USING WELL LOGS TO INFER PERMEABILITY WILL THERE EVER BE A PERMEABILITY LOG?

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ABSTRACT

Absolute permeability is a property of the rock only, while effective perm is a property of the rock and the fluids present in the rock. In the most general sense, permeability used in the petroleum industry is a constant in Darcy's flow equation that equates flow rate, pressure gradient, and fluid properties. Even though a formation has a permeability regardless if it is flowing or not, by this definition a direct measurement of permeability requires a dynamic process not a static process.

Historically, well logs have been used to estimate permeability via correlations related to a commonly logged property: porosity. Perm-porosity correlations are generated from core and transformed to well log porosity. These correlations are generally semilog in nature in the general form of $y = ax^b$. Other correlations attempt to estimate effective perm by incorporating irreducible water saturation estimated from resistivity logs and Archie's equation.

Most well logging environments are static conditions, where invasion of mud filtrate into the permeable formations has ceased at the time the well is logged. This paper reviews traditional and new methods of quantitatively inferring permeability from well logs and addresses the feasibility of a true permeability log.

INTRODUCTION

Permeability is a property of a porous medium that quantifies the capacity of a material to transmit fluids. In other words, permeability is a measure of fluid conductivity of a porous media. By analogy to electrical flow in a conductive material, permeability represents the reciprocal of the electrical resistance.

Permeability is an important (Ahmed et al., 1989) rock property and one of the most difficult of all petrophysical properties to determine and predict (Johnson, 1994). For a petroleum engineer, an accurate estimate of permeability is essential because permeability is a key parameter that controls strategies of well completion, production, and reservoir management. Core analysis has been traditionally used to determine permeability. The analogy of electrical conductivity with permeability has been applied in core analysis. Kozeny (1927) and Archie (1941) were amongst the first few people to quantify permeability based on electrical measurements made on core samples.

Frequently, core based permeability data are not available either because of the borehole conditions or due to the high cost of coring. For these reasons, over the years attempts have been made to estimate permeability by alternative ways. One of the comparatively inexpensive and readily available sources of inferring permeability is from well logs. Various models have been used to achieve this goal. Leverett (1941), Tixier (1949), Wyllie and Rose (1950), Timur (1968), Coates and Dumanoir (1974) developed correlations based on well log measurements to determine permeability. Statistical models have been used to determine permeability (Zhang et al., 1996; Balan et al., 1995; Lin et al., 1994). Instead of rigid correlations, statistical methods predict an average or expected value of permeability, corresponding to a given set of rock properties and statistical parameters. Empirical models provide the guidelines for selecting the dependent variables, which are to be used in the predictor development. Also NMR technology (Quintero, et al., 1999; Coates, et al., 1999; Kenyon, 1997; Timur, 1969) has been used in inferring permeability. **A** relatively new technique, NMR uses hydrogen protons as an indicator of the presence of fluids.

The limitation of accuracy and reliability of permeability correlations based on estimations from well logs such as porosity and water saturation may be due to two significant and unavoidable reasons: 1) the definition of permeability from Darcy's equation and 2) the pore-scale features of the porous media that dominate permeability (compared to other rock properties used in correlations).

A Darcy, the fundamental unit of permeability in Petroleum Engineering, is defined as the permeability that is required to **flow** 1 cc/s of a fluid of 1 cp a distance of 1 cm through a cross-sectional area of 1 sq. cm. with a pressure drop of 1 atm. The key word is "flow". Consequently, by definition the calculation of permeability must be dynamic. Even though a core without flow has a value of permeability, it not measurable without fluid flow.

The correlations of permeability with porosity and water saturation are limited because of the portion of the porous media that dominates permeability, porosity and water saturation are different. Permeability is dominated by the smallest restrictions to flow, the pore throats. Porosity and water saturation are dominated by the volume within the pore bodies, not the pore throats. Hence, correlations for permeability are inherently limited when correlating to porosity and water saturation or any other rock property that is strongly influenced by any part of the porous media other than the pore throat.

The objective of this project is to study the qualitative estimation of permeability using well logs and to discuss the use of well logs as an adequate source of information on permeability and if a permeability log is likely. To achieve this objective, a study of available literature on determining permeability using well logs has been conducted. (In the cited literature, permeability has units of the Darcy except where noted. Also, The 1989 Schlumberger Principles and Applications text was used as a supplementary reference in many parts of this paper.)

PERMEABILITY ESTIMATION BY CORE ANALYSIS

Permeability determination by core analysis is considered a standard measurement because permeability derived from all other methods is usually compared with core permeability. This paper is a review of methods for determining permeability from well logs; however, permeability is generally derived from core analysis. Consequently, some of the reviewed works are correlations developed from core data that have become popular in well log analysis.

Kozenv's Work

Kozeny (1927) introduced a relationship, which provided a direct dependence of permeability (k) on porosity (f). By introducing surface area **(S),** he included the dependence of ***k*** on local rock texture. Mathematically his equation can be written

$$k = \frac{A\phi}{S^2} \quad \text{eq .1}$$

A is the empirical constant known as the Kozeny constant; *S* is the grain surface area **per** unit bulk volume.
Carman (1937) modified Kozeny's equation, which became known as Carman-Kozeny (CK) equation expressed as follows:

$$k = B\frac{\phi^3}{S^2} \quad \text{eq .2}$$

where *B* is the geometric factor.
To obtain *S*, the pore surface area was derived from mercury injection and then normalized by the sample's bulk volume. Permeability, porosity and surface area were evaluated by core analysis and used in equation 1 to obtain a value of ***A*.** However, Carman introduced the constant8 which is related to $(L_e/L)^2$ which is called tortuosity. Le is the apparent length, and *L* is the actual length.

Both equations I and 2 have been derived mathematically. The CK relation has been experimentally verified for clean, well-sorted and fairly porous natural sands and porous sandstones. The success of the application of the CK relation in porous media is dependent on a representative value of B and S.

Carman stated that the greatest uncertainty in the application of the Kozeny equation lies in the evaluation of the constant ***A*** and **8.** Limitation includes failure at low porosity, where the permeability decreases much more rapidly with decreasing porosity. **Also,** it's difficult to determine the surface area, which may be estimated by special core analysis (mercury injection).

Archie's Work

Archie in 1942 laid the basis for quantitative log interpretation by introducing the formation resistivity factor, *F*. He provided the following formula:

$$F = R_o / R_w \quad \text{.eq .3}$$

where Ro is the resistivity of rock with all pores tilled with brine, and Rw is the resistivity of the brine itself. The formation resistivity factor is a function of the type and-character of the formation and has been experimentally found to vary with porosity, clay content, and degree of cementation in some rock samples. Archie proposed the following relationship for porosity – formation factor:

$$F = \phi^{-m} \quad .... \quad .eq.4$$

where-m is defined as the cementation factor as a result of early observations of the variations in m with the degree of cementation. Later, Winsauer et al. (1952) modified this relation to a more

$$F = a\phi^{-m} \quad .... \quad eq.5$$

Here a is the tortuosity coefficient. Uncertainty in the parameters a and m are the key reasons for the uncertainty associated with water saturation estimations calculated using the formation resistivity factor concept. Based on Archie's work, a relationship between permeability and formation factor has been derived (after Bassiouni, 1994). This has been discussed below.

Because the only electrical conductive medium in the rock sample is the brine water, it is possible to replace the core sample by a volume of water of the same resistivity and still obtain the same resistance between the two electrodes. Le, the actual flow path of fluids in the rock, will be longer than the macroscopic flow path, L. Π is defined as the tortuosity factor, which is the ratio of the actual flow path Le in the porous media to the length macroscopic length L.

The relation between resistance (r) and resistivity (R) for the rock and brine samples is given by the resistivity equations **6** and **7.**

$$r_o = R_o \frac{L}{A} \quad .... \quad eq.6$$

$$r_w = R_w \frac{L_e}{A_e} = R_w \frac{L_e^2}{\phi AL} \quad .... \quad .eq.7$$

Ions moving through a porous rock follow a tortuous path, so the length of equivalent water volume, Le, is greater than actual length, L. If the porosity of the rock is f, then the volume of the water in the rock sample is f AL. To maintain the same resistivity, this volume should also be that of the equivalent water body. Thus, the cross sectional area Ae of the equivalent water volume has to be f AL/ Le. But ro = rw. Setting equation 6 equal to equation 7 yields equation 8:

$$\Rightarrow R_o \frac{L}{A} = R_w \frac{L_e^2}{\phi AL} \quad .... \quad eq.a$$

The formation factor from Archie's equation can be represented as follows:

$$F = \frac{R_o}{\quad} = \left(\frac{L_e}{\quad}\right)^2 \frac{1}{\quad} - \frac{\tau^2}{\quad} \quad eq.9$$

The actual fluid velocity ve is related to v, the macroscopic velocity (also called the Darcy velocity) as follows:

$$v_e = \frac{v}{\phi}\frac{L_e}{L} = \frac{v}{\phi}\tau \quad .... \quad eq.10$$

Writing Darcy's equation in terms of the macroscopic velocity as follows:

$$v = -\left(\frac{k}{\mu}\frac{dp}{dl}\right) \qquad eq\ 11$$

dp/dl is the pressure gradient; m is the fluid viscosity. Solving equation **10** for *v* and substituting it into equation 11 yields the following variation of Darcy's equation:

$$k = -\frac{v_e \mu \phi}{\tau \left(dp / dl\right)} \qquad eq.\ 12$$

This equation suggests that permeability is directly proportional to porosity and is inversely proportional to tortuosity. Combining equation 5, **10,** and **12** yield the following relations:

$$k = aF^{-b} \qquad eq.\ \mathbf{13}$$

$$k = c\phi^{d} \qquad eq.\ \mathbf{14}$$

where a, b, c and d are constants for a specific geologic formation that should be determined through core analysis. Based on equations **13** and 14, a number of laboratory correlations have been derived by different researchers; some appear in Table 1 and ***2.*** Once the coefficients are known for a specific formation, permeability can be found based on core or log derived f or F. To use these formulas in well log analysis, core samples/analysis are required to derive formation specific values of a, b, c and d or the use of common or accepted values of these constants from the literature can be used. An economical (non-core) and reliable alternative (formation specific) means for determining permeability is desired.

ESTIMATION OF PERMEABILITY FROM WELL LOGS

A literature survey over the published work done by the authors demonstrates that no direct method to determine permeability is available using well logs. The literature survey does convey that permeability from well logs comes through measurement of rock properties, which are related to permeability. These properties are porosity, water saturation, capillary pressure, formation resistivity factor, and lately using NMR T1 and T2 parameters. The major works cited in the literature survey are discussed in the following section.

Tixier's Work

Tixier (1949) used resistivity gradients in oil/water transition zones above the oil/water contact from a deep investigation resistivity tool (lateral or focused log corrected for borehole effects) to determine permeability. Empirical relationships exist between resistivity and water saturation. Water saturation and capillary pressure are related. Permeability is dependent on capillary pressure. Knowing the resistivity gradient, Tixier was able to determine permeability using the equation below:

$$k = C\left(a\frac{2.3}{\rho_w - \rho_o}\right)^2 \qquad eq.15$$

$$a = \frac{\Delta R}{\Delta D}\frac{1}{R_o} \qquad eq.16$$

where C is a constant and usually has a value of *20.* ΔR is the change in the resistivity (ohm-m) and ΔD is the change in vertical depth (ft) corresponding to ΔR . ρ_o, and ρ_w are the oil and formation water density, respectively.

Limitations for this method are below:

- The derived equations use a constant value of 2 for the saturation exponent and thus, at any water saturation, capillary pressure is related to permeability as:

$$P_c = \frac{A}{k^{1/2}} \qquad \text{eq. 17}$$

- where A is a constant.
- Relative paucity of well logs exhibiting valid oil-water contacts makes the method unacceptable at most places.
- Calculated permeability is an average for the zone corresponding to the resistivity gradient.

Work bv Wvllie and **Rose**

Wyllie and Rose (1950) gave a relationship between permeability, formation resistivity factor and connate water saturation. Formation factor and connate water saturation can be calculated from the well logs. Their work was based on the following assumptions:

- Minimum water saturation computed in a reservoir is equal to irreducible connate water saturation, S_{wi} .
- Irreducible water saturation is a linear function of the grain surface
- Tortuosity, *t*, applicable to fluid flow of the wetting phase in a porous media, is the same as tortuosity affecting electrical conductivity through the same media.

Their model for permeability is expressed

$$k = A\left(\frac{1}{P_c^2 F^{(2-1/m} S_w}\right) \qquad \text{eq. 18}$$

Where A is a constant with a value of $\frac{21.2\sigma^2}{t_s}$ . . is the interfacial surface tension and its units are dynes/cm. Value for ts varies from 2.0 to 2.5 and is essentially a constant. m is the cementation factor. Where the oil-water contact in the reservoir is not available (i.e. capillary pressure), the following corelation:

$$S_{wi} = C\left[\frac{1}{k^{1/2} F^{0.67}}\right] + C^1 \qquad \text{eq. 19}$$

C is the textural constant with the dimensions of a length connecting irreducible water saturation to permeability and formation factor and C1 is a dimensionless constant. For clean sands with no interstitial water held in clays, C1 is zero as the straight line for the above equation passes through the origin. C1 can be obtained by plotting Sw against (kf-1/2)(F)-1 for a specific formation.

Timur's Work

Timur (1968) gave a relationship for estimating permeability of sandstones from in situ measurements of porosity and residual oil saturation. Swi was provided from the Nuclear Magnetism Logs (NML) log. To establish such a relationship several possibilities were tested, through laboratory measurements of permeability, porosity, and residual water saturation on 155 sandstone samples from three different oil fields in North America. He proposed the following empirical equation:

$$k = \frac{\phi^{4.4}}{S_{wi}^2} \quad \text{eq. 20}$$

The application of this formula for estimating permeability in three different oil fields was illustrated through scatter diagrams that plot log k vs. log ($^{4.4}/S_{wi}^2$).

Estimating residual water saturation in sandstones, when porosity and permeability are known, is also investigated by testing several possible relationships. The best one was found to estimate S_{wi} from a combination of measurements of ϕ and ***k*****,** with a standard error of 14% pore volume.

Limitations:

- Applicable where condition **of** irreducible water saturation exists.
- Timur assumed a value of 1.5 exists for the cementation factor, *m*, in all cases, which is not necessarily universal.

Work bv Coates and Dumanoir

Coates and Dumanoir (1974) presented a new approach in permeability estimation. They adopted a common value, w for both the saturation exponent, *n*, and cementation exponent, *m*. This was done by support of core and log studies. They proposed a relationship between ***w*****,** porosity, and formation resistivity at irreducible water saturation, which is given in equation **21.** Based on the knowledge of the *w* exponent this method yields permeability values in good agreement with core and production data in sandstone and carbonate formations. Field examples illustrate the mechanism of this new approach and the results obtained.

$$k^{1/2} = \frac{C}{w^4} \frac{\phi^{2w}}{R_w / R_t} \quad \text{eq. 21}$$

where $C = 23 + 465\rho_h - 188\rho_h^2$

and $w^2 = (3.75 - \phi) + \frac{1}{2}\left[\log_{10}(R_w / R_t) + 2.2\right]^2$

Equation 21 is valid for clean, oil-bearing formations with oil density equal to 0.8. For hydrocarbon density appreciably different from 0.8, the log readings of R_t are multiplied by the correction factor given by:

$$\frac{R_{tcorr}}{R_{t\log}} = 0.077 + 1.55\rho_h - 0.627\rho_h^2 \quad \text{eq. 22}$$

A technique is also described for adapting this relationship to conditions of mobile water saturation ($S_w > S_{wi}$). Variations in the value of this new exponent, ***w*****,** are found to be indicative of the nature of the formation matrix. This method is the first to satisfy the condition of zero permeability at zero porosity when irreducible water saturation is 100%. Values for the exponents *m* and *n* are not required as they are obtained as a result of the use and computation of w (shown above). Later in 1981, Coates proposed a simpler formula for permeability estimation, given as:

$$k^{1/2} = 100 \frac{\phi^2 (1 - S_{wi})}{S_{wi}} \quad \text{eq. 23}$$

Here ***k*** is in millidarcies.

This formula satisfies the condition of zero permeability at zero porosity and when Swi is 100%. However, the formation must be at irreducible water saturation to apply this formula.

Semmelbeck's Work

Semmelbeck, et al. (1995) developed a method of determining permeability based on invasion of mud filtrate into a formation. By using an iterative simulation process that integrated reservoir volumetric and fluid flow concepts (material balance and Darcy flow equations), a mud cake thickness model, and a salinity distribution model, they were able to estimate the resistivity profile (distribution) of the formation around the well bore. This information along with porosity and saturation derived from other logs became the feedback for the AIT (Array induction tool – Schlumberger tool), from which a radial response function was generated. Parameter estimation was from the response function. One of the parameters estimated from the response function is permeability.

They claimed this method worked best in medium permeability formations. This method does incorporate the dynamics of fluid flow and does not have the weakness of other models that are based on static (non-flowing) conditions.

STATISTICAL METHOD FOR DETERMINING PERMEABILITY FROM WELL LOGS

In recent years. efforts have been made in permeability estimation in heterogeneous reservoirs. This method has been applied to complex sandstone. Researchers (Balan et al., 1995; Lin et al. 1994; Zhang et al. 1996) have tried to determine permeability using statistical methods. They adopted the following procedure in their work:

- **Data preparation and pre-processing:** Borehole environment corrections and depth matching were done using standard procedures, while confusing and incoherent data were discarded. Core porosity and permeability data were correlated with the well log responses.
- **Predicting lithofacies:** The determination of the lithofacies in a heterogeneous reservoir is of fundamental importance as the lithofacies are the major controlling factor in fluid flow and fluid distribution in the reservoir. Log parameters have been observed to vary from one lithofacies to the other. Sonic, gamma ray density and deep investigation resistivity logs are some of the logs used by Lin et al. (1994). Lithofacies were identified on the well logs using the geostatistical methods. Lithofacies identification can also be done using core data, if it is available. Identification of the lithofacies allows unique permeability correlations for each zone.
- **Permeability estimation:** Any number of permeability correlations/models can be considered and entered into the statistical regression for each lithofacies. Permeability is the dependent variable and porosity is often the independent variable in these models. The final model appropriate to a particular lithofacies is selected based on correlation coefficients and standard error for the models under consideration. Generally, the models are logarithmic and semi-logarithmic equations.

Limitations of this statistical methodology as mentioned by Balan, et al. (1995) are listed below:

- With use of regression, the distribution of predicted permeability values is narrower than that of the original data set. On average, regression provides the best estimate.
- The ability of a regression model to predict the permeability extremes (maximum and minimum values) is enhanced through a weighting scheme of high and low values. But because of this, the statistical estimator can become unstable and become statistically biased.
- The error is assumed to be related only to the dependent variables (log variables). Logs of acceptable quality have errors that are function of the physics of the tool, its response characteristics, and the borehole environment. These errors can cause anomalies in permeability predictions if the errors are not normally distributed and have a mean value of zero.

The authors describe the results as encouraging, reliable and accurate in the evaluation of heterogeneous reservoirs.

PERMEABILITY FROM NMR LOGS

To initiate a two-step NMR measurement cycle, magnetic nuclei (protons) are aligned with a static magnetic field, B_o. Protons aligned in the static magnetic field are described as polarized. Polarization does not occur immediately but rather increases with time according to the equation below (Kenyon, 1997):

$$M_z(t) = M_0(1 - e^{-t/T1}) \qquad .eq.24$$

where t is the time the protons are exposed to the B_o field. $M_z(t)$ is the magnitude of magnetization at time t. M_o is the final and maximum magnetization in a given magnetic field. T_1 (longitudinal relaxation time) is the time at which magnetization reaches 63% of its final value, and three times T_1 is the time at which 95% polarization is achieved. The final step in the NMR measurement cycle is to change the magnetization from the longitudinal direction to the transverse plane. This is accomplished by applying an oscillating magnetic field B1 perpendicular to Bo, the static magnetic field.

T2 relaxation time is the time constant of the transverse magnetization decay of the protons in the porous media (Kenyon, 1997). The amplitude of the spin echo train at time t, which is the amplitude of the transverse magnetization

$M_x(t)$, is given by:

$$M_x(t) = M_{ox}\, e^{-t/T2} \qquad eq.25$$

where M_{ox} is the magnitude of the initial transverse magnetization (at t = 0, the time at which 90o pulse ceases). T2 decay of a formation reflects most of the petrophysical information obtainable from NMR logging and therefore is of prime objective of NMR petrophysical measurements. In the laboratory TI and T2 can be measured, however, the paucity of time during logging operations do not allow TI measurements of the formation fluid. It has been experimentally found that T2 provides all the information TI provides. **As** such, currently only T2 is available for log analysis.

NMR logs differ from conventional neutron, density, sonic and resistivity logs in that NMR logs provide information only on formation fluids. No matrix information is furnished on NMR logs, because the NMR signal from the rock matrix decays too quickly to be detected by the NMR logging tools.

T1 and T2 have been correlated to the pore size, surface relaxivity, porosity, permeability, irreducible water saturation, capillary pressure, and fluid typing. For the purpose of this paper the NMR discussion is limited to permeability estimations.

In 1966, **Seevers** gave a simple relationship between NMR relaxation and permeability:

$$k = \phi T_1^2 \qquad eq.26$$

Subsequently, **Timur** (I 968) proposed a model, which related NMR relaxation with irreducible water saturation, S_{wi}:

$$k = \frac{\phi}{S_{wi}^2} \qquad eq.27$$

The model is often known as the free fluid model, because calculation of S_{wi} involves calculating bulk volume irreducible (BVI) and the free fluid index (FFI = ϕ -BVI) which influence the selection of the TI and T2 cutoff for estimating f, S_w, and S_{wirr}

Kenyon in 1988 developed a model based on the fact that permeability has the dimensions of length squared (area). The relationship below relates pore wall relaxation time and the pore size (Kenyon, 1992):

$$\frac{1}{T_s} = \rho \frac{S}{V_p} = \rho L_{NMR} \qquad eq.28$$

Vp is the volume of the pore, S is the surface area of the pore, which is exposed to the same intensity of magnetization throughout, and ρ is the surface NMR relaxivity parameter (ability of the surface to cause relaxation of proton magnetization). T_s is simply surface relaxation and is inversely proportional to both T, and T,. L_{NMR} is the pore size (length). In other words,

$$L_{NMR} = \rho T_2 \qquad eq.29$$

On the basis of dimensional analysis, Kenyon proposed the following lor permeability:

$$k = cL_{NMR}^2 = c(\rho T_2)^2$$

where c is a constant to be determined using crossplots from various samples.

Also, it is evident that ρ will affect the estimation of permeability. To determine the unknowns, Kenyon conducted experiments on a collection of sandstone samples, and proposed the following model for evalua-

$$k = C\phi^a T_2^b \qquad eq.30$$

He found that best estimation of samples was made with the exponents a and b equal to four (4) and two (2), respectively. He also suggested that a better estimate of permeability might be found by replacing ϕ^4 with $1/F^2$

NMR log interpretation shows that Kenyon's model works very well for water based muds. However, if oil based mud filtrates (or oil from other sources) are present, the mean T2 is skewed towards the bulk liquid T2, and permeability estimates are erroneous. In the Coates et al. (1 997) model, determining the exact T2cutoff may be a problem, which may lead to erroneous determination of BVI. Kenyon says "to estimate permeability, a logging measurement sensitive to size is needed, more specifically a throat size is needed". This statement emphasizes that throat size is required for determining permeability, and not just the pore size. All NMR logging estimates are based on the pore size distribution and not throat size distribution. This is the limiting factor for NMR permeability estimation. Kenyon's statement emphasizes the Introduction to this paper, and in a broader sense points out the fundamental weakness inherent in all traditionally used permeability correlations.

RESULTS AND ANALYSIS

The mathematical representation of permeability in the petroleum industry may be the sole reason permeability correlations are unreliable, and, consequently, a permeability log is impossible. Permeability in Darcy's equation does not include the pore scale features that influence permeability: pore body and pore throat size and shape, degree of cementation, and connectivity of pores. In other words the pore scale properties that determine the permeability of a rock are "lumped" together into the permeability calculated from Darcy's equation for a specific porous media. Permeability from Darcy's equation is a correlation constant based on fluid flow. All of the static models that attempt to correlate a dynamically defined property (permeability) with statically determined properties (porosity and water saturation) will prove unpredictably unreliable.

Various methods exist in the literature for correlating permeability with parameters obtainable from well logs. Log responses give the estimations of properties that are translated into porosity, water saturation, irreducible water saturation, capillary pressure, and resistivity gradients. Subsequently, these terms are used in correlations that yield permeability. However, no tool has been designed to directly measure the permeability from the formation. The practical problem in developing a permeability log is the fact that permeability is a dynamic property of the formation. Permeability of a formation near a well bore at a particular time depends on fluid flow (invasion), buildup of mudcake, relative permeability of the various phases present, diffusion between the mud filtrate and reservoir fluids. In other words, dependence of permeability on properties mentioned above is not well defined quantitatively, but varies with time and space. For example, the saturation exponent may not necessarily be equal to ***2***, a limitation for Tixier's work. It may have a variable value depending on the invasion of mud filtrate and the flow rate of the reservoir fluids / formation waters.

Semmelbeck et al. have tried to determine permeability using an invasion based dynamic model. However, even in their method, the permeability can only be estimated in conjunction with other logs, i.e. not a single log supplied information to estimate permeability. Nonetheless, of the literature reviewed in this paper, Semmelbeck et al. are the only researchers that attempted to quantify permeability using a dynamic approach.

Amongst all the static methods discussed in this work, Coates and Dumanoir's free tluid model is a pioneer work, because it meets the zero permeability at zero porosity when Swi is 100%. Statistical methods try to average the information, thereby reducing the error to a mean value of permeability. NMR technology is a new method, which requires substantive research in relaxation mechanisms before a permeability log can be developed. As Kenyon points, while the objective is to measure the throat size, NMR logs provide information about pore size. Though they are related to each other, this may not be very realistic in a quantitative model as expressed in equations 5.4 and 5.7.

CONCLUSION

All methods of permeability determination from well logs use a relationship of permeability with rock and fluid properties like porosity, surface area per unit volume, water saturation, capillary pressure, or proton density. The source of information for permeability is "indirect" and a relationship between the independent (porosity) and dependent (permeability) variables is not well defined.

Permeability, as defined in the petroleum industry, is a dynamic function of fluid flow. Any attempt to derive permeability from logs will be a failure, until the pore-scale rock features that directly affect the flow of fluids through porous media represent permeability.

Unless, this is met, a permeability log is not possible.

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Table 1
Laboratory Derived Permeability Correlations Based on the Formation Resistivity Factor in the General Form of $k=a/F^b$ (Table based on Ogbe, et al.).

Reference	Formation	a	b	Relationship
Porter and Carothers	Limestone	$4x10^8$	3.65	$k = 4*10^8/ F^{3.65}$
Porter and Carothers	Sandstone	$7x10^8$	4.5	$k = 7*10^8/ F^{4.5}$
Winsauer et al.	-	$1.64x10^8$	4.9	$k=1.64*10^8/F^{4.9}$
Ogbe et al.	SA + GF	$1.10x10^{10}$	4.74	$k=110*10^8/F^{4.74}$
Ogbe et al.	Gulf coast unconsolidated	$2.25x10^{14}$	11.5	$k=2.25*10^{14}/F^{11.5}$

Table 2
Laboratory Derived Permeability Correlations Based on the Formation Porosity in the General Form of $k=af^b$ (Table based on Schlumberger SLIP/A, 1989).

Reference	Formation*	a	b	Relationship
Tixier	Sandstone	$6.25x10^4$	6.0	$k = 6.25x10^4 \phi^6/S_{wi}$
Timur	Sandstone	$10x10^4$	4.5	$k = 10.0x10^4 \phi^{4.5}/S_{wi}$
Coates and Dumanoir**	Sandstone	$0.141x10^4$	4.0	$k = 0.141x10^4\phi^4/S_{wi}^2$
Coates	Sandstone	$4.90x10^4$	4.0	$k = 4.90x10^4\phi^4 (1-S_{wi})^2/S_{wi}^2$

* Derivation **based** on intergranular porosity; **Schlumberger SLIP/A** (1989) states restriction to **sandstones *is* unnecessary.**

** For comparative purposes, **the** *w* coefficient **assumed equal** to 2.0 in this equation.