PROTOCOLS FOR CALIBRATING NMR LOG-DERIVED PERMEABILITIES

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ABSTRACT

There have been numerous papers published on methodologies for calibrating NMR log-derived permeabilities with low field laboratory NMR measurements of core samples. The focus of this paper is to review the methodologies for calibrating NMR log data using core data that may include laboratory NMR data with a particular focus on heterogeneous reservoir rock. Examples will be shown where the Coates permeability equation parameters used to predict permeability from NMR logs could be derived from core data including porosity, permeability, capillary pressure, and Dean-Stark saturations.

Core heterogeneity below the vertical resolution of log NMR measurements can also affect the method used to calibrate NMR log-derived permeability using core permeability. One way to compare core permeabilities with NMR log-derived permeabilities is to use high-density profile probe permeability data with averaging techniques to simulate the vertical resolution of the NMR log thereby accounting for sample volume differences.

If laboratory NMR measurements are used, the measurements should be taken under conditions that are as close as possible the reservoir wettability conditions. A proposed experimental protocol is provided.

INTRODUCTION

Typically, calibration of NMR log permeabilities is a two-step process. The first step is to calibrate the T_2 cutoff. The second step is to calibrate the Coates parameters C, m, and n. The T_2 cutoff can be calibrated with irreducible saturations from core measurements, with or without laboratory core NMR measurements.

Experimental laboratory NMR protocols for log calibration have evolved over the past decade in the same way that experimental protocols for relative permeability have evolved over the past five decades. The later have gone from ambient condition laboratory oil-brine systems to restored-state reservoir conditions with live reservoir fluids. Laboratory NMR measurements have been moving in the same directions. Core wettability, native reservoir wettability, and wettability altered by OBM filtrate, clearly affect the magnitude of the T_2 cutoff. [1, 2] Thus to evaluate native-state (unaltered by OBM filtrate) and OBM-altered wettability, laboratory NMR measurements should be obtained on as-received cores as well as cores that have had their wettability restored.

What Permeability to Calibrate Against?

When calibrating the NMR log-derived permeability to the core permeability, we must determine which core permeability to use. Potential choices include:

- air permeability
- Klinkenberg-corrected air permeability
- absolute brine permeability
- oil or gas permeability at connate water saturation
- oil permeability at as-received water saturation

Whatever permeability is chosen it should have been measured at reservoir net confining stress. Typical core analysis consists of one porosity measurement and one air permeability measurement per foot of conventional whole core. The other permeability measurements, absolute brine permeability and oil or gas permeability at connate water saturation, are obtained on special analysis plugs. Furthermore, typically only about 1/10 the number of these permeabilities is obtained compared to the number obtained from routine core analysis plugs.

Wells drilled in unconsolidated reservoir rock may only have percussion sidewall core (SWC) data that includes no measured permeability and a porosity measurement having a high level of uncertainty due to sample disturbance induced by sample acquisition. Thus, the only permeability data may be that predicted from laser grain size distribution (LPSA) data. If the LPSA prediction algorithm has been calibrated against conventional core permeability data from the same reservoir then the predicted permeabilities can be compared with the log NMR permeabilities to see if they are similar. If the LPSA algorithm was not calibrated against conventional core data from the same reservoir, there is additional justification for acquiring conventional core samples on the next well.

If the NMR log-derived permeability attempts to predict the reservoir permeability, for an oil or gas reservoir the most appropriate permeability would be oil or gas at connate water saturation. [3] This would be the permeability to compare with permeabilities derived from well test, DST, or formation tester derived mobilities. The permeability used to populate reservoir simulator grid cells could be either oil/gas permeability at connate water saturation or core plug air permeability. The question is where is the conversion from laboratory permeability to reservoir permeability performed—in the calibration of the NMR log permeability or at the point of use. Either way, the conversion method is the same: obtain a transform between core plug air permeability with the appropriate relative permeability end-point, that is, oil or gas at connate water saturation. The magnitude of this conversion typically ranges from $k_o(\mathrm{cw})/k_{air} < 0.5$ for k_{air} of 1 mD and close to 1.0 for an air permeability of 1000 mD.

PROCEDURES

Regression Techniques for Obtaining Coates Parameters

The Coates permeability model (Eq. 1):

$$k_{coates} = \left(\frac{\phi}{C}\right)^m \cdot \left(\frac{BVM}{BVI}\right)^n \qquad (1)$$

contains three parameters with default values of $C = 10, m = 4,$ and $n = 2$, respectively, when porosity is expressed in porosity units (p.u.). The values of porosity, irreducible water volume (BVI), and movable fluid volume (BVM, also called FFI in some literature) required for calculating k_{Coates}, are all available from NMR logging. A T_2 cutoff is often used for dividing the NMR effective porosity distribution into BVI and BVM. The T_2 cutoff is selected to match the irreducible saturation at a given pressure and is treated mainly as a static, rock property. Where as, connate water saturation is a function of the capillary pressure and the distance from the oil-water-contact (OWC) to the point where the rock sample was taken. [4]

Applying regression directly to Eq. (1) to obtain *C*, *m*, and *n* results in a nonlinear optimization problem. However, this problem can easily be solved in Excel using the **Solver** function available under the **Tools** menu. Using the **Solver** function, the three Coates parameters are treated independently.

Alternatively, we can take the logarithm of both sides of equation (1):

$$\begin{aligned}\log_{10} k_{Coates} &= m\left(\log_{10}\phi - \log_{10} C\right) + n\left(\log_{10} BVM - \log_{10} BVI\right) \\ &= m\log_{10}\phi - l + n(\log_{10} BVM - \log_{10} BVI)\end{aligned} \tag{2}$$

where:

$$l = m\log_{10} C \tag{3}$$

l is another pseudo-independent parameter in the data fitting process. Taking the logarithm renders the nonlinear problem a linear problem and we solve for *l*, *m*, and *n*. After *l* and *m* are determined from the regression, the parameter *C* is readily determined from Eq. (3):

$$C = 10^{l/m}. \tag{4}$$

However, we see that parameters *C* and *m* are not completely independent variables. After converting to a linear problem, we can use multivariable linear regression (Least-Squares) method to minimize the equation:

$$\left[\log_{10}\left(k_{measured}\right) - \log_{10}\left(k_{predicted}\right)\right]^2, \tag{5}$$

with non-negative constraints applied to *l*, *m*, and *n*.

In practice, independently determining the three parameters, *C*, *m*, and *n*, (or *l*, *m*, and *n*) without stringent constraints may yield unrealistic results. This is likely to occur in cases where one set of *C*, *m*, and *n* may not be sufficient to represent all the data, measurement uncertainty is high, or the data set is too small. Therefore, it is routine to apply constraints to these coefficients. In particular, the estimated permeability values are very sensitive to large values of the exponents *m* and *n*. Therefore, often the porosity exponent, *m*, is constrained. In this paper, we fixed *m* at 4.0. After fixing the *m* value, use either the Excel **Solver** to perform a linear optimization of the two remaining parameters (*C* and *n*) or use Eq. (2) to solve the linear regression problem (*l* and *n*). In both cases, the sum of Eq. (5) is minimized.

In general, the optimization for *C*, *m*, and *n* should be done for samples taken from similar facies. For different facies, the T_2 cutoff may be different if their surface relaxivities differ. Therefore, to include samples from different facies in one optimization process, one should compute *BVI* with different T_2 cutoff values for samples belonging to different facies, provided the T_2 cutoff variation can be justified. Therefore, within one facies the scope of a sample's T_2 cutoff values should be confined to a relatively small range. Thus, we may be able to define a tolerance range based on surface relaxivity tolerance, measurement error, etc. Any sample falling outside of the tolerance is considered to belong to another facies.

Upscaling High Density Core Permeabilities to be Equivalent to NMR Log-Derived Permeability

The large difference in sample volume is always a concern when comparing rock properties from core and log data. Volumetric-based parameters (i.e., porosity) and non-volumetric-based parameters (e.g., permeability) require different methods of upscaling. With heterogeneous core samples, it is especially critical to determine the proper method for averaging core permeability data to obtain permeabilities equivalent to those derived from NMR logging. The mini permeameter (profile probe permeability) provides high-density permeability data. However, individual measurements investigate a rock volume that is typically less than 2 cm in diameter. To check the quality of the profile probe permeability data, the core permeability data can be compared to the profile permeability data at the same depth. Typically, there is a data cloud that falls near the 1:1 line. If a bias is present, one may develop a transform to correct the profile permeability data to the core data.

A simple boxcar filter (i.e., arithmetic averaging) applied to the profile permeability data over a depth interval corresponding to the resolution of the NMR logs is not equivalent to the NMR log-derived permeability since permeability is not a volumetric-based quantity and correlates non-linearly with S_{wi} and, thus, BVI. The NMR log measures pore fluid T_2 relaxation distributions, effective porosity, BVI, and BVM, which are all volumetric-based quantities. Therefore, the log NMR permeability from the large-scale, volumetric measurements is neither the simple arithmetic nor a simple geometric mean of the profile permeability data but is more closely approximated with the geometric mean than with the arithmetic mean. [5]

The impact of arithmetic and geometric averaging on the computed NMR permeability can be illustrated by calculating the NMR permeability across a composite of ten layers of equal thickness composed of various ratios of two sands:

- Sand A with NMR permeability of 50 mD, porosity of 25%, and S_{wir} of 47%
- Sand B with NMR permeability of 0.13 mD, porosity of 15% and S_{wir} of 86%

Where S_{wir} is irreducible water saturation. The two sands are mixed in ratios from 0% to 100% in increments of 10%.

The permeability, porosity, and S_{wir} are consistent with Coates default parameters of 10, 4, and 2. The NMR permeability based on average rock properties across the ten layers of sands (called "measured permeability") was calculated by volumetrically averaging the porosity and the BVI for all of the layers based on the porosity and BVI data for Sands A and B. This "measured" permeability was then compared with the arithmetic, geometric, and harmonic "calculated averages" of the separate layers. The results are shown in Figure 1. Geometric averaging is closer to the "measured permeability" than the arithmetic or harmonic averaging.

The deviation between the geometric average and the rock property "average" permeability may be related to the heterogeneity of the rock and phenomenologically correlates to the ratio of the arithmetic and the geometric averages. We found that the arithmetic/geometric ratio raised to the ~0.3 power provided a correction factor that resulted in a closer match to the "average" permeability for this synthetic data set and the actual core data. This correction while simple to obtain may not be justified since the probe profile permeabilities are a more qualitative (not quantitative) assessment of permeability variability.

Calibrating T_2 Cutoff

Log Based Calibration:

If hydrocarbon-bearing sands high on structure are logged, reservoir saturations calculated from resistivity are likely to be at or near "irreducible" and can be used to select the most appropriate NMR T_2 cutoff. For reservoir sands in the transition zone, the near wellbore reservoir rock for OBM-drilled wells are at a flushed saturation and the shallow resistivity should potentially equate to the "irreducible" saturation. A resistivity log based calibration of the most appropriate T_2 cutoff assumes knowledge of R_w and Archie parameters; if these are in error, then obviously, the T_2 cutoff also will be in error.

Empirically, you do not need to know the T_2 cutoff. You can always use a default T_2 cutoff and adjust the Coates parameters to match the permeability. However, Coates parameters obtained this way may not yield optimal values because an error, Δ , in BVI estimation propagates to:

$$k' = \left(\frac{\phi}{C}\right)^m \cdot \left(\frac{BVM + \Delta}{BVI - \Delta}\right)^n = \left(\frac{\phi}{C}\right)^m \cdot \left(\frac{BVM}{BVI}\right)^n \cdot \left(\frac{1 + \Delta / BVM}{1 - \Delta / BVI}\right)^n = k \cdot \left(\frac{1 + \Delta / BVM}{1 - \Delta / BVI}\right)^n \quad (6)$$

Thus, the error introduced by the wrong T_2 cutoff cannot be fully compensated for by adjusting the Coates parameters. To mitigate the unknown T_2 cutoff problem, repeat the regression process with BVM/BVI computed from a set of T_2 cutoff values that are, say, 1/4, 1/2, 1.5, and 2 times the default T_2 cutoff value and then choose the T_2 cutoff that yields the highest R^2 value.

Core-Based Calibration

The core samples that have been measured for S_{wir} are depth-shifted to the log and assigned the nearest NMR log porosity and BVI at several different T_2 cutoffs. Then the T_2 cutoff from the log NMR data that provides the best match to the core S_{wir} is selected. Because of the large differences in sample volume and vertical resolution between logs and core samples, one can expect a low R^2 in the regression of core S_{wir} and NMR log S_{wir}. Whether the S_{wir} of a 1.0 or 1.5-inch diameter core sample corresponds to the average S_{wir} of a several-foot interval of reservoir rock depends on the homogeneity of the rock. A refinement would be to compare the log total porosity and the calculated total water saturation with the core porosity and Dean Stark water saturations (if available from OBM cut cores). If these values are not similar then the rock volumes are not likely to have similar rock properties, i.e. permeability and, therefore, the permeability regression is likely to be in error. Thus, to improve regression one could remove core-log data pairs where there is a large mismatch in porosity and water saturation.

RESULTS AND DISCUSSION

The core and log analysis data used as examples in Figures 2-10 were the subject of earlier papers. The first set of data is based on fairly homogeneous core samples taken from the North Sea. [6] The second set of data is based on unconsolidated sands from deepwater Gulf of Mexico (GoM) portions of which are heterogeneous at or below the plug scale. [7, 8, 9]

Calibrating Log NMR-Derived Permeabilities Using Core Analysis Data without Lab NMR Data

Core-to-Log Permeability Calibration

The core is depth-matched to the log and assigned to the nearest log NMR data (porosity and BVI). Then the Coates parameters are regressed using core permeabilities. Because of the large differences in sample volume and vertical resolution between log and core plugs, the regression R^2 is generally small. As with the T_2 cutoff, to improve the regression, one can remove core-log data pairs where there is a large mismatch in porosity and water saturation.

Figure 2 illustrates the impact on calibrating NMR log-derived permeabilities with core permeability data [6]. The figure compares the core permeabilities with the NMR log permeabilities using the default parameters of $C = 10$, $m = 4$, and $n = 2$ that over-estimate the permeability by nearly an order of magnitude. By following the above protocol the Coates parameters were regressed to match the core permeabilities and a new set of Coates parameters are obtained: 15.22, 4.0, and 2.29 that provide a much better match between log and core-derived permeabilities. As previously stated, we fixed the value of "m" to 4 to obtain a more robust regression and to facilitate comparison of the different regression results. Figure 3 is a plot of the measured core k_{air} versus regressed predicted permeability with an R^2 correlation of 0.56.

A core-to-log permeability calibration example from GoM is illustrated in Figure 4 for cores that are more heterogeneous than those shown in Figure 1. With this reservoir the regression on the Coates parameters only moderately improves the agreement between core and log-derived k_{air}. The regressed Coates parameters are listed in Table 1. Figure 5 is a plot of the measured core k_{air} versus regressed predicted permeability with an R^2 correlation of 0.24.

The effect of rock heterogeneity can be illustrated with higher density permeability data than is normally obtained with routine, one-per-foot core analysis data. The profile probe permeability ("mini-permeameter") measurements collected at 10 samples per foot on sections of the GoM cores shown in Figure 6 indicate heterogeneity on the core plug scale. This set of core samples has been the subject of several previous articles that describe its heterogeneity. [7, 8, 9]

The profile permeability data has been geometrically averaged and cross-plotted with the NMR log-derived permeability in Figure 7. The Coates parameters for the log data were regressed using the geometrically averaged profile permeability data with all data weighted uniformly. The regressed parameters are provided in Table 1. There is closer agreement between the profile permeability data and the regressed NMR log-derived permeability than with the core permeability data.

Figure 5 also contains a plot of the measured core k_{air} versus regressed geometrically averaged profile-predicted permeability. Both sets of data are for the same depth interval and include a similar number of data points. The R^2 for the core plug data is 0.24 and the R^2 for the geometrically averaged profile permeability data is 0.6. Neither R^2 is particularly good, but the profile permeability data is of higher quality since it likely better represents what the NMR log responds to in this rock that is heterogeneous on the plug scale.

There is always the question of depth shifting and the large differences in the sampled rock volume, two especially critical issues in heterogeneous rocks. These issues can be partially mitigated by having high-density core permeability data, by choosing core permeability measurements from the thickest lithologies, and by removing data points where there is a poor match between core and log porosity or saturations.

Obtaining Coates Parameters by Using Core S_w Data

The two prior examples of calibrating the NMR log-derived permeability used core permeabilities, core plug, and profile permeability data. In these two cases, the Coates parameters were applied to NMR porosity and BVI log data, and regressed against the core permeability. However, as previously mentioned there are concerns regarding correctly depth shifting the core and log data and regarding the large difference in rock volume sampled by the core measurements versus the NMR log.

It is possible to get an estimate of the Coates parameters from core measurements alone by regressing core plug permeability against either Dean-Stark saturation data or capillary pressure S_{wir} data. One can assume that Dean-Stark saturations are equivalent to BVI if an OBM cut core is taken high on structure, where reservoir saturations are likely to be at irreducible. If an OBM core is taken in the transition zone then both the core and the near wellbore reservoir rock are likely at a flushed saturation. To verify whether the flushed zone saturation is similar to the irreducible saturation, one can compare the NMR log BVI with a log-calculated S_w from shallow resistivity data. Capillary pressure irreducible saturation should by definition be equivalent to BVI. The regressed Coates parameters using Dean-Stark saturation and capillary pressure are listed in Table 1 and are similar to those obtained by regressing core permeabilities.

Figure 8 is a comparison of the results of least squares regression between core permeability and S_{wir} from capillary pressure (Pc) measurements and from Dean-Stark S_w saturations. The R^2 for the twelve core plug k_{air} versus S_{wir} at 200-psi air-brine data is 0.945. The R^2 for the core plug k_{air} versus Dean-Stark S_w saturations is 0.79. Both R^2s are much better than the previous core-to-log regression results probably because the differences in the sampled rock volume have been removed. The four different calibrations of the NMR logs so far discussed are compared with that calculated from the default Coates parameters shown in Figure 9.

The approach of core-to-core data calibration eliminates the issues of depth shift and rock volumes sampled since regression is between data on the same core plug. However, it does introduce other complication: the NMR log instruments are different from the laboratory instruments. In particular, the laboratory instruments typically are homogeneous field instruments while the NMR log tools have significant magnetic field gradients. On the other hand, the laboratory NMR spectrometers provide much higher S/N data than the NMR log instruments. These differences can have an impact on computed T_2 spectra and T_2 cutoff values [6]. Further, to use core capillary pressure data one needs to know the reservoir OWC to calculate capillary pressure in the reservoir but the OWC may not be known. For example, no OWC was encountered in the cored GoM well that is the basis for this paper. Based on a regional OWC, we can calculate that the equivalent air-brine capillary pressure was in excess of 200 psi over the cored interval.

To use the core-to-core calibration technique one needs to know the NMR log T_2 cutoff. This can be obtained from:

- Comparison with the log S_w calculated from Archie parameters, **but this technique presumes an accurate knowledge of these.** Archie saturations can be partially validated with Dean-Stark S_w saturations for an OBM core if wettability has not been altered by surfactants in the OBM filtrate.
- Examination of the NMR log T_2 distribution (Figure 10). In the case of this GoM well, there is a valley in the distribution at about 33 ms, thus unless the actual T_2 cut-off is <10 or >60 ms there should be little impact from using 33ms. Log S_w and Dean-Stark saturations support 33ms.
- Use of a laboratory NMR program. However, to obtain valid T_2 cutoffs, one needs to re-establish reservoir wettability or the wettability in the flushed near-well bore region seen by the NMR tool.

Calibrating NMR Log-Derived Permeabilities Using Laboratory NMR Data

The focus of this paper has been on calibrating NMR log-derived permeability using core analysis data that did not include laboratory NMR measurements. This is often what we encounter even today more than a decade after the commercialization of NMR logging. Typically, the laboratory NMR protocol involves measuring the CPMG T_2 distribution of 5 to 10 core plugs at 100% brine saturation and again after desaturation by centrifuging or on a porous plate. This data provides information used to select the T_2 cutoff and to regress the Coates parameters to obtain the best fit to the permeability measured on the NMR plugs. However the T_2 cutoff and the Coates parameters are only applicable to reservoir rock that are water-wet or remain water-wet after drilling with an OBM filtrate that likely contains wettability altering surfactants. Rock wettability is dependent on the location of the fluids in the pore space. Likewise, the NMR response is also related to the location of the fluids in the pore space, and thus when rock wettability has been altered the NMR response (the T_2 distribution) is also likely to have been altered. [1, 2]

A recent protocol refinement is to replace the air space in the S_{wi} plugs with a mineral oil that has the same viscosity at laboratory NMR measurement conditions as the reservoir live oil does at reservoir conditions. This typically results in a different T_2 cutoff than that obtained from 100% brine saturated core plugs. This still does not restore the core plug to reservoir wettability which requires aging in crude oil or to the wettability caused by OBM filtrate invasion that requires aging with OBM filtrate. An experiment protocol is provided in the Appendix that should assist in quantifying the impact of wettability alteration on T_2 cutoff and Coates parameters.

Core plugs from the GoM reservoir (Figure 4) had an average T_2 cutoff of 11ms for 100% brine, 25ms for S_{wi} plus viscosity-matched oil, and 11ms for S_{wi} plus OBMF. The various Coates parameters are listed in Table 1.

What Does The NMR Log-Derived Permeability Represent?

Does this calibrated NMR log permeability represent the permeability of the rock for fluid flow into the well bore? For flow in a parallel series of beds, an arithmetic average of permeabilities is typically recommended. [5, 10] If the series of discrete beds have a lateral extent and are of such thickness as to be significantly less than the resolution of the NMR log, then the NMR log averages the permeability for these beds with an expression that is closer to a geometric average. This averaging has the potential to underestimate the permeability (assuming corrections for relative permeability effects have been made). If the rock is very heterogeneous, as the GoM example cited here, then the relevant permeability for the flow is best obtained by a geometric average of the permeabilities across the interval. This permeability should be similar to the permeability calculated from the NMR log data.

The NMR log permeability should also be compared with field permeability measurements from formation tester mobilities, mini-DST, or well tests. [3] The only permeability that might be considered ground truth is the permeability measured on core plugs that are no longer part of the reservoir and can not always be scaled up to represent flow on a reservoir simulator scale.

CONCLUSIONS

A number of core-to-log permeability calibrations have been attempted based on core plug permeabilities, high density profile probe permeabilities, core Dean-Stark saturations, capillary pressure data, and NMR lab data. For the example of GoM heterogeneous core samples, the resulting NMR log permeability curves vary by as much as one order of magnitude. The objective of this study was to illustrate the various potential permeability calibrating data sources and the techniques involved in their use.

For these GoM sands, the core plug calibrated profile permeability data probably provides the best approach for calibrating NMR log-derived perms. Permeabilities derived from flow tests; formation tester mobilities, well test, or mini DST tests, are needed to verify if this is the correct core data choice.

The results of the core-to-log permeability calibrations can be summarized as follows:

- When the core samples are heterogeneous, it is important to calibrate the log-based NMR permeability with the core measurements that have the highest density of core permeability data. Typically, this is the profile permeability data.
- Calibration of the NMR log-derived permeability using core permeabilities tends to over state the log-derived permeability for heterogeneous rock.
- Laboratory NMR data may help in selecting the T_2 cutoff, but only if reservoir wettability conditions are reestablished.
- An experimental protocol is provided to use to obtain laboratory NMR data that quantifies wettability alteration and its impact on the T_2 cutoff.

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APPENDIX: MEASUREMENT PROTOCOLS FOR CORE CUT WITH OBM

Fresh-State Measurements on Subset of Samples (Three Samples or 1/3 of Total)

1. Vacuum-saturate samples with base oil.
2. Measurement Conditions: ambient and reservoir temperatures at NCS (net confining stress).
3. Data Collected: ambient temperature T_2 (shortest *TE*) distribution and reservoir temperature T_1 and T_2 with multiple *TE*s .
4. Information Obtained: rock wettability, quantification of internal magnetic field gradients.
5. Post Fresh-state NMR Core Measurements: Dean-Stark saturation, porosity, and permeability.

100% Brine and S_{wir}

1. Vacuum-saturate samples with brine. After NMR measurements are taken, desaturate samples on a porous plate to a capillary pressure corresponding to the oil column height in the reservoir. Desaturation at multiple *Pc*’s with accompanying NMR measurements provides a means to calibrate NMR logs over a large oil column height and provides the data needed to calibrate an NMR capillary pressure model.
2. Measurement Conditions: ambient temperature and NCS.
3. Data Collected: T_2 distributions from echo trains with multiple *TE*s.
4. Information Obtained: quantification of BVI.

S_{wi} Plus Viscosity-Matched Lab Oil

1. Flush core samples at S_{wi} under backpressure with viscosity-matched lab oil and measure k_o at S_{wir}. The viscosity of the oil at laboratory measurement conditions must be the same as the reservoir live crude oil at reservoir conditions.
2. Measurement Conditions: ambient and reservoir temperature and NCS.

3. Data Collected: ambient temperature; T_2 (shortest *TE*) distribution, reservoir temperature; T_1 (only on fresh-state samples) and T_2 with multiple *TE*s.
4. Information Obtained: rock wettability, quantification of internal magnetic field gradients, and T_2 cutoff to match BVI (only provides data on water-wet core).

S_{wi} Plus OBMF (Only on Original Fresh-State Samples or 1/3 of Total)

1. Flush core at S_{wi} under backpressure with OBMF measure k_o(cw).
2. Measurement Conditions: reservoir temperature and NCS.
3. Data Collected: T_1 and T_2 with multiple *TE*s after initial flushing and again several days to a week later. Need to consider the effect on the T_2 distribution due to the consumption of dissolved oxygen at elevated temperatures and the long duration of the experiments. [11]
4. Information Obtained: rock wettability, quantification of internal magnetic field gradients, T_2 cutoff to match BVI at reservoir wettability.
5. Post Test Measurements: Dean-Stark saturation to confirm S_{wi} saturation.

Fluid Samples

1. Obtain dead crude oil and samples of the oils in the rock pore space by centrifuging fresh-state samples.
2. Measurement Conditions: ambient and reservoir temperature.
3. Data Collected: T_2 with multiple *TE*s.
4. Information Obtained: T_2 distribution.

Table 1: Summary of Coates Parameter Regressions

			Coates Parameters			
Regressed data	Measurement Density (#/ft)	Figure #	*C*	*m*	*n*	% LS SUM reduction*
Log to core permeability	1	2	15.22	4.0	2.29	0.09
Log to core permeability	1	4	11.31	4.0	0.82	0.69
Log to profile permeability	10	7, 9	10.88	4.0	0.99	0.39
Dean-Stark S_w	1	9	15.50	4.0	1.18	0.12
Capillary Pressure	0.05	9	13.43	4.0	1.09	0.02
Lab NMR:100 % brine	0.03	9	14.96	4.0	2.00	0.23

*New least square regression sum/old least regression square sum

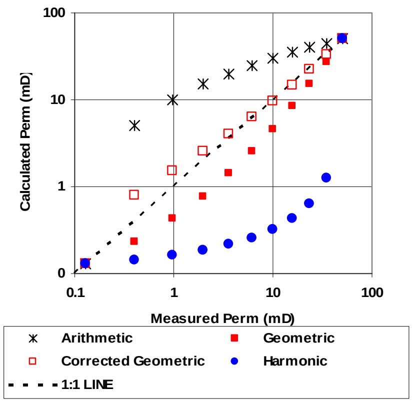

Fig. 1. Comparison of permeability averaging models on synthetic binary sands.

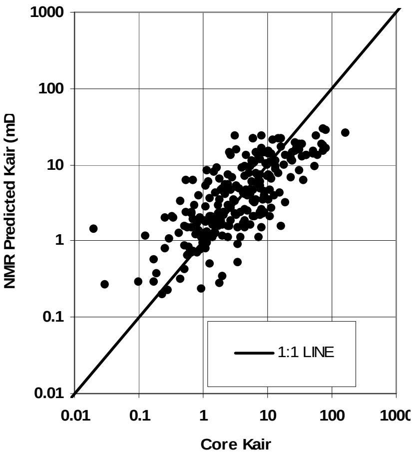

Fig. 3. Core-to-log k_{air} calibration after regression on Coates parameters.

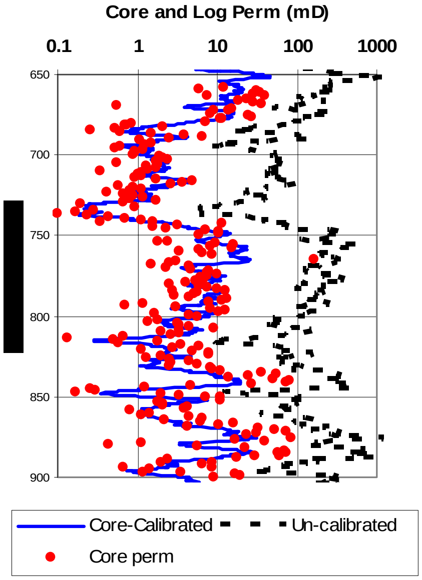

Fig. 2. North Sea NMR log permeability, comparison of core-calibrated versus default

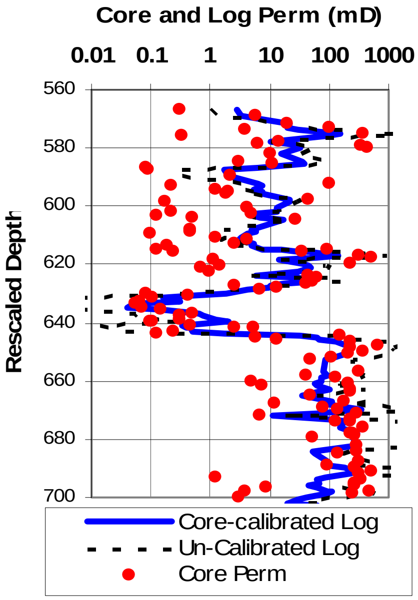

Fig. 4. GoM NMR log permeability, comparison of core-calibrated versus default Coates parameters.

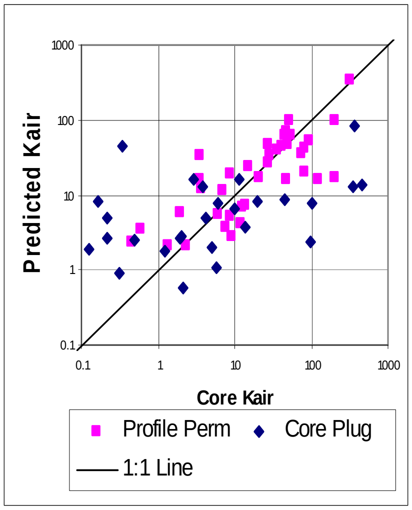

Fig. 5. Core-to-log k_{air} calibration after using regression on Coates parameters.

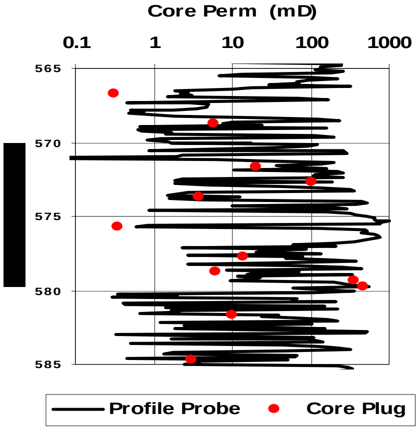

Fig. 6. Comparison of the high-resolution probe permeameter (10/ft) with core plug (1/ft) permeabilities.

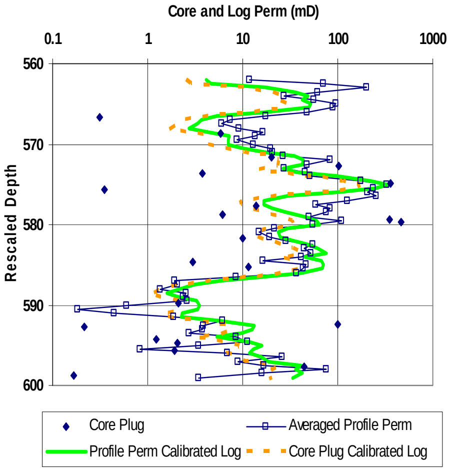

Fig. 7. Compares the various Coates calibrations of the NMR log with core plug perms and profile permeability data.

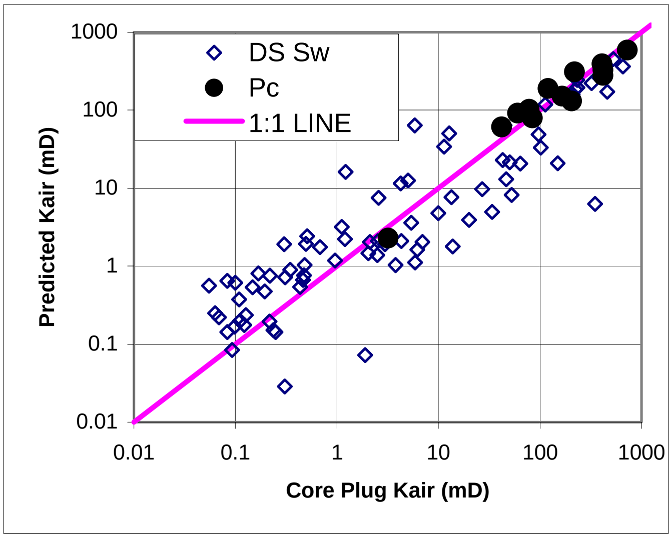

Fig. 8. Predicting Core k_{air} by using regression on water saturation data, Dean-Stark S_w, or capillary pressure S_{wir}, and porosity.

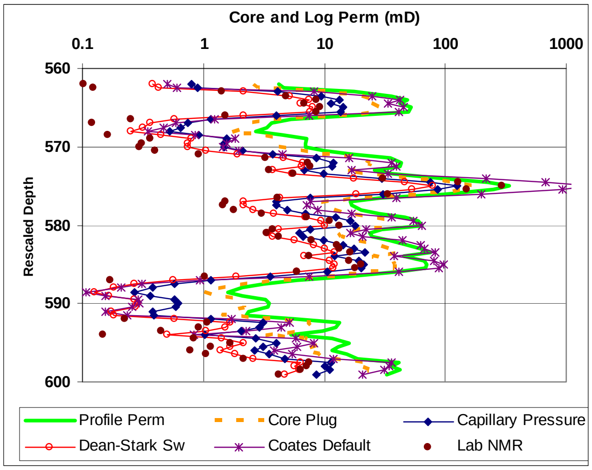

Fig. 9. Compares the various Coates calibrations from core plug perms, Dean-Stark S_w, capillary pressure S_{wir}, and laboratory NMR data.

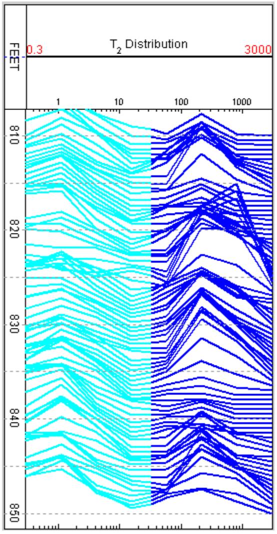

Fig. 10. The T_2 distribution of the GoM well showing a distinctive dual-peak pattern with the 33 ms T_2 cutoff in the valley between the two peaks, For such cases, accurate T_2 cutoff is not very important to the estimation of BVI and permeability.