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Permeability Prediction : Core Vs Log - Derived Values

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Abstract

Rock formation permeability is the most important parameter that indicates how efficient the reservoir fluids flow through the rock pores to the wellbore. Regardless of operations available downhole, its importance is reflected by the number of available techniques (core measurement and well - log evaluation) typically used to estimate it. Permeability estimates by individual techniques within the various permeability sources can vary with the state of rock (in situ environment), fluid saturation distribution, flow direction, and the scaling of measurement. This paper reviews the available permeability-estimation techniques and discussed the important factors that illustrate their relationships. Usefulness of the relationship is demonstrated with field data.

Introduction

Of all the reservoir rock parameters that petroleum engineers need, permeability is one of the most important. In the oil and gas industry, it used to determine whether a well should be completed and brought on line. Similar to the heat transfer coefficient calculation in chemical engineering, permeability is also essential in overall reservoir management and development (e.g., for determining depth and spacing of perforation, optimal drainage point and production rate, injection optimization and EOR patterns). Many oil and gas companies have different opinion on the accuracy and repeatability of how the permeability is predicted. They have use both accurate and approximate values and then correlate with other predicted values without much attention on the sources and methods to determine permeability. Such correlation or com-arison may cause severe impact especia-ly during the development phase of new field. Many investigations frequently ignore the scale factor, measurement environment and physics of fluid when conducting the correlation study.

The scale factor considers the relative size of the volumes being investigated and the nature of heterogeneity, the measurement environment and physics of fluid consider the state of the rock environment, status of fluid saturation distribution, flow direction and sensitivity of the measured variables that constitute permeability calculations.

Rock Permeability Definations

The classic defination of permeability as defined by Darcy in 1856 is the intrinsic characteristic of the rock. It is a measure of the rock that permits the fluids flow through it. In the petroleum industry, Darcy is a standard unit for permeability which is represents 1 cm^3 of fluid with a viscosity of 1 cp flowing through a 1 cm^2 cross-sectional area of rock in 1 second under a pressure of 1 atm per 1 cm of length in the direction of flow. This measured rock property is called absolute permeability when the rock is completely (100%) saturated with one type of fluid.

Permeability also can be expressed in reference to other fluid if more than one single fluid present in the rock pores. This permeability is called as effective permeability and it is usually refers to how efficient non-wetting phase flows over wetting phase in the pores. In the petroleum reservoir simulation and the EOR study, permeability of the rock is expressed in terms of the ratio of effective permeability to absolute permeability. This permeability ratio is called relative permeability and used to estimate wetting phase breakthrough and oil residual saturation.

When downhole rock permeability is measured, however, complications arise because of lack of knowledge about the downhole environment, the volume, and the measurement method. Almost every discipline in the oil industry defines the permeability at different perception. This inconsistency creates a serious difficulty when the permeability is to be used to predict productivity of particular formation, reservoir or well. A core analyst defines the permeability by using 1-in diameter and 1-in long core sample. Usually measurements made in the laboratory ignore the initial saturation condition in the formation, in-situ rock stresses, wetting condition and formation temperature The log - derived permeability, however is influenced by the complexity of rock structures and inadequate parameterization which is makes the measured data nonuniversal. Log-derived techniques can provide level-by-level (foot-by-foot) permeability values. Accurate reservoir characterization demands the various measurements. Therefore, we need to understand the various permeability measurement techniques used by the industry.

Permeability Measurement Techniques

Core Analysis. This technique produce direct measurement of permeability which can be performed either under controlled laboratory conditions or reservoir conditions. Core-derived permeability is often considered to be the standard and used as reference value for most reservoir engineering calculations Core permeability is an accurate representation of a particular core sample under specific conditions. The suitability of core permeability to represent formation permeability is depend upon the test conditions. As long as the measurements are consistent over a particular interval, however, the core permeability can be useful in completion design, specifically in choosing the phasing and vertical spacing of perforation. Usually, cores are analyzed on two diameter scales which is 1 in or 11/2 in. plugs. The length of core samples vary from 1 in. to 2 ft. long. The analysis of 2 ft. long core samples sometimes is called whole-core analysis, but the number of whole core test is limited due to difficulty in recovering such pieces.

Two types of permeability can be measured on core samples in the laboratory : absolute and relative core permeability.

(I) **Absolute Core Permeability.** Two commonly used methods to measure the absolute core permeability are the steady-state method, and pulse-decay methods. In both methods, air or water can be used as the fluid medium. The core are cleaned and dried before they are measured. In the steady state method, permeability is obtained by placing the core in a chamber and measuring the pressure differential and stabilized flow rate of fluid pumped through the rock. The permeability is calculated by using the Darcy's equation for single phase flow. In pulse-decay method, the core is subjected to a pressure pulse, as when a pressure transient is imposed. The subsequent pressure-transient falloff is measured and analyzed for permeability. Three values of permeability can be obtained from both method; horizontal permeability, K_{max}, permeability at 90° to K_{max}, K_{90} and vertical permeability, K_V.

(ii) **Relative Core Permeability.** This method has similar measurement procedures with the steady state method but it considers the present of wetting phase in the pore space. Initially the rock is saturated with the wetting phase at 100 percents saturation. Then displace the wetting phase with non-wetting phase while monitoring the pressure and volumetric flow rates of the two fluids. The displacement continues until the wetting phase reaches at immobile saturation. This method permits the measurement considers many controlling parameters such as temperature, confining pressure and wettability. The resulting flow rates and pressures determine the relative permeabilities and effective permeability to each fluid.

Wireline Log Measurements . Three common methods will be discussed here for obtaining permeability from Wireline tool measurements : (1) empirical correlation of permeability with porosity, ϕ, and intergranular surface area, (2) measurement of producible formation fluid with the nuclear magnetism log (NML) and pressure/time measure-ment of formation fluids with the modular formation dynamic tester tool (MDT)

(I) **Empirical Correlations.** The first approximation that used to predict the permeability of formation was proposed in 1927 by Kozeny and modified by Carman (1).

$$K = \phi^3 / [5 A_g^2 (1-\phi)^2] \quad \text{..............(Eq.1)}$$

Where A_g is the surface area of grains exposed to fluid per unit volume of solid material. However, the greatest drawback of the Eq. 1 is that Ag can be determined only by means of core samples, and then only with special care and equipment.

With the introduction of the Coates Dumanoir(2) relationship of the free-fluid model, the new equation was derived that ensured zero permeability at zero porosity and when S_{wi} is 100%. The equation relate the saturation of interstitial water and porosity.

$$K^{1/2} = 100\phi_e^2[(1-S_{wi})/S_{wi}] \quad \text{........(Eq.2)}$$

Where ϕ_e is effective porosity. But Morris and Biggs(3) observed that it is generally easier to predict a rock's bulk volume interstitial water rather than the actual value of S_{wi}. This requires a minor modification of Eq.2

$$K^{1/2} = 100\phi_e^2[(\phi_t - V_{bwi}) V_{bwi}] \quad \text{.....(Eq.3)}$$

Where ϕ_t is total porosity. Figure 1 compares the free fluid model with previous pattern as S_{wi} approaches 100%. Permeability corrlations with S_{wi} and ϕ are of limited use in carbonates because of low effective porosity. Porosity in carbonates may not be intergranular.

(II) **NML Measurements.** The NML provides two specific products that indirectly can be related to formation permeability; l_f and t_1. l_f is a measure of movable fluid (oil and water but not gas) and t_1 is spin-lattice relation time which is the time constant involving the alignment of proton spin axes along magnetic fields. l_f typically is obtained by applying a large polarizing magnetic field to the formation and then turning it off. Signal decay in solids and bound fluids is too rapid for detection with the NML tool. Only decay in the free fluid can be measured, l_f is proportional to the number of protons in free fluid. Thus, l_f is related to S_{wi} by

$$S_{wi} = 1 - (l_f / \phi) \quad \text{................(Eq.4)}$$

Where S_{wi} can be applied to Eq. 1 through Eq.3.

t_1 is a property of the rock and fluid wetting its surfaces and thus, Kenyon et al (4) related t_1 to K as follows

$$K = 1.6 \times 10^{-9} t_1^{2.3} \phi^{4.3} \quad \text{................(Eq.5)}$$

(iii) **MDT Measurements** .It is a similar tool to Repeat Formation Tester (RFT) tool but has wider application in Wireline logging. MDT is a trade mark of Schlumberger Wireline and has been claimed as the first wireline tool able to measure anisotropic permeability. It can measures static pressure faster than any other tool of its type. Modular Formation Dynamic Tester tool samples reservoir fluids and measures formation pressure vs time at specific depth station. MDT has three-probe configuration measures pressure response at three locations as shown in Figure 2 . These measurements allow accurate determination of near-wellbore horizontal and vertical permeability characteristics. The tool is first positioned at specific depth and then open the probe modules to allow mud filtrate and formation fluids flow into the sample module at controlled flow rate. Figure 3 shows the plot of pressure change against the flowing time as recorded by three probes. Once the sample module is filled, probes will record the increase in pressure response. This phase of the test is called buildup. The buildup test provides a permeability value that is often reflective of near-wellbore fluid movement(6). To calculate permeability, the pressure derivative is first plotted to identify the flow regime and is followed by specialized plots and equations.

Technique Interrelationships

The three most important factors that differentiate between the individual techniques are scale factor, measurement environment, and the measurement physics.

Scale Factor

Figure 4 shows the conceptual scales associated with porous media averaging.

1. *Microscopic* relates to pores and sand grains. Scalewise , all the techniques discussed here pertain to a larger volume, so this category is not discussed in detail.

2. *Macroscopic* relates to conventional core-plug scale.

3. *Megascopic* relates to the scale of gridblocks in simulation models and is represented by the wireline-log measurement scale.

4. *Gigascopic* relates the total formation or regional scale and is represented by well-test area of investigation. However it will be discussed in this paper

Measurement Environment and Physics

Most core analysis are performed at standard bench conditions. Certain tests such as dynamic method are performed at simulated in-situ effective stress (overburden minus pore pressure), temperature and saturation. Most wireline logging methods satisfy all in-situ requirements, with the possible exception of reservoir fluid saturation.

Core Testing.

The absent of in-situ stress, pore pressure, temperature and fluids saturation make laboratory permeability values orders of magnitude higher. A practical way to incorporate these factors in the core analysis method is to combine absolute-permeability measurements at in-situ pressure with relative-permeability data.

Wireline - Log Analysis.

Wireline logs and empirical correlations except MDT tool calculate permeability based upon 100% invaded-fluid movement which is equivalent to the absolute permeability . To relate absolute permeability to effective permeability it has suggested that to use the relative permeability concepts as developed by Coates and Denoo(5) as follows

$$K_{rw} = [(S_w - S_{wi})/(1 - S_{wi})]^3 \quad \text{.......... (Eq.6)}$$

$$K_{rh} = (1 - S_w)^{2.1} / (1 - S_{wi})^2 \quad \text{...........(Eq.7)}$$

Where K_{rh} is hydrocarbon relative permeability. Wireline techniques, however calculate the permeability indirectly from others measurable properties of formation. The strength of the wireline - log permeability data lies in their capability to provide continuous permeability throughout a particular interval. In a particular basin, the ratios of permeability between various zones and layers more valuable than the absolute values. Such ratios can be used to correlate with core permeability as long as the scale factor, environment and physics are adequately addressed. Table 1 summarizes the relationship among the various permeability techniques.

Field Example

Table 2 and table 3 are the rock permeability data from core analysis and wireline log analysis. The data are obtained from M gas field located in Central Luconia, offshore Sarawak, Malaysia. The field has medium size of gas reserve in which the gas is piped to MLNG-Dua in Bintulu, Sarawak. The M3 field was discovered and appraised by well M3.2. M3.2 had been logged with a modern suite of logs and porosity estimations in this well are of good quality. The well was fully cored and analysed by standard core measurements. The standard core data set comprises a geological description, porosity and permeability. From the figure 5, a discrepancy between core and log data was observed in the top of the M3 reservoir.

Conclusion

1. The interrelationships among the wireline-log and core analysis permeabilities depend on three important factors : measurement scale, environment, and physics.

2. Too many correlations are made without proper regard these factors, resulting in inadequate answer. Intergration of available information pertaining to these factors enhances correlation between the various techniques.

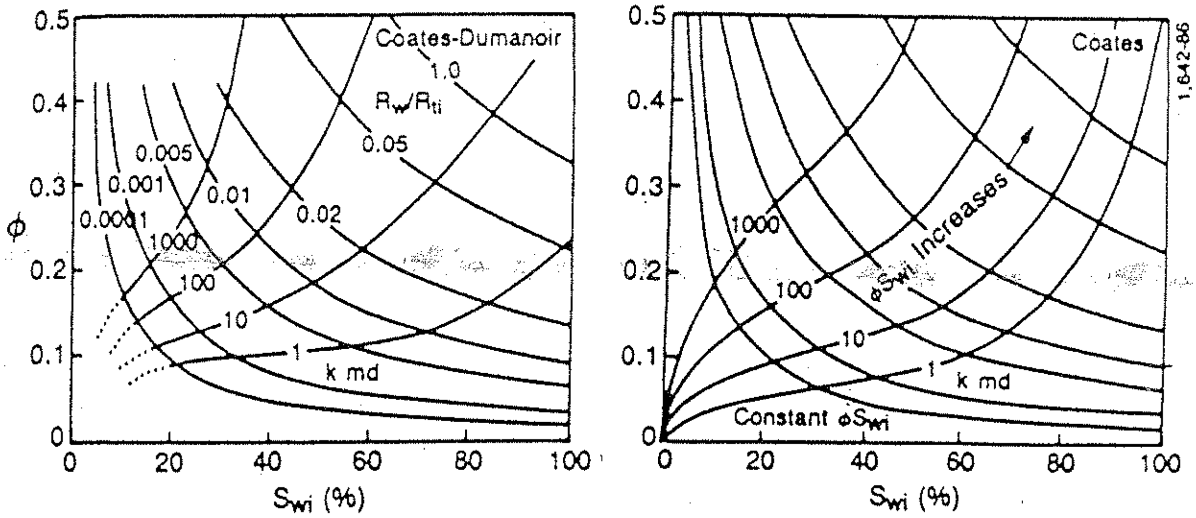

Figure 1. : Charts for estimating permeability from porosity and water saturation.

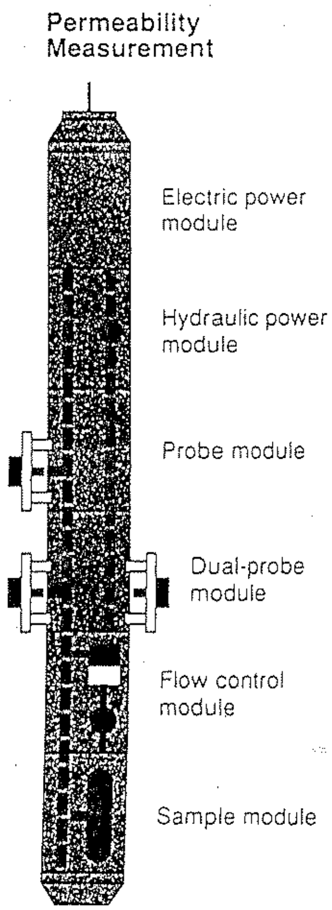

Figure 2. : The Modular Formation Dynamic Tester (MDT) tool configuration.

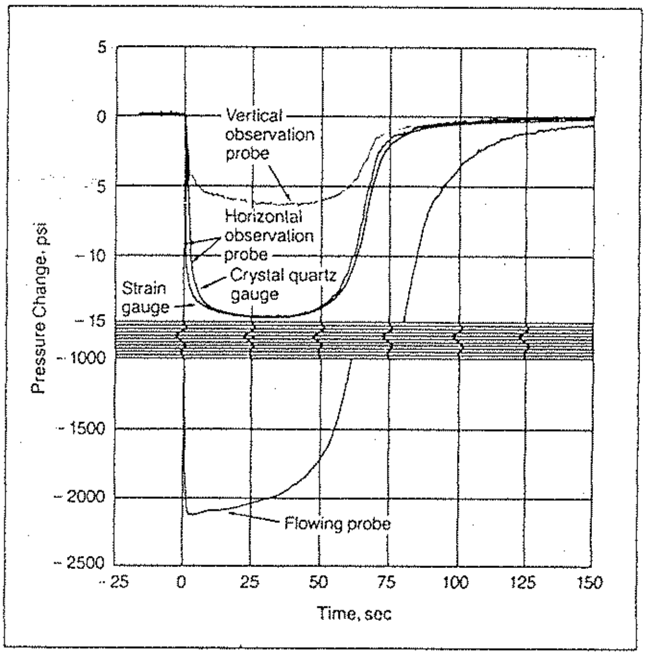

Figure 3. : The MDT pressure response profile

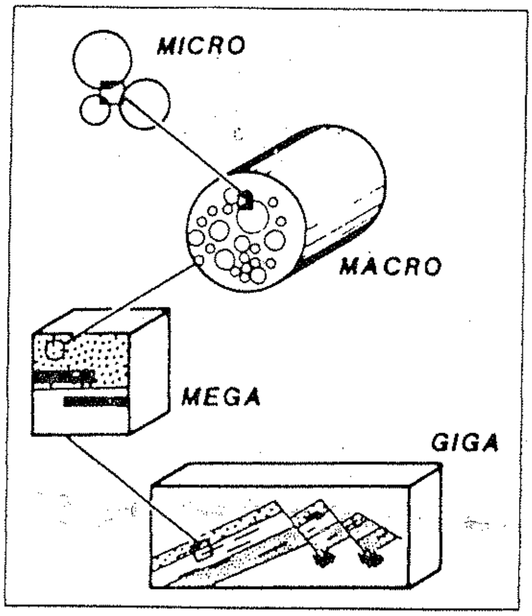

Figure 4. : Conceptual scales associated with porous media averages.

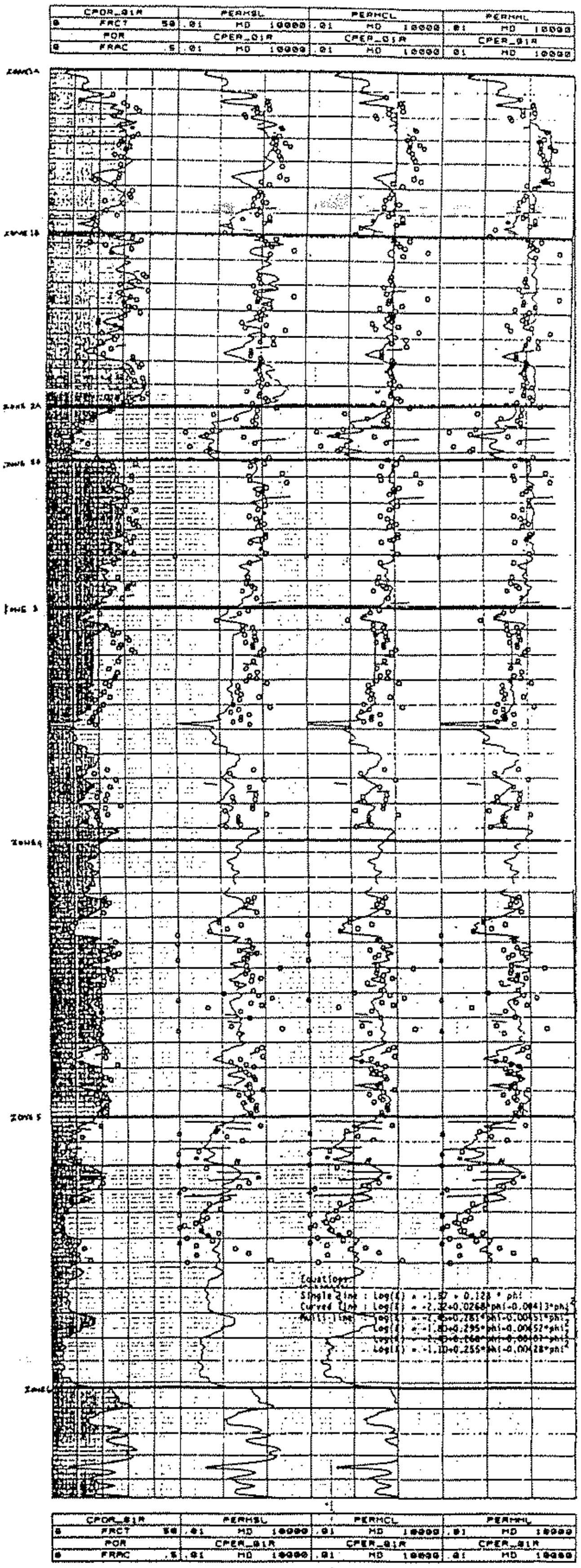

Figure 5.
Log-derived permeability vs core permeability

Table 1 Summary of factors affecting permeability measurement

Technique	Scale	Pressure & Temperature	Saturation	Method	Quantity
		Environment & Physics			
Core	Macroscopic				
Absolute		Ambient*	Absolute	Direct	Permeability
Relative		Ambient*	Relative	Direct	Permeability
Wireline-Log	Megascopic				
K-Est.		In-situ	Absolute	Indirect	Permeability
NML		In-situ	Absolute	Indirect	Permeability
MDT		In-situ	Absolute	Direct	Conductivity

* can be measured at simulated downhole pressure and temperature

Table 2 Core Permeability VS Log derived Permeability (M3-2 Core)

LAYER NO	Reservoir Zone	CORE mD	Method 1 LOG K(SL)mD	Method 2 LOG K(CL)mD	Method 3 LOG K(DL)mD	Method 4 LOG K(ML)mD
		K(g)	K(g)	K(g)	K(g)	K(g)
1	Zone 1A	*	2	3	4	*
2	Zone 1A	136	37	49	45	155
3	Zone 1B	97	121	78	81	85
4	Zone 2A	8	2	3	3	2.4
5	Zone 2B	76	57	68	56	78
6	Zone 3	16	12	22	23	23
7	Zone 4	10	6	11	13	11.4
8	Zone 5	0.3	1	0.6	0.6	1.4
9	Zone 5	*	0.5	0.2	0.1	*
10	Zone 6	*	17	27	26	*

Table 3 Core VS Derived Permeability and Anisotrophy Estimates for Cored Intervals (M3-2)

RESERVOIR ZONE	CORE mD			LOG K(ML)mD		
	Kh	Kv	Kv/Kh	Kh	Kv	Kv/Kh
GAS	51.00	1700	0.33	70.48	16.44	0.23
WATER	3.50	0.50	0.14	8.11	0.76	0.09

Method 1 - Log derived permeability based on single line relationship
Method 2 - Log derived permeability based on single curved relationship
Method 3 - Log derived permeability based on dual line relationship
Method 4 - Log derived permeability based on multifacies line relationship

Kh - arithmetic mean of individual geometric means and a measure of horizontal permeability
K - harmonic mean of individual geometric means and a measure of vertical permeability
Kg - geometric mean = Average permeability of respective intervals

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Nomenclature

A_g = surface area of grains exposed to fluid per unit volume of solid material.
I_f = free fluid index
K = permeability,md
K_{rw} = water relative permeability, fraction
K_{rh} = hydrocarbon relative permeability, fraction
S_{wi} = irreducible water saturation, fraction
ϕ = porosity, fraction