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Delineation of reservoir sand quality by integrating leading edge technology well log data and calibrating to core data

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Abstract: This study targets effective methods of identifying those sand sequences within the shallow clastics of the Late Miocene/Pliocene which are most productive. This example comes from offshore Bintulu within the South China Sea. These sands are characteristically unconsolidated, generally fine grained, and greenish in color resulting from their glauconitic content. The reservoir sands are deposited in a shallow marine (possibly shoreface) depositional environment. The environment is interpreted from a bioturbated sand facies and a laminated sand facies. The bioturbated sand has shell fragments and burrowing which is indicative of a shallow water depth. Due to the reduced reservoir quality associated with bioturbated sands, it is advantageous to be capable of differentiating these sand sequences from fine grained or laminated sands. Additionally, a method of determining mobile fluid within the porosity is essential as these sands are generally quite high in irreducible capillary bound water. An effective method of identifying permeability is also required in order to identify good quality reservoir sands. Magnetic Resonance log data was acquired on this well with the objective of identifying capillary bound bulk volume irreducible water in addition to acquiring a continuous permeability. This permeability is computed from the relationship between bulk volume irreducible and movable fluid. These parameters were to be calibrated from capillary pressures and poroperm data acquired from conventional cores. A further objective was to establish calibrations such that real time acquisition of accurate permeability and BVI would be available on further wells. Simultaneous Acoustic and Resistivity image data was also acquired on this well with the intention of using this textural information to predict lithofacies. This can be achieved by using a multivariate histogram database populated with dual image attribute electrofacies, conventional log data, magnetic resonance log data and core lithofacies. Interrogation of the database with all but core lithofacies enables prediction of core lithofacies. Historically this technique has been used with marginal success in differentiating facies types, but with the inclusion of dual image data (resistivity and acoustic image), results prove so improved as to be capable of predicting with very high confidence core lithofacies. Calibrated reservoir quality indicators such as permeability, lithofacies, bulk volume irreducible and porosity with an accurate quantification of hydrocarbon results in the ability to selectively perforate these reservoirs to produce at maximum optimal rates with minimal surface handling equipment costs. The ability to calibrate this acquired data allows for real time acquisition of permeability and BVI.

INTRODUCTION

Targeting optimum production from specific gas sands within a sand shale sequence means to selectively perforate sands in order to maximize gas production, minimize water production, minimize costs, and prolong the life of the reservoir. Reservoir quality must be identified in order to do this. Generally, reservoir quality is governed by porosity, lithology and permeability, the latter of which is the most important. As lithology increases in complexity, however, a combination of these parameters may be required in order to accurately define reservoir quality. Within the glauconite rich shallow clastics found within certain areas of Asia Pacific such as the South China Sea and the Natuna Sea, all 3 indicators may be required with the inclusion of one additional one of no less importance, BVI (bulk volume irreducible water) (Dyson, 1998; Zhang and Salisch, 1997, 1998; Zhang *et al.*, 1997).

This study demonstrates how the most current wireline logging technology in addition to the use of modern modeling techniques and subsequent calibration to core data parameters can result in accurately identifying and delineating the highest quality reservoir sands (Coates *et al.*, 1991; Georgi *et al.*, 1993; Tetzlaff *et al.*, 1989; Waxman and Smits, 1968; Zemanek, 1989). This paper will discuss the basic NMR measurement and its associated parameters of importance namely, MPHE (Magnetic resonance measured effective porosity corrected for hydrogen index), MBVI (Magnetic resonance measured bulk volume irreducible water), and MPERM (magnetic resonance measurement derived permeability), and how these parameters are calibrated to core data. This resulting calibration can subsequently be applied during data acquisition on concurrent wells. This paper will also discuss how dual borehole image data (resistivity and acoustic) is ideally suited for providing textural information about the formation. This textural data with the inclusion of conventional log data, magnetic resonance log data and core lithofacies is included in a model from which accurate prediction of lithofacies can be made over sands where all of said data excluding core lithofacies exists. Examples of the accuracy of the match between logged core lithofacies and predicted lithofacies are presented within this paper to illustrate the marked improvement of this technique over previous techniques (previous techniques generally relied on one image type for textural information).

DEPOSITIONAL ENVIRONMENT

As no detailed depositional environment study was undertaken, the interpretations set out here should be considered as speculative. All facies referred to are described in detail later within this paper. The presence of bioturbation (and glauconite) is usually interpreted as a shallow marine environment. The interpretation broadly suggests a low energy environment, which would indicate a tidal to shoreface environment of deposition. The mudstone (Facies 1) is indicative of a quiescent environment such as either lagoonal or lower shoreface. The laminated sands (Facies 2 and 3) may be indicative of channel mouth bars such a tidal channel mouth bars. The bioturbated facies (Facies 3, 4, 5, 7 and 8) potentially represent shoreface sands above a fair weather wave base. Some sands (Facies 7 and 8) have shell fragments together with bioturbation, which may suggest some reworking of shoreface sands. The storm deposited sand (Facies 9) indicates vigorous re-working. The presence of the mudstone fragments indicates possible erosion and re-deposition of Facies 1.

THE MAGNETIC RESONANCE MEASUREMENT

MRILTM measurements make use of nuclear magnetic resonance (NMR) by means of the spinecho technique. The MRILTM tool is composed of three elements: a permanent magnet, a radiofrequency (RF) transmitter, and an RF receiver. The basis for the MRILTM measurement process is that at every depth level logged, a series of RF pulses are used to stimulate the hydrogen protons in the reservoir pore space, generating a series of decaying spin-echo amplitudes. From these measurements, the initial maximum amplitude of the received signal is proportional to the formations effective porosity, MPHE, and the decay rate of the received signal is related to pore and grain-size distribution. Analysis of this information provides a direct measurement of a rock's bound fluid (bulk volume irreducible or capillary bound fluid), MBVI, and movable fluid, MBVM. Permeability is derived using the Coates equation which is essentially a function of the relationship between bulk volume irreducible, bulk volume movable and effective porosity.

NMR ANALYSIS OBJECTIVES

Within the reservoir, the targeted sands are glauconitic and contain gas with a characteristically low hydrogen index. NMR data was recorded on this well with objective of accurately identifying effective porosity, bulk volume irreducible, and permeability within this sand-shale sequence. In order to achieve this, logging runs of various activation types were employed. Two passes using different wait times (T_w) were recorded.

Effective porosity (hydrogen index corrected) would best be identified from a logging pass which employs a wait time of 4 seconds. This wait time allows for sufficient polarization of all fluids in the pore space. The resulting free fluids are subdivided into hydrocarbon and water components by means of the Waxman Smits saturation algorithm. Clay typing (to delineate as structural, dispersed and/or laminated) is then performed.

Due to the presence of low pressure gas, BVI would best be identified from a logging pass which employs a short wait time of 0.225 seconds. This short wait time minimizes the gas effect. Low pressure gas causes a portion the gas signal to appear in the irreducible portion of the T_2 spectrum and causes a resultant apparent increase in bulk volume irreducible. This observed BVI would then be calibrated to the irreducible water calculated from the capillary pressure data from core plugs.

Permeability is then calculated using the Coates permeability equation. The results (porosity and permeability) are then calibrated to conventional core plug poroperm data.

NMR measurements can be performed on core plugs to identify the appropriate T_2 cutoff to be applied to the initially recorded echo train to separate capillary bound water from movable water. The core measurements can improve the accuracy of the distribution of fluids contained within the effective porosity (i.e. BVI & BVM). This additional calibration was not performed due to time constraints.

If electrical properties (i.e. a = formation resistivity factor, m = cementation exponent and n = saturation exponent) are determined from core plugs, these values can be verified and applied within the petrophysical analysis. Electrical properties were not performed on these core plugs due to time constraints.

NMR INTERPRETATION METHODOLOGY

A comprehensive petrophysical interpretation software package was used for water saturation evaluation (this iterative software contains both deterministic and statistical modeling modules and the output parameters are comprehensively interrelated). NMR effective porosity consists of both movable fluid and irreducible fluid components. In this interpretation the volume of shale (VSH) was determined by using a Neutron ϕ -NMR ϕ_{eff} crossplot (gas effect is thus minimized as both the neutron and NMR measurements experience similar effects due to hydrogen index — Fig. 3).

Clay Bound water was determined as the differential of an externally recorded total porosity curve and the gas corrected NMR effective porosity. Whilst present NMR technology allows for real time recording of total porosity, it was not recorded on this well.

Total porosity less gas corrected NMR effective porosity yields the clay bound water porosity. Dividing this clay bound water (CBW) by the total porosity provides a saturation of clay bound water (SWB).

Constructing a crossplot of SWB or CBW against VSH determines if the NMR porosity has been affected by hydrogen index (Fig. 4). As VSH increases, the clay bound water content should increase. If a hydrogen index effect exists, the NMR effective porosity will undergo apparent reduction due to the hydrogen content. In this situation, the resulting clay bound water volume will be too high. The VSH computed using the neutron-NMR porosity should be negligibly affected by hydrogen index as both the neutron and MRILTM porosities undergo reduction to a similar degree. Typical indications of hydrogen index effect on uncorrected NMR effective porosities are evident when VSH is low and CBW is high. A hydrogen index correction is then applied to the gas affected points by forcing them vertically to the diagonal (Figs. 3 and 4). Establishing the amount of hydrogen

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index correction required to apply to the NMR effective porosity can alternatively be performed using time domain analysis directly from the NMR time domain echo train data. This method, however may prove less accurate in gas sands which exhibit low hydrocarbon index as the gas component signal reduction results in a subsequent decrease of the signal to noise ratio in this environment.

A density-neutron crossplot produced a reliable total porosity. A calibration check is performed by comparing these to core plug total porosities (see Fig. 11). The Waxman Smits model proved to be the best saturation delineator.

The Thomas Steiber model (Fig. 7) was preferred for clay typing over a neutron-density crossplot clay triangle. The Thomas Steiber technique showed improvement over the neutron-density crossplot technique specifically in delineating more laminated component in sands where lamination was evident on the STAR image.

The NMR computed permeability is derived using the Coates Equation as shown below:

$$k = \left(\frac{100\phi}{C}\right)^{m} \left(\frac{S_{moveable}}{Swir}\right)^{n}$$

or:

Permeability = (MPHE/C)^m _{*}(MBVM/MBVI)ⁿ

N.B. see the Nomenclature section of this paper for definitions of the terms shown above. NMR permeability is compared to core permeability to obtain the calibration values of C, m and n for the Coates equation. The default values of C, m and n are 10, 4 and 2 respectively. In this reservoir, the values obtained from the calibration to core permeability are 8.6, 5.251 and 1.12 for C, m and n respectively (see Fig. 11 for comparison).

Two logging passes of different activation types were recorded and are interpreted. One pass had echo train parameters optimized for the identification of bulk volume irreducible. The second pass was designed to acquire both a differential spectrum (for hydrocarbon indication) and included a wait time sufficient to polarize all fluid components and enable accurate estimation of effective porosity.

The bulk volume irreducible pass was made in order to obtain an accurate BVI that was not affected by the gas signal from the formation. The low pressured gas (low hydrogen index 0.11) causes the gas signal to appear in the irreducible portion of T_2 spectrum thus causing an apparent increase in the bulk volume irreducible. By using a wait time of 0.225 seconds, the water signal in the bulk volume irreducible was fully polarized with negligible gas signal detection. This data was then calibrated to Sw_{ir} determined from capillary pressures curves from core plugs (Fig. 2).



Figure 1. The diagram illustrates an echo train (from sequential spin echo amplitudes) and demonstrates how the decay curve delineates ϕ MRIL, BVM and BVI. The illustration entitled Dual Wait Time Mode demonstrates how sequential echo trains resulting from short and long wait times are simultaneously recorded for differential spectrum recording.



Figure 2. The graph demonstrates capillary pressure curves generated from conventional core plugs. It is this data which is used to calibrate the NMR BVI parameter.



Figure 3. The crossplot shown was used in the computation of VSH. A shale triangle has been superimposed to show how percent shale is calculated. It is clearly one of the best methods of calculating shale volume and is particularly useful in shaly sands where the sand contains gas. Gas tends to move points towards the southwest along the same axis as the parallel percentage shale lines within the shale triangle.

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Figure 4. Initially we compute clay bound water as the differential between total porosity and NMR recorded effective porosity. Points that lie above a diagonal (as shown on graph below) defined by a slope and offset describing maximum expected CBW vs VSH, will be corrected by forcing them vertically to the diagonal. The slope and offset are defined by the user based on the relative quantities of clay types within the shale. The circled points are a rough generalization of which points will be corrected.



Figure 5. After correction to the diagonal, the corrected clay bound water vs shale volume is shown in the crossplot. The NMR petrophysical interpretation package allows for the estimation of a variable value for m. This is required to account for the tortuosity difference in sands and shales and their effect on water saturation. An apparent m is calculated and crossplotted against VSH (determined from the shale indicator) and a wet trend can be observed. This water wet trend supports the intrinsic variations of m and should intercept the Y-axis near the appropriate m value for clean formations.

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The differential spectrum was logged with dual wait times: a short wait time of 1.025 seconds to ensure full polarization of the water and a long wait time of 4.043 seconds to ensure sufficient polarization of all the fluid components. The short and long wait times are established based on the expected fluid type (gas or oil), and the expected diffusivity of gas if present. Essentially the short wait time allows only for full polarization of the water whereas the long wait time allows for full polarization of water and sufficient polarization of remaining fluids such that a full polarization value can be established by time domain analysis. This data was presented in the form of three spectrums (of the decaying spin-echo amplitude train), one produced by the short wait time, one produced by the long wait time, and a differential spectrum computed and presented as a fluid type delineator.

NMR INTERPRETATION PARAMETERS

All parameters used in the NMR petrophysical interpretation are listed below:

- The bulk volume irreducible data was obtained from the BVI pass with a T_w of 0.225 sec.
- NMR effective porosity was obtained from the DTR pass with a T_w of 4.043 sec.
- NMR permeability within the reservoir was calculated based on the following parameters:

Coates denominator C = 8.6, Coates exponent m = 5.25, Coates exponent n = 1.12.



Figure 6. The graph demonstrates the apparent M vs VSH crossplot. The key parameter for the Waxman Smits equation is Qv, which is the cation caption capacity. Qv is calculated using the Hill, Shirley and Klein method as suggested by Juhasz (1979).

- A = 0.81
- M = variable with clean matrix value of 1.76

• N = 1.80

- Rw used is 0.155 @ 150 DEGF
- The final effective porosity from NMR is borehole corrected for washout effect
- Best fit calibrations performed (see Fig. 11): ZDL/CNC crossplot porosity to core plug total porosity

(results adjusted by addition of heavy mineral or re-investigation of HI correction) MBVI to Sw_{irr} calculated from core plug capillary pressures

(user is required to make slight modifications to T_{o} cutoff to make MBVI conform)

MPERM to core plug permeabilities at overburden conditions

(results in modification of the Coates coefficients: C, m and n)

OBSERVATIONS (RELATED TO NMR INTERPRETATION)

The Thomas Steiber clay distribution delineation technique showed improvement over crossplot neutron-density clay triangle specifically in determining more laminated component in sands where lamination was evident on STAR image.

NMR data addresses the issue of identifying movable fluid which helps explain low gas saturation as derived from conventional logs, by providing a computation of irreducible bulk volume of the pore space.

MRILTM provides a continuous permeability prediction over the logged interval which can be calibrated with core permeability.



Figure 7. The graph shows the clay distribution within the effective porosity model of the Thomas Steiber method for delineating clay types (Steiber and Thomas, 1975).

The calibration of the NMR interpretation parameters to core porosities, permeabilities and capillary pressures results in accurate readjustment of all calculated outputs of the NMR petrophysical interpretation due to the highly integrated nature of this petrophysical interpretation software package.

LITHOFACIES PREDICTION OBJECTIVES

The intention is to attempt to replicate then predict lithofacies provided from core lithofacies by utilizing a multivariate histogram modeling package. Initially, STAR image data is processed to produce image attributes and resultant image electrofacies. The HORIZON modeling software package (A multivariate histogram databasing software package for class estimation) is used in populating a database with dual image (resistivity and acoustic image) electrofacies data, core lithofacies and conventional log data (inclusive of NMR petrophysical interpretation results data). Core data must be critically depth matched by two processes; importation of core photos with resultant scrupulous comparison to image data, and the comparison of core gamma to both the conventional log data recorded gamma ray and the image data recorded gamma ray. Finally the populated database is interrogated by submitting all aforementioned data with the exception of core lithofacies resulting in the prediction of this data.

LITHOFACIES PREDICTION METHODOLOGY

The following procedures define the process of estimating lithofacies (Pseudofacies) from STAR Image and Conventional Log data in conjunction with Core Lithofacies. Three main processes are involved. These are:

- 1. Image Characteristics Electrofacies Analysis: Both Resistivity and Acoustic images are processed to identify and delineate various image attributes which are consequently utilized for the creation of image electrofacies (Fig. 8).
- 2. Core Photo Import: Digital core image is imported with corresponding core gamma to ensure accurate depth matching (Figs. 9 and 10).
- 3. A Multivariate Histogram model is populated and queried for the classification of a statistically predicted match to core lithofacies: This process relies on accurate core lithofacies description over the cored interval.

Image Characteristics Electrofacies Analysis

The steps of this process are as follows:

- 1. Generation of histograms of image data values For resistivity and acoustic images.
- 2. Identification of image ranges Amplitude (acoustic image) and resistivity (resistivity image) ranges are identified from histograms.
- **3.** Computation of image attribute curves *As define below.
- 4. Evaluation of best estimator curves Attribute curves with least similarity are the best estimators (Fig. 8).
- 5. Determination of image electrofacies this process uses multi-level histograms of the best estimator curves to determine a number of facies (up to 40) based on cluster analysis. Weighting can be applied to specific attribute curves by increasing its step length. Decreasing search length increases the number of facies as smaller clusters of data are considered statistically significant (Fig. 9).

*The following list identifies those image attribute curves which are computed by step 3. Further description of these attributes is not available due to proprietary issues.

(Image texture and radial anisotropy)

DYNDIF	"Radial anisotropy"
PTEXT	"Image texture"
CONTM	"Normalization matrix difference"
CONTR	"Normalization radial difference"

(Maximum color continuity)

BMAX	"Black maximum"
GREXMAX	"Gray maximum"
WHIMAX	"White maximum"

(Image continuity black and white) DLLEN "Average black" DHLEN "Average white" LENSUM "Length sum"

(Average color gap length)

BGAP	"Black Gap Length"
GREYGAP	"Grey Gap Length"
WHITGAP	"White Gap Length"

(Matrix and feature pixel size)	
MEDPC	"Matrix length"
GRAIN	"Average features"

(Color abundancy)

BABUN	"Black abundance"
WABUN	"White abundance"

(Black-Grey-W	'hite pixel continuity)
BAVG	"Black length"
GREYLEN	"Gray length"
WHITLEN	"White length"

(Auxiliary curves) IPDHS "Divergence texture"



Figure 8. The plot shows image attribute data as generated over the cored interval.



Figure 9. The plot compares the gamma of two cored intervals against the conventional log gamma ray and image log gamma ray. Additionally, the supplied core lithofacies is shown in green and image electrofacies in red (acoustic) and blue (resistivity).

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SLIM	"Spectrum"
ISDEV	"Standard deviation"
PENHIS	"Pixel entropy"
ENTDIF	"Pixel difference entropy"
PHGRV	"Median gradient"
PDHGRV	"Divergence gradient"
VHETA	"Vertical anisotropy"

(Image min-	max and median)
IMIN	"Minimum"
IMAX	"Maximum"
IMED	"Median"
IAVG	"Average"

Digital Core Photo Import

The digital Core Photo is imported into the image visualization program and depth matched to ensure accurate correlation of core lithofacies to image electrofacies and conventional log data. Core gamma can be used alternatively or additionally.

Multivariate Histogram population and interrogation

1. Electrofacies from resistivity image and acoustic amplitude image are input along with conventional log data into a multivariate histogram with core lithofacies. This multivariate histogram database can be imagined as a multi dimensional crossplot on which a grid has been superimposed. Three values are imposed by the user for each input; minimum, maximum and number of steps.

- 2. The multivariate histogram database is queried with all inputs in step 1 with the exception of the core lithofacies enabling prediction of lithofacies from the Database. This resultant predicted lithofacies is a prediction from the multivariate histogram database based upon those values acquired from core lithofacies. Only lithofacies existent within the core can be predicted, unless the program is used iteratively to redefine lithofacies over zones that are not representative within the core.
- 3. The generation of predicted lithofacies inclusive of probabilities and description at each change in facies. A plotting routine enables the presentation of these lithofacies in the form of a curve whose scale is indicative of probability. At each change in facies, a text description corresponding to the equivalent facies is created (Figs. 10, 12 and 13).



Figure 10. The plot shows the excellent match between core logged lithofacies (in black) and predicted lithofacies (in purple). This plot shows the cored interval of the reservoir.

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PROCESS AS SPECIFIC TO THIS DATASET

The steps outlined above define the generic process. Specifically with this dataset, the results achieved were exceptional. The degree of accuracy of replication of the core lithofacies is a benchmark by which the success of this process can be measured. Initially eight lithofacies from core were defined, but further investigation suggested similarity between facies types, and it was decided that 3 sets of 2 facies were so similar that a more generic facies type be described with the inclusion of two additional facies types, tight sand, and shale with tight laminae.

The detailed facies defined within this study



Figure 11. The plot displays the comparison of the calibrated continuous MPERM (in purple with light yellow shading) to the core plug perms (black asterisk points) as well as the comparison of the CNC/ZDL crossplot total porosity (in pink) to the core plug total porosity (black asterisk points).

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Figure 12. Lithofacies prediction.

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Figure 13. Lithofacies prediction and other information.

are as follows:

- 1. Mudstone
- 2. Fine grained, laminated sand
- 3. Fine grained, bioturbated sand with minor laminations
- 4. Fine grained, bioturbated sand with concretions and dispersed organic material
- 5. Fine grained, fragmented sand with minor bioturbation
- 6. Coarse, shale rich layered storm deposited
- 7. Fine grained, bioturbated sand with abundant shale debris
- 8. Fine grained, fragmented sand with spurious shell debris and burrowing

The all inclusive generic facies defined in this study are (see Figs. 10, 12 and 13):

Mudstone
Laminated sand
Bioturbated sand
Clean fragmented sand
Coarse, shale rich layered storm
deposited
Tight sands
Shale with tight laminae

OBSERVATIONS (RELATED TO LITHOFACIES PREDICTION)

The lithofacies characteristic of the core were sufficient to predict facies over all predicted intervals with the exception of tight sand (as no tight sand existed within the core). Laminated sand depending upon the thickness and degree of density of laminations required user intervention. Iterative prediction of facies was not required as a result of almost 100% of available facies predicted.

The lithofacies prediction process is extremely dependent upon both acoustic and resistivity image data. The process is extremely unreliable without the use of image data.

CONCLUSIONS

Reservoir quality and deliverability can be identified by a combination of factors. This paper identifies many such factors, some of which are relatively good indicators on their own, and others which add qualitative information. These indicators are specifically NMR measurement derived permeability (calibrated to core plug permeability), predicted lithofacies, NMR measured porosity. Also of importance to deliverability and quality is the NMR measured BVI (bulk volume irreducible water).

Sw is not a meaningful parameter without the quantification of bulk volume irreducible water.

Within these sand sequences NMR is extremely helpful in resolving this parameter.

Facies prediction in this reservoir reveals that reservoir quality is not reduced significantly by bioturbation. In comparing the predicted lithofacies with the NMR computed permeabilities, the quality of the bioturbated sands was very similar to that of the clean, fine grain and laminated sands.

Both resistivity and acoustic image data are requirements for the textural input required for accurate facies prediction based on core lithofacies. For sand sequences with lower permeabilities, knowledge of facies will have a significant impact on the quantifiable deliverability of the reservoir.

NOMENCLATURE

NMR	=	nuclear magnetic resonance
MPHE	=	MRIL [™] effective porosity
STAR	=	simultaneous acoustic and resistivity
		imager
VCL	=	clay volume (%)
BVI	=	bulk volume irreducible
VSH	=	shale volume (%)
BVM	=	bulk volume movable
φ	=	porosity (fractional)
DTR	=	differential wait time recording
QV	=	cation caption capacity
T_	=	wait time (buildup time)
CWB	=	clay bound water (%)
Α	=	formation resistivity factor
SWB	=	clay bound water saturation (%)
М	=	cementation exponent
CNC	=	compensated neutron porosity (%)
MA	=	apparent cementation exponent
RD	=	deep resistivity
N	=	saturation exponent
MBVM	=	MRIL [™] bulk volume movable (%)
Rw	=	formation water resistivity
BVMF	=	bulk volume movable fluid (%)
Coates C	=	denominator
Coates n	=	Coates exponent 'n'
Coates m	=	Coates Exponent 'm'
К	=	permeability
MPERM	=	MRIL [™] computed permeability
Sw _{irr}	=	irreducible water saturation
HI	=	hydrocarbon index
T,	=	echo train decay data

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