

# Determination of Initial Fluid Saturations - A Key Factor in By-Passed Pay Determination

D.B. Bennion, F. B. Thomas, R. F. Bietz  
Hycal Energy Research Laboratories Ltd.

---

## Abstract

Proper evaluation of initial water saturation is essential for proper reserves evaluation, informed decisions on which zones to complete to obtain water-free production, and influences a variety of productivity and formation damage issues. The most common methods of initial water saturation determination, electrical log resistivity measurements and direct saturation measurements on in-situ core samples, are described and the advantages and disadvantages of these techniques discussed in this paper. A study presented illustrates the effect of a variety of properties, such as saturation exponent ( $n$ ), Archie exponent ( $a$ ), cementation exponent ( $m$ ), water resistivity ( $R_w$ ) and formation resistivity ( $R_f$ ) on water saturations calculated from electrical log data. It illustrates that some formation values may significantly deviate from the standard assumed values for " $a$ ", " $m$ " and " $n$ " of 1, 2 and 2, and that this can significantly over or underestimate the value of the initial water saturation. Various techniques for the correct determination of correct " $a$ ", " $m$ " and " $n$ " values in a controlled laboratory environment for actual reservoir rock from the formation under consideration, for a greater degree of confidence in log calculated water saturations, are described.

Various types of coring programs, including low invasion coring, traced fluid coring and analysis techniques, sponge coring, gel coring and sidewall coring are described. The advantages and disadvantages of each method and techniques utilized to obtain the most accurate possible initial saturation data are discussed.

## Introduction

Initial fluid saturations, the fraction of the interstitial space in a pore system occupied by oil, water and gas, are key factors in determination of initial reserves and dominate reservoir flow properties due to the influence they exhibit on relative permeability. Surprisingly, in many cases, initial fluid saturations are virtually unknown or improperly measured, resulting in gross over or under estimation of oil or gas reserves in place and greatly affecting potential for formation damage due to phase trapping, resulting in a poor appraisal of deliverability. In many cases, improper saturation measurements can lead to the bypassing of potentially productive pay zones resulting in significant lost reserves, or the erroneous completion of ineffective pay resulting in lost revenue.

### The Hazards of Insufficient Knowledge of Initial Fluid Saturations

Improper determination of the initial oil, water or gas saturations which exist in porous media may often lead to expensive mistakes in the development of a field. In some cases, large amounts of capital are invested where minimal reserves are present, or marginal flow is obtained. In other cases, viable pay is overlooked due to a perceived belief, from improper saturation evaluations, that the pay will be wet or non-productive. The hazards involved with an inadequate understanding of initial saturation conditions can generally be grouped into three categories:

**Poor Initial Reserves Evaluation.** Oil or gas in place is based on a simple volumetric calculation of hydrocarbon volume present in the effective porosity of the system. Since this value is usually assumed to be  $1-S_{wi}$ , it can be seen that over or underestimation of the initial water saturation can grossly affect the perceived amount of oil or gas in place in the reservoir. An underestimation of  $S_{wi}$  could result in costly development of a field which has much less oil or gas in place than anticipated, resulting in limited or negative return on ultimate investment. Conversely, if  $S_{wi}$  is overestimated, a potentially viable and highly lucrative pay zone may be abandoned.

A recent example is a field where log derived saturation values indicated water saturations of between 40-50%, yet upon completion of the wells, they surprisingly produced no free water. Subsequent traced coring programs indicated that the log calibration constants were in error and that the true in-situ water saturation was, in fact, in the range of 20-22%, resulting in a 56% increase in the amount of oil present in the field and a significant alteration in the economics of the project.

Many very low permeability gas reservoirs exist in conditions of "subirreducible" initial water saturation<sup>6,7,8</sup>. If relatively little fluid invasion has occurred during the drilling and completion process, this can often be detected by significant separation between the shallow and deep induction logs and extremely high resistivities in the deep, uninvaded portion of the formation (sometimes in the hundreds or thousands of ohmmeters). Due to the adverse capillary nature of these very low permeability systems, they tend to both spontaneously imbibe and permanently retain invaded water based filtrate in what is known as an "aqueous phase trap" or "water block"<sup>8</sup>. If deep invasion occurs, this can result in the creation of a zone of extremely high water saturation about the wellbore, which may be misinterpreted as wet. Some tight gas sands which are subirreducibly saturated may exhibit trapped saturations of 70% or greater, when the initial saturation may be actually be quite low (perhaps 10-15%). In this situation, both reserves and productive potential may be grossly underestimated. An example of this nature was a shallow tight sand zone that had been routinely penetrated for years while targeting deeper oil bearing strata. Conventional gel chemical based muds with high fluid losses were typically used to drill the uphole sections which had inevitably resulted in significant fluid losses to this zone. Gas shows were common when penetrating the horizon, but subsequent logging showed high water saturations (due to deep invasion) and testing indicated uneconomic or no gas production rates. Close evaluation of logging suites, after many years of drilling through this zone, suggested that a zone of low water saturation, and potentially high gas productivity and reserves existed beyond the near wellbore damaged region. A gas based (CO<sub>2</sub>) fracturing

program penetrated effective pay, and a multi Bcf gas field, which had been overlooked for 20 years, was brought onto production.

**Poor Completion Zone Selection.** Figure 1 illustrates a typical set of water-oil or gas-water relative permeability curves. It can be seen that underestimation of the initial water saturation may result in completion of zones with high potential water phase relative permeability which will result in immediate high water cuts and poor oil or gas production rates (i.e. the water saturation was believed to be at point "A", when, in fact, it is actually at point "B" on Figure 1). Conversely, over estimation of initial water saturation may result in the decision to not complete a zone which could conceivably produce at economic rates, resulting in lost opportunities and revenue (i.e. the water saturation was thought to be at point "B" on Figure 1 in this case when it was actually at point "A").

**Flow Mechanics.** Multiphase flow is governed by the relative permeability which exists between the individual phases. Relative permeability is, in turn, governed directly by the respective saturations of the individual fluid phases which are present in the porous media. Proper knowledge of both the relative permeability characteristics of the porous media (which are determined by appropriate experimental tests in the laboratory) and the initial saturation conditions will allow inflow calculations to determine if, in the presence of mobile or immobile water or gas saturations, economic production rates of oil or gas will be feasible.

### Saturation Determination Techniques

Initial saturations are commonly determined using the following techniques:

- Log based saturation evaluations
- Direct saturation measurements on in-situ samples

Both techniques have pros and cons.

**Log Based Saturation Evaluations.** Water saturation determinations in clean (non-shaley) formations are based on Archie's equation<sup>1</sup>:

$$S_w^n = (FR_w) / R_t \quad (1)$$

where

- $S_w$  = Fraction of pore space occupied by water
- $n$  = Saturation exponent
- $R_w$  = Formation water resistivity
- $R_t$  = True water resistivity
- $F$  = Formation factor

The formation factor is given by the equation:

$$F = a/\phi^m \quad (2)$$

where

- a = Archie constant  
 m = cementation exponent  
 $\phi$  = Porosity fraction

Therefore, combining equations 1 and 2 yields:

$$S_w^n = (aR_w) / (\phi^m R_t) \quad (3)$$

Potential saturation determination errors may be associated with variations in:

**Saturation Exponent Value.** The saturation exponent value is a function of both pore system geometry and formation wettability. Although a value of 2.0 is commonly assumed for the saturation exponent, this value can vary considerably from formation to formation and may result in over or under estimation of water saturation in many situations. Since the saturation exponent is derived as the slope of a plot of resistivity index vs water saturation, it assumes that a continuous slope is obtained (i.e. the relationship is a linear one on a semi-logarithmic plot). This assumption is generally satisfied for water wet porous media, where in the wetting, water saturation forms a continuous film on the surface in the porous media, allowing conductive paths for current transmission even down to very low saturation levels. Conversely, for oil wet porous media, the water saturation is contained in discontinuous droplets in the central portion of the pore space. Saturation exponents for strongly oil wetted systems generally are similar to water wet systems with values around 2.0 at high water saturation levels, but as water saturation is reduced, the slope of the  $RI/S_w$  relationship can increase radically. Saturation exponent values as high as 8-10 have been measured at low water saturation conditions (which approximate the initial reservoir saturation condition we are attempting to determine through logging) in strongly oil wet situations. Figure 2 provides a comparative illustration of the effect of variation in "n" value with wettability. If too low of a saturation exponent value is used, it will result in a significant underestimation of initial water saturation and potentially the erroneous completion of wet zones in the mistaken belief that they contain mobile oil or gas saturations.

Table 2 provides a illustrative set of data indicating how the value of the saturation exponent can alter the calculated value of the initial water saturation. Using the fixed "standard" values given in Table 1 for a, m, n,  $R_w$  and  $R_t$ , the "true" water saturation value is calculated at around 28.7%. Holding all other parameters constant and varying only the "n" value, one can see that, in the range of "n" values from 1.0 to 8.0, the

computed water saturation can vary radically. Lower "n" values than the standard 2.0, usually used, will result in lower  $S_{wi}$  values (8.2%  $S_{wi}$ , for example, at an "n" value of 1.0) and higher "n" values, which are often associated with the transition to a more oil wet state of a uniform pore system, will cause increases in true  $S_{wi}$  (to 73%, for example, at an "n" value of 8). The data of Table 2 has been plotted for illustrative purposes and appears as Figure 3.

Accurate determination of the saturation exponent value is therefore of essential importance for the calculation of "true" initial water saturation from logs. Saturation exponents are normally determined experimentally in the laboratory on core samples of the actual formation under consideration to obtain a more realistic evaluation of the "n" value. Due to the fact that the "n" value varies with both lithology and wettability, a suite of "n" value measurements is often conducted on samples from a range of permeabilities, porosities and lithologies which may be present in the formation. Most laboratory "n" value determinations have been conducted in the past using water and gas on cleaned core samples using the base assumption that all formations are water wet. This is a gross oversimplification as many researchers<sup>3,4,5</sup> have demonstrated that, on average, only approximately 50% of sandstone oil bearing formations and less than 10% of carbonate oil bearing formations exhibit strongly water wet behaviour. This is possibly why the standard "n" value of 2.0 used so widely in the industry has gained acceptance, as the vast majority of the measurements conducted have used cleaned, artificially water wet, porous media which typically do exhibit saturation exponent values near 2.0.

Saturation exponent measurements are conducted in the laboratory using the following four methods:

- Bulk porous plate method where a large group of samples are simultaneously desaturated from a condition of 100% water saturation on a large porous plate to generate a range of gradually lower water saturation levels. Successively higher gas pressures are used to achieve this desaturation. After each higher pressure, the apparatus is disassembled and the discrete samples are removed and subjected to individual resistivity measurements. This technique suffers from deficiencies, due to grain losses and capillary redistribution of the fluids, because of the necessity to continuously be removing and re-inserting the samples in the porous plate cell as well as fluid losses due to evaporation by continual cyclic disturbance of the equilibrium environment.
- Centrifuge methods, where samples are spun at gradually increasing speeds to reduce the water saturation and generate a range of saturation values at which resistivity can then be evaluated. Like the bulk porous plate method, these techniques suffer from core disturbance, grain loss

and evaporation effects which can compromise the accuracy of the obtained saturation exponent data.

- Individual porous plate methods consist of special cells in which single core samples are mounted with individual porous plates and electrodes attached to the samples to monitor in-situ resistivity. A micro pipette is used to track fluids produced from the core as capillary pressure is increased to cause the water saturation reduction, and hence the entire test can be run without disrupting the core sample by removing the applied pressure which can cause phase redistribution within the core and eliminating the potential for grain losses and evaporation. The technique has these advantages over the bulk porous plate and centrifuge methods described previously, but suffers from the drawback of being a time-consuming method, particularly for samples of low permeability, where literally months may be required to obtain an effective desaturation.
- The continuous injection technique is a relatively new method for saturation exponent determination and consists of mounting the sample in a pressurized core cell with a porous plate at the outlet end of the core. A micro injection pump is used to inject non-wetting phase into the sample (oil or gas) at an extremely low rate to slowly reduce the water saturation in the porous media over a period of time. Resistivity measurements are obtained on a continuous basis and average fluid saturations are obtained by an accurate material balance of fluid produced from the core sample. In this manner, a complete RI vs  $S_w$  curve with literally hundreds of points can be constructed, covering the entire range of saturations and detecting any subtle changes in saturation exponent with water saturation. The technique has all the advantages of the individual porous plate method, plus it is generally much faster and can easily be conducted at full reservoir conditions of temperature, pressure, overburden pressure and using live reservoir fluids if required.

Figures 4a-4d provide schematic illustrations of the bulk porous plate, centrifuge, individual porous plate and continuous injection techniques respectively.

**Archie Constant Value.** Archie constant values are measured experimentally for a series of formation factors determined on a range of porosity value samples for a given lithology expected to exist in a specific formation. Generally, the lower the degree of consolidation, the lower the value of the Archie constant. A value of 0.62 for the Archie constant was derived by Humble for poorly consolidated sands. The value tends towards 1.0 for compacted sands and may exceed 1.0 as the degree of compaction becomes extreme.

Table 5 provides an indication of the expected variation of

calculated water saturation as the value of "a" changes. This data has been plotted and appears as Figure 5. Once again the fixed parameter data of Table 1 is utilized holding all parameters constant except for the "a" value. Examination of this data indicates that variations in "a" alter the water saturation values, but not to the extent that variations in "n" did previously. Variation of "a" from 0.4 to 1.7 resulted in a range of water saturations from 18.1 to 37.4%, indicating that significant departure from the value of 28.7% calculated with a typical "a" value of 1.0 could still occur.

**Formation Water Resistivity.** This is an extremely important factor in the calculation of initial water saturation as the ionic composition of the water affects its overall electrical conductivity and hence resistivity. Fresh waters exhibit high resistivity, while highly saline brines are extremely electrically conductive, and hence exhibit low resistivity values. Log resistivities in the near wellbore region are complicated by the fact that during most overbalanced drilling processes, losses of mud filtrate to the near wellbore region occur. This invaded filtrate is generally of a different composition than the in-situ formation water (usually fresher in most cases). This results in a zone of invasion of altered resistivity about the wellbore, a transition zone of blended invaded and in-situ water and then non-flushed reservoir. This phenomena is complicated with time as dispersion continues due to capillary forces, generally resulting in an outward imbibition of filtrates from the wellbore into the formation. Blending of fluids during production will also alter the complex configuration of the fluid invasion patterns. Therefore, significant mathematical manipulation of the resistivity data may be necessary to obtain a hope of obtaining an accurate saturation profile, particularly in the case of deep invasion. Such discussions are beyond the scope of this paper, but are contained in the literature<sup>9</sup>.

Formation water resistivities are commonly determined using the following techniques:

**Direct Measurement.** If produced formation water samples are available, these can be used to obtain an exact measurement of resistivity. Since resistivity is a strong temperature function, these measurements must either be conducted at reservoir temperature, or corrected for temperature effects. One must ensure that the water samples produced from the formation are, in fact, representative of the true in-situ water. Deviations may exist due to:

- Contamination from invaded drilling, completion or kill fluids which are still being produced back from the formation;
- Concurrent production of water from different zones of varying water composition due to multiple flowing zones or poor cementing;
- Dilution of produced water by fresh water of condensation from the gas phase if high gas rates are present;

- Presence of a "dual water" system in the reservoir where the mobile water saturation has a different salinity and composition than the bound water locked into the microporous clay fraction present in the porous media.

*From Water Catalogues.* Often extensive lists of produced waters from various formations are compiled and are commonly used by companies when they are evaluating similar zones in the same regional trend. This technique hinges on the assumption that the resistivity measurements conducted on the original samples which are in the catalog are correct and also that the formation under consideration has no variation in water chemistry from the one used in the catalog as the data source. Verification of the  $R_w$  value from the SP curve or from resistivity-porosity comparison is recommended in such a situation<sup>10,11</sup>.

*From Chemical Analysis.* In some cases the chemical analysis of the water is known, either from a catalog or a historical sample. Various techniques have been detailed in the literature for calculating resistivity based on compositional analysis<sup>12,13,14</sup>. One must be aware that the composition of the water, being used as the basis for the resistivity calculation, may be affected in a similar fashion as described in the section "Direct Measurement" for the direct measurement of resistivity. If the analysis is in error this will obviously compromise the accuracy of the calculated resistivity.

*Resistivity from the SP (Spontaneous Potential) Log.* Good values of  $R_w$  can sometimes be obtained from the SP curve if the formation is clean and non-shaley since the static SP value is related to the chemical activity of the formation water and mud filtrate.

Table 4 provides a summary of the effect of a variation of  $R_w$  on calculated water saturation over a range of  $R_w$  values from 0.01 to 7 ohm.m. This data has been plotted and appears as Figure 6. Water resistivity very strongly influences the value of the log calculated water saturation. Using the baseline values given in Table 1, which provide a water saturation of 28.7% at a  $R_w$  value of 0.1 ohm.m, it can be seen that reducing resistivity an order of magnitude to 0.01 ohm.m results in a reduction in water saturation to only 9%. Alternatively, as  $R_w$  increases, computed water saturation soars (rapidly to unrealistic values greater than the entire pore saturation of 1.0, as can be seen from Table 4 and Figure 6).

A major challenge in subirreducibly saturated gas bearing formations and strongly oil wet oil bearing media is the fact that due to the abnormally low initial water saturation in these cases there is no produced mobile liquid saturation to evaluate for accurate  $R_w$  measurements. In the case of subirreducibly saturated tight gas sands, where the mechanism of the low water saturation establishment is believed to be regional gas

migration and desiccation effects, this results in the trapped low water saturation exhibiting abnormally high salinity for what may be typical in the regional trend. The use of normal catalog  $R_w$  values in a situation such as this may lead to a significant overestimation of initial water saturation and bypassing of potentially productive gas bearing strata.

*Cementation Exponent.* The value of the cementation exponent is highly dependant on the degree and type of cementation in the pore system. Although a value of 2.0 is commonly used, this value can vary highly as is illustrated in Figure 7<sup>15</sup>. For poorly cemented rocks  $m$  maybe less than 2.0 and in highly cemented or oolitic rocks " $m$ " values as high as 3.0 have been observed.

Table 5 provides a summary of how variations in " $m$ " value affect calculated water saturation. This data has been plotted and appears as Figure 8. It can be seen that variations in " $m$ " also influence water saturation calculations, albeit in a somewhat weaker fashion than " $n$ " and  $R_w$  variations discussed previously. Low " $m$ " values around 1.0 result in a reduction in water saturation to 13.4% in comparison to a 52.6% saturation calculated at a " $m$ " value of 2.8. This compares to the water saturation of 28.7%, which would be calculated using the standard " $m$ " value of 2.0.

Both the Archie constant and the cementation factor are determined by lab measurements of formation factor (this being the relationship between the resistivity of a rock saturated 100% with water and resistivity of the water itself). Formation factor measurements are usually conducted on plug samples in the laboratory. Obviously, as can be seen from equation 2, the formation factor is influenced strongly by porosity. For this reason, the test sequence is usually conducted on a range of porosities to obtain as accurate evaluation as possible of the relationship between  $a$ ,  $m$  and porosity. Since porosity is influenced by overburden pressure (which will change the pore geometry and hence alter the resistivity of the 100% brine saturated matrix) formation factor measurements should always be conducted at the net effective reservoir overburden pressure. In addition, for some reservoirs, the formation factor, and hence the values of  $a$  and  $m$ , may change significantly as overburden pressure changes. This means that during a typical reservoir depletion process, where reservoir pressure is dropping, that the net effective overburden pressure is increasing. Hence, a different set of  $a$  and  $m$  values may be required for accurate field water saturation evaluation purposes as depletion proceeds. For this purpose, most sets of formation factor measurements are run at a series of increasing overburden pressures to facilitate the inclusion of this pressure variation in the reservoir as a function of time so that accurate evaluations of initial water saturation in newly drilled wells in partially depleted zones can still be obtained.

**Determination of  $R_T$ .** The basic assumption of the calculation of water saturation from resistivity logs is that the rock and any other fluids it contains (oil and gas) are perfect insulators. Oil and gas generally fulfil this requirement nicely (as they are often used for electrical insulators in transformers and other situation due to their non-conductive nature); however, certain minerals, which may occur naturally in some formations, have a degree of electrical conductivity. These would include materials such as pyrite (FeS or "fools gold"), galena or chalcopyrite. These materials, even when completely dry, have high conductivity. If present in sufficient quantity in the reservoir they can significantly lower overall resistivity. This would lead to a belief that the zone under consideration is wet, when it may in fact be at an extremely low water saturation and produce water free oil or gas. Several examples of this are presented in the literature<sup>16</sup>.

Clays and shales may also contribute to formation conductivity. These materials exhibit natural conductivity due to the ion-exchange process which exists as a function of the active exchange sites on the surface of the clay particles. The effect of shaliness on shaley sand conductivity is often disproportionately large in comparison to the amount of shale present in the sand and depends on the amount, type and distribution of the shale and the composition of water trapped. Various correlations are presented in the literature to correct log responses for the effect of conductive shales<sup>17,18,19,20,21</sup>.

Table 6 illustrates the effect of varying  $R_T$  on calculated water saturation using all other parameters fixed as given in Table 1. This data has been plotted and appears as Figure 9. Obviously water saturation increases with reductions in  $R_T$ . It is interesting to note how a relatively small reduction in  $R_T$ , such as might be caused by the presence of conductive materials in the rock matrix, from 25 to 15 ohmmeters, causes an increase in the apparent calculated water saturation from 28.7 to 37.1 %. This may be the difference between mobile and immobile water in many situations and a key factor in location of a preferential zone for completion.

### Direct Saturation Determination

It can be clearly seen from the preceding discussion that, although log techniques are commonly used to evaluate initial water saturations, there may be significant uncertainty with respect to the absolute validity of the numbers obtained, particularly in the absence of any accurate actual measurements of the electrical properties of the rock under consideration.

Another, potentially less ambiguous and more accurate technique is obtain a direct measurement of fluid saturations from in-situ core samples obtained from the formation during the initial drilling process. This data, if properly obtained, can provide representative fluid saturation measurements which are often used to calibrate field logs and then apply the corrected

log calibration constants to other wells in the same field (which may not have been cored). Obviously, core from an unswept zone (by waterflooding or coring) is a requirement in this case.

Challenges which face the operator in designing a coring program to obtain representative initial water saturations include:

**Obtaining Core Material Which Has Not Been Flushed By the Coring Fluid.** In most situations, the objective is to obtain the initial water saturation which exists in the porous media. Typical coring operations, particularly in higher permeability porous media, can result in significant flushing of the obtained core material by the coring fluid. If the coring fluid is water based, this will obviously result in an undesirable increase in the measured water saturation. If the coring fluid is oil based, the initial water saturation will be unaltered, if it is at a subirreducible or irreducible value (ie - immobile), but if the water saturation is mobile (such as in a transition zone or aquifer zone) oil based mud filtrate may flush the core and reduce the obtained water saturation. Oil based coring fluids, therefore, usually provide a good estimate of the initial irreducible water saturation which exists in a reservoir, but may underestimate the actual water saturation which exists in some zones if mobile water is present. Gas has also been used as a coring fluid. Due to the poor heat transfer capacity of gas, a large amount of heat is generated during the coring process. This heat, combined with the dehydrated nature and high rate of gas circulation required to clean the hole, often results in desiccation of the core and artificially low water saturations being obtained.

Flushing of the obtained core during the coring process can be significantly reduced through the use of a "low invasion" core bit. This technology is relatively new, but is becoming quite popular and most coring companies now offer some variant of a low invasion core tool. The jet orientation on the bit is slightly different on a low invasion core bit, such that a vortex of high velocity and low pressure is created at the outer circumference of the bit which creates a low pressure zone which tends to draw the coring fluid away from the surface of the core as it is cut. The location of the inner core barrel is also altered, so that it core immediately enters the core barrel after cutting, minimizing the time in contact with the circulating coring fluid. Figure 10 illustrates the mechanism of a low invasion coring process. The technology has been documented to reduce core flushing by over 90% in certain applications and is definitely recommended for any coring program where in-situ saturation determination is an objective. A variant on low invasion coring is "gel" coring. This technology marries a low invasion core bit with an extremely viscous water based gel in the core barrel. As the core is taken, the viscous gel is extruded in the annular space between the core and the core barrel. This isolates the core from contact

with the drilling fluid, plus generally seems to improve core recovery in some highly laminated sands or fractured zones by the stabilizing influence of the encapsulating gel. Some difficulty can be encountered when trying to remove the core from the core barrel after a gel coring operation, but these problems can generally be handled with experience and proper technique.

Some possibility of invasion, particularly in zones of high permeability, exist even when low invasion coring is used. For this reason, the water saturations evaluated from a low invasion coring process using a water-based mud may still be in question. This can be remedied by the use of some type of tracer in the coring fluid. If the tracer is present in the water removed from the core samples, it can be ascertained that invasion has occurred and, if flushing is not complete, the concentration of the tracer in the central section of the core can be used to back out the degree of invasion and hence calculate the true initial water saturation which existed in the porous media. The tracer is generally some element which is easily detectable in low concentrations and not naturally present in the formation water. Baseline samples of drilling fluid are taken from the circulating drilling fluid stream regularly during the coring process to obtain a "reference" value of the tracer as a function of depth. This is due to the fact that tracer concentration can vary due to dilution with formation fluids or additions of fluid to the mud system to account for uphole losses or losses to the formation. Two classifications of tracers are normally used, these being chemically based tracers and radioactive tracers.

Chemically based tracers would include materials not normally present in the formation water such as various alcohols and soluble ions such as bromide, iodide or nitrates. Chemical tracers are generally inexpensive and easy to analyze, but their deficiency centres about the fact that some chemical tracers will complex with in-situ formation clays, affecting the analysis, and that fact that for an accurate chemical tracer analysis a sufficient volume of water must be removed from the core to obtain an accurate analysis. The water must be removed by a direct reduction technique such as centrifuging or gas displacement, as high temperature extraction (the normal method for cleaning most cores and removing oil and water) will result in the volatilization of the water from the system but soluble ionic tracers will remain in the sample and not be detected. Commutation of the core after such a process, and analysis of the precipitated salts has been used in some situations, but has not tended to be a highly accurate technique. Soluble alcohols will be removed by extraction, but condensation is often incomplete and inaccuracies are often present due to a loss of the volatile tracer from the core due to evaporation between the time the core is removed from the core barrel and when analysis actually occurs.

So called radioactive tracers commonly include isotopic forms of water, these being deuterium and tritium. Deuterium, or heavy water as it is sometimes referred to, is inert and easy to use. Since it is an isotopic form of water it is removed from the core during a conventional extraction process and is not subject to many of the problems associated with chemically based tracers. Disadvantages of deuterium include its expense (typically approx \$1000/litre and up to 20 litres may be required to dope a typical mud system to a concentration of 250-350 ppm), the fact that mud systems are doped in fairly low concentrations, which decreases the detection limit sensitivity, and the point that deuterium is a stable natural isotope of water and exists in most formation waters in a concentration of 120-150 ppm. This natural preexisting concentration is not an issue if produced water samples from the field are available to allow an accurate baseline determination, but if samples are unavailable (such as in many low initial water saturation formations) accuracy of the method may be degraded for low levels of invasion due to uncertainty as to the baseline concentration of preexisting deuterium in the natural formation water.

Tritium is less expensive than deuterium (a typical mud system can be treated generally for about one-tenth of the cost), is analyzable in concentrations of down to 1 picocurie/ml (pci/ml) (in comparison to the doping concentration of 5000-10000 pci/ml) and does not naturally exist in formation waters in any significant concentration so that the need to have a sample of in-situ water for a baseline analysis is negated. Tritium analysis is also quick, less problematic and less expensive in comparison to deuterium analysis. Tritium is a beta emitter, with a half life of 12.3 years and concerns are often expressed about the safety of its use. Drinking water standard for tritium is 1000 pci/ml and disposal standard is 1,000,000 pci/ml, so one can see that the concentration in which mud systems are normally doped represents no hazard to humans or the environment. An atomic energy permit, however, is required to handle the concentrated tritium which is used to dope the initial mud system at site and this process should only be conducted by experienced personnel who will conduct the appropriate site monitoring to ensure that no contamination of concentrated tritium has occurred. Tritium is the preferred tracer for in-situ water saturation determination for most reservoir applications from both a cost and technical viewpoint.

Figure 11 illustrates how core is sectioned on site to determine a tracer invasion profile. In some cases, where only the true water saturation is desired, only the central section of the core is analyzed for tracer content to reduce costs and time. If an evaluation of the degree of flushing is required all three sections may be evaluated. Liquid nitrogen is generally used either onsite or immediately upon receipt of the core material at the analysis lab to cut the plugs to fix saturations in place and avoid the introduction of any other extraneous oil or water based fluids into the core. The cutting process should be

conducted as soon as possible to avoid the imbibition of drilling mud into the core which will occur if static exposure over an extended period of time occurs if the core sits immersed in mud in the core barrel. Proper technique is also important and the samples should be cut in a dry environment. The condensation of water on the surface of the frozen core after cutting can totally disrupt the accuracy of the saturation and tracer measurements, particularly on the small outer section end cuts where surface volume of condensation is large compared to actual pore volume of the samples. Figure 12 provides an example of invasion down the length of typical core. Spikes in invasion are usually associated with either high permeability streaks, vugs or natural fractures, surges in pump pressure during coring, static rotation or cessation of drilling in a single spot or at breaks between individual core barrel trips where long term static exposure of mud floods into the top section of the first section of core to be taken once coring resumes. Figure 13 illustrates the tritium invasion profile from a typical traced core Table 7 provides a summary of typical corrected and uncorrected water saturation measurements for a tritium based coring program.

**Degassing and Fluid Losses.** For core samples which contain fluids at saturation levels above the irreducible value, fluids may be lost from the core as the core is pulled to surface and pressurized gas contained either as a free phase in the pore system, or as a solubilized phase in liquid hydrocarbons, evolves and displaces either oil or water from the pore system. Two techniques are usually used in this situation, these being pressure coring and sponge coring.

Pressure coring involves using a special core barrel which can maintain reservoir pressure and in some cases reservoir temperature (through the use of electrical heating elements) to maintain the core at full reservoir conditions during the tripping operation. Liquid nitrogen is used to freeze the core at surface, at which time the samples are removed and placed in the extraction system complete with all fluids (including gas) intact. Pressure coring is a complex and expensive operation with sporadic success rates due to a high number of failures with the pressure integrity of the core barrel and is therefore utilized infrequently.

Sponge coring involves the use of a special core barrel with a non hydrocarbon reactive sponge material placed around the inner face of the core barrel. As the core enters the core barrel it fits tightly against the sponge. As the core is brought to surface and depressurization occurs, gas leaks off through small pinholes helically placed in the outer surface of the core barrel, but any water or oil produced is captured in the sponge material. Analysis of the sponge material adjacent to each core section can allow determination of the volume of oil produced from the core. If a traced water based system is used to drill and initially saturate the sponge material, any significant losses of connate water from the core into the sponge can also be

determined. Sponge coring may be a useful technique to consider in a situation where free gas, oil and water may all exist in the subject formation. Adjustments must be made for the swelling of oil present at formation pressure due to thermal and gas solubility effects if oil saturation is to be determined directly. This can be obtained from PVT volumetric studies conducted on the oil. Thermal adjustment to the volume of water measured may also be required if high reservoir temperatures are present. High concentrations of CO<sub>2</sub> and H<sub>2</sub>S in reservoir fluids may also result in high solubility in the in-situ water phase (normal hydrocarbon gases have very low solubility in water and do not normally appreciably affect water formation volume factor) and corrections may be required for water shrinkage due to gas evolution in such situations as the core is depressurized.

Saturations on core samples are generally determined using a soxhlet or dean stark extraction apparatus where hot solvent is used to remove both the water and hydrocarbons from the core samples. The oil volume obtained from these saturation evaluations is often determined by mass difference of the sample, whereas the water volume removed is measured directly. This means that the oil volume must be corrected for density effects. In many situations, the oil density is assumed to be 1.000 g/cc, which often results in a significant underestimation of the oil volume in place, particularly for light oil systems.

### Sidewall Cores

Sidewall cores are often obtained to obtain petrographic or reservoir quality data in the absence of full diameter core. Sidewall cores are obtained in the flushed zone directly adjacent to the wellbore and hence tend to be heavily invaded with drilling mud filtrate and, in general, may not be representative for saturation evaluation. If an oil based system is used in the drilling and sidewall coring process, evaluation of initial or irreducible water saturation (in a mobile water saturation system) may be determined from sidewall core samples. Since traced water-based mud systems are not normally used in a situation where a conventional drilling process (where no core is being obtained) is utilized, the use of sidewall cores in such a situation usually results in erroneously high water saturations. Even in the situation where a traced system is used to drill the well prior to a sidewall coring operation, unless fluid losses to the formation are very low, near total flushing of the sidewall core region may occur which will make accurate evaluation of the initial water saturation impossible.

### Conclusions

The determination of initial fluid saturations is a key factor in reserves determination and optimizing production and locations for well completion. Water saturation determinations from logs

may be affected as follows:

	Effect on $S_w$ (If Under Estimated)	Effect on $S_w$ (If Over Estimated)	Effect of Small Error
Saturation Exponent (n)	Value too low	Value too high	Strong
Archie Constant (a)	Value too low	Value too high	Moderate
Water Resistivity ( $R_w$ )	Value too low	Value too high	Strong
Cementation Exponent (m)	Value too low	Value too high	Moderate
Total Resistivity ( $R_T$ )	Value too high	Value too low	Strong

Accurate determination of electrical calibration properties on representative samples of actual reservoir core material is illustrated as essential for ensuring valid log saturation evaluations. The direct measurement of liquid saturations using a variety of coring techniques has also been described. A combination of low invasion coring technology with an oil based or traced water based drilling fluid system (tritium based systems being the most popular) have been utilized as a definitive technique to obtain in-situ water saturation and directly calibrate log data.

### Acknowledgments

The author wishes to express appreciation to Maggie Irwin and Vivian Whiting for their assistance in the preparation of the manuscript and the figures and the Hycal Energy Research Laboratories for the funding of this work and permission to present the data.

### References

1. Archie, G.E., "The Electrical Resistivity as an Aid in Determining Some Reservoir Characteristics", *JPT*, Jan. 1942.
2. Archie, G.E., "Classification of Carbonate Reservoir Rocks and Petrophysical Considerations", *Bull AAPG*, Feb. 1952.
3. Trieber, L.E. et al, "A Laboratory Evaluation of the Wettability of 50 Oil Producing Reservoirs", *SPEJ*, Vol 13 (4), 1973, 221.
4. Chillingar, A. et al, "Oil and Gas Production From Carbonate Rock", Elsevier, Amsterdam, 1972.
5. Anderson, W.C., "Wettability Literature Survey", *JPT*, Oct. 1986.
6. Masters, J.A., "Elmworth - Core Study of a Deep Basin Gas Reservoir", *AAPG Memoir* 38, 1984.
7. Katz, D.L., et al, "Absence of Connate Water in Michigan Reef Gas Reservoirs - An Analysis", *AAPG Bulletin*, Vol 66, No. 1, Jan. 1982, 91-98.
8. Bennion, D.B., "Water and Hydrocarbon Phase Trapping in Porous Media - Diagnosis, Prevention and Treatment", Paper 95-69 presented at The Petroleum Society of CIM in Banff, Alberta, Canada, May 14-17, 1995.
9. "Schlumberger Log Interpretation Principles and Applications", *Schlumberger Educational Services*, July, 1989, Houston, Texas.
10. Segesman, F., "New S.P. Correction Charts", *Geophy*, Dec. 1962, 27, No.7.
11. Worthington A.E., et al, "Departure Curves for the Self Potential Log", *JPT*, Jan, 1958.
12. Dunlap, H.F., et al, "The Calculation of Water Resistivities From Chemical Analysis", *Trans AIME* (1951) 192.
13. Moore, E.J., et al, "Determining Formation Water Resistivity From Chemical Analysis", *JPT*, March, 1966.
14. Moore, E.J., "A Graphical Description of New Methods for Determining Equivalent NaCl Concentration From Chemical Analysis", *Trans*, 1966, SPWLA Annual Logging Symposium.
15. Winsaver, W.O., et al, "Resistivity of Brine Saturated Sands in Relation to Pore Geometry", *Bull AAPG*, Feb. 1952, 36, No. 2.
16. Crowell, E.C., "The Use of Petrophysical Properties to Determine Bypassed Pay", Paper presented at the 1995 Annual Technical Meeting of the Petroleum Society of CIM, June, 1995.
17. Worthington, P.F., "The Evaluation of Shaley Sand Concepts in Reservoir Evaluation", *The Log Analyst*, Jan-Feb. 1985.
18. Poupon, A., et al, "Log Analysis of Sand-Shale Sequences, a Systematic Approach", *JPT*, July, 1970.
19. Poupon, A., et al, "A Contribution to Log Interpretations in Shaley Sands", *JPT*, June, 1954.
20. Poupon, A., et al, "Log Analysis in Formations with Complex Lithologies", *JPT*, Aug, 1971.
21. Waxman, W.H. and Smits, L.J.M., "Electrical Conductivities in Oil Bearing Sands", *Society of Petroleum Engineers Journal*, June, 1968.

**Table 1**  
**Parameters Used in Water Saturation Calculations**

Property	Value
Saturation Exponent (n)	2
Cementation Exponent (m)	2
Archie Constant (a)	1
Porosity Fraction	0.22
Formation Resistivity ( $R_f$ )	25 ohm.m
Water Resistivity ( $R_w$ )	0.10 ohm.m

**Table 2**  
**Effect of Variation in Saturation Exponent On Calculated Water Saturation**

Saturation Exponent 'n'	Water Saturation
1.0	0.083
1.2	0.125
1.5	0.190
1.7	0.231
1.8	0.250
2.0	0.287
2.2	0.322
2.4	0.354
2.6	0.383
3.0	0.436
5.0	0.607
8.0	0.732

**Table 3**  
**Effect of Variation in Archie Exponent on Calculated Water Saturation**

Archie Exponent "a"	Water Saturation
0.4	0.182
0.5	0.203
0.6	0.223
0.8	0.257
1.0	0.287
1.1	0.302
1.2	0.315
1.3	0.328
1.4	0.340
1.5	0.352
1.6	0.364
1.7	0.375

**Table 4**  
**Effect of Variation in  $R_w$  on Calculated Water Saturation**

$R_w$ Value (ohm.m)	Water Saturation
0.01	0.091
0.03	0.157
0.08	0.257
0.10	0.287
0.50	0.643
1.00	0.909
2.00	1.286
3.00	1.575
4.00	1.818
5.00	2.033
6.00	2.227
7.00	2.405

**Table 5**  
**Effect of Variation in Cementation Exponent on Calculated Water Saturation**

Cementation Exponent	Water Saturation
1.0	0.135
1.2	0.157
1.4	0.183
1.6	0.212
1.8	0.247
1.9	0.267
2.0	0.287
2.1	0.310
2.2	0.334
2.4	0.389
2.6	0.453
2.8	0.527

**Table 6**  
**Effect of Error in  $R_T$  on Calculated Water Saturation**

$R_T$ Value	Water Saturation
2.2	0.969
3.0	0.830
4.0	0.719
6.0	0.587
8.0	0.508
10.0	0.455
15.0	0.371
25.0	0.287
100.0	0.144
200.0	0.102
500.0	0.064
2000.0	0.032

**Table 7**  
**Example of Water Saturation Calculations Using Tritium Based Coring Program**

Sample No.	Depth (m)	Perm (m)	Porosity (Frac)	Drilling Mud Tritium (pci/ml)	Outer Core Section Data			Middle Core Section Data			Central Core Section Data		
					Measured Sw	Tritium Concent. pci/ml	Corrected Sw	Measured Sw	Tritium Concent. pci/ml	Corrected Sw	Measured Sw	Tritium Concent. pci/ml	Corrected Sw
1	1600	43.700	0.156	6433	0.655	3109	0.338	0.389	1102	0.322	0.345	344	0.327
2	1601	35.400	0.148	6423	0.723	2560	0.435	0.523	1045	0.438	0.456	105	0.449
3	1602	678.200	0.255	6300	0.834	4801	0.198	0.581	4103	0.203	0.411	3260	0.198
4	1603	23.500	0.144	6305	0.588	2690	0.337	0.397	1100	0.328	0.344	333	0.326
5	1604	0.085	0.064	6121	0.788	1045	0.653	0.599	102	0.589	0.567	0	0.567
6	1605	0.022	0.033	5880	0.812	965	0.679	0.633	98	0.622	0.622	0	0.622
7	1606	1.260	0.112	5629	0.634	1467	0.469	0.495	888	0.417	0.417	102	0.409
8	1607	34.600	0.155	5303	0.478	2105	0.288	0.388	965	0.317	0.333	98	0.327
9	1608	23.600	0.166	5333	0.555	1965	0.351	0.399	710	0.346	0.349	122	0.341
10	1609	11.800	0.132	5143	0.499	1322	0.371	0.402	344	0.375	0.370	6	0.370

FIGURE 2  
VARIATION OF "N" WITH WETTABILITY

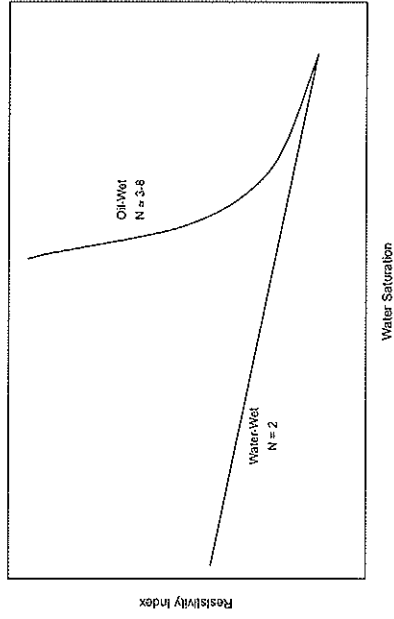


FIGURE 1  
EFFECT OF INITIAL SATURATION CONDITIONS ON WATER AND OIL OR GAS PHASE RELATIVE PERMEABILITY

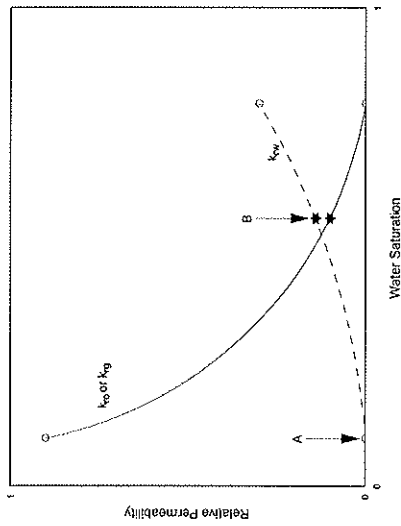


FIGURE 4  
SCHEMATIC ILLUSTRATION OF VARIOUS EXPERIMENTAL METHODS FOR SATURATION EXPONENT DETERMINATION

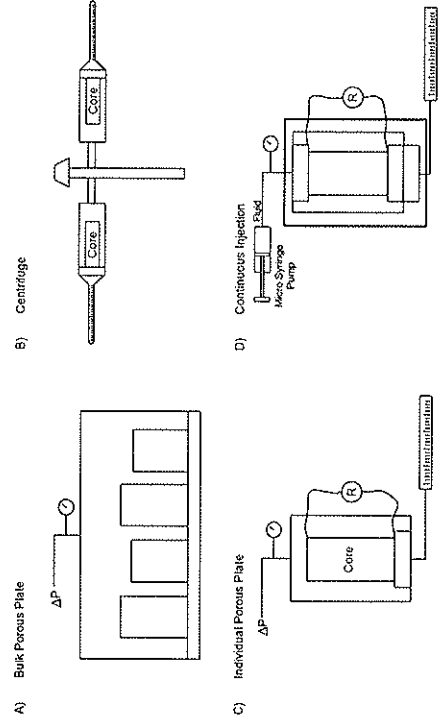


FIGURE 3  
VARIATION OF WATER SATURATION EFFECT OF VARIATION IN N VALUE

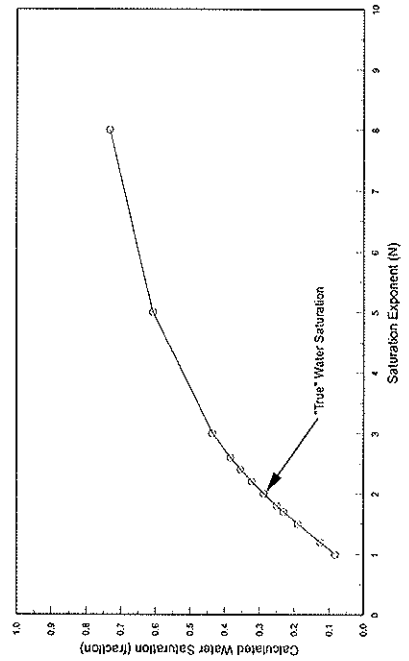


FIGURE 6  
 VARIATION OF WATER SATURATION  
 EFFECT OF VARIATION IN  $R_w$  VALUE

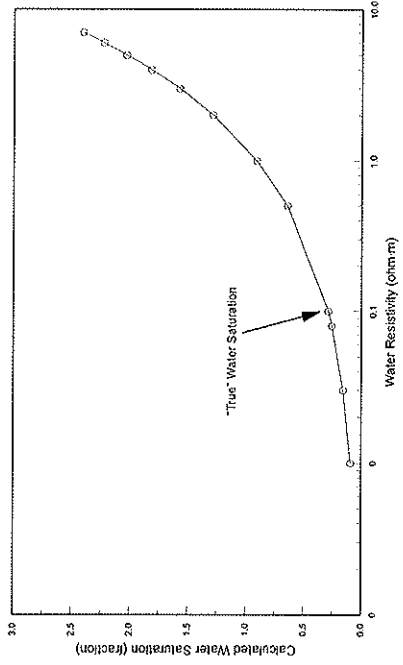


FIGURE 5  
 VARIATION OF WATER SATURATION  
 EFFECT OF VARIATION IN  $n$  VALUE

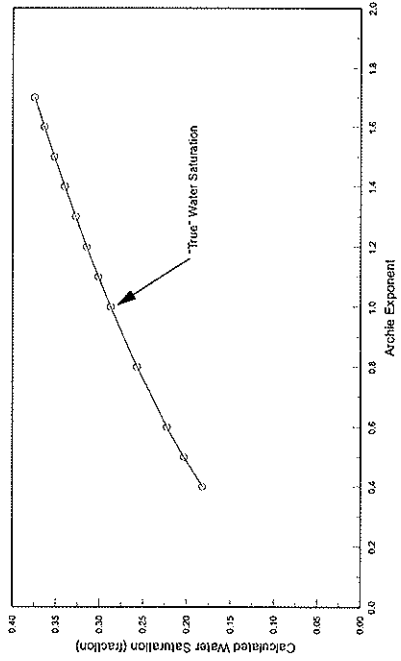


FIGURE 7  
 FORMATION FACTOR vs PERCENT POROSITY  
 FOR VARIOUS DEGREES OF RESERVOIR CEMENTATION

FIGURE 8  
 VARIATION OF WATER SATURATION  
 EFFECT OF VARIATION IN  $m$  VALUE

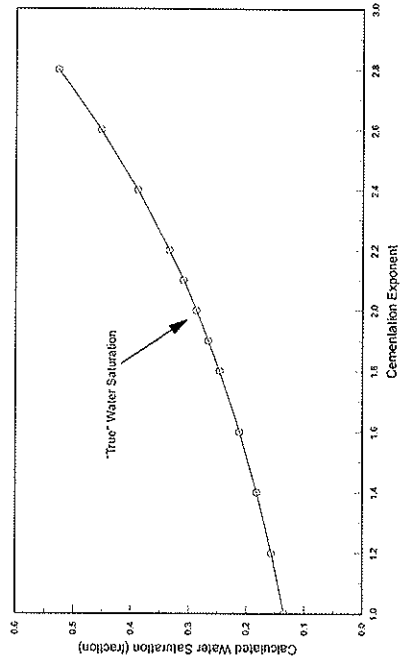


FIGURE 10  
SCHEMATIC OF THE LOW INVASION CORING PROCESS

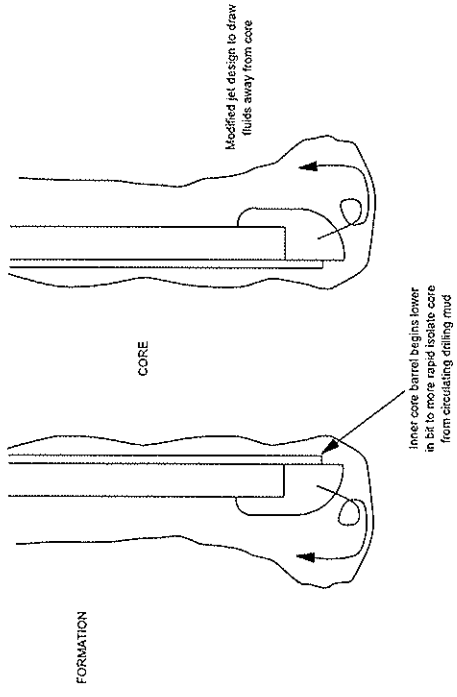


FIGURE 9  
VARIATION OF WATER SATURATION  
EFFECT OF VARIATION IN RI VALUE

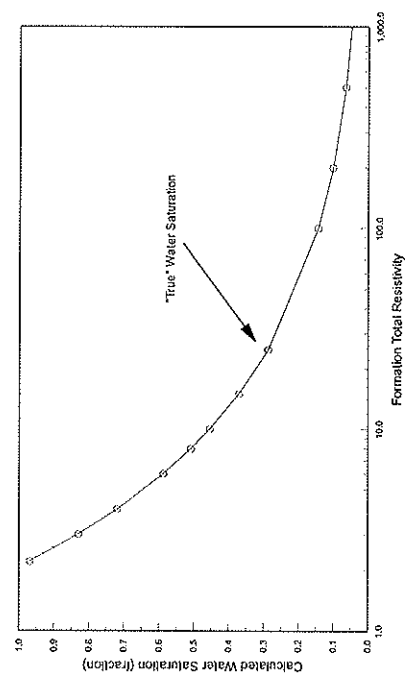


FIGURE 11  
TYPICAL CORE CUTTING PROFILE FOR SATURATION  
DETERMINATION USING A TRACED CORING FLUID SYSTEM

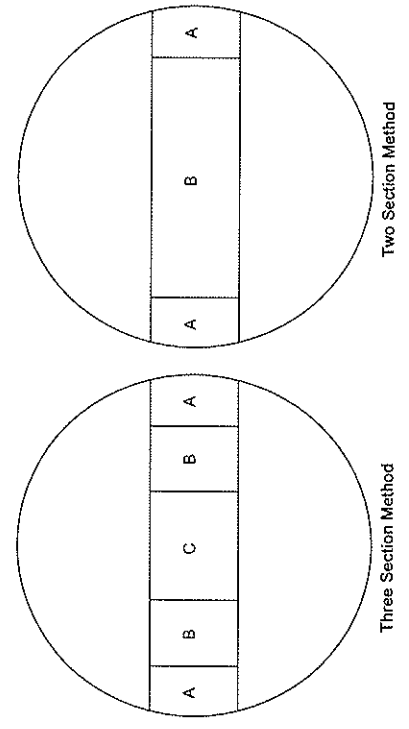


FIGURE 12  
ACTUAL AND CORRECTED WATER SATURATIONS  
TRITIUM TRACED CORING PROGRAM

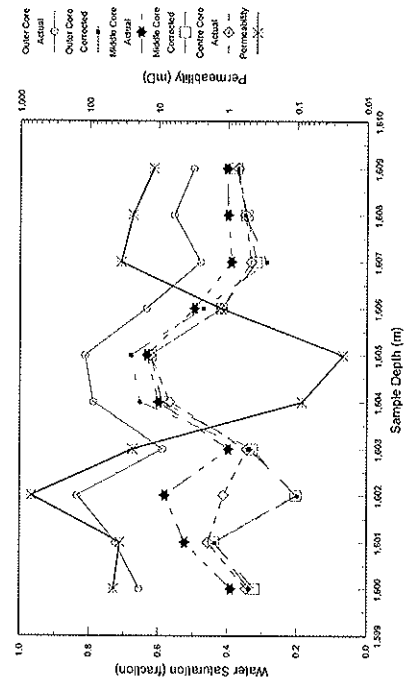


FIGURE 13  
TRITIUM INVASION PROFILE  
TRITIUM TRACED CORING PROGRAM

