Permeability Estimation: The Various Sources and Their Interrelationships

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Summary. Rock-formation permeability is one important flow parameter associated with subsurface production and injection. Its importance is reflected by the number of available techniques (well-log evaluation, core measurements, and well testing) typically used to estimate it. The literature is full of comparisons and correlations of permeability from these sources. Too often these comparisons and correlations are used to make important conclusions without proper regard to the interrelationships among them. 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 scale of the medium under investigation. This paper reviews the commercially available permeability-estimation techniques and discusses the important factors that illustrate their interrelationships. Knowledge of appropriate interrelationships among the various techniques allows meaningful permeability comparisons and correlations. Usefulness of the interrelationships is demonstrated with field data. Also, the interrelationship concepts presented are a cornerstone for reservoir flow characterization.

Introduction

Of all the formation parameters that petroleum engineers use, permeability is one of the most important. In the oil and gas industry it is used to determine whether a well should be completed and brought on line.1 Permeability is also essential in overall reservoir management and development (e.g., for choosing the optimal drainage points and production rate, optimizing completion and perforation design, and devising EOR patterns and injection conditions).

Oil and gas companies use both accurate and approximate permeability values. These values frequently are compared and correlated without much attention to how each value was determined. Such comparisons and correlations are then used to make important conclusions about formation flow potential and for various aspects of reservoir management and development. But establishing a correlation between unstressed core plug permeability and drillstem-testing (DST) permeability and then using the correlation with other unstressed core plug permeabilities to evaluate the flow potential of other zones, for example, may be futile unless the scale factor, measurement environment, and physics are adequately considered. The scale factor considers the relative size of the volumes being investigated and the nature of heterogeneity, and the measurement environment and physics consider the state of the rock environment, fluid saturation distribution, flow direction, and sensitivity of the measured or inferred variables that constitute permeability calculations.

To address the appropriate correlations among techniques, we first define the various permeabilities that are measured by the various techniques.

Permeability Definitions

The classic definition of permeability, as described by Darcy,2 is the intrinsic characteristic of a material that determines how easily a fluid can pass through it. In the petroleum industry, the darcy is the standard unit of measure for permeability. It 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 gradient of 1 atm per 1 cm of length in the direction of flow. This intrinsic rock property is called absolute permeability when the rock is 100% saturated with one fluid phase.

Permeability is also measured in reference to a fluid phase when the rock is saturated with a multiple-fluid phase. Such a permeability is called the effective permeability of the rock to the particular flowing fluid. (The ratio of effective to absolute permeability is called the relative permeability.) These definitions are simple and straightforward when the measurement is performed in the laboratory. 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 within the oil industry has its own definition of permeability. This inconsistency creates a significant problem when permeability is to be used to define the production performance of a particular formation, reservoir, or well. A core analyst's version of permeability may be an accurate representation of the 1-in.-diameter, 1-in.-long core sample; however, the measured value may have no significant bearing on the production characteristic of the formation represented by the core sample. The core measures absolute permeability, but formation flow is governed by relative permeability. Also, core permeabilities are influenced by the microscopic nature of the measurement and the environment (absence of in-situ pressure, temperature, and saturation conditions). At times, a combination of these influences may result in a permeability that corresponds to the well flow performance, but this is more a coincidence than a planned result. Similar consequences are observed when petrophysicists evaluate permeability with log-measured values. Most log methods, except the repeatformation-tester (RFT™) method, measure absolute permeability. Even though the parameters used to infer permeability from logs are measured at in-situ conditions, the complexity of rock structures and inadequate parameterization make the log-derived permeability transforms nonuniversal. Log-
derived techniques can provide level-by-level (foot-by-foot) permeability values. Well-test permeability, however, is a direct measurement of the flow that provides permeability when the contributing interval is known but that lacks foot-by-foot resolution. During the well test, if more than one fluid phase is produced, then the calculated permeability may not predict well performance accurately. Unlike most core- and log-measured permeability, well-test and RFT methods measure effective permeability. Detailed accurate reservoir characterization demands the use of various measurements. Therefore, we need to understand the various permeability measurement techniques used by the industry.

**Permeability Measurement Techniques**

The three major permeability measurement techniques are wireline-log analysis (including the RFT method), laboratory testing of core samples, and well testing.

**Wireline-Log Measurements.** Five methods are established for obtaining permeability from wireline tool measurements: (1) empirical correlation of permeability with porosity, \( \phi \), and intergranular surface area; (2) measurement of producible formation fluid with the nuclear magnetism log (NML)\(^{26} \); (3) estimate of mineral concentration by the geochemical logging tool (GLT)\(^{27} \); (4) correlation of permeability with Stoneley wave velocity by acoustic logging tools; and (5) pressure/time measurement of formation fluids with the RFT tool.

**Empirical Correlations.** The first equation relating measurable rock properties with permeability was proposed in 1927 by Kozeny and modified by Carman\(^{3,4} \):

\[
k = \phi^3/[A_g \phi^2(1-\phi)^2],
\]

(1)

where \( A_g \) = surface area of grains exposed to fluid per unit volume of solid material.\(^3 \)

Eq. 1 describes permeability in packs of uniformly sized spheres, such as powder packs. This formulation breaks down in other sands. The greatest drawback is that \( A_g \) can be determined only by means of core samples, and then only with special care and equipment. However, this model notes that porosity alone cannot reliably predict permeability and that it is somehow inversely related to the exposed surface area.

Not surprisingly, the first approach to finding permeability from logs did not use the surface area concept directly. Starting with Tiexier,\(^5 \) Wylie and Rose\(^6 \) conjectured that grain surface area was related approximately to irreducible water saturation, \( S_{iw} \), of clean sandstone. Timur\(^7 \) extended Wylie and Rose's empiricalism on the basis of laboratory studies of 155 sandstone cores.

The derivations so far suffer from two limitations: the difficulty of deriving \( S_{iw} \) from logs and yielding zero permeabilities when \( S_{iw} \) approaches 100% and when porosity approaches zero. These derivations honor only the porosity limit for zero permeability approximation and disregard \( S_{iw} \) approaching 100%. The derivation of \( S_{wi} \) from resistivity logs needs a more methodical approach.

With the introduction of the Coates-Dumaroin\(^8 \) relationship of the free-fluid model, a new equation was derived that ensured zero permeability at zero porosity and when \( S_{wi} = 100\% \). Coates and Denoo\(^9 \) accommodated the two conditions with the following relationship:

\[
k^{1/2} = 100\phi^2\left(\frac{\phi_1 - V_{bw}}{V_{boi}}\right),
\]

(2)

where \( \phi_1 \) = effective porosity. Determining \( S_{wi} \) for rocks that are not at irreducible water saturation is difficult, if not impossible in some cases. Height above the water table alters \( S_{wi} \), so that even in a single lithology, \( S_{wi} \) may vary from top to bottom. In many reservoirs, however, the variance in \( S_{wi} \) is small, especially if we consider it to be bulk volume. Morris and Biggs\(^10 \) observed that it is generally easier to predict a rock's bulk-volume irreducible water, \( V_{boi} = \phi_1 S_{wi} \), than the actual value of \( S_{wi} \).

This requires a slight modification of Eq. 2, made by multiplying the numerator and denominator by total porosity, \( \phi_1 \):

\[
k^{1/2} = 100\phi_1^2\left(\frac{\phi_1 - V_{bw}}{V_{boi}}\right),
\]

(3)

**Fig. 1**—Charts for estimating permeability from porosity and water saturation.

"Because of increased fluid production, permeabilities estimated during superflow correspond with the hydrocarbon-related effective permeability more than with the invaded fluid movement."

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The GLT measurements are transformed into mineral concentrations and substituted for the surface-area term in a logarithmic form of the Kozeny-Carman relationship (Eq. 1), as illustrated in Ref. 19:

$$\log_{10}(k) = T_m + 3 \log_{10}(\phi) - 2 \log_{10}(1 - \phi) + \Sigma B_i f_i$$  \hspace{1cm} (6)

where $T_m =$ textural maturity based on feldspar content, $B_i =$ mineral constant (for clays, cements, and framework minerals), and $f_i =$ weight fraction of each mineral in the solid rock. The surface-area term can also be substituted in the Coates-Dumanoir free-fluid model. 8

**Stoneley-Wave Attenuation and Dispersion**

The Stoneley wave is acoustic energy that travels predominantly along the borehole wall. It is generated when an acoustic pulse from a sonic logging tool meets the interface between the drawdown and borehole fluid. If the borehole crosses a permeable formation, the Stoneley wave attenuates by moving fluid in the pores. It is also dispersed, meaning that different frequency components are slowed at different rates.

This attenuation and dispersion relates to the formation’s permeability, matrix or natural fractures. Although correlations between Stoneley behavior and permeability have been observed in the field, a quantitative prediction of permeability from Stoneley energy measurements is eluded investigators. 23, 24 Various investigations, however, continue to use Stoneley waves to directly measure permeability and as a fracture indicator. 25

**RFT Measurements**

The formation tester tool samples reservoir fluids and measures formation time at specific depth stations (see Fig. 2). With the RFT, three sets of data can be collected to quantify permeability. The first two (in association with pretest) are relatively quick, and the last one, called superflow, can last several minutes. The tool is first positioned to allow mud filtrate and formation fluids to fill a first sample chamber at a controlled, low flow rate (first pretest). This step is followed immediately by the filling of a second sample chamber at a controlled, high flow rate (second pretest). This phase of the test is called drawdown. The subsequent phase of the test, buildup, is a measurement of increasing pressure once the chambers are filled. The final phase, superflow, involves long-term drawdown while measuring the cumulative volume and transient pressures.

Both the drawdown and buildup tests provide a permeability value that is often reflective of near-wellbore fluid movement. 26 To calculate permeability, the pressure derivative is first plotted to identify the flow regime and is followed by specialized plots. For drawdown pressures, where normal (10 cm$^3$/s) pretest chambers are used, the flow pattern is typically hemispherical, a mixture of horizontal and vertical flow with a bias to horizontal. Buildup permeability typically illustrates a spherical flow pattern, a mixture of horizontal and vertical flow with a bias to the vertical. Buildup permeability measurements are reliable only in low-permeability formations ($< 50$ md) because of limitations in the resolution of the pressure measurements. 28

During superflow, the pressure data are history-matched, taking into account the cumulative fluid production. Because of increased fluid production, permeabilities estimated during superflow correspond with the hydrocarbon-related effective permeability more than with the invaded fluid movement.

**Core Permeability**

Core analysis allows direct measurement of permeability under controlled laboratory conditions. For this reason, core-derived permeabilities are often considered to be the standard. This notion, however, can be misleading. Core permeability is an accurate representation of a particular core sample under specific laboratory conditions. Using this permeability value to represent reservoir formation permeability can be incorrect. As long as the measurements are consistent over a particular interval, however, the core permeability can be very useful in completion design, specifically in choosing the phasing and vertical spacing of perforation.

Cores are analyzed on four length scales. The smallest scale is the sidewall core analysis, in which samples < 1 in. long are taken from the wellbore. The scale of the core plug is also very similar, in which samples 1 to 1.5 in. long are taken from a full-diameter core every 6 in. These small sample sizes can bias the sample in heterogeneous formations, in which permeability can vary widely from one sample to the next. Full-diameter core analysis tests 6-in. sections of core samples on the medium scale. The largest-scale sampling is whole-core analysis, in which cores up to 2 ft long are tested. The number of whole-core tests is limited, however, primarily because of the difficulty in recovering such pieces.

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

**Absolute Core Permeability**

Two commonly used techniques to measure absolute core permeabilities are the steady-state and the pulse-decay methods. 29, 30 The pulse-decay method was introduced for low-permeability rocks where attainment of steady state can take anywhere from days to weeks. In both techniques, air or water can be used as the fluid medium.

The cores are cleaned and dried before they are measured. In the steady-state technique, air permeability, the most common measurement, is obtained by placing the core in a chamber and measuring the pressure differential and stabilized flow rate of air pumped through the rock. Permeability is calculated for this single phase with the Darcy equation. In the pulse-decay method, the core is subjected to a pressure pulse, as
when a pressure transient is imposed. The subsequent pressure transient fall-off is measured and analyzed for permeability.

With both techniques, three values are usually established: the maximum horizontal permeability, \( k_{\text{max}} \); the permeability at 90° to \( k_{\text{max}} \), \( k_{\text{d}} \); and the vertical permeability, \( k_{\text{v}} \). Air permeability is higher than liquid permeability and requires a correction in low-permeability formations. This correction accounts for gas slippage (a gas has a higher velocity near a grain surface than does liquid), commonly known as the Klinkenberg effect.\(^{31}\)

Relative Core Permeability. Relative core permeabilities are measured in several ways. A common method is the steady-state technique, where the core is saturated with the wetting phase (usually water) and oil and water are flowed together in proportion to maintain the desired water saturation. The resulting flow rates and pressures determine the relative permeabilities to each fluid. Another technique is to saturate the core with oil, then displace the oil with water while monitoring the pressure and volumetric flow rates of the two fluids. This permits calculation of the relative permeabilities as functions of water saturation. The pulse-decay technique can also be applied to measure relative permeability as long as the pulsing pressure is lower than the capillary pressure of the saturating fluid.\(^{30}\)

Permeability From Well Testing. The many procedures that fall under well testing can be classified into three categories: (1) short-term tests involving DST, IMPULSE\(^{30}\) testing, and transient-rate and -pressure testing (TRAP\(^{30}\)) where the radius of investigation is typically limited; (2) conventional tests—classic pressure drawdown (TD, injection test) and pressure buildup (or fall-off test) involving single or step rate; and (3) advanced tests involving methods beyond the traditional single-layer horizontal-permeability evaluation, including layered reservoir testing, vertical interference testing, and multilayer interference testing. Although each technique has a different application, all involve making an abrupt change in flow—starting, stopping, or abrading flow, injecting fluid, or changing the flow from one value to another. Reservoir properties are deduced from the well’s response to these changes, measured by bottomhole pressure (BHP) gauges and bottomhole transient rates in TRAP and layered reservoir testing.\(^{32}\)

Short-Term Testing. This group includes techniques that require a relatively short test period; thus the radius of investigation is relatively shallow (typically < 100 ft). DST. Short-term DST typically is done in open hole after drilling through a promising zone. (Wells with unconsolidated rock formation, typically offshore wells, are cased and cemented, and then cased-hole long-term DST is performed by means of perforations.) DST involves two drawdowns with subsequent buildups. Interpretation steps are similar to those for RFT drawdowns and buildup (pressure derivative for flow-regime identification and specialized plots to calculate permeability). Because of the short test times, DST permeability estimates can be obscured by wellbore storage and drilling mud invasion.\(^{33}\)

**IMPULSE Testing.** IMPULSE-testing techniques allow one to test the well after a perforation job without making an extra trip.\(^{34,35}\) The well is subjected to an instantaneous rate drawdown or injection for a period of time (Fig. 3) and the well is subjected to an instantaneous rate drawdown or injection for a period of time. Instant withdrawal or injection of a unit volume of fluid causes a change in pressure proportional to the derivative of the reservoir’s pressure response. Therefore, the IMPULSE testing plot (Fig. 3) allows flow-regime identification similar to that of RFT tests. The test data can be plotted as a pressure derivative and/or plotted as a rate-normalized Horner plot\(^{35}\) to calculate permeability.

**TRAP.** TRAP testing uses the transient drawdown pressure and rate.\(^{36,37}\) The technique was introduced in the early 1980's to combat the existence of variable flow rate during drawdown tests and to eliminate wellbore storage effects. The elimination of wellbore storage is used here to shorten the test duration. Even though the test takes less than a few hours, the calculated formation permeability is typically unaffected by near-wellbore damage.

**Conventional Testing.** There are many variations of conventional well-test methods. For the past 40 years, the two most straightforward ways to measure permeability have been drawn down and buildup tests, performed in fundamentally the same manner as RFT drawdown and buildup tests. The buildup test is more common than the drawdown test because the flow rate is known when the well is shut in. Before shut-in, a constant flow rate is typically maintained for a period of time. For the buildup test, the pressure vs. time is measured continuously beginning at shut-in. The same variables as in the drawdown test are used to obtain permeability, but the plot is BHP vs. superposition time function, which accounts for production history.

In these tests, the rate does not have to remain constant. In the case of varying flow rate, accurate analysis can be performed as long as the bottomhole rate data are available.\(^{36}\)

**Advanced Test Techniques.** These techniques go beyond the traditional single-layer horizontal-permeability evaluation. Included in this group are layered reservoir testing, vertical interference testing, and multilayer interference testing.

**Layered Reservoir Testing.** With use of regular production logging tools (equipped with at least the pressure and flowmeter sonde), one can evaluate the permeability of individual layers by imposing a transient at each layer and measuring the pressure and flow-rate response. This technique has been applied successfully to several reservoirs and requires good, stable flow-rate data.\(^{38,39}\) Recently, low-flow-rate meters, like the inflatable diverter flowmeter (ID\(^{36}\) tool,\(^{40}\) have been introduced to address low-permeability reservoirs.

**Vertical Interference Testing.** In vertical interference testing, a pressure transient is applied to one horizon and pressure is measured at another horizon in the same well. Vertical interference testing permits the assessment of presence and degree of vertical communication and vertical permeability.

**Multilayer Interference Testing.** In multilayer testing, the transient is applied at one horizon in one well and the pressure is measured at the same horizon in another well. This can yield an average permeability/thickness value and indicate the horizontal extent of the reservoir and whether the two wells are in horizontal communication.

**Technique Interrelationships**

More than a dozen techniques were identified that provide rock or formation permeability estimates. The three most important factors that differentiate between the individual techniques are scale factor, measurement environment, and the measurement physics.
averaging applies when megascopic log data are compared.

**Megascopic-Scale Data—Wireline-Log Data.** Here we examine the volume of rock that wireline logs (specifically permeability-estimation logs) encompass. The typical investigation depth of permeability-related logs (neutron-porosity, density, and gamma ray) from 6 to 12 in. (conservatively). We use 9 in. in our calculation. The appropriate permeability estimate deduced from wireline logs measuring 2 ft of rock at a time around 9 in. into the formation (assuming wellbore diameter of 7 in.) encompasses a log volume, \( V_{\text{LOG}} \), of roughly 6.6 ft\(^3\). The ratio of log-to-core volume, \( V_{\text{LOG}}/V_c \), is then \( 9.660 \).

Haldorsen\(^{41}\) and Collins\(^{42}\) work in statistically homogeneous reservoirs regarding the normal or Gaussian form of porosity distribution could be applied to log-permeability distribution. The permeability standard deviation, \( \sigma_k \), of the permeability distribution can then be shown to vary inversely as the square root of the volume per sample:

\[
\sigma_k = \sqrt{V_0} (\bar{k}) \quad \text{...(7)}
\]

Thus, to relate log and core permeabilities, the theoretical standard deviation of permeabilities estimated from wireline logs, \( \sigma_{k(\text{LOG})} \), is given by

\[
\sigma_{k(\text{LOG})} = \sqrt{\left(V_c/V_{\text{LOG}}\right) k_c} = 1.021 \times 10^2 \text{kcc} \quad \text{...(8)}
\]

Also, the theoretical standard deviation of core-measured permeability, \( \sigma_{k(\text{core})} \), to log permeability is

\[
\sigma_{k(\text{core})}/\sigma_{k(\text{LOG})} = 98.38 k_{\text{LOG}} \quad \text{...(9)}
\]

**Gigascopic-Scale Data—Well-Test Data.**

Gigascopic permeability estimates are possible with transient-pressure testing, especially through long-term drawdown and buildup tests. For most well tests, the radius of investigation varies from hundreds to thousands of feet and normally engulfs large-scale heterogeneities. The horizontal permeability calculated from such a test is essentially a gross average over the vast volume and correctly represents total reservoir flow behavior. For a test in a 100-ft-thick sand with a 1,000-ft radius of investigation, the volume is \( 3.14 \times 10^8 \text{ ft}^3 \).

Where all 100 ft of sand is fully cored, taking one core plug from every foot would result in a volume of 6.8 \( \times 10^2 \text{ ft}^3 \), and the well-test/core-volume ratio would then be \( 4.6 \times 10^9 \). Furthermore, the well-test/log volume ratio would then be \( 9.33 \times 10^3 \).

The scale relationships for log test permeability and other permeabilities can be further established through the standard-deviation concept illustrated in Eq. 7. Therefore, the theoretical standard deviations of core-measured and log-inferred permeabilities to well-test permeability can be expressed as follows:

\[
\sigma_{k(\text{core})} = 2.14 \times 10^3 k_{\text{wt}} \quad \text{...(10)}
\]

and

\[
\sigma_{k(\text{LOG})} = 9.66 \times 10^2 k_{\text{wt}} \quad \text{...(11)}
\]
sivity. Therefore, to calculate a permeability, we need to ascertain the thickness of the formation that responds to the perturbation during the test. Typically, openhole logs (gamma ray, spontaneous-potential, porosity-development) are used to ascertain formation thickness. The contributing formation thickness during the test may not correspond to the log-estimated formation thickness. The only way to solve this problem accurately is to have a production profile (Fig. 5) of the layer(s) available during drawdown and production. A gradual slope of the cumulative production curve (from bottom to top) indicates uniform production through a zone, and an abrupt change reflects a thin heterogeneous producing layer. With the flow-profile-per-depth information, the transient-diffusivity equation for a drawdown test can be modified as follows.

\[ P_{BH} = P_i - \frac{162.6}{k} \sum_{i=1}^{N} \frac{q_i}{h_i} \log t_i \]

\[ + \log \left[ \frac{k}{\mu \phi c_t r_w^2} \right] \left( 3.2275 + 0.86859F_s \right) \]

\[ \ldots \ldots \ldots \ldots \ldots (14) \]

Such a formation assumes that the skin factor is relatively uniform throughout the test interval. A plot of flowing BHP vs. the logarithm of flowing time should be a straight line with slope \( m \), where

\[ m = \frac{162.6B_\mu}{k} \sum_{i=1}^{N} q_i \frac{1}{h_i} \]

\[ \ldots \ldots \ldots \ldots \ldots (15) \]

or \( k = \frac{162.6B_\mu}{m} \sum_{i=1}^{N} q_i \frac{1}{h_i} \)

\[ \ldots \ldots \ldots \ldots \ldots (16) \]

The calculated permeability represents the formation thickness that responds to the pressure and rate transients. If necessary, use an nth-layer \( q \) and \( h \) to evaluate the permeability of the specific zone (provided that no formation crossflow exists).

Table 1 summarizes the relationships among the various permeability techniques.

Interrelationship. The objective of the interrelationship presented here is to allow meaningful comparisons of permeabilities. The discussions on scale factor, measurement environment, and physics show how to account for differences in permeability estimates. Here, we develop a simple relationship that allows meaningful correlations among well-test and core and log permeability measurements.

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 are 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. The layer-by-layer (or foot-by-foot) permeability from cores and wireline logs may then be related to the well-test formation diffusivity if a means of permeability averaging is chosen. Whether the averaging should be arithmetic or geometric, or even harmonic, eludes various reservoir engineering studies. For layers, however, the arithmetic average is preferred. For vertical wells, use of the layer concept is an accepted model. Therefore, we present the following arithmetic averaging model to relate core and log permeability to well-test permeability.

\[ \frac{(q)_{awt}}{k_{rh}S_h} = \sum_{i=1}^{N} F_i k_i h_i \]

\[ \ldots \ldots \ldots \ldots \ldots (17) \]

Field Examples

Example 1. Fig. 6 compare wireline-log values (from empirical correlation and Eq. 12 for effective permeability) and laboratory measurements at standard ambient conditions. The quality of comparison (standard deviation) through the 8,550- to 8,700-ft interval is good. Such comparisons are often found in basins where enough data have been generated to establish a good value for the constants in the geophysical equation (Eqs. 1 through 3). The standard deviation in the 8,850- to 8,950-ft interval, however, is not good.

Note that the wireline-log values represent the hydrocarbon effective permeability at in-situ conditions, whereas the core values represent the absolute permeability at standard conditions. The question to ask is, had we compared apples to apples, would the quality of correlation through the 8,850- to 8,950-ft interval be improved? Fig. 6 also represents the comparison where the core-data measurements were corrected for in-situ pressure conditions and a 0.7 relative-permeability effect to calculate hydrocarbon effective permeability. The quality of comparison has certainly improved throughout all the intervals, especially through the 8,850- to 8,950-ft interval. The average zone well-test permeability is indicated by the bar. With use of produc-
Table 1—Summary of Factors Affecting Permeability Measurements

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*Can be measured at simulated downhole pressure and temperature.

Example 2. Fig. 7 pertains to wireline-log-derived permeability using volumetric analysis. RFT data at 6,887 ft includes pretest drawdown and buildup and subsequent long-term superflow data. Both the geophysical log and the RFT pertain to in-situ conditions; however, the pretest RFT technique responds to invaded fluid movement and the superflow test pressures respond to hydrocarbon fluid movement. For this reason, the wireline-log average oil effective permeability (265 md), when compared to the RFT results, should correlate better with the superflow permeability (238 md), as shown in Fig. 8.

Also, the superflow RFT permeability should be closer to the typical well-test permeability. The well-test permeability of the zone of interest in the entire basin averages near 100 md. This indicates good basin-wide agreement. Any agreement, however, between relatively macroscopic/megasopic measurement (superflow RFT) and gigascopic measurement (well-test) occurs if the formation or zone is homogeneous. Open-hole logs suggest that the formation is homogeneous, at least vertically (see Fig. 7).

**Recommendations**

In this study, we concentrated our efforts on defining the correlation axioms between the various permeability sources. Identification of areas where the various techniques stand out uniquely and where any correlation attempt may be futile was not part of the discussion. For example, zone-by-zone permeability from geophysical logs and/or cores may not be quantitatively representative of the formation flow potential and in places may be uncorrelatable, but these values have unique applications (e.g., in the decision process to identify the perforation interval, perforation density, or perforation phasing). We recommend that future studies concentrate on uncorrelatable sources to identify unique applications for them. Also, considering the vastness of the technical area discussed here, we suggest that studies be performed to enhance the interrelationships among the various sources (e.g., in formations with nonuniform layers or zones).

**Conclusions**

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

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

3. Transient well-test data provide the best quantitative formation permeability if production profile of the formation is available and single-phase flow is maintained.

4. Geophysical-log and core-analysis permeabilities define layer-by-layer (or foot-by-foot) permeability profiles.

**Nomenclature**

- \( A_g \) = surface area of grains exposed to fluid per unit volume of solid material
- \( B = E/F, RB/STB \)
- \( B_i = \) mineral constant
- \( c_r = \) system total compressibility, \( \text{ps}^{-1} \)
- \( f_i = \) weight fraction of each mineral in solid rock
- \( F = \) correction factor for Zone 1, dimensionless (can be

![Fig. 6—Geophysical log interpretation summary, Example 1.](image-url)

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**Interpretation Summary**

**Zone Name:** BIG 2  
**Zone Depth:** 6850.0 to 6950.0

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net Pay</td>
<td>12.0 Feet</td>
</tr>
<tr>
<td>Gross Sand Count</td>
<td>69.0 Feet</td>
</tr>
<tr>
<td>Reservoir Hydrocarbons in Place</td>
<td>1433 bbls/Acre-Ft</td>
</tr>
<tr>
<td>Average Porosity</td>
<td>27.7 %</td>
</tr>
<tr>
<td>Average Water Saturation</td>
<td>33.3 %</td>
</tr>
<tr>
<td>Average Intrinsic Permeability</td>
<td>494.6 Millidacies</td>
</tr>
<tr>
<td>Average Oil Permeability</td>
<td>264.6 Millidacies</td>
</tr>
<tr>
<td>Average Water Permeability</td>
<td>7.0 Millidacies</td>
</tr>
<tr>
<td>Cumulative Porosity</td>
<td>3.3 Feet</td>
</tr>
<tr>
<td>Cumulative Hydrocarbon Filled Porosity</td>
<td>2.2 Feet</td>
</tr>
<tr>
<td>Cumulative Intrinsic Permeability</td>
<td>5955 Millidacy-Feet</td>
</tr>
<tr>
<td>Cumulative Oil Permeability</td>
<td>3173 Millidacy-Feet</td>
</tr>
<tr>
<td>Cumulative Water Permeability</td>
<td>84 Millidacy-Feet</td>
</tr>
</tbody>
</table>

**Fig. 7—Geophysical log interpretation summary, Example 2.**

- $F_s$ = van Everdingen-Hurst skin factor, dimensionless
- $h$ = formation thickness, ft
- $h_i$ = thickness of zone representing corresponding $k_i$
- $I_{ff}$ = free fluid index
- $k$ = permeability, md
- $k_c$ = core plug permeability, md
- $k_{LOG}$ = log-derived permeability, md
- $k_{max}$ = maximum horizontal permeability, md
- $k_{rh}$ = hydrocarbon relative permeability, fraction
- $k_{rh\%}$ = relative permeability thickness-averaged by hydrocarbon, fraction
- $k_{rw}$ = water relative permeability, fraction
- $k_v$ = vertical permeability, md
- $k_{90}$ = permeability at right angles to maximum permeability, md
- $k_f$ = average formation permeability, md
- $k_i$ = average core or wireline log permeability of Zone $i$, md
- $k_R$ = average reservoir permeability, md
- $k_{wt}$ = average well-test permeability, md
- $m$ = slope of linear portion of semilog plot of pressure-transient data, psi/cycle

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Fig. 8—Pressure history match of superflow data from RFT test, Example 2.

\[
\begin{align*}
N &= \text{number of flow layers or zones} \\
P_{bhf} &= \text{bottomhole flowing pressure, psi} \\
p_i &= \text{initial pressure, psi} \\
\Delta p &= \text{pressure change, psi} \\
q_l &= \text{individual layer/zone flow rate, STB/D} \\
r_w &= \text{wellbore radius, ft} \\
R_u &= \text{resistivity of uninvaded formation at irreducible water saturation, } \Omega - \text{m} \\
R_w &= \text{resistivity of formation water, } \Omega - \text{m} \\
s &= \text{sample size} \\
S_h &= \text{thickness-averaged hydrocarbon (oil or gas) saturation at time of test, fraction} \\
S_{wir} &= \text{irreducible water saturation, fraction} \\
t_l &= \text{spin lattice relaxation time, seconds} \\
t_p &= \text{equivalent production time before shut-in, hours} \\
t_r &= \text{test time, hours} \\
\Delta t &= \text{running testing time, hours} \\
T_m &= \text{textural maturity term based on feldspar content} \\
V &= \text{characteristic volume, ft}^3 \\
V_{bwi} &= \text{bulk volume irreducible water, fraction} \\
V_c &= \text{volume represented by a core plug, ft}^3 \\
V_{\text{LOG}} &= \text{volume represented by a typical permeability-related petrophysical log, ft}^3 \\
V_{mr} &= \text{volume represented by a typical well test, ft}^3 \\
\eta &= \text{formation diffusivity, md-ft} \\
\bar{\mu} &= \text{average fluid viscosity, cp} \\
\sigma_k &= \text{permeability standard deviation} \\
\phi &= \text{porosity, fraction} \\
\phi_e &= \text{effective porosity, fraction} \\
\phi_t &= \text{total porosity, fraction} \\
\phi_a &= \text{average porosity, fraction} \\
\end{align*}
\]

Acknowledgments

We thank Schlumberger management for allowing this work to be presented as a technical paper. We also extend thanks to Mohan Manohar and Tom Braton for providing information pertaining to the field examples. Thanks and appreciation are also extended to Lois Cole for her untiring effort in typing and preparing the manuscript.

References


### SI Metric Conversion Factors

- acre × 4.046 873 E-01 = ha
- atm × 1.013 250* E+05 = Pa
- bbl × 1.599 873 E-01 = m³
- cp × 1.0* E+00 = m²/s
- ft² × 2.831 853 E-02 = m²
- in² × 2.54* E+00 = cm
- psi × 6.894 757 E-01 = kPa

*Conversion factor is exact.

### Provenance