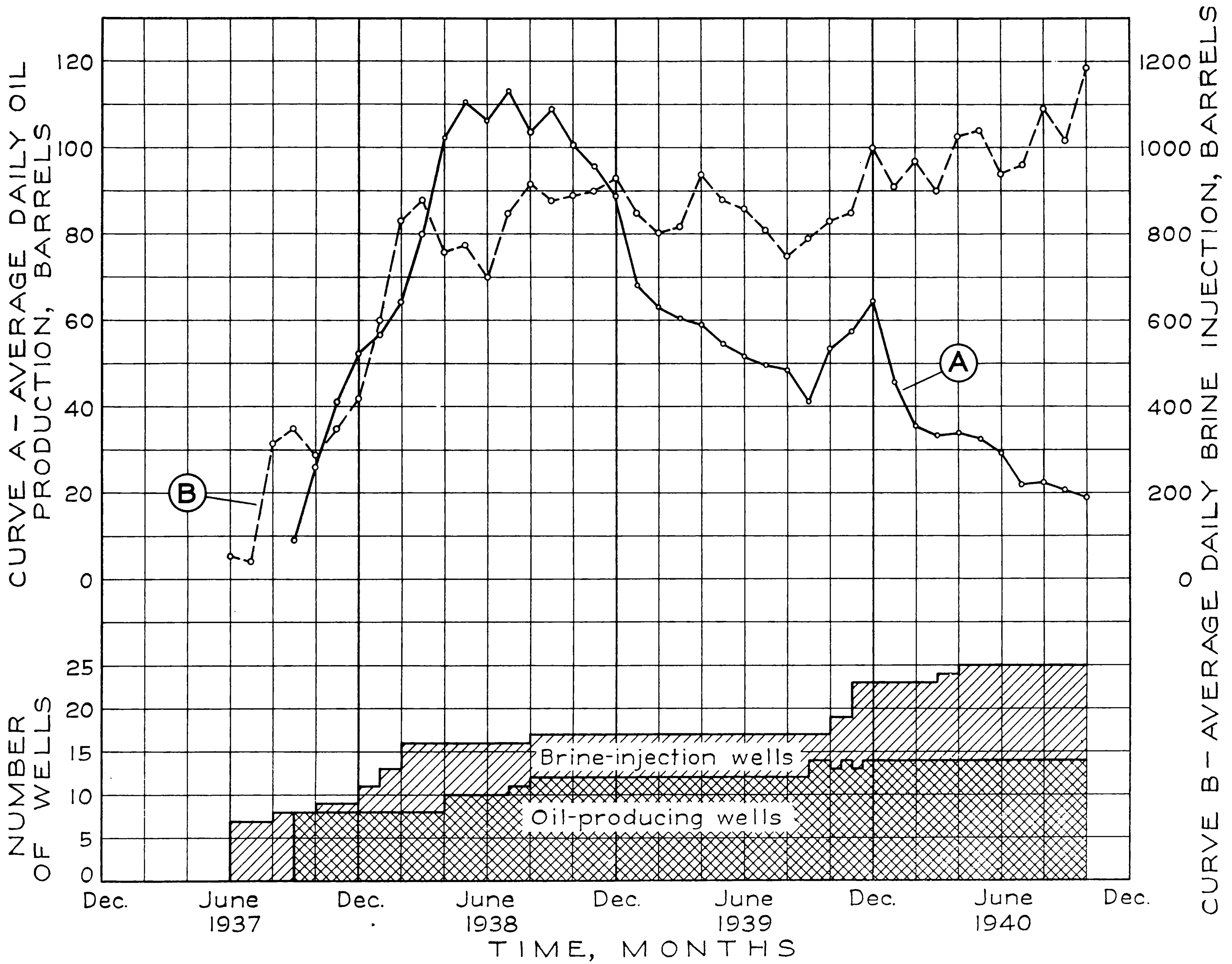

FIGURE 7.-CURVES SHOWING OIL PRODUCED, BRINE INJECTED, AND WELLS IN OPERATION ON LEASE C.

the project was commenced until production reached a peak in the latter part of December 1938.

History of Oil Production and Brine Injection on Lease C

As mentioned, lease C was operated as the experimental unit of the flood project. The effect of drilling inside location wells was studied, channeling or bypassing of injected brine between injection and producing wells was traced with dye, and attempts were made to reduce channeling of the injected brine by repairing wells. From results obtained in drilling inside location wells the operator concluded that the optimum spacing program had been exceeded at several points for the conditions under which the project was being conducted.

A fluorescein dye was used effectively to trace the path of the brine and to ascertain the time required for the injected brine to pass through the formation from injection wells to various producing wells; time intervals of less than 1 hour to as much as 8 hours were measured.

Considerable experimental work was done by the operator to reduce channeling or bypassing of the brine. Several materials and procedures were eliminated in the first attempts. Recent well repairs were successful when the procedure was varied according to the condition of the individual well.

The production data were plotted in figure 6 by years, as the oil production from lease C was obtainable only in yearly totals before flooding was begun. Although the exact time when vacuum was applied to the producing formation was not available, the decline curve indicates that probably it was applied during 1936, as the average daily production of oil from the lease dropped only 2 barrels from 1935 to 1936. The break in the curve from March 1937 to September 1937 indicates the period during which production data were not available. The first section of the curve illustrates clearly the rapid decline in production of oil on lease C. The section of the curve from 1937 to 1940 shows the effect of the flooding program on output. The lease had been at the point of abandonment under primary recovery operations.

The total volume of oil produced from lease C by flooding the producing formation with brine to November 1, 1940, was 66,950 barrels. With an estimated original volume of approximately 315,000 barrels of oil in the formation (see p. 9) the recovery of 27,500 barrels by primary producing methods amounts to 8.7 percent and the recovery of 66,950 additional barrels of oil by water flooding, to 21.3 percent. For the 15.7 acres under flood in lease C, approximately 4,300 additional barrels of oil were recovered per acre by flooding to November 1940. At the time this report was written (December 1940) oil still was being produced from lease C. The total ultimate recovery of oil is problematical and depends partly on the effectiveness of proposed remedial work on injection wells to reduce channeling of the brine through the more permeable sections of sand.

Figure 7 illustrates graphically the average daily volumes of oil produced and brine injected on lease C from the time the flood project was begun in June 1937 until November 1, 1940, as well as the number of brine-injection and oil-producing wells. Curve B shows the average daily volume of brine injected since June 1937. The injection of brine affected the production of oil in September 1937, as shown by curve A. The block diagram at the base of the chart indicates the number of brine-injection and oil-producing wells. The flood project was begun on lease C with 7 injection wells, and by April 1940 the number had been increased to 25.

The ratio of the volume of brine injected to the volume of oil produced on lease C may be calculated from curves A and B (fig. 7) for any desired interval of time. This ratio was approximately 9 to 1 from June 1937 until August 1, 1938. The peak in production of oil was reached during July 1938 after 13 months of brine injection. From August 1, 1938 to August 1, 1939, the ratio was approximately 12 to 1; from August 1, 1939, to August 1, 1940, approximately 25 to 1; and for the 3 months from August 1 to November 1, 1940, approximately 53 to 1. For the entire period of flooding on lease C, from June 1937 until November 1, 1940, the ratio of brine injected to oil produced approximated 14 to 1.

The natural decline in production was changed by producing and injection wells drilled during September, October, and November 1939. From April to July 1940 all but two of the pumping wells were converted to flowing wells; however, this change in the method of production has had little effect on the normal decline in production, as shown by curve A (fig. 7), except for July 1940 when the decline was slightly abnormal; the following 3 months production followed the general trend of the decline curve.

PERMEABILITY OF CORES TAKEN ON LEASE C

The operator analyzed a large number of the cores from lease C for permeability of the sand specimens. As the permeability of the cores from individual wells varied widely, a tabulation of calculated average permeabilitie would be misleading. Calculations based upon permeability determinations on several core samples taken at various points throughout the sand sections of the wells, indicated that the average permeability of the central section of the formation on a north-south line through the lease was higher than that of the east or west edges of the formation.

A section was taken through lease C on a general north-south line (see fig. 1), and the permeability of the cores from the intercepted wells was plotted in figure 8. The horizontal scale is the permeability expressed in millidarcys, and the vertical scale is the elevation in feet above sea level of the point of sampling of the formation. The permeability data were plotted for the entire section of sand that was cored and analyzed. The points at which the packers were set also are indicated in figure 8.

The wide variations in permeability extended into the north-central part of lease C, whereas the permeability of the cores from the three wells on the north end of the section was more uniform. The core from well X19 had a maximum permeability of 700 millidarcys and the highest average permeability of any core obtained on lease C.

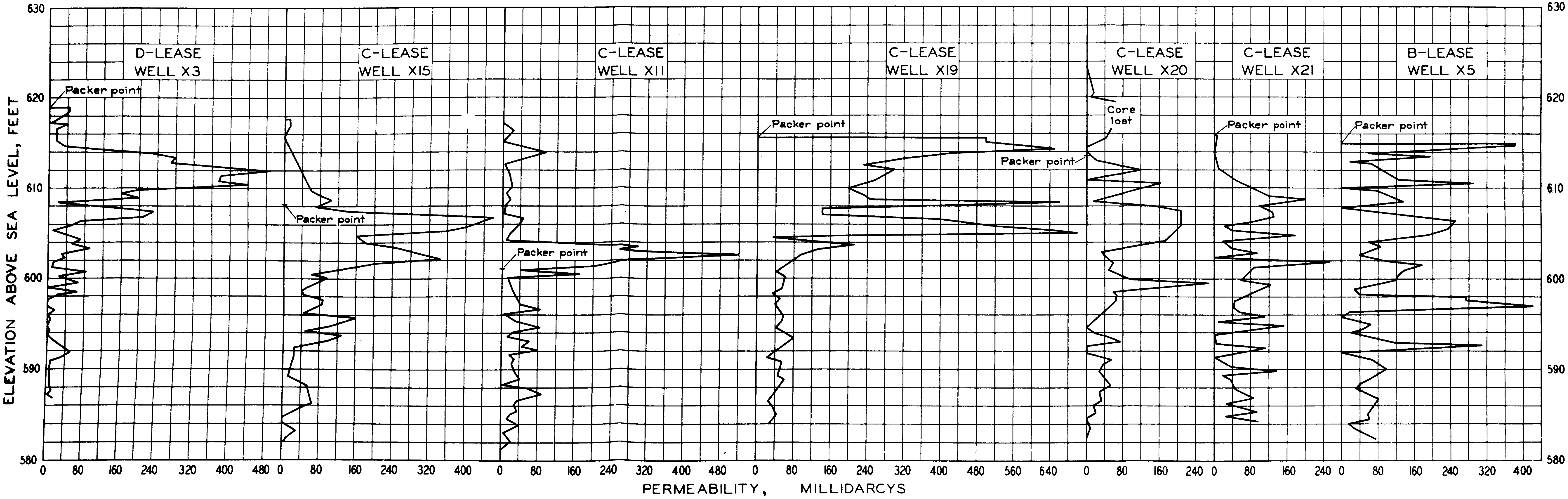

FIGURE 8.-PERMEABILITY PROFILES OF A SOUTH-TO-NORTH SECTION THROUGH LEASE C.

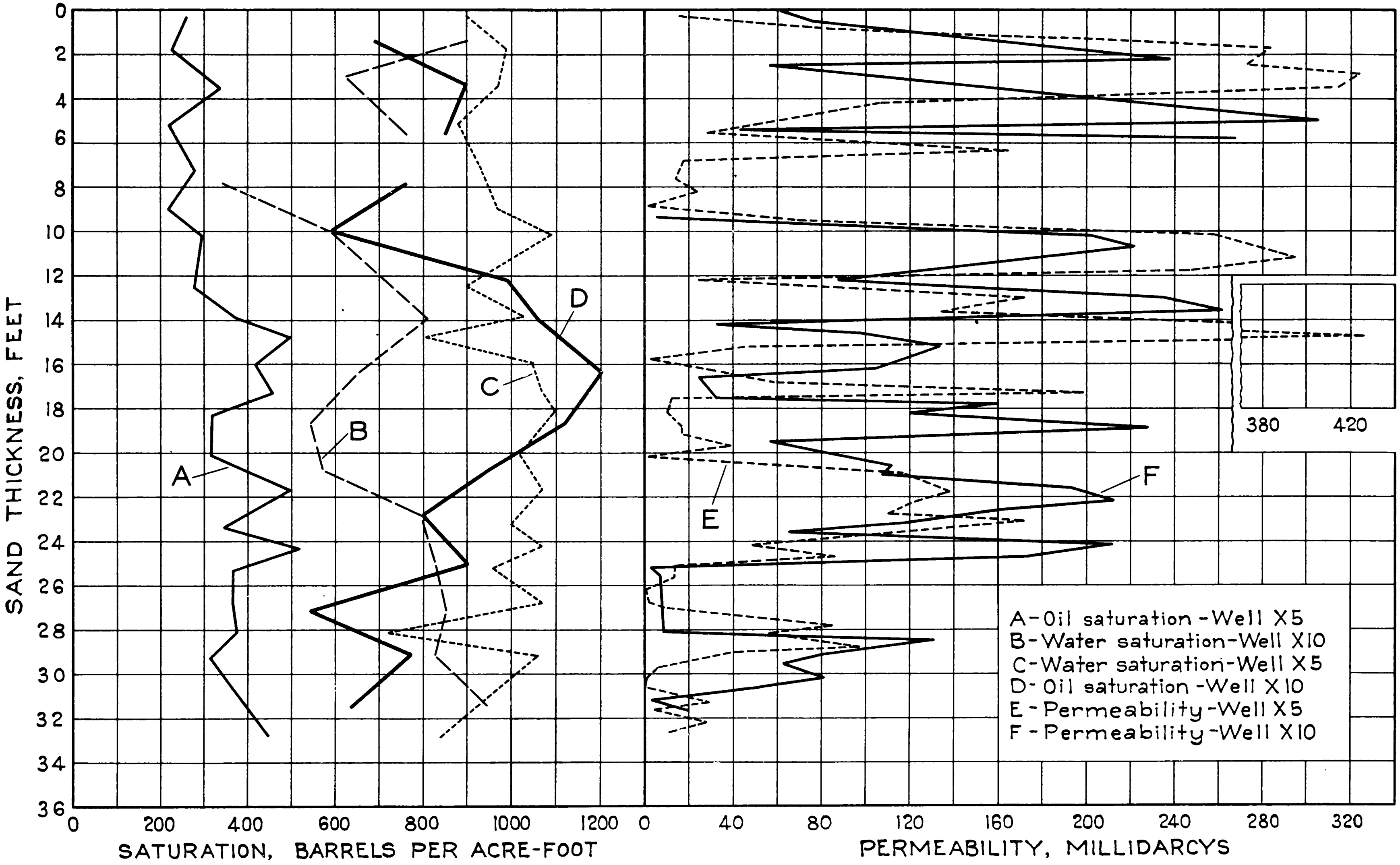

FIGURE 9.-CORE ANALYSES INDICATING THE EFFECT OF THE FLOODING ACTION ON SATURATION.

OIL RECOVERABLE FROM LEASE C

Operators of flood projects in northeastern Oklahoma and eastern Kansas have various methods of estimating the quantity of recoverable oil in a particular property. Generally they assume from experience with other flood projects, laboratory study, or both, the average quantity of oil that will be retained in the formation at the end of the flooding operation. Then they calculate the quantity of recoverable oil from information furnished by core analyses.

The total production of oil to November 1940 as a result of flooding lease C was 66,950 barrels, or the equivalent of a recovery of 154 barrels of oil per acre-foot of formation. The average oil saturation was estimated at 678 barrels per acre-foot at the time flooding was begun, so that the volume of oil remaining in the formation as of November 1940 was approximately 524 barrels per acre-foot, or approximately 33.8 percent of the pore space in the formation.

Operators estimated the volume of unrecoverable oil as 225 to 450 barrels per acre-foot under present operating conditions in flood projects in eastern Kansas. The oil from lease C was of lower A.P.I. gravity and higher viscosity than, for example, typical oil from the Bartlesville sandstone formation; therefore, the volume of oil retained in the formation possibly would be nearer the higher limit.

Figure 9 is a graph of the core analyses of two injection wells, X̄5 and X̄10, on lease C. The relative location of the two wells is shown in figure 1. These analyses are presented to indicate the action of flooding in the vicinity of an injection well.

Well X̄10 was drilled before the formation had been affected by the water, therefore the core analysis is considered typical of the area surrounding the well. Well X̄5 was drilled 12 feet from an injection well after 5,000 barrels of water had been injected into the original well. The original well was plugged and abandoned after the oil formation had been sealed by repair work in an attempt to decrease channeling, then well X̄5 was drilled. Well X̄10 was chosen for a basis of comparison, as it was the closest well with approximately the same sand thickness and wide range in permeability similar to those of well X̄5. The sand sections in the two wells cannot be compared directly owing to variations in permeability and the presence of a shale lens in the core from well X̄10 that was not evident in well X̄5.

The average oil saturation of the core from well X̄10 was 865 barrels per acre-foot, and the average water saturation was 722 barrels per acre-foot. This saturation of oil and water was high compared with the average for lease C; however, it was characteristic of cores obtained near the center line north and south through the shoestring.

The average oil saturation of the core from well X̄5 was 343 barrels per acre-foot, and the average water saturation was 979 barrels per acre-foot. Compared with the estimated average oil saturation of 524 barrels per acre-foot for lease C on November 1, 1940, the average oil saturation of the core from well X5 indicates considerably more efficient flooding action than was realized; however, this is to be expected because well X5 was only 12 feet from the injection well and the scrubbing action on the formation is more efficient in close proximity to an injection well owing to the larger volume and greater rate of flow of brine. Moreover, the analysis for the oil saturation of the core from well X5 shows that the injection pressure of the brine was sufficient to force the brine past well X5 through sand having relatively low permeability; however, this does not indicate that flooding would continue in the same manner through the oil formation to the oil-producing well. The relatively wide variation in permeability of the formation (see fig. 9), the oil saturation at the time flooding was begun, and the characteristics of the oil are all factors that influence the action of the flood as it extends farther from the injection well; therefore, a minimum of oil probably is retained in the formation in the vicinity of injection wells.

After the original injection well was drilled it was shot with 11 quarts of nitroglycerin, the shot being placed opposite 10 feet of sand near the bottom of the hole. The shot was not tamped with water or sand. Inspection of the analysis of the oil saturation of the core from well X5 indicates that no major fractures were present with resultant bypassing of brine through them, therefore it is concluded that the intensity of the shot in the original injection well was not sufficient to extend fractures in the formation 12 feet.

A comparison of the core analyses in figure 9 shows that the entire section of sand at well X5 was flooded. This condition indicates that serious plugging of the producing formation had not occurred. The same conclusion is drawn from data on the performance of the lease and from tests of the brine injected and the oil produced, which are discussed later. These facts indicate that the recovery of oil has been governed by the wide range in permeability of the sand. As the decline in average daily output of oil (fig. 7, curve A) shows that the point of abandonment of the lease may soon be reached, corrective measures must be taken to reduce channeling of the brine through the more permeable sections of the producing formation and thus increase the ultimate recovery of oil.

CHARACTERISTICS OF OIL PRODUCED

According to the Bureau of Mines Hempel analysis, the oil has an intermediate base, is greenish black, and has an average gravity of approximately 32° A. P. I. Table 2 gives a complete Hempel analysis of a typical sample of the oil. The intermediate character of the oil is shown by the correlation index (C.I., column 8) which is a number whose magnitude indicates certain characteristics of a crude-oil distillation fraction. If a fraction were composed exclusively of normal paraffin hydrocarbons, the value of the index number would be zero. If the fraction were from a paraffin-base crude oil of the usual type, its index would not be zero but would be small, while fractions from intermediate and naphthene-base crude oils would have increasingly greater values for the indexes.[12]

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[12] Smith, Harold M., Correlation Index to Aid in Interpreting Crude-Oil Analyses: Bureau of Mines Tech. Paper 610, 1940, 34 pp.

TABLE 2.- Bureau of Mines Hempel analysis of a typical oil sample from the McCune field, Crawford County, Kans.

McCune field | Sample 38319 | Kansas

Crawford County

GENERAL CHARACTERISTICS

Specific gravity, 0.865 A.P.I. gravity, 32.1°
Sulfur, percent, 0.28 Color, greenish black
Saybolt Universal viscosity at 77°F., 76 sec.; at 100°F., 60 sec.

DISTILLATION, BUREAU OF MINES HEMPEL METHOD

Distillation at atmospheric pressure, 743 mm. First drop, 34°C. (93°F.)

Fraction No.	Cut at— °C.	Cut at— °F.	Percent cut	Sum, percent	Sp. gr., 60/60°F.	°A.P.I. 60°F.	Correlation index	S.U. visc., 100°F.	Cloud test, °F.
1	50	122							
2	75	167	2.0	2.0	0.656	84.2	-		
3	100	212	2.7	4.7	.704	69.5	14		
4	125	257	3.8	8.5	.734	61.3	19		
5	150	302	4.1	12.6	.754	56.2	21		
6	175	347	4.3	16.9	.774	51.3	23		
7	200	392	4.3	21.2	.792	47.2	26		
8	225	437	4.5	25.7	.811	43.0	29		
9	250	482	5.3	31.0	.826	39.8	31		
10	275	527	6.9	37.9	.839	37.2	32		

Distillation continued at 40 mm.

Fraction No.	Cut at— °C.	Cut at— °F.	Percent cut	Sum, percent	Sp. gr., 60/60°F.	°A.P.I. 60°F.	Correlation index	S.U. visc., 100°F.	Cloud test, °F.
11	200	392	4.6	42.5	0.858	33.4	37	42	Below 5
12	225	437	6.5	49.0	.866	31.9	37	48	20
13	250	482	5.7	54.7	.879	29.5	40	62	40
14	275	527	5.9	60.6	.890	27.5	42	97	60
15	300	572	6.7	67.3	.900	25.7	44	190	75
Residuum			31.4	98.7	.955	16.7			

Carbon residue of residuum, 10.1 percent; carbon residue of crude, 3.2 percent.

APPROXIMATE SUMMARY

	Percent	Sp. gr.,	°A.P.I.	Viscosity
Light gasoline	4.7	0.684	75.4	
Total gasoline and naphtha	21.2	.747	57.9	
Kerosene distillate	4.5	.811	43.0	
Gas oil	21.0	.845	36.0	
Nonviscous lubricating distillate	11.2	.868- .890	31.5-27.5	50-100
Medium lubricating distillate	6.8	.890- .901	27.5-25.6	100-200
Viscous lubricating distillate	2.6	.901- .905	25.6-24.9	Above 200
Residuum	31.4	.955	16.7	
Distillation loss	1.3			

TABLE 3.- Analyses[1] of oil samples taken during a 20-month period, McCune field, Crawford County, Kans.

Lease and well No.	Date sampled	Specific gravity at 60°F.	Saybolt Universal viscosity in seconds at 77°F.	Saybolt Universal viscosity in seconds at 100°F.	Temperature, first drop, °F.	Fraction 1		Fraction 2		Fraction 3	
						Sum, percent	Specific gravity of cut	Sum, percent	Specific gravity of cut	Sum, percent	Specific gravity of cut
B-3	Dec. 1938	0.867	79	62	100	-	-	2.2	0.653	4.7	0.710
B-6	Sept. 1938	.874	98	76	136	-	-	-	-	3.0	.710
C-1	Sept. 1938	.863	74	60	88	-	-	2.4	.649	5.1	.705
C-1	Apr. 1940	.864	75	59	93	0.9	0.649	2.0	.658	4.5	.703
C-4	Sept. 1938	.869	85	66	93	-	-	1.4	.655	3.2	.703
C-4	June 1939	.866	78	61	100	-	-	2.2	.656	4.7	.710
C-4	Apr. 1940	.864	75	61	81	-	-	1.6	.654	4.3	.701
C-6	Sept. 1938	.865	77	66	86	-	-	2.0	.653	4.8	.707
C-6	Apr. 1940	.868	82	63	93	-	-	1.3	.662	3.2	.704
C-8	Dec. 1938	.864	75	60	93	-	-	2.4	.651	5.7	.708
C-8	Apr. 1940	.867	81	64	93	-	-	1.6	.661	4.6	.710
D-2	Dec. 1938	.865	76	60	88	-	-	2.4	.651	5.3	.709
D-2	Apr. 1940	.869	85	64	91	-	-	1.3	.662	3.5	.704
D-4	June 1939	.865	76	59	88	-	-	2.1	.650	4.9	.712
D-4	Apr. 1940	.867	82	65	99	.7	.666	1.8	.675	4.0	.703
D-7	Dec. 1938	.872	92	68	136	-	-	1.5	.685	3.0	.718
D-7	June 1939	.864	74	59	91	1.1	.637	3.7	.671	5.6	.718
D-7	Apr. 1940	.866	78	62	82	.9	.639	2.1	.669	4.7	.710
D-13	Sept. 1938	.868	81	65	90	-	-	1.5	.660	4.2	.712
D-13	June 1939	.871	91	68	99	-	-	-	-	2.7	.694
D-13	Apr. 1940	.869	83	65	90	-	-	1.7	.654	3.8	.711
K-7	Apr. 1940	.870	85	66	100	-	-	.9	.673	3.4	.708

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[1] Data represents portions of Bureau of Mines Hempel analyses.

Several of the oil wells were sampled at different times during 1938, 1939, and 1940 in an attempt to trace a general trend in the characteristics of the produced oil. Table 3 presents data from a few tests made in the Hempel analyses of samples of oil obtained from wells located at various points on leases B, C, and D and from a well on lease K which is approximately 1 mile south of the flood project and is not being flooded. The results of remaining tests made in the Hempel analyses (not shown in table 3) were reasonably comparable with those shown in table 2. In table 3 fraction 1 is the percentage distilled from the sample at a temperature up to 50° C. (122° F.) at atmospheric pressure, fraction 2 is the sum of the percentage distilled up to 75° C. (167° F.), and fraction 3 is the sum of the percentage distilled up to 100° C. (212° F.)

In general, the results of the Hempel analyses indicate that the properties of the produced oil did not vary enough to show any definite change in the characteristics of the oil as the flood progressed. The viscosity and percentage of the three fractions usually follow the trends of the specific gravity of the oil samples from individual wells.

The specific gravity and viscosity of the crude-oil samples were determined as soon as the samples were obtained at the various wellheads. These analyses were made in the field with a modified Ostwald viscometer [13] and are given in table 4.

Table 4 shows that the viscosity of the produced oil varied as the flood progressed; however, the results indicate that the viscosity of the oil from an individual well did not increase steadily. Possibly this condition was caused by the fact that most of the oil was flooded from the more permeable sections first with an accompanying increase in viscosity; then as the more permeable sections were flooded the less permeable sections produced a larger percentage of the total output with further variation in the viscosity of the oil. The determinations made in the field were generally higher than those made in the laboratory, indicating that the samples tested in the field contained traces of suspended water or emulsified oil.

Salt Content of Produced Oil

A survey was made of the salt content of the oil produced to ascertain if the use of brine as a flooding medium affected the salt content of the crude oil. The method of analysis is described by Horne and Christianson.[14]

The samples of oil were placed in a constant-temperature bath at 70° F. and allowed to stand 24 hours. The "clear oil" was then separated from the settled water and bottom sediment and agitated thoroughly with an electric stirrer. Part of the sample was used for determinating the amount of bottom sediment and the remainder for determining the salt content.

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[13] Described by Cannon, M. R., and Fenske, M. R., Viscosity Standardization of Petroleum Lubricating Fractions: Oil and Gas Jour., vol. 33, No. 47, April 11, 1935, pp. 52-55.

[14] Horne, J. W., andChristianson, L. F., Determination of Total Water-Soluble Chlorides in Petroleum: Bureau of Mines Rept. of Investigations 3517, 1940, 16 pp.

TABLE 4.- Specific gravity and viscosity of oil samples from several wells, McCune field, Crawford County, Kans.

Lease and well No.	Date sampled	Specific gravity at 60°F.	Viscosity in centistokes		Viscosity in centipoises	
			70°F.	100°F.	70°F.	100°F.
B-3	Dec. 1938	0.869		9.36		8.00
	June 1939	.876		11.12		9.59
	Apr. 1940	.870	18.06	10.50	15.64	8.99
C-1	Dec. 1938	.866		9.34		7.96
	June 1939	.870		10.31		8.83
	Apr. 1940	.868	17.05	9.89	14.73	8.45
C-2	Dec. 1938	.865		8.96		7.62
	June 1939	.865		8.82		7.51
	Apr. 1940	.868	16.52	9.67	14.27	8.26
C-3	Dec. 1938	.867		9.81		8.37
	June 1939	.875		10.30		8.87
	Apr. 1940	.872	18.66	10.67	16.20	9.15
C-4	June 1939	.870		10.07		8.62
	Apr. 1940	.867	15.96	9.45	13.77	8.06
C-5	Dec. 1938	.870		9.48		8.11
	June 1939	.875		11.88		10.23
	Apr. 1940	.869	20.72	11.65	17.92	9.96
C-6	Dec. 1938	.870		9.30		7.96
	June 1939	.871		10.50		9.00
	Apr. 1940	.871	18.89	10.79	16.38	9.25
C-7	Dec. 1938	.866		9.14		7.79
	June 1939	.876		11.89		10.25
	Apr. 1940	.870	18.20	10.49	15.76	8.98
C-8	Dec. 1938	.867		9.43		8.04
	June 1939	.876		11.27		9.71
	Apr. 1940	.872	18.74	10.71	16.27	9.19
C-11	Dec. 1938	.868		9.85		8.41
	June 1939	.868		9.80		8.36
	Apr. 1940	.873	20.93	11.72	18.19	10.07
C-12	Dec. 1938	.868		9.87		8.43
	June 1939	.870		10.94		9.36
	Apr. 1940	.872	20.40	11.50	17.71	9.87
D- 2	Dec. 1938	.867		9.42		8.04
	June 1939	.873		11.27		9.68
	Apr. 1940	.871	19.21	10.88	16.66	9.32
D-3	Dec. 1938	.869		10.45		8.93
	June 1939	.869		9.55		8.17
	Apr. 1940	.869	17.61	10.16	15.23	8.69
D-4	June 1939	.875		11.45		9.86
	Apr. 1940	.870	18.07	10.41	15.65	8.91
D-6	Dec. 1938	.867		10.92		9.31
	June 1939	.872		10.37		8.90
	Apr. 1940	.867	16.78	9.81	14.48	8.37
D-7	Dec. 1938	.872		11.16		9.58
	June 1939	.886		10.22		8.91
	Apr. 1940	.870	20.09	11.36	17.40	9.72
D-8	June 1939	.871		10.45		8.96
	Apr. 1940	.869	18.30	10.48	15.83	8.96
D-13	Dec. 1938	.875		12.23		10.53
	June 1939	.873		11.54		9.91
	Apr. 1940	.872	19.54	11.11	16.96	9.53

The salt content, calculated as sodium chloride, of the samples of oil from the various wells totaled zero to 20 pounds per 1,000 barrels of oil with only one exception. The one sample of oil with a salt content above this range had a salt content of 55 pounds per 1,000 barrels. When this well was sampled it was not producing enough fluid to fill the working barrel as it was pumping. The sample contained 0.7 percent bottom sediment in the clear oil, whereas all other samples contained zero to 0.5 percent of bottom sediment. The percentage of bottom sediment was not indicative of the salt content. Oil samples from several wells to which the injected brine was channeling contained no salt. As the injected brine had a lower mineral content than the formation brine, possibly salt was removed or washed from the oil when there was sufficient contact between the oil and brine.

CHEMICAL AND CORROSIVE CHARACTERISTICS OF INJECTED BRINE

The chemical and corrosive characteristics of the brine used for flooding were tested three times over a period of 20 months. It was realized that the type of water injected would vary throughout the entire period of flooding. At the time flooding was begun all flood water was obtained from the Arbuckle brine well. When the producing wells reacted to the flood by producing oil and brine (eventually a mixture of both formation and injected brine) the characteristics of the brine injected were changed by addition of the produced brine.

The operator estimated that approximately one-fifth (400 barrels) of the brine being injected daily in November 1938 was cycled from the producing wells. In June 1940 he estimated that one-half (1,100 barrels) of the brine being injected daily was cycled brine. During this interval the number of injection wells on the entire project had increased from 30 to 45. On the basis of chloride analyses of the cycled brine, the brine from the Arbuckle well, and the injected brine, the cycled brine amounted to approximately 56 percent of the injected brine in November 1938 and 63 percent of the injected brine in June 1940.

The making of chemical and corrosion tests in the field was facilitated by the use of a trailer laboratory equipped with the necessary testing apparatus. Standard mineral analyses were made on samples of brine sent to a routine testing laboratory.

Methods of Test

The chemical characteristics of the brines were determined by standard methods of water analysis, except where modifications of standard methods were necessary because gases or high concentrations of mineral salts interfered with the titrations. In general, the methods of analysis were similar to those employed in previous studies of subsurface brine-disposal systems.[15]

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[15] Taylor, Sam S., and Christianson, L. F., Application of Sand Filters to Oil-Field Brine-Disposal Systems: Bureau of Mines Rept. of Investigations 3334, 1937, 28 pp.

The procedure used in testing the corrosiveness of the brine also had been used in previous studies of subsurface brine-disposal systems.[16] Briefly, the relative corrosiveness of the brines was determined by measuring the loss in weight of a 2-inch steel disk suspended for a set period in a brine flowing at a definite velocity. The steel disks were cut from sheets of copper-bearing steel employed in the construction of oil storage tanks. Thus, the rate of corrosion obtained in the tests would be comparable with that expected initially in field installations under similar conditions.

Summary of Tests Made During November 1938

Table 5 summarized the corrosion and chemical-test data accumulated in the first series of tests made during November 1938. The points of testing were chosen to obtain data on the brine passing through the conditioning plant and distribution system and on the brine being produced with the oil. The Arbuckle brine well was sampled at the tubing head where the brine entered the flow line to the pond. The auxiliary flow tank was a collecting tank for the brine produced with the oil from lease C and served as a secondary separator of oil and brine. The clear-well tank contained brine that had passed through the conditioning plant. Injection wells X4, lease B, X11, lease C, and X24, lease D, were chosen as testing points so that changes might be determined in the characteristics of the conditioned brine as it flowed through the distributing system. The producing wells listed in table 7 are representative of wells with various degrees of channeling of the injected brine. Figure 1 shows the relative position of injection and producing wells.

The tabulated results of the corrosion tests indicate that the Arbuckle brine and the brine from the producing formation are relatively noncorrosive to steel before exposure to the atmosphere. Only after the brine has passed through the conditioning plant is a decided increase in corrosiveness shown. A comparison of corrosion rates at several points in the brine-distributing system indicatesthat the brine is less corrosive farther from the conditioning plant. The corrosion tests made at the producing wells show a wide variation in the corrosiveness of the brine, as the loss in weight of the steel test specimens ranged from 0.011 to 0.067 gram.

The corrosion-test data should be considered in conjunction with the chemical-test data. The results indicate that oxygen content is a governing factor in corrosiveness of the brine. Other factors, such as velocity of brine past the specimen, temperature, hydrogen sulfide content, and supersaturation of carbonates may influence the rate of corrosion, but they do not appear as important as oxygen content in these tests. The influence of factors other than oxygen content is evidenced by the fact that the rate of corrosion is not in direct ratio to the oxygen content.

The data obtained from analyses of the samples for total and soluble iron show considerable variation in the quantity of total iron in the produced brine and in the ratio of total to soluble iron. A comparison of the

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[16] Taylor, Sam S., Wilhelm, C. J., and Holliman, W. C., Typical Oil-Field Brine-Conditioning Systems: Preparing Brine for Subsurface Injection: Bureau of Mines Rept. of Investigations 3434, 1939, pp. 13 and 14.

analyses for dissolved oxygen and total and soluble iron shows that the samples with a higher oxygen content had a higher ratio of total to soluble iron, thus the dissolved oxygen caused precipitation of part of the soluble iron.

No chemical analysis was made of the coating formed on the corrosion specimens; however, the appearance of the coatings indicated that the black coating was iron sulfide, that the reddish-brown coating was an oxide of iron, and that the gray coating was principally calcium carbonate. The iron sulfide and iron oxide coatings were removed easily from the steel specimen. The gray coating usually was tight and was removed by dipping the specimen in a hot solution of caustic and zinc. In this series of tests only the steel specimens exposed to brine that had passed through the conditioning plant had a general coating of calcium carbonate, and on all specimens the coating was spotted, permitting corrosion of the exposed areas.

The test data show relatively wide variation in the characteristics of the brine produced with the oil. The corrosiveness and oxygen content of the brine produced from well 4, lease C, show definitely that a large percentage of the produced brine was injected brine, and analyses of samples from other producing wells indicate that injected brine also was present in various proportions. The presence of injected brine in the produced brine is shown more clearly in the summarized mineral analyses of brines in table 9.

Summary of Tests Made During June 1939

Table 6 presents the corrosion and chemical test data for the second series of tests made during June 1939. In these tests the sampling points were located at the clear-well tank, two brine-injection wells, and five oil-producing wells.

In general, the test results on the brine-distributing system were similar to those of the first series, except that differences were larger throughout the system. The oxygen content of the brine at well X28, lease D, was only 3.3 parts per million and the loss in weight of the corrosion specimen 0.083 gram compared to 5.8 parts per million of oxygen and a loss in weight of 0.112 gram at the clear-well tank. Upon completion of the corrosion tests the steel specimens were similar in appearance to those in the tests of the first series in that they were partly protected from the corrosive action of the brine by spotted coatings of calcium carbonate.

In tests of the brine produced from the oil wells conditions varied more than in tests of the first series. The corrosion tests at wells 4 and 9, lease C, and wells 3 and 4, lease D, indicate corrosion rates that compare favorably with those of the first series. The loss in weight of 0.116 gram of the steel specimen at well 1, lease C, is not explained by the chemical-test data shown in table 6; however, this relatively high rate of corrosion was found to be due to hydrochloric acid that had been injected into one of the brine injection wells for "cleaning-out" purposes.

TABLE 5.- Summary of corrosion and chemical tests made in November 1938

Sampling point or specimen position	Corrosion-test data				Chemical-test data							
	Average velocity of brine past specimen, cm. per sec.	Average temperature of brine, °F.	Loss in weight, of specimen, gram	Appearance of specimen after test	Average reducing compounds as hydrogen sulfide, p. p. m.	Average alkalinity in bicarbonate as calcium carbonate, p. p. m.	Average super-saturation in bicarbonate as calcium carbonate, p. p. m.	Average dissolved oxygen, p. p. m.	Average hydrogen-ion concentration, pH	Average turbidity as silica, p. p. m.	Average total iron (Fe), p. p. m.	Average soluble iron (Fe), p. p. m.
Arbuckle brine well	0.35	76	0.017	Loose black coating with no visible corrosion.	26.0	354	3	0.4	7.1	0	0.6	Trace
Auxiliary flow tank	.34	64	.050	Slight coating - no visible corrosion.	3.6	483	28	2.6	7.3	[1]	5.7	1.0
Clear-well tank	.36	63	.103	Loose iron oxide coating - also spotted gray coating and spotted corrosion.	3.8	356	19	7.1	7.4	2	.4	Trace
B-X4[2]	.36	65	.101	do.	3.8	356	19	5.8	7.4	5	.3	.2
C-X11	.27	63	.098	do.	3.4	356	17	6.0	7.4	5	.5	.1
D-X24	.27	64	.097	do.	4.0	355	19	5.2	7.4	5	1.2	.2
C-1	.29	63	.016	No coating - no evidence of corrosion.	5.9	800	22	0.2	6.9	[1]	3.8	3.3
C-3	.35	60	.056	Slight coating - no evidence of corrosion.	2.0	592	30	1.8	7.3	[1]	3.7	1.4
C-4	.35	61	.067	do.	2.5	484	27	5.0	7.3	[1]	6.4	.8
C-9	.35	62	.024	Spotted,thin black coating - no evidence of corrosion.	3.5	461	25	.4	7.3	[1]	8.0	2.8
D-3	.34	63	.011	do.	2.7	532	1	.0	6.7	[1]	7.3	6.6
A-1	.27	65	.017	No coating - no evidence of corrosion.	5.7	956	72	.2	6.9	[1]	27.0[3]	23.0

[1] Turbidity indeterminate due to the amount of cut oil and iron oxide in the samples.
[2] Lease and well number.
[3] High iron content probably due to well standing idle for several months before this test.

TABLE 6.- Summary of corrosion and chemical tests made in June 1939

Sampling point or specimen position	Corrosion-test data				Chemical-test data							
	Average velocity of brine past specimen, cm. per sec.	Average temperature of brine, °F.	Loss in weight of specimen, gram	Appearance of specimen after test	Average reducing compounds as hydrogen sulfide, p. p. m.	Average alkalinity in bicarbonate as calcium carbonate, p. p. m.	Average super-saturation in bicarbonate as calcium carbonate, p. p. m.	Average dissolved oxygen, p. p. m.	Average hydrogen-ion concentration, pH	Average turbidity as silica, p. p. m.	Average total iron (Fe), p. p. m.	Average soluble iron (Fe), p. p. m.
Clear-well tank	0.35	77	0.112	Half of surface covered with loose iron oxide coating - other half with tight gray coating.	3.2	322	31	5.8	7.7	2	0.3	0.2
D-X24[1]	.34	75	.093	do.	2.9	322	28	5.5	7.7	2	.3	.2
D-X28	.33	76	.083	do.	2.4	315	25	3.3	7.7	5	1.1	.6
C-1	.36	70	.116	Thin black coating - spotted corrosion.	5.4	702	33	1.6	6.9	[1]	2.4	1.6
C-4	.36	69	.049	Thin black coating - only one small spot of corrosion apparent.	3.8	446	25	1.6	7.3	[1]	5.1	1.7
C-9	.31	72	.010	Thin black coating - no evidence of corrosion.	4.5	455	32	.2	7.3	[1]	11.0	3.5
D-3	.35	71	.006	do.	6.2	495	22	.2	7.1	20	3.7	1.5
D-4	.36	73	.083	Covered with a loose coating of iron oxide.	2.9	496	58	3.8	7.4	15	1.8	.4

[1] Lease and well number.
[2] Turbidity indeterminate due to the amount of cut oil and iron oxide in the samples.

Analyses also were attempted for carbon dioxide content and mineral acidity of the brine samples. These data were not included in the summarized tables, as the analysis for carbon dioxide was not considered reliable because iron compounds interfered in the titration. Although no other salts interfered in the test for mineral acidity, the brine sample from well 1, lease C, was the only sample in which mineral acidity was found during these tests. The mineral acidity of this sample was 21 parts per million.

Summary of Tests Made During April and May 1940

The corrosion- and chemical-test data for the third and final series of tests, conducted during April and May 1940, are summarized in table 7. In these tests the sampling points were the Arbuckle brine well, the auxiliary flow tank, the clear-well tank, three brine-injection wells, and six oil-producing wells.

The results of tests at the various sampling points do not correlate as well as results of tests in the first two series. In the brine-distribution system the loss in weight of the corrosion specimens did not follow the trend in oxygen content of the brine as it did in the other series. If this trend had been followed the loss in weight of the steel specimen at the clear-well tank would have been the highest obtained in the brine distribution system. Moreover, the losses in weight of the steel specimens at well X11, lease C, and wells X24 and X28, lease D, would have been progressively less than the loss at the clear-well tank.

The results of tests on the brine from the producing wells also indicated a wide variation in conditions. The loss in weight of the steel specimens ranged from 0.006 to 0.137 gram, and the oxygen content of the brine ranged from 0.3 part to 5.6 parts per million. The brine from well 4, lease C, with the low oxygen content of 0.3 part per million, was the least corrosive, but the brine with the highest oxygen content (5.6 parts per million) caused the steel specimen to lose only 0.088 gram. The brine from well 1, lease C, with an oxygen content of 1.9 parts per million, was the most corrosive, as the steel specimen lost 0.137 gram. In this series, unlike the second series, the brine produced by well 1, lease C, showed no mineral acidity to explain its high corrosiveness.

A comparison of the analyses for total and soluble iron in the samples of brine from producing wells shows that generally the proportion of soluble iron to total iron was small when the dissolved oxygen content was relatively high.

Comparison of Data from Three Series of Tests

Table 8 gives part of the results obtained in the three series of tests.

The test results indicate virtually no change in the characteristics of the brine produced at the Arbuckle brine well, whereas the brine at the auxiliary flow tank shows a slight increase in corrosiveness. This increase is to be expected, as the produced brine will contain a higher ratio of injected brine to formation brine when the formation is flooded.

TABLE 7.- Summary of corrosion and chemical tests made in April and May 1940

Sampling point or specimen position	Corrosion-test data				Chemical-test data							
	Average velocity of brine past specimen, cm. per sec.	Average temperature of brine, °F.	Loss in weight of specimen, gram	Appearance of specimen after test	Average reducing compounds as hydrogen sulfide, p. p. m.	Average alkalinity in bicarbonate as calcium carbonate, p. p. m.	Average super-saturation in bicarbonate as calcium carbonate, p. p. m.	Average dissolved oxygen, p. p. m.	Average hydrogen-ion concentration, pH	Average turbidity as silica, p. p. m.	Average total iron (Fe), p. p. m.	Average soluble iron (Fe), p. p. m.
Arbuckle brine well	0.27	77	0.017	Thin black coating — no evidence of corrosion.	25.4	337	8	0.5	7.1	0	0.3	0.3
Auxiliary flow tank	.27	63	.062	do.	2.7	492	17	1.3	7.3	1/	5.5	1.8
Clear-well tank	.35	59	.142	Spotted iron oxide coating with evidence of corrosion underneath — remainder covered by tight gray coating.	1.7	390	35	6.7	7.7	0	.3	Trace
C-X11 2/	.35	59	.148	do.	1.3	389	35	6.5	7.7	0	.2	.1
D-X24	.35	57	.083	Same as above except not so pronounced.	1.3	388	35	6.2	7.7	0	.1	.1
D-X28	.34	57	.117	do.	1.0	384	32	5.5	7.7	2	.4	.2
C-1	.35	63	.137	Loose black coating — even corrosion evident — no pits or blisters.	4.1	576	22	1.9	7.1	10	2.1	1.5
C-3	.35	62	.020	No coating, pits, or blisters.	3.7	582	31	.9	7.3	1/	19.8	10.0
C-4	.32	63	.006	Thin, spotted black coating — no evidence of corrosion.	7.1	438	26	.3	7.3	5	.7	.5
C-6	.35	62	.124	Thin, loose black coating — several small blisters.	2.9	494	18	1.8	7.4	5	2.3	1.8
D-3	.23	66.	.046	Several small spots of iron oxide coating.	2.7	480	25	2.1	7.3	1/	10.0	3.6
D-4	.35	69	.088	Loose iron oxide coating — spotted with several small pits and blisters.	2.6	483	38	5.6	7.5	1/	3.9	.5

1/ Turbidity indeterminate due to the amount of cut oil and iron oxide in the samples.
2/ Lease and well number.

TABLE 8.- Summary[1] of the three series of corrosion and chemical tests

Sampling point or specimen position	Corrosion-test data						Chemical-test data								
	Corrosion rate, loss in weight of specimen, gram			Average velocity of brine past specimen, cm. per sec.			Average dissolved oxygen, p. p. m.			Average supersaturation in bicarbonates as calcium carbonate, p. p. m.			Average reducing compounds as hydrogen sulfide, p. p. m.		
	1938	1939	1940	1938	1939	1940	1938	1939	1940	1938	1939	1940	1938	1939	1940
Arbuckle brine well	0.017	-	0.017	0.35	-	0.27	0.4	-	0.5	3.0	-	8.0	26.0	-	25.4
Auxiliary flow tank	.050	-	.062	.34	-	.27	2.6	-	1.3	26	-	17.0	3.6	-	2.7
Clear-well tank	.103	0.112	.142	.36	0.35	.35	7.1	5.8	6.7	19	31	35.0	3.8	3.2	1.7
B-X4[2]	.101	-	-	.36	-	-	5.8	-	-	19	-	-	3.8	-	-
C-X11	.098	-	.143	.27	-	.35	6.0	-	6.5	17	-	35.0	3.4	-	1.3
D-X24	.097	.093	.083	.27	.34	.35	5.2	5.5	6.2	19	28	35	4.0	2.9	1.3
D-X28	-	.083	.117	-	.33	.34	-	3.3	5.5	-	25	32	-	2.4	1.0
C-1	.016	.116	.137	.29	.36	.35	.2	1.6	1.9	22	33	22	5.9	5.4	4.1
C-3	.056	-	.020	.35	-	.35	1.8	-	.9	30	-	31	2.0	-	3.7
C-4	.067	.049	.006	.35	.36	.32	5.0	1.6	.3	27	25	26	2.5	3.8	7.1
C-6	-	-	.124	-	-	.35	-	-	1.8	-	-	18	-	-	2.9
C-9	.024	.010	-	.35	.31	-	.4	.2	-	25	32	-	3.5	4.5	-
D-3	.011	.006	.046	.34	.35	.23	.0	.2	2.1	1	22	25	2.7	6.2	2.7
D-4	-	.083	.088	-	.36	.35	-	3.8	5.6	-	58	38	-	2.9	2.6
A-1	.017	-	-	.27	-	-	.2	-	-	72	-	-	5.7	-	-

[1] Summarized from tables 5, 6, and 7.

[2] Lease and well number.

The results of testing the brine at various points in the brine-distributing system show that the brine gradually was becoming more corrosive, increasing in supersaturation of bicarbonates, and decreasing in concentration of reducing compounds such as hydrogen sulfide. The analyses for dissolved oxygen are significant in that the oxygen content of the brine decreased less as it passed through the distribution system in the third series of tests than in the first and second series. This condition may have been due to a combination of two factors. The flood project had been extended farther south by the drilling of additional injection wells. This necessitated an increase in the rate of flow of brine through the distribution system to supply the additional brine required. Moreover, as the conditioned brine was supersaturated with bicarbonates at all times of testing carbonate scale may have formed gradually and provided more protection for the steel pipe and other equipment. The decrease in reducing compounds such as hydrogen sulfide in the injected brine is to be expected, as the ratio of Arbuckle brine, which contains hydrogen sulfide, to cycled brine had decreased considerably from 1938 to 1940.

The results of tests of the brine from the producing wells show the variable character of the brine as flooding progressed. More frequent testing would be necessary to trace the flooding action at the various producing wells. In general, the results of corrosion tests follow the trend of the dissolved-oxygen content of the brine at the points tested. For example, in three tests during the 20-month period the loss in weight of the specimen at well 1, lease C, increased from 0.015 to 0.137 gram, and the dissolved oxygen increased from 0.2 part to 1.9 parts per million; over the same period at well 4, lease C, the loss in weight of the specimen decreased from 0.067 to 0.006 gram while the dissolved oxygen decreased from 5.0 parts to 0.03 parts per million. The influence of characteristics of the brine other than dissolved-oxygen content is shown by the results of four tests with 0.2 part per million of dissolved oxygen and with a loss in weight of the steel specimens of 0.016, 0.010, 0.006, and 0.017 gram.

Corrosion of Water-Flooding Equipment

Corrosion of equipment in a water-flood project is of interest to operators principally because of the cost of replacing the equipment and because of plugging of injection wells by the products of corrosion. Although corrosion has occurred continuously in this flood project, as shown by corrosion tests, the rate of corrosion had not been sufficient to necessitate replacement of much equipment by November 1, 1940; however, the operator periodically has "back-flowed" the injection wells to remove small accumulations of corrosion products.

Early in the operation of the flood project some difficulty was experienced with corrosion of oil-well pumps, pumping rods, and tubing. At that time the pumping wells had been operated with the outlets of the casing heads open to the atmosphere. In 1938 the outlets were closed; this eliminated accelerated corrosion of the pumping equipment by oxygen from the atmosphere. From 1938 to June 1940, when the pumping wells were converted to flowing wells, replacement of pumping equipment was materially reduced.

Mineral Analyses of Brine

Several samples of brine were taken at three points on the brine-conditioning system and at 10 oil-producing wells for mineral analysis. Table 9 gives results of these analyses.

The analyses of the brine samples from the Arbuckle brine well indicate a small, gradual decrease in content of total solids from May 1938 to April 1940. The various components of the brine follow the general trend of the total solids, except for the sulfates, which show considerable variation.

The analyses of brine from well 6, lease B, and well 13, lease D, taken during September 1938, indicate that these brines are representative of brine from the oil-producing formation before it was diluted with injected brine. The two analyses show that the brine has a total solid content of approximately 24,000 parts per million and that no sulfates are present. Most of the values for the other chemical components in these two analyses averaged considerably higher than those in the other analyses.

Periodic mineral analyses of the injected and produced brine are valuable in the efficient operation of a water-flood project when they will distinguish between the two brines. Standard mineral analyses, such as those in table 9, can be employed in choosing one or more components of the brine by which to trace the flooding action, then the samples obtained periodically can be analyzed for only the components chosen. Standard mineral analyses could be used occasionally to check results obtained from these individual tests. For example, the mineral analyses in table 9 indicate that on this project the content of total solids and the chloride content are the best guides for showing the extent to which injected brine is mixed with formation brine. As the oil-formation brine contains no sulfates, this analysis could be used to show when the injected brine had reached the producing wells; however, the sulfate analyses in table 9 show that the sulfate content of the brine samples is not indicative of the amount of mixing.

SUMMARY AND CONCLUSIONS

This study was undertaken to determine the feasibility of using brine for flooding partly depleted oil sands to increase the ultimate recovery of oil. The results indicate that brine, when properly conditioned, is effective as a flooding medium, also that it is advisable to employ brine for flooding in areas where fresh water is limited or where fresh-water supplies might be contaminated by the brine produced in flooding. The use of either fresh water or brine for flooding presents treatment problems, and under certain conditions theproper treatment of brine might be less-complicated than that of fresh water.

This report includes a survey of all available oil-production and brine-injection data, with detailed core data on one lease. It also summarizes results obtained in a study of the corrosion and chemical characteristics of the brine produced from and the brine injected into the producing formation.

TABLE 9.- Mineral analyses of brine samples[1] from the brine-conditioning system and oil-producing wells

Source of sample	Date sampled	Sampling point	Total solids, p. p. m.	Iron (Fe), p. p. m.	Calcium (Ca), p. p. m.	Magnesium (Mg), p. p. m.	Sodium [2] (Na), p. p. m.	Carbonate (CO_3), p. p. m.	Bicarbonate (HCO_3), p. p. m.	Sulfate (SO_4), p. p. m.	Chloride (Cl), p. p. m.
Arbuckle brine well	May 1938	Wellhead	1,641	1.1	78	36	480		356	59	730
Do.	Oct. 1938	do.	1,522	.5	79	35	467		382	107	660
Do.	June 1939	do.	1,504	.6	78	34	446		383	84	640
Do.	Apr. 1940	do.	1,477	.5	80	35	444	4.8	378	92	635
Auxiliary flow tank	Nov. 1938	Sample tap	9,030	9.3	159	70	3,361		569	49	5,300
Do.	Apr. 1940	do.	8,130	2.3	139	64	2,900	12	588	21	4,533
Clear-well tank	Oct. 1938	Sample tap	5,855	.1	129	62	2,068		403	139	3,260
Do.	June 1939	do.	4,700	.0	112	54	1,627		394	81	2,575
Do.	Apr. 1940	do.	5,580	.0	122	55	1,976	9.6	437	77	3,100
B-6[3]	Sept. 1938	Wellhead	23,900	60	436	267	8,295		1,049	0	13,775
B-3	June 1939	Wellhead	18,340	14	338	175	6,261		1,042	8.6	10,175
Do.	Apr. 1940	do.	15,100	4.6	278	144	5,253		1,033	2.9	8,408
C-1	Nov. 1938	Flow tank	15,550		294	142	5,468		961	7.0	8,800
Do.	June 1939	do.	11,960	4.9	230	104	4,182		834	8.6	6,675
Do.	May 1940	do.	9,580	1.0	175	83	3,349		708	20	5,288
C-4	Sept. 1938	Wellhead	9,650	8.5	176	86	3,372		534	33	5,425
Do.	June 1939	do.	6,690	3.0	128	55	2,382		505	29	3,750
Do.	May 1940	do.	6,820	.4	122	46	2,418	9.6	484	47	3,750
C-6	Sept. 1938	Wellhead	10,170	6.0	176	79	3,617		581	41	5,750
Do.	June 1939	do.	8,670	3.0	142	62	3,140		600	7.4	4,925
Do.	Apr. 1940	Flow tank	7,140	1.5	118	55	2,593	12	581	2.9	4,013
C-8	June 1939	Wellhead	8,240	23	126	62	2,924		510	13	4,650
Do.	Apr. 1940	do.	8,400	13	130	62	3,020	26	543	10	4,713
D-2	June 1939	Wellhead	9,670	20	158	75	3,425		573	12	5,475
Do.	Apr. 1940	do.	7,970	1.3	134	60	2,854	19	547	9.4	4,465
D-7	June 1939	Wellhead	11,010	24	158	71	3,964		500	106	6,275
Do.	Apr. 1940	do.	10,660	14	179	85	3,705	26	495	37	5,930
D-9	June 1939	Wellhead	16,550	14	262	108	5,819		622	21	9,400
Do.	Apr. 1940	do.	14,970	10	227	96	5,280		620	8.2	8,455
D-13	Sept. 1938	Wellhead	24,400	26	356	200	8,000		544	0	13,225
Do.	June 1939	do.	9,370	14	125	53	3,467		600	32	5,375
Do.	Apr. 1940	do.	9,450	17	144	64	3,418	9.6	600	16	5,340

1/ Analyses by the Kansas State Board of Health.

2/ Sodium calculated by difference, includes potassium.

3/ Lease and well number.

Analysis of the oil production and core data of one lease indicates that 8.7 percent of the original volume of oil in the formation was recovered before flooding and 21.3 percent to November 1, 1940, by flooding. The average ratio of the volume of brine injected to the volume of oil produced on lease C was approximately 14 to 1 from the time flooding was begun until November 1940. The Hempel distillations and the specific gravity and viscosity of a large number of oil samples taken at three intervals over a 20-month period show only slight changes in the properties of the oil produced. This fact indicates that the injected brine gradually was flooding the less permeable sections of the formation and that it was not supersaturated with bicarbonates to such an extent that precipitation of carbonates and sealing of part of the formation were occurring. The results of a survey show that the injected brine did not increase the salt content of the produced oil.

The corrosion- and chemical-test data show that after the brine passed through the conditioning plant it was still supersaturated with bicarbonates, that it was much more corrosive than before treatment, and that generally the turbidity increased as the brine passed through the distributing system. The supersaturation of bicarbonates in the brine, as shown by the chemical tests, was substantiated by the appearance of the coating on the specimens of steel exposed at different points in the distributing system. The corrosiveness of the brine to steel usually was caused by the high content of dissolved oxygen in the conditioned brine. The increase in turbidity of the brine as it passed through the distributing system can be attributed to precipitation of excess carbonates and to products formed by the corrosive action of the brine on the equipment. As yet, no serious difficulties have been experienced with the flood project owing to the condition of the injected brine; however, later developments may indicate the need for more adequate treatment.

Although this report presents data for only one secondary recovery project on which brine was being used as the flooding medium, several general conclusions may be drawn from an analysis of the data.

1. Brine can be employed successfully for water-flooding operations. The necessary degree and type of conditioning will vary with the type of brine in the producing formation and the type of brine used for "make-up" fluid.

2. The chemical characteristics of the injected brine and the brine in the formation should be tested to show that a mineral salt will not precipitate when the two brines mix in the formation.

3. The supersaturation of bicarbonates in most brines should be reduced so that precipitation will not occur in any part of the brine-distributing system. The permissible carbonate supersaturation should be determined by chemical analysis and inspection of equipment, as the amount of supersaturation of carbonates without precipitation sometimes varies for different brines. The corrosion tests indicated that the effectiveness

of the carbonate coating that formed on the test specimens was questionable in controlling the rate of corrosion.

4. The oxygen content of the conditioned brine should be held at a minimum because dissolved oxygen is a controlling factor in the corrosiveness of a brine to steel.