The Use of Special Coring and Logging Procedures for Defining Reservoir Residual Oil Saturations*

R. P. MURPHY and WILLIAM W. OWENS
Amoco Production Company

INTRODUCTION

During the producing life of a reservoir, it is not unusual to make estimates of oil-in-place and recoverable reserves for three different phases of production; i.e., primary, secondary, and tertiary. Although it is desired that all three estimates be as reliable as possible, the economics of primary and secondary recovery programs are usually so attractive that considerable error in the estimates of recoverable reserves can be tolerated. However, a much greater degree of confidence is needed in the estimates of tertiary reserves. This is because tertiary recovery processes are much more expensive than primary or secondary processes on the basis of cost per barrel of oil recovered.

In estimating the oil-in-place prior to a secondary or tertiary recovery program, both the volume of oil and its distribution within the reservoir are important. Several methods have been developed in the past and are in use today for providing a measure of the reservoir oil saturation. For purposes of this discussion, these methods will be referred to as "conventional methods of measurement" and are discussed briefly in the following section. Two less conventional and more recently developed methods, which are the primary subject of this paper, are discussed in a later section and are referred to as "specialized coring and logging procedures."

CONVENTIONAL METHODS OF MEASUREMENT

Material Balance

Probably the first to be developed and still most widely used method for determining reservoir oil volume is based upon material balance concepts. Using this approach, the volume of oil remaining in the reservoir at any stage of depletion is found by subtracting the produced oil volume (accounting for shrinkage) from the original volume of oil-in-place. Since the produced oil volume is usually known precisely, the accuracy of this approach depends entirely upon the reliability of the original oil-in-place estimate. While this method of analysis may yield a reliable value for the total volume of oil remaining in the reservoir, it does not define the distribution of the oil. Knowledge of the oil saturation distribution, both laterally and vertically within the reservoir, can be a critical factor in the planning of a secondary or tertiary recovery program.

The material balance approach is frequently used to calculate the remaining oil in a vertical section of the reservoir between an original water-oil contact and the location of the contact higher in the pay at some later time in the reservoir production life. This approach, of course, assumes a knowledge of the lateral continuity and extent of the flushed zone, plus an accurate appraisal of the original volume of oil-in-place in this zone. The remaining oil volume computed by this method is assumed to be uniformly distributed within the swept zone, which may or may not be factual.

Interpretation of Standard Core Analysis

When a formation is cored conventionally with a water-filtrate type mud, the oil and water saturations in the cores may be of limited use in defining reservoir saturations. Invasion of filtrate into the cores during coring and subsequent expulsion of fluids by gas expansion during travel of the core to the surface, can contribute to serious alterations in core oil and water saturations. There are conditions, however, under which the core saturations at the surface may be quite similar to those in the reservoir. As examples, if the reservoir interval cored has been waterflooded and the residual oil contains little or no gas in solution, then the reservoir oil saturations will be essentially preserved in the cores until analyzed. It also has been observed that coring a

*Permission granted by Society of Petroleum Engineers of AIME (see note at end of paper).

pressure depleted reservoir with air or gas may provide cores whose oil saturations are changed little from those in the reservoir. Thus, under certain conditions, conventional cores can provide reliable data on reservoir oil saturation; but in general, the oil saturations of such cores will be lower than those existing in the reservoir.

Special Core Flow Tests

Over the past 25 years a considerable amount of research has concentrated on the development of special core testing techniques that will provide reliable data on microscopic oil displacement efficiency from porous media. Such data obtained on cores collected and tested under carefully controlled conditions may accurately reflect the oil displacement behavior of a uniform, small unit volume of the reservoir. These data must then be incorporated in a mathematical model of the reservoir with the active displacement mechanism to define reservoir oil recovery performance and remaining oil-in-place. Since we are somewhat lacking in our present ability to define the three-dimensional anatomy of a reservoir and to adequately express these data in a mathematical model, the model usually is a highly simplified version of the reservoir. Thus, while overall reservoir behavior may be predicted within the desired degree of engineering accuracy, the oil saturation and its distribution within localized areas of the reservoir may not be known with sufficient confidence to make possible the economic evaluation of a subsequent oil recovery program.

Conventional Log Analyses

Electric logs have become important tools for the estimation of formation saturation. Many different equations have been proposed for calculating water saturations from the response of these logs. However, most of the useful equations are a modification of the Archie empirical equation,[1] $(Sw)^n = FRw/Rt$. A quantitative interpretation of electric logs is inherently dependent upon a knowledge of the parameters used in these equations and is obtained by measurements on core and water samples or by experience in a particular locality. Unreliable values for formation factor (F) and saturation exponent (n) are the major sources of error. The accuracy of the water saturations computed from conventional electric log analyses is generally in the range of ± 15 saturation percent. If no gas saturation exists in the pore space, the oil saturation is computed as the percent of pore space not filled with water.

In wells where casing has been set through the formation of interest, the formation water saturation can be computed from the response of a thermal neutron decay time log (Neutron Lifetime or TDT log). The formation water saturation is computed from the response of these logs by relating the decay rate of neutrons in the formation to the thermal neutron capture cross section of the formation. The thermal neutron capture cross section is a basic physical parameter that is highly sensitive to the amount and type of fluids in the pore space. If no gas saturation exists in a formation, the oil saturation can be computed from the response of a single thermal neutron decay time log by the equation[2]

$$S_o = 1 - \frac{\Sigma_t - \Sigma_r}{\phi\,(\Sigma_{ws} - \Sigma_h)} - \frac{\Sigma_r - \Sigma_h}{\Sigma_{ws} - \Sigma_h} \qquad (1)$$

where:

S_o = formation oil saturation, fraction of pore space.

Σ_t = thermal neutron capture cross section of formation as measured by log, capture units ($10^{-3}\,cm^2/cm^3$).

Σ_r = thermal neutron capture cross section of rock matrix. Is assumed from knowledge of lithology or calculated from intervals of known saturation (capture units).

Σ_{ws} = thermal neutron capture cross section of formation water. Computed from chemical analysis of water or measured with logging tool in calibration tank filled with produced sample (7-½ bbl), capture units.

Σ_h = thermal neutron capture cross section of formation oil. Charts available for estimating from oil gravity and formation pressure and temperature (capture units).

ϕ = porosity, fraction of bulk volume. Determined from core and/or log analysis.

The thermal neutron capture cross section of the rock matrix, as well as porosity, and the capture cross section of the fluids in the pore space must be known to compute the oil saturation from the response of this log. The parameter most difficult to define is the capture cross section of the rock matrix because in shaly formations the value can vary from 8 to >18 capture units. Also, if a gas saturation exists, the magnitude of the gas saturation plus the formation pressure and temperature must be known. The accuracy of the saturations computed from the response of this log is also generally in the range of ± 15 saturation percent.

SPECIALIZED CORING AND LOGGING TECHNIQUES

Pressure Coring

A pressure core barrel differs from a conventional barrel in that it provides a means for retaining the core at bottomhole pressure conditions as it is brought to the surface. A core barrel of this type was developed and patented by Jersey Production Research, now Esso Production Research Company, in 1940.[3] With that particular core barrel, a rotary valve above the core bit closes the barrel and holds the core under pressure when the drill string is lifted off bottom. When the core barrel is retrieved at the surface, either of two procedures is normally used to handle and analyze the core. One procedure involves bleeding the pressure in the core and core barrel while collecting and measuring all of the produced liquids. The depressured core is then removed from the barrel and analyzed by conventional procedures. The fluids collected from the barrel during depressuring are then proportionately added to the volumes of liquids found in the cores on analysis, thus providing a "reconstructed" reservoir core saturation. A second procedure involves freezing the entire core barrel assembly after first displacing the drilling mud between the inner and outer barrels with a gel-like material. Once the core is frozen, the inner barrel is removed from the assembly and shipped in dry ice to the laboratory for analysis. At the laboratory, the core is cut into sections, removed from the metal inner barrel, then analyzed. Using this procedure, the fluid saturations in the core when it enters the barrel at the bottom of the hole are retained in the core until it is analyzed. This is the process that was used in the present study.

Regardless of the type of core barrel that is used to retrieve the core, significant changes in the saturations of the rock being cored can occur before the core enters the barrel. These changes result from invasion of the drilling fluid filtrate into the formation ahead of the bit. The factors found to influence the degree of this invasion are (1) formation vertical fluid conductivity, or permeability, (2) overbalance of pressure between the mud column and the formation, (3) spurt-loss of the mud which is controlled by the mud particle size distribution, (4) rate of bit penetration, (5) the interfacial tension between the reservoir oil and the drilling fluid filtrate, and (6) the core diameter. If the oil in the formation being cored is mobile, then lower displacement forces are required to change the oil saturation during coring than if the formation has previously been waterflooded to a residual oil saturation. However, as indicated by the research conducted by Jenks, et al,[4] some reduction in residual oil saturation can occur when coring waterflooded formations if the above factors are not within a favorable range of limits.

Analysis of frozen pressure cores can be handled in one of several manners. The full-diameter well cores may be analyzed directly for oil content by a retort or extraction procedure, or plug samples drilled from the large cores (using liquid nitrogen) may be analyzed by a procedure such as the Dean-Starke extraction. This latter procedure is the one used in this study. Since the oil recovered from the core upon analysis is essentially dead oil, the core oil saturations calculated on the basis of these oil volumes will be lower than the reservoir oil saturations. Corrections for oil shrinkage can be made if the saturation pressure of the reservoir oil is known.

Log-Inject-Log Procedures

As discussed earlier, the formation saturations computed by conventional analysis of electric or radioactive logs are not always reliable. A procedure that involves the use of two logging surveys, run with the same tool before and after an induced change in formation conditions, can provide more reliable values for reservoir saturations. This procedure, which frequently is referred to as log-inject-log or time lapse logging, provides more accurate reservoir saturation values by eliminating the need for some of the basic parameters required in the conventional analyses of single logs.[5,6] These procedures which can be applied with both electric and thermal neutron decay time logs can be used to measure formation saturations at any time during its history. They can be used to measure initial or connate saturations or they can be used to evaluate the effectiveness of such recovery techniques as a waterflood, a micellar flood, or a miscible flood. However, since the injection techniques and the interpretation procedures developed for the thermal neutron decay time logs are simpler than those for electric logs, only the procedures developed for the former log will be presented.

Of the various parameters required to compute formation saturations from the response of thermal neutron decay time logs as presented in Eq. 1, the capture cross section of the rock matrix is the most difficult to define. However, since fresh water (low chloride content) and most crude oils have capture cross sections that are nearly equal, the capture cross section of the rock matrix can be computed from the response of a thermal neutron decay time log run after fresh water has been injected into the formation to displace the saline formation water from the volume of rock investigated by the log. The equation for this computation is

$$\Sigma_r = \frac{(\Sigma_{ff} - \Sigma_{wf})\,\phi}{1 - \phi} \qquad (2)$$

where

Σ_{ff} = thermal neutron capture cross section of formation after injecting fresh water to completely displace formation water from vicinity of well, capture units.

Σ_{wf} = thermal neutron capture cross section of injected fresh water or formation oil, usually about 22 capture units.

By combining Eqs. 1 and 2, the formation oil saturation can be computed from the difference in response of the thermal neutron decay time logs run prior to and after the fresh water injection (log-inject-log procedure) by the relationship

$$S_o = 1 - \frac{\Sigma_t - \Sigma_{ff}}{\phi\,(\Sigma_{ws} - \Sigma_{wf})} \qquad (3)$$

This approach thus eliminates the need for estimating a value for the capture cross section of the rock matrix.

If after the above log-inject-log procedures, the formation pore space near the well can be completely filled with formation salt water or a fluid that affects the TDT log like salt water, the determination of formation oil saturation can be further simplified. This may be accomplished by injecting into the intervals of interest a micellar solution or an alcohol followed by formation saltwater to completely displace the oil from the rock in the vicinity of the well. Another procedure that can be used is to inject a chlorinated hydrocarbon-oil mixture (that has the same capture cross section as the formation water) to displace the formation oil from the vicinity of the well. If one of these procedures is used, the formation oil saturation can be computed from the log-inject-log-inject-log procedure by the relationship

$$S_o = \frac{\Sigma_{fs} - \Sigma_t}{\Sigma_{fs} - \Sigma_{ff}} \qquad (4)$$

where

Σ_{fs} = thermal neutron capture cross section of formation after injecting a micellar solution or an alcohol followed by formation salt water or after injecting a chlorinated hydrocarbon-oil mixture, capture units.

One major advantage of the use of this latter procedure is that it also eliminates the need for having accurate porosity data for the zones of interest. This may be particularly desirable in shaly sands or zones of porosity less than 10 percent or in zones having wide variations in porosity over short vertical distances. An accuracy in the range of ± 5 oil saturation percent can be expected of this procedure within the following limitations:

1. The same logging tool and auxiliary equipment with identical scales and instrument settings are used for all logging runs.
2. Adequate repeat logs are obtained during each logging sequence to minimize the statistical variation of the log response. Four repeat logs are usually adequate.
3. The injected fluids invade all intervals of interest and completely displace the in-

tended formation water or oil. Procedure would therefore be limited to permeable intervals that are not highly fractured.

4. No gas saturation exists in the pore space. However, if a gas saturation exists, a separate log-inject-log procedure[7] can be used to compute the formation gas saturation.
5. The oil and water saturations in the volume of rock investigated by the log are representative of the saturations in the vicinity of the well. May be necessary to produce the well under controlled conditions to reestablish representative saturations.
6. The formation water salinity is > 50,000 ppm NaCl at a porosity of 20 percent. Actually, the higher the salinity the better the accuracy.
7. The formation water salinity is known and uniform.

Waterflood Log-Inject-Log Procedure

The salinity of the water in the pore space of a formation being waterflooded is usually unknown, being between the limits of the initial formation water and flood water salinity. Therefore, to determine the residual oil saturation of such a formation requires a modification of the log-inject-log procedures described above. If it is assumed that all intervals of interest have been waterflooded and no movable oil saturation exists, a salt water of known salinity can be injected into the formation to displace the mixed salinity waters in the vicinity of the well. Thus by logging the well after injecting salt water and again after injecting a water of widely different salinity[8] (usually fresh water), the residual oil saturation can be computed from the equation

$$S_{or} = 1 - \frac{\Sigma_{fw} - \Sigma_{ff}}{\phi(\Sigma_{ws} - \Sigma_{wf})} \qquad (5)$$

where

Σ_{fw} = thermal neutron capture cross section of formation after injecting salt water, capture units.

To simplify the definition of terms used, it was assumed (although not necessary) that the injected salt water and initial formation water were of the same salinity and that the contrasting water was fresh water.

In actual field experience, to be discussed later, it was not necessary to inject fresh water because the logs obtained after coring and after fresh water injection had nearly identical responses. Therefore, the relationship used to compute the residual oil saturation becomes

$$S_{or} = 1 - \frac{\Sigma_{fw} - \Sigma_{fc}}{\phi(\Sigma_{ws} - \Sigma_{wm})} \qquad (6)$$

where

Σ_{fc} = thermal neutron capture cross section of the formation after coring with fresh mud, capture units.

Σ_{wm} = thermal neutron capture cross section of mud filtrate, usually about 22 capture units.

Laboratory test data presented by Schlumberger[9] indicate that the TDT log must be corrected for diffusion effects. These effects are reportedly a result of the tendency of neutrons to move from regions of high neutron density to regions of lower neutron density. The diffusion corrections used in this study were obtained from Schlumberger and were based upon a consideration of water salinity, hole size, open or cased hole, and formation porosity. Unfortunately many of the diffusion corrections are based upon an extrapolation of existing test data, so the reliability of the corrections is unknown. More test data to improve the accuracy of the diffusion corrections are needed. Dresser-Atlas, on the other hand, does not consider diffusion correction necessary with their Neutron Lifetime log. Therefore, in the field studies conducted, diffusion corrections were applied to the TDT logs but not to the Neutron Lifetime logs.

FIELD EXAMPLES

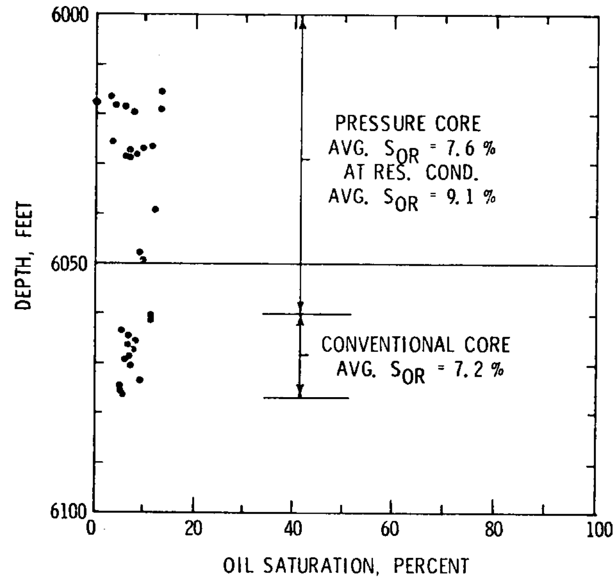
To demonstrate the utility of pressure coring, and log-inject-log procedures for measuring formation oil saturations, the results of four field studies will be presented. In each study a new well was drilled in a waterflooded portion of the field. In one field the sand had been flooded as a result of natural water influx, and in two of the others the test wells were drilled in close proximity to water injection wells (approximately 100 ft away). Thus the formation oil saturation in each of the wells was considered to be near a minimum residual oil value. An attempt was made to obtain pressure cores in three wells and log-inject-log procedures were used in all four wells.

Frio Sand Field

The sand of this example was flooded to a residual oil saturation by an undip natural water drive. The sand is loosely consolidated and is characterized by high porosity (30%) and permeability (1000 md). Many productive intervals exist in the Frio sands in this well, but the interval of specific interest is approximately 20 ft thick at a depth of about 6000 ft. The formation pressure is approximately 2500 psi, which is slightly below the hydrostatic pressure expected at this depth. Pressure cores were obtained over an interval of about 70 ft, and conventional cores (rubber sleeve) obtained over a 20-ft interval.

A special low spurt-loss mud, aerated with nitrogen to reduce the effective mud density, was used to minimize the flushing of the cores by the mud filtrate while the cores were being cut with the pressure core barrel. Bottomhole pressure measurements obtained prior to coring, while circulating mud through the drill string, were used to determine the quantity of nitrogen required to balance the bottomhole mud pressure with the formation pressure. The effective pressure differential during coring was in the range of 300 psi. No cores were recovered from the specific interval of interest; however, core samples were recovered from a lower waterflooded sand. Of the 70 ft of formation pressure cored, recovery was only 19 percent. The poor core recovery may have been a result of the expansion of the nitrogen in the mud as it passed through the core bit, providing a jetting-type action that fluidized the loosely consolidated core materials before it could enter the core barrel. This hypothesis is based upon the near 100 percent recovery obtained with the pressure core barrel in another well cored through similar sands in the same field when the mud was not aerated. The low pressure differential (mud column to formation) may in some way also have been a contributing factor since in the nonaerated mud system, the pressure differential during coring was about twice that existing in the well under discussion.

The oil saturations of the pressure and conventional cores recovered are presented in Fig. 1. The oil saturations of the pressure cores vary from 0 to 13.4 per cent with an average of 7.6 percent pore space. The oil saturations of the conventional cores are in the same range, averaging 7.2 percent. The low magnitude and the close agreement between the oil saturations derived from the two different coring methods imply that the pressure core procedures used were of little aid in preserving representative saturations in the cores. This suggests that the sand was probably severely flushed by mud filtrate during both the pressure and conventional coring operations, and that gas expansion did not effectively displace the residual oil from the conventional cores as they were being brought to the surface.

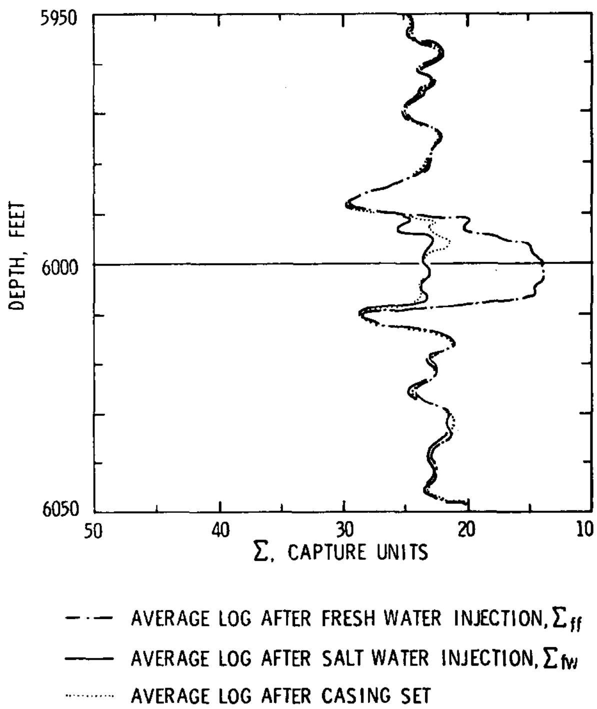


CORE ANALYSIS OIL SATURATIONS, FRIO SAND, TEXAS

FIGURE 1

Thermal neutron decay time (Neutron Lifetime) logs were run through the sand eight weeks after casing was set, again after injecting formation salt water, and again after injecting fresh water into the sand. The casing was perforated for injection purposes only over the 20-ft sand interval of interest. Average logs of these surveys are shown in Fig. 2. To insure that mud filtrate was not in the volume of rock investigated by the log, 100 bbl of formation salt water was injected into the sand to move the mud filtrate into the formation away from the zone investigated by the logs.

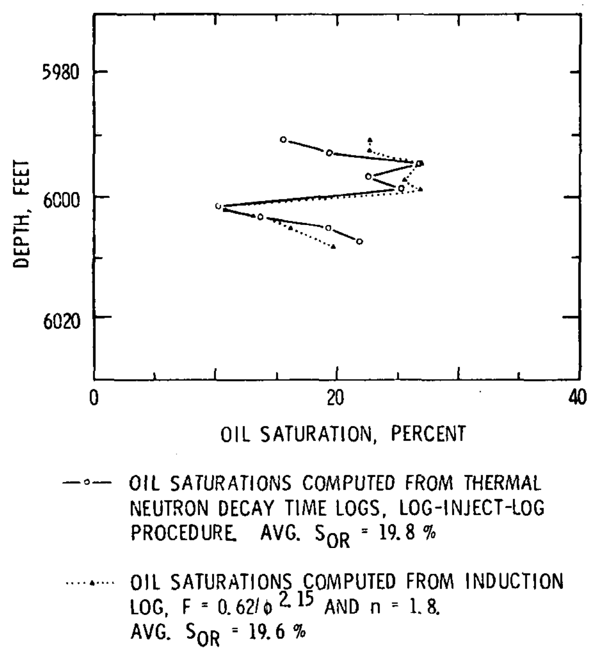
The logs run before and after formation salt water was injected into the sand are nearly the same except in the top six feet of the sand. This difference in log response is attributed to the inability of the fresh mud filtrate to diffuse into the formation water in the shaly, low permeability (verified by tracer survey) sand rather than to the displacement of oil by the injected salt water.



AVERAGE THERMAL NEUTRON DECAY TIME LOGS, FRIO SAND, TEXAS

FIGURE 2

The response of the logs run after salt water and after fresh water injection was used to calculate, by Eq. 5, the magnitude and distribution of the residual or immobile oil saturations. These saturations varied from 10 to 26.5 percent and averaged 19.8 percent pore space for the total sand thickness. The residual oil saturations computed from the response of an induction log averaged 19.6 percent pore space. The results of both methods are presented graphically in Fig. 3. Residual oil saturations at complete water floodout were also determined from core flow tests on 19 core samples from other wells in the field. These residual oil saturations averaged 23 percent pore space. Thus, from the fair agreement between the saturations derived from the three different procedures, it is concluded that the waterflood residual oil saturation in the Frio sand well is near 20 percent pore space and that the log-inject-log procedure yielded reliable values for reservoir waterflood residual oil saturation.



OIL SATURATIONS DERIVED FROM LOG ANALYSES, FRIO SAND, TEXAS

FIGURE 3

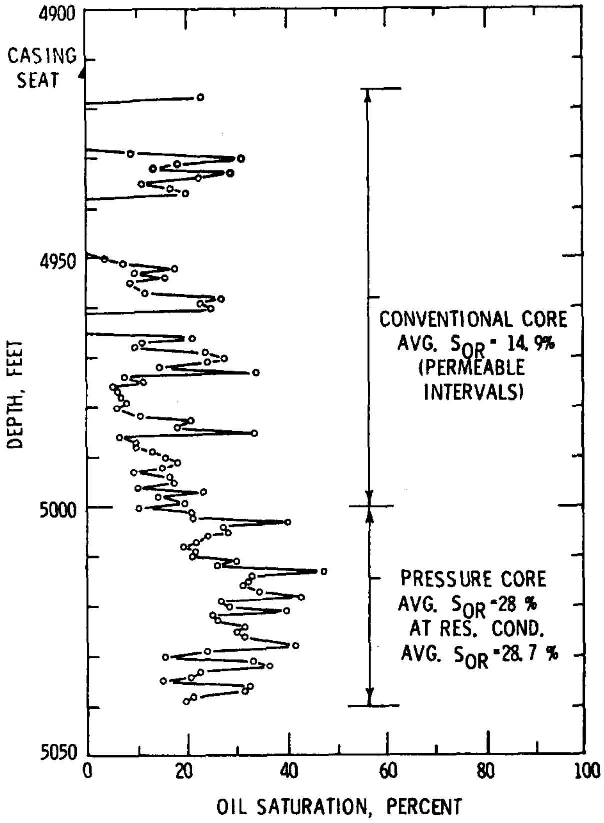
San Andres Field A

The San Andres formation in this field is primarily dolomite with varying amounts of anhydrite. The core porosities and permeabilities are low, averaging 10 percent and <1 md, respectively. However, in the more porous and permeable intervals porosities as high as 20 percent and permeabilities as high as 50 md exist. The formation depth is approximately 5000 ft and the formation pressure is approximately 2200 psi.

A low weight, low spurt-loss mud was used to minimize the flushing of the cores during coring. The effective pressure differential during coring was in the order of 300 psi. The oil saturations determined from both pressure and conventional cores are presented in Fig. 4. The oil saturations of the conventional and pressure cores with permeabilities greater than 0.1 md averaged 14.9 percent and 28.0* percent pore

*Pressure core oil saturations in this example are based upon an assumed oil density of 0.77 gm/cc whereas other examples are based upon an assumed density of 0.84 gm/cc.

space, respectively. When the pressure core saturations are corrected to bottomhole conditions, the average saturation of the pressure cores is increased to 28.7 percent pore space. The large difference between the average saturations in the two types of cores implies that the pressure core barrel equipment and procedures prevented expulsion of oil from the cores by gas expansion. Also, the magnitude

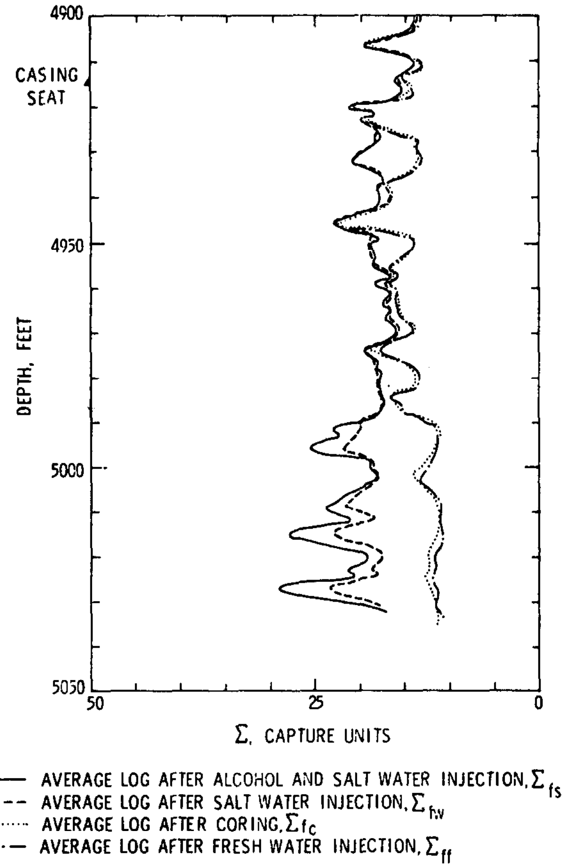


CORE ANALYSIS OIL SATURATIONS, SAN ANDRES FIELD "A", TEXAS

FIGURE 4

of the oil saturations measured suggests that the pressure cores were not severely flushed by mud filtrate during the coring operation, as was indicated in the study of the poorly consolidated Frio sand.

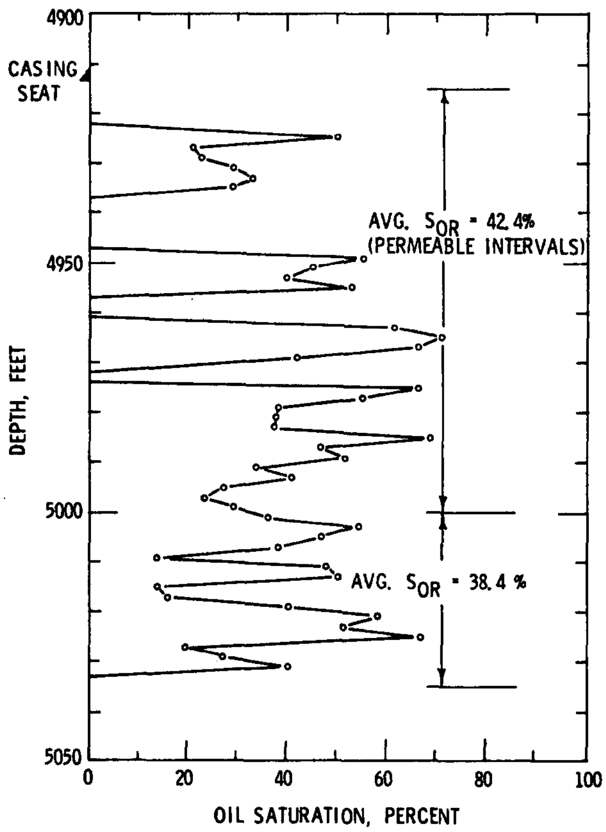
Thermal neutron decay time (TDT) logs were run (1) after coring with fresh mud in the hole, (2) after injecting 300 bbl of salt water (250,000 ppm NaCl), (3) after injecting 300 bbl of fresh water, and (4) again after injecting 110 bbl isopropyl alcohol followed by 100 bbl of fresh water and 300 bbl of salt water. The logs, as shown in Fig. 5, indicate by the difference in response that permeable San Andres intervals extend from approximately 4922 to 4937, 4947 to 4957, 4961 to 4972, and 4974 to 5040 ft. The permeable intervals identified by the logs are in general agreement with the core analysis permeability measurements.



AVERAGE THERMAL NEUTRON DECAY TIME LOGS, SAN ANDRES FIELD "A", TEXAS

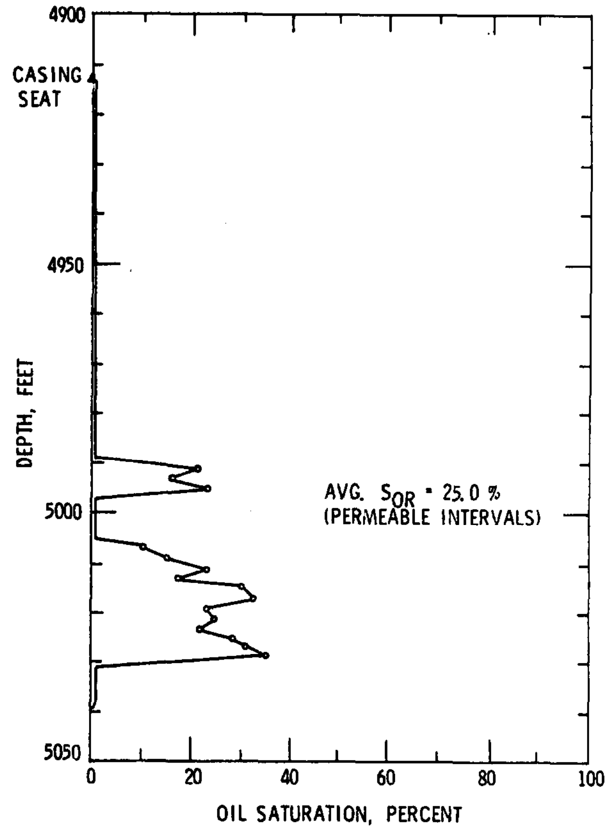
FIGURE 5

The residual oil saturations computed from the thermal neutron decay time logs run after coring and after saltwater injection using Eq. 6 are presented in Fig. 6. These saturations range from 0 to 70 percent with an average of 42.4 percent for the permeable intervals and 38.4 percent pore space for the interval pressure cored. The residual oil saturations computed from the logs run after coring, after salt water injection, and after the alcohol injection procedure, are shown in Fig. 7. Only the intervals from 4990 to 4997 and 5005 to 5030 ft were indicated by the logs to have been swept by the injected alcohol. These intervals were also indicated by the wide separation between the logs run after coring and salt water injection to be the most permeable. The oil saturations of these permeable intervals computed from Eq. 4 averaged 25 percent pore space. The difference in the saturations determined from the pressure cores and the two log-inject-log procedures just described is wide and could be a result of one or more factors. They are (1) mud filtrate flushing oil from the cores as the cores were cut, but this is considered unlikely; (2) incomplete displacement of formation water by mud filtrate; (3) incomplete displacement of mud filtrate by injected saltwater; (4) incomplete displacement of oil by alcohol; (5) incomplete displacement of alcohol by salt water; and/or (6) erroneous diffusion corrections being applied to the response of the thermal neutron decay time logs. The latter is considered the major contributing factor to the differences cited because the diffusion corrections used were an extrapolation of cased well data to open-hole conditions. Also the saturations computed from the alcohol procedure, where the diffusion corrections cancel out of the computation, are in fair agreement with the pressure core saturations. Further verification is given in Fig. 8 where the saturations computed from induction logs run after salt water injection and after the alcohol procedure average 25.7 percent pore space for the permeable intervals flushed by the alcohol flood. However, if the diffusion corrections are not used, unrealistic saturations are computed for some intervals; i.e., oil saturations < 0 percent. Thus it appears that diffusion corrections are necessary with the TDT log but additional information on these corrections under a variety of wellbore conditions will be required to increase the accuracy of the calculated formation oil saturations. Based upon the observations cited, the average oil saturations in the vicinity of the San Andres Field A test well is concluded to be approximately 28 percent pore space.



OIL SATURATIONS COMPUTED FROM THERMAL NEUTRON DECAY TIME LOGS RUN AFTER CORING AND SALT WATER INJECTION. SAN ANDRES FIELD 'A', TEXAS

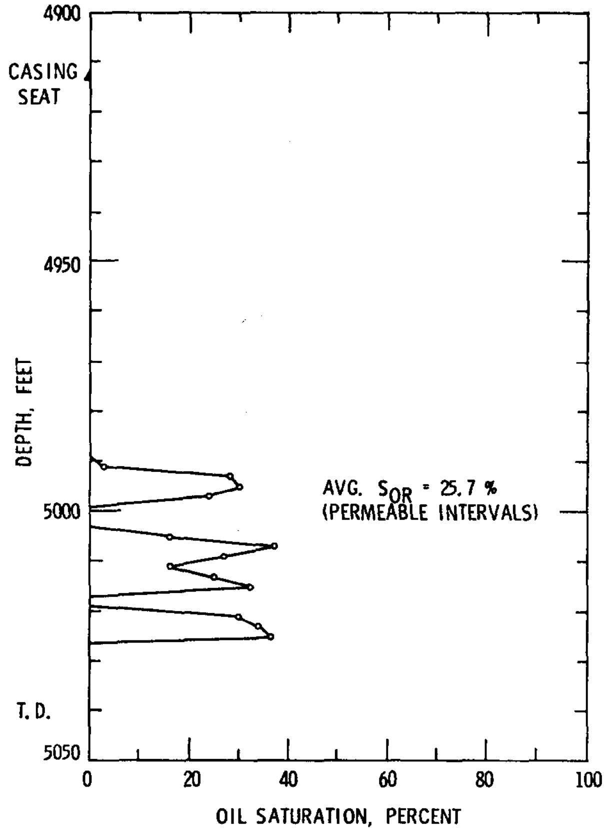
FIGURE 6



OIL SATURATIONS COMPUTED FROM THERMAL NEUTRON DECAY TIME LOGS RUN AFTER CORING, AFTER INJECTING SALT WATER, AND AFTER INJECTING ALCOHOL FOLLOWED BY SALT WATER, SAN ANDRES FIELD 'A', TEXAS

FIGURE 7

Oil-water steady-state relative permeability tests were conducted on a number of oil-cut (native-state) cores from the area of the reservoir in which this well was drilled. The flood-out residual oil saturations in these cores ranged from about 20 to 33 percent. The flow behavior of all samples indicated that the residual oil saturation achieved was a function of the flood



OIL SATURATIONS COMPUTED FROM INDUCTION LOG-INJECT-INDUCTION LOG PROCEDURE, SAN ANDRES FIELD "A", TEXAS

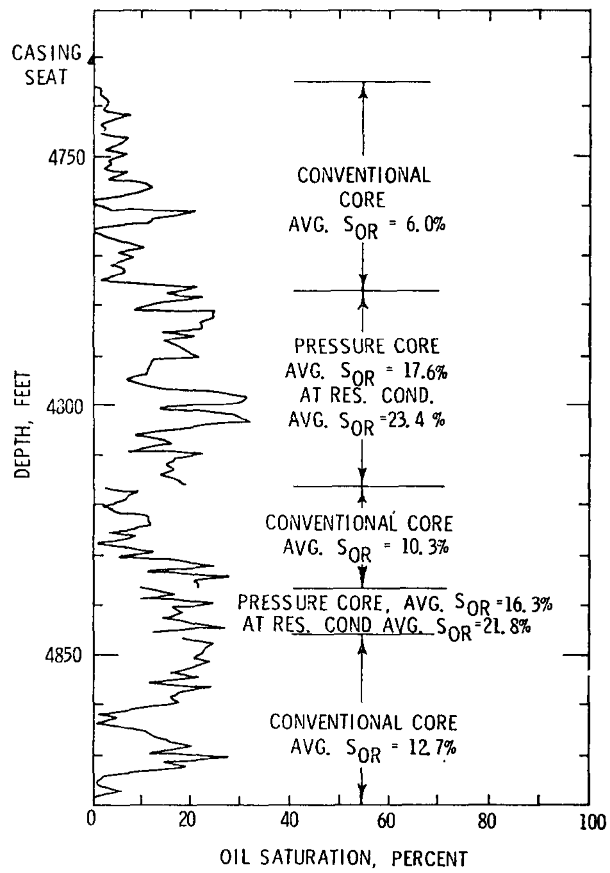
FIGURE 8

water volume throughput; i.e., considerable oil production after breakthrough. Buckley-Leverett type frontal advance calculations using an average of the measured relative permeability data indicated a significant oil saturation gradient behind the waterflood front. When this gradient is taken into account together with the close proximity of the cored well to the injection well and the volume of water calculated to have moved past the location of this well, an average residual oil saturation of about 30 percent is calculated for the swept zone in the well. This is considered to be excellent agreement with the average values obtained from the pressure cores and the log-inject-log calculations in which no diffusion corrections were necessary.

San Andres Field B

The characteristics of San Andres Field B are very similar to those described for San Andres Field A with the exception that the depth is slightly shallower, approximately 4800 ft, and the formation pressure is higher, approximately 2600 psi.

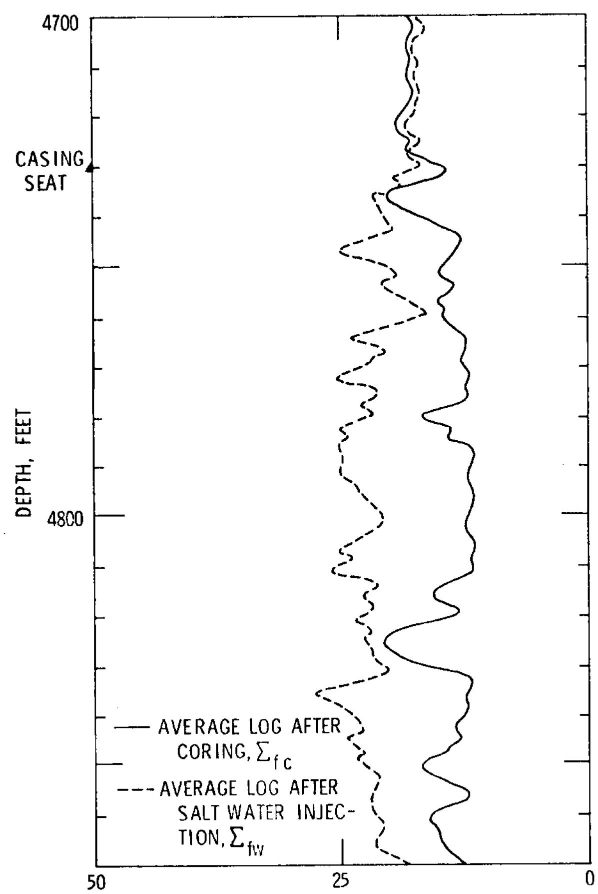
As in the previous example, a low spurt-loss and low weight mud (pressure differential approximately 300 psi) was used to minimize flushing of the cores during coring operations. The oil saturations determined from both pressure and conventional cores are presented in Fig. 9. The average oil saturation of all the conventional cores is 9.3 percent and the average saturation of the pressure cores is 17.3 percent pore space. When the pressure core saturations are corrected to bottomhole conditions, the saturation is increased to 23.1 percent. As in the previous example, the large difference between the saturations implies that the pressure core procedures minimized the expulsion of oil from the cores by gas expansion. The low magnitude of the pressure core oil saturations, however, suggests either that the waterflood was very effective in flooding the cored intervals in this well or that the cores were flushed by mud filtrate as the cores were cut.



CORE ANALYSIS OIL SATURATIONS, SAN ANDRES FIELD "B", TEXAS

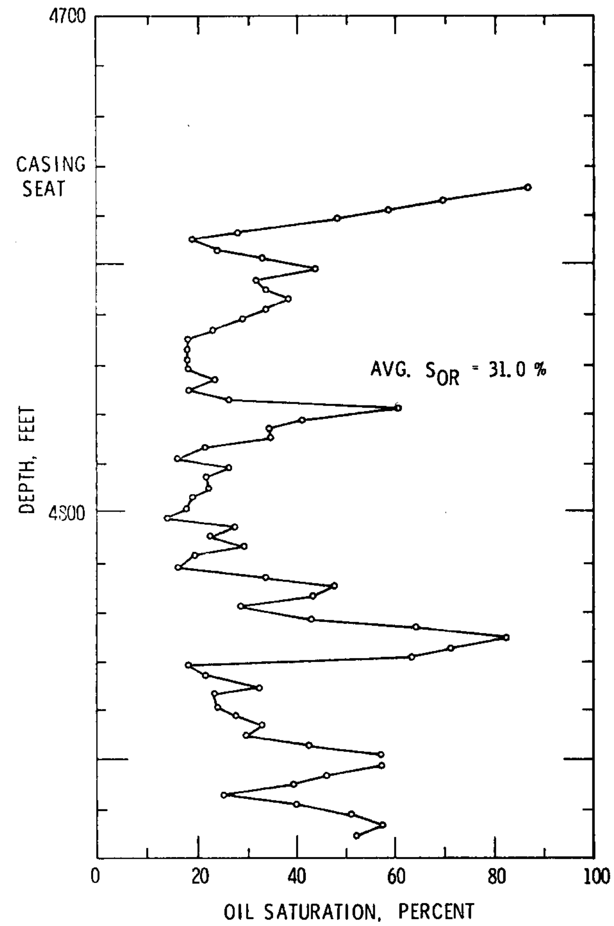
FIGURE 9

The log-inject-log procedure, which involved running a thermal neutron decay time (TDT) log after coring and again after injecting 900 bbl of salt water (250,000 ppm NaCl), was used to measure the magnitude and distribution of the residual oil remaining in the formation. These logs are shown in Fig. 10, and the saturations computed from these average logs by Eq. 6 are presented in Fig. 11. The oil saturations average 31 percent pore space for the permeable (core permeabilities > 0.1 md) intervals of the formation. The saturations calculated from the logs for the intervals cored with the pressure core barrel averaged 28.6 percent which is somewhat higher than the average of 23.1 percent obtained with the pressure cores. This disagreement between the oil saturations determined by the two methods is consistent with the results of the previous San Andres example discussed and is considered most likely a result of inaccurate diffusion corrections to the logs.



AVERAGE THERMAL NEUTRON DECAY TIME LOGS, SAN ANDRES FIELD "B", TEXAS

FIGURE 10



OIL SATURATIONS COMPUTED FROM THERMAL NEUTRON DECAY TIME LOGS RUN AFTER CORING AND AFTER SALT WATER INJECTION, SAN ANDRES FIELD "B", TEXAS

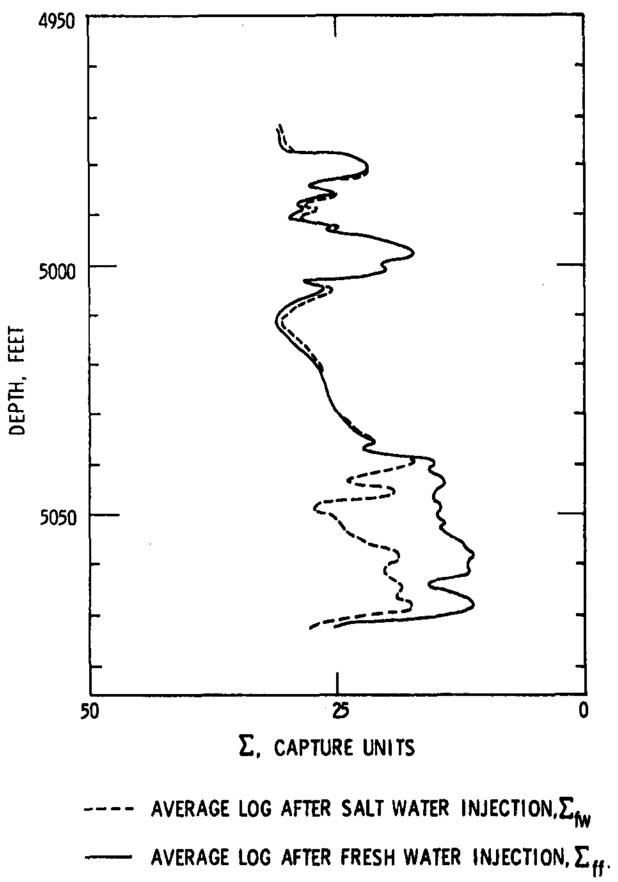
FIGURE 11

Oil-water steady-state relative permeability tests were conducted on more than 30 oil-cut (native-state) cores from this reservoir. The floodout residual oil saturations achieved in these cores ranged from 7 to 40 percent pore space. As in the case of the earlier discussed San Andres core tests, the residual oil saturations were a function of the volume of water flooded through each core. Buckley-Leverett type calculations were made using the data obtained on a core whose porosity, permeability, and connate water saturation were close to the reservoir average. These calculations indicated a significant saturation gradient behind the waterflood front, and further indicated a residual oil saturation of 22 percent pore space for the location at which the test well was drilled (100 ft from a water injection well). These calculations tend to substantiate an end point residual oil saturation in the range of 20-25 percent as obtained in the pressure cores. The diffusion corrections to the TDT logs again are considered to account for the higher residual oil values calculated from the log-inject-log procedure.

Muddy Sandstone Field (Denver-Julesburg Basin)

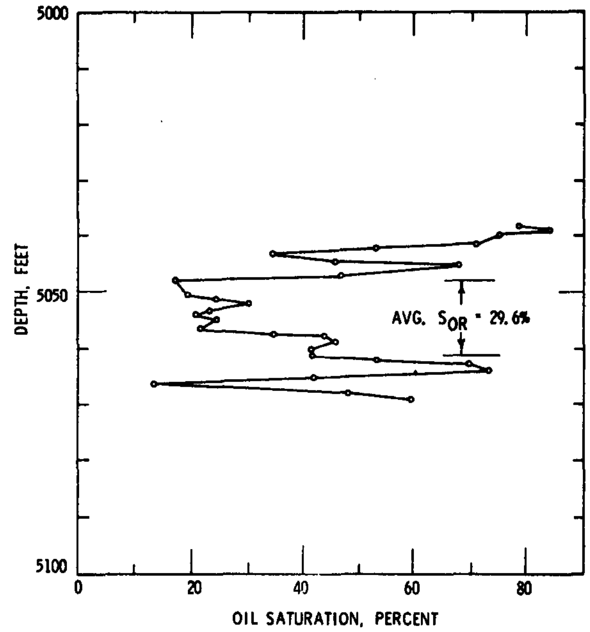
The Muddy sandstone in the example well grades from a shaly sandstone at the base and top of the formation to a clean sandstone in the central section that is approximately 13 ft thick. The average porosity of the clean sandstone is approximately 20 percent and the average permeability is approximately 200 md. The formation is at a depth of 5050 ft with a formation pressure of about 1500 psi.

Conventional cores were cut to aid in the calibration of the porosity logs; these cores were also used for relative permeability tests. The thermal neutron decay time (TDT) logs run in a log-inject-log sequence to measure the oil saturation remaining in the formation after the



AVERAGE THERMAL NEUTRON DECAY TIME LOGS, MUDDY SAND, COLORADO

FIGURE 12



OIL SATURATIONS COMPUTED FROM THERMAL NEUTRON DECAY TIME LOGS RUN AFTER INJECTING SALT WATER AND FRESH WATER, MUDDY SAND, COLORADO

FIGURE 13

waterflood are shown in Fig. 12. These logs were obtained after injecting approximately 150 bbl of salt water (170,000 ppm NaCl) and after injecting fresh water into the formation. The residual oil saturations computed from these average logs from Eq. 5 are shown in Fig. 13. In the clean sandstone interval in the middle of the formation the oil saturation varies from 18 to 45 percent and averages 29.6 percent pore space. The oil saturations computed for the shaly sands above and below this interval are not considered reliable. Apparently, because of low permeability, the injected waters did not completely displace the fluids as intended in these shaly intervals.

Three core samples from this well were subjected to relative permeability tests without cleaning or drying. The average residual oil saturation obtained at floodout was 25.8 percent pore space. Fourteen oil-cut (native-state) cores from another well drilled earlier in the life of this field yielded residual oil saturations during water-oil flow tests ranging from 17.2 to 33.7 percent pore space (average 23.1 percent). In both series of tests, the residual oil saturations were noted to be dependent upon the volume of water throughput. Since the well drilled in this study was in an area flanked by several injection wells, a reliable estimate could not be made of the volume of water that may have flooded this well location. Thus, Buckley-Leverett type calculations as made for the other wells previously discussed were not made. Nonetheless, the residual oil saturations computed from the log-inject-log procedure appear to be in the range obtained in the core flow tests, provided the formation in the test well had not been flushed to the same degree as the cores flooded in the laboratory tests.

The results of the example field tests are summarized in Table 1. In the two sandstone formations logged, the residual oil saturations calculated from the log-inject-log procedure were in fair agreement with values obtained in core flow tests. In the two carbonate reservoirs, the residual oil saturations found in the pressure cores were lower than calculated from the log-inject-log procedure. This difference may be due to the diffusion corrections used in the analysis of the logs.

SUMMARY AND CONCLUSIONS

The results of this study indicate that under certain conditions reliable values for residual oil saturation at a given location within a waterflooded reservoir can be obtained from pressure cores, core flow tests, and/or log-inject-log procedures. The use of pressure cores appears to be limited to well consolidated formations in which there is sufficient pressure to permit coring with normal weight drilling fluids without establishing a large pressure gradient across the core. The success of the log-inject-log process depends largely upon the ability to inject into and displace fluids from the zone of interest. Additional information on diffusion corrections under a variety of wellbore conditions would increase the accuracy of the calculated formation oil saturations. Flow tests on cores can provide reliable information on waterflood residual oil saturation, but such data must be incorporated in some type of computation to take into consideration variations in residual oil saturation with volume throughput.

All of the procedures evaluated in this study provide values for residual oil saturation at a single areal location (the cored well and its vicinity) within a reservoir. Data of such limited

TABLE 1

SUMMARY OF RESIDUAL OIL SATURATION VALUES

OBTAINED BY VARIOUS METHODS IN FOUR FIELD EXAMPLES

	Average Residual Oil Saturations, %			
Field	Pressure Cores	Log-Inject-Log	Conventional Logs	Core Flow Tests
Frio Sand	9.1	19.8	19.6	23.0
Muddy Sandstone	–	29.6	–	25.8
San Andres "A"	28.7	38.4 25.0* 25.7**	–	–
San Andres "B"	23.1	31.0	–	–

*Average residual oil saturation computed from thermal neutron decay time logs run after coring, after injecting salt water, and after injecting alcohol followed by salt water.

**Average residual oil saturation computed from induction logs run after injecting salt water and after injecting alcohol followed by salt water.

areal extent may be suitable for planning a pilot test program. However, if a reservoir-wide estimate of residual oil saturation and its distribution is needed, several wells in different areas of the reservoir should be cored, or logged. In the absence of areal distribution data provided in this manner, reservoir mathematical models can be used if reliable relative permeability data and reservoir anatomy information are available. The saturation gradient behind a waterflood front is frequently overlooked and this oversight can lead to low estimates of reservoir residual oil saturation if only point values are obtained as discussed in this study.

REFERENCES

1. Archie, G. E.: The Electrical Resistivity Log as an Aid in Determining Some Reservoir Characteristics, *AIME Trans.*, Vol. 146 (1942).
2. Youmans, A. H., et al: Neutron Lifetime, A New Nuclear Log, *AIME Trans.*March, 1964.
3. Sewell, B. W.: Pressure Coring Device, U.S. Patent No. 2,216,962, October 18, 1940.
4. Jenks, L. H., et al: Fluid Flow Within a Porous Medium Near a Diamond Core Bit, *Jour. Canadian Petr. Tech.*, October-December, 1968.
5. Patent Applications Filed.
6. Murphy, R. P. and Owens, W. W.: Time Lapse Logging—A Valuable Reservoir Evaluation Technique, *Jour. Petr. Tech.*, January, 1964.
7. Owens, W. W.: Logging Oil Saturations in Reservoirs, U.S. Patent No. 3,282,095 November 1, 1966.
8. Richardson, J. E. and Wyman, R. E.: Method for Determining Residual Oil Content of a Formation Using Thermal Decay Measurements, U.S. Patent No. 3,562,523 February 9, 1971.
9. Wahl, J. S., et al: The Thermal Neutron Decay Time Log, *SPE Jour.*, December, 1970.

*This paper was originally presented as SPE 3793 preprint, Improved Oil Recovery Symposium, April 16-19, 1972, Tulsa, Oklahoma, and was reproduced with the permission of the Society of Petroleum Engineers of AIME.