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The Integration of Petrophysical Data for the Evaluation of Low Contrast Pay

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Abstract

To date eight gas/condensate fields has been discovered through exploration and appraisal drilling by Carigali Triton Operating Company Sdn. Bhd., Operator of Block A-18, JDA on behalf of its Shareholders Petronas Carigali (JDA) Sdn. Bhd., Triton Oil Company of Thailand (JDA) Ltd., and Triton Oil Company of Thailand Inc., Contractors to the Malaysia-Thailand Joint Authority (MTJA). Sequences 0-II of these fields include stacked ‘shaly sand’ reservoirs containing low contrast pay. The suppressed resistivities of these reservoirs are caused by cm-dm clay distributions, which vary between facies, making the identification and quantification of reserves difficult.

An integrated petrophysical approach has been adopted to overcome these difficulties. Borehole image-log interpreted facies are treated as classes of clay distribution, and the log responses of each facies are calibrated to core data, acquired separately for each facies. Saturation-height functions are used with wireline formation pressures to project initial conditions capillary pressure saturations into all cored intervals, providing foot by foot log independent gas volumes. For each facies, the log data and Waxman Smits equation are calibrated to these gas volumes through the saturation exponent (n^*). The role of n^* as a core-log matching parameter is analogous to apparent fluid density in a core-log porosity evaluation. In addition, gamma ray is used to optimise n^* for each facies. Results are supported by the fluid mobility seen on limited magnetic resonance logs, and all other available data.

The technique provides a simple, reliable and inexpensive means to evaluate the hydrocarbon potential of low contrast pay. The determination of formation water resistivity (R_w) is circumvented and data acquisition costs are minimal as the

required data has often been acquired for other purposes. In this case study its application will result in a gas reserves upgrade for CTOC, its Shareholders and the Malaysia-Thailand Joint Authority.

Introduction

Reserves estimates require only the contact depths and equivalent hydrocarbon column (EHC) from petrophysics, where EHC equals the product of netpay thickness, porosity and hydrocarbon saturation ($h \times \phi \times Sh$). In freshwater shaly sands logged conductivity is complex and imperfectly modeled and basing EHC solely on its interpretation introduces a considerable and avoidable risk to the development decision. Uncertainties arise from a combination of phenomenon including: a lack of knowledge of matched true formation resistivity (R_t), porosity (ϕ) and the effective concentration of clay exchange cations (Q_v) for the variously shaped and sized sandy lenses; a lack of resistivity contrast between pay and non-pay; reduced hydrocarbon saturation (Sh) through invasion; uncertain R_w ; and inappropriate cementation exponent (m^*) and n^* for the log data’s resolution (**Table 1**). The above parameters refer to the Waxman Smits¹ equation (WS) as the vehicle for transforming R_t into S_w . R_t and ϕ can be squared to finer resolutions in an attempt to model extensive homogeneous parallel beds, however core photographs (**Fig. 1**) reveal a three-dimensional clay conductivity network infinitely more complex than such simplistic analogies allow. Essentially, in these reservoirs, supplying matched, accurate inputs to any log data transform for EHC involves simplification and assumptions which may or may not be acceptably realistic. Log dependent EHC should therefore always be compared with, and probably calibrated to, log independent values of EHC .

In contrast to log data interpretations the removal of a section of whole core from the reservoir and observing directly how much gas it stores when subjected to a gas phase pressure equal to that which it experiences in the reservoir, provides a somewhat more confident indication of EHC (**Fig. 2**). However, most reservoir intervals remain uncored so it becomes necessary to use logs to mimic these cored gas volumes where core is absent.

In this technique the conventional logs are matched to the cored gas volumes separately for each facies. Facies are based on core but recognised beyond core by image logs (**Fig. 3**).

Facies represent classes of clay distribution and therefore characterise distinct core-log relationships. The matching parameter between the cored Sh and logged Rt/Ro , where Ro is the water saturated value of Rt , is the apparent n^* , derived from core and log data rather than the usual special core data. In this technique the laboratory Rt/Ro is replaced with the logged Rt/Ro , since it is logged Rt/Ro which is actually used during evaluation. Essentially, this method integrates logged Rt/Ro and image logs with the established saturation-height method (Fig. 4). Oil mud core or low invasion core Sw 's would also provide the required log independent Sw for the $\text{Log}(Sw)$ axis of the n^* plot (Fig. 4)

Data

The required data is usually readily available in modern developments, although possibly acquired separately by geologists and engineers. The data available to this study included conventional logs, virgin formation pressures, image-log facies and regularly (machine) sampled routine core data. Capillary pressure core data (Table 2), Qv , m^* and n^* were also acquired per facies group (although here n^* is replaced by its core-log value). Magnetic resonance logs are not required input but concurred with the study results and can be fully integrated via Qv if widely available. Theoretically, image logs could be replaced by any reliable core calibrated means of delineating facies groups, although image-logs are preferred because of their ability to directly reveal different clay distributions. All special core parameters except the centrifuge Pc data (which was corrected) were acquired at reservoir equivalent hydrostatic stress with simulated reservoir brines. Reservoir temperatures were not achievable.

Log data was not specially processed, although the finest resolution logs available were carefully depth matched and the best possible Rt used. Enhanced resolution logs are desirable, not essential.

Method

Petrophysical zonation. The purpose of zonation in core-log studies is to reliably predict varying core-log relationships. In this study clay distribution dominates core-log relationships thus image log facies serve as excellent petrophysical zonation criteria.

The number of facies was reduced from 12 to 4, in close consultation with geologists (Table 3). This data reduction exercise is based on the similarity of clay distribution and not necessarily depositional environments or sedimentary processes. For example, Facies 11&12 (Sand with Discontinuous Clay) have conductive clays arranged discontinuously in a continuous sand matrix, whereas the same clay volume in Bioturbated ssts has a more continuous network of conductive clay. Clay distribution is the disturbing influence on Rt , and so must be the guiding principle during the facies grouping exercise.

Separate core Pc - Sw predictive relationships and all parameters were derived for each facies group unless stated otherwise.

Capillary Pressure Data. Capillary pressure data was acquired on 1.5inch diameter plugs by centrifuge and spanned the full range of reservoir capillary pressures. Corrections to the Pc data were small. Extrapolation to infinite time was not included, however, its effect would be to slightly increase Sh . Stress corrections were:

$$Pc^* = Pc (\phi_{res} / \phi_{lab})^{0.5}$$

$$Snw^* = Snw (\phi_{res} / \phi_{lab})^{0.5}$$

The fluid pair used to generate the capillary pressure data was air and simulated reservoir brine, so clays remain wetted and no claybound water correction is necessary. In contrast to oil-brine systems which typically are not uniformly water wet, gas is non-wetting in all reservoir gas-brine systems, with the contact angle $\theta \sim 0$ and $\cosine\theta \sim 1$. Any surface roughness will tend to decrease θ below its theoretical value, increasing water wetness. Interfacial tension (T) is affected by temperature and pressure, being influenced largely by the density contrast across the fluid interface. Temperature and pressure increases the density of the brine vapour and at critical conditions the densities become equal and T becomes zero. Hough et al² indicates 48 dynes/cm as an appropriate value for T for methane and water in these reservoirs (Fig. 5). Concerned readers who feels $T\cosine\theta$ is inaccurate may well be correct, however its impact will be greatest for low permeability oil reservoirs, and least for high permeability gas reservoirs such as in this development. In the conversion from Pc to reservoir Height above Free Water Level (Height, FWL) errors move the data up or down the height axis, which has little effect on Sw at the 'irreducible' condition, which dominates all reservoirs studied.

These procedures for deriving capillary pressure-saturation relationships are designed for the correct core-log integration³ of core calibrated total density porosity, permeability and saturation. Such integration requires a standard ϕ parameter from all three data sets: special core, routine core and logs.

Multi-variate regression of Pc data for Sw . The derivation of predictive Sw equations from Pc is notoriously awkward, but can be simplified by removal of the extraneous low Pc data which represents the near FWL reservoir heights. The near $Pc=0$ inflexion in Pc curves degrades the fit and is not relevant to the cored intervals, thus all data below $Pc=4$ psi (Height~7feet) was ignored. Numerous methods of fitting the Pc core data set were used including the established J Function⁴ approach, however the most successful was a multiple linear regression for $\text{Log}(Sw)$ from ϕ , $\text{Log}(k)$ and $Pc^{-0.25}$. These represent reasonably linear expressions of the predictive terms with $\text{Log}(Sw)$. The form of the predictive equation is:

$$\text{Log}(Sw) = a \times \phi + b \times \text{Log}(k) + c \times Pc^{-0.25} + d$$

where a, b, c and d are regression constants, different for each facies group. The ability of these equations to predict Sw is excellent (Fig. 6). This intra-core data capillary pressure

predicted S_w is termed S_{wpc} .

Conversion of P_c to reservoir Height. Conversion of the corrected laboratory capillary pressures to the corresponding reservoir Height is achieved by:

$$\text{Height} = \frac{P_{cab} \times \frac{T \cos \theta_{res}}{T \cos \theta_{ab}}}{g_w - g_{hc}}$$

The above indicates that $\text{Height above FWL} = P_{cab} \times 1.81$ feet. P_{cab} can now be replaced by Height in the S_{wpc} equations. The Height of each core is derived from wireline formation pressure depth plots in the conventional manner (Fig. 7). Height, routine core ϕ and k and the image-log facies group is entered into the log database for each section of core, and S_{wpc} predicted from the regressions.

At this point a log independent curve of ϕSh has been generated over all 900 feet of core data. Providing the routine core data is a statistically valid sample of the whole core this curve will provide a sound basis for log calibration. The core based curve of ϕSh is valid, regardless of fine beds or clay distribution, due to the machine sampling of all routine core data (Figs. 1 & 8).

Having generated S_{wpc} it is now necessary to integrate the logs in such a way as to duplicate it, just as cores and logs are integrated in a Juhasz³ evaluation to duplicate machine sampled core porosity through apparent fluid density (ρ_{hof}). The log integration for S_w is conceptually similar, but more involved.

Deriving log porosity. Log total porosity is derived in the established core-density log manner via regression crossplots of environmentally corrected ρ_{hob} versus stressed core porosity to determine ρ_{hof} (Fig. 9). Mean grain density (ρ_{hog}) provides a fixed point for ρ_{hob} at zero porosity. ρ_{hof} is derived per facies group and per fluid zone. ρ_{hof} derivation is not described here since it is already accepted good practice, at least where ρ_{hog} and ρ_{hof} are stable³. The numerous ρ_{hof} values generated may seem rather pedantic but are an essential prerequisite for the consistent evaluation of a core based ϕSh . ρ_{hog} and ρ_{hof} are used in:

$$\phi_t = \frac{\rho_{hog} - \rho_{hob}}{\rho_{hog} - \rho_{hof}}$$

During the derivation of core-log n^* ϕ_t is set to core porosity where core exists to minimise error. Differences between log and core porosity would create artificial variation in core-log n^* .

Deriving log saturation. We have described how S_{wpc} , the log independent reference for log saturation, is derived. The approach to log saturation uses the Waxman-Smiths equation as the vehicle for transforming logged parameters into useful output:

$$S_w = \left[\left(\frac{R_w}{R_t \phi_t^{m^*}} \right) \left(\frac{1}{1 + R_w B Q_v / S_w} \right) \right]^{(1/n^*)}$$

In this study the WS equation serves three specific functions:

- 1) to predict water saturated resistivity R_o ;
- 2) to calculate the apparent saturation exponent n^* continuously over cored intervals;
- 3) to predict S_w from n^* matched to S_{wpc} , and from conventional special core data n^* .

Water saturated resistivity, R_o . The prediction of R_o ($1/Co$) is via WS with S_w set to one. Expressed as conductivity this becomes:

$$Co = \phi_t^{m^*} (C_w + B Q_v)$$

The conventional derivation of these parameters is described only briefly here. The WS cementation exponent m^* is from special core analysis at reservoir equivalent hydrostatic stress using simulated reservoir brine. m^* is the 'intrinsic' or clay free ($BQ_v=0$) value of the Archie cementation exponent m . m^* varies from 1.84 to 1.92. These special core values are used in preference to log derived water zone m^* because of the zero uncertainty associated with laboratory R_w and the $S_w=1$ condition, which must be assumed in the logged water zone method. It should be noted that if predicted R_o does differ from logged R_o in 100% water zones the special core value of m^* , Q_v and or R_w are inappropriate. In this method these R_o errors will be absorbed by n^* , providing $S_{wpc} \sim S_{wpc}$. However, R_o must be predicted correctly if the full range of S_w 's are to be accurate and R_o should therefore be examined in some detail. The petrophysical ideal of accurate, full range ϕ and S_w is crucial to h in marginal rock.

For the Shallow reservoirs R_w ($1/C_w$) is assumed as 0.120ohmm, consistent with a recent R_w study. Some uncertainty is associated with R_w in that it may vary in hydrocarbon saturated reservoirs where its value is difficult to ascertain. However, the $[\phi-S_w-k-P_c]$ relationships and log derived S_w 's suggest this is a valid and reasonably stable value for R_w . An important benefit here is that any R_w error is compensated, and the R_w value used will be appropriate, providing R_w does not vary from the cored interval.

Q_v was determined conventionally on 63 samples by crushing and titration. During evaluation Q_v is derived continuously from its relation to porosity since Q_v samples have their porosity measured directly in core. Unfortunately the absence of core plug gamma ray disallows Q_v derivation from the more probable gamma ray- Q_v relationships. XRD and spectrographic core data were also not found to be useful in predicting core Q_v values.

WS B , the equivalent conductivity of exchange cations, is a function of temperature and R_w :

$$B = \frac{0.225T - 1.28 + 0.0004059T^2}{1 + R_w^{1.23} (0.045T - 0.27)}, \text{ mho/m per meq/cc}$$

The above parameters enable R_o to be predicted in water

and hydrocarbon zones, per facies.

It should be noted that clay distribution is not accounted for by BQ_v or any term in the WS equation, but can influence the apparent value of B during water zone log analysis. Here, these deleterious clay distribution effects are accounted for by the facies based n^* calibrations, overcoming this shortcoming.

Apparent saturation exponent n^* . The saturation exponent n^* dictates the rate at which calculated S_w drops below 1.00 as Rt/R_o rises above 1.00. Conventionally, n^* is determined by special core analysis, however this links the laboratory Rt/R_o to laboratory S_w whereas we require a more useful link, namely, that between **logged Rt/R_o** and **cored S_w** (**Fig. 4**). This is achieved by using the equation inputs so far with S_w set to S_{wpck} , and solving for n^* for each routine core plug. This is the mathematical equivalent of an n^* definition plot per routine core plug, and provides an n^* curve over cored intervals. Logged Rt/R_o is suppressed, particularly in centimeter heterolithic facies, by clay conductivity, so we can expect n^* to have low values under such conditions.

Rt is taken from the best Rt logging source available, typically the Azimuthal Resistivity Imager (ARI). The role of Rt needs explanation here since a key point of this technique is that it seeks to circumvent the need for a perfect Rt , which is anyway not possible, or even not meaningful in heterolithic or bioturbated facies (Introduction). The industry suffers from a certain degree of tunnel-vision and naivete with respect to Rt , which one glance at a core photograph should dispel! Core shows that sand and shale are rarely arranged in 'beds' circumferentially around the borehole (bioturbation, flaser beds) and finer resolution may not address the problem of how to use the logged $\emptyset$, V_{sh} (shaliness or BQ_v) and Rt together, to achieve the volumetrically correct average values of S_w necessary for correct EHC evaluation.

S_w from n^* and special core data n^* . The third function of the WS equation, to predict S_w from the core-matched n^* , is improved by a knowledge of clay volume. Essentially, variations in clay distribution are captured by facies, whereas variation in clay volume are captured by gamma ray. Gamma ray has the best correlation with clay volume and remains useful over washouts and changing fluid zones and saturations, unlike clay volumes based on density-neutron separation. Each facies group's apparent n^* values were regressed against normalised gamma ray ($sgrnorm$) from all cored wells. These regressions generally showed n^* decreased with increasing gamma ray e.g. for the Sands with discontinuous clays facies $n^* = 4.95 - 0.0437sgrnorm$. The facies group and gamma-ray modulation provide a prediction of n^* which forces the WS output (S_{wvs}) to mimic S_{wpck} . S_w from special core analysis n^* is also evaluated, which departs from S_{wvs} (**Fig. 10**).

S_{wvs} is solved iteratively using S_w from the Archie equation as the initial S_w value. Then $\emptyset Sh = \emptyset(1 - S_{wvs})$.

Netpay. That portion of the calculated hydrocarbons which should be excluded from reserves, if any, has not been addressed so far. Hydrocarbons which reside in rock so

impermeable that they cannot contribute to production over the life of a field should be excluded, for example, hydrocarbons in source rock shales. Netpay cut-offs are always difficult to establish and in new reservoirs which lack production history amount to an a-priori assertion. In permeable gas reservoirs it seems reasonable to assume that all gas will retard depletion somewhat, and no cut-off should be applied. However, conventionally a 0.1mD cutoff is applied in gas reservoirs. In intergranular pore systems the parameter which correlates best with permeability is $\emptyset Sh$, as seen from an annotation of Schlumberger⁶ chart k-4 in which $\emptyset Sh$ remains constant along lines of constant permeability. Concern over the accuracy of low end permeabilities has led to adopting an extremely conservative cut-off of 8mD, equivalent in the core P_c data set to $\emptyset Sh \sim 0.075$. A further conservative precautionary measure of normalised gamma ray being less than 100api precludes washed out intervals where borehole corrected gamma ray may be optimistic, and gas which may be associated with shales. These two extremely conservative cut-off criteria are intended to quash criticism of the increases in EHC reported by this study.

Results

The change from a conventional full core-log Waxman Smits evaluation to the technique described here represents an increase in EHC exceeding 20%. This is broadly in line with other detailed core-log studies of Tertiary shaly sands⁷. The 'Clean Sands' facies group are least affected at +9%, the 'Sands with Discontinuous Clay' slightly more affected at +16%, the 'Poor Reservoir' are more affected at +20%, and the 'Bioturbated and cm Heterolithic Sands' are most affected at +30% (**Table 5**). Unlike 'Poor Reservoir' the heterolithic facies do contain moderate volumes of gas which are heavily obscured by logs. See Conclusions.

Uncertainties

Can routine core analysis plugs correctly represent the EHC of heterolithic facies? This issue primarily concerns the heterolithic facies which comprise 20% of the total thickness but only approximately 12% of reserves due to their lower storage capacity. If core plugs are machine sampled, as logging tools sample the formation, core analysis will be representative assuming the plug numbers are adequate. Approximately 900 plugs are involved in the core-log calibrations (**Table 4**), and average values will prevail. Strict instructions to machine sample plugs accompanied all core analysis since inception. Core photographs, and a histogram analysis of the routine core data's sample increment (**Fig. 8**), confirms that this has been achieved. **Fig. 1** is a typical example of regular plugging regardless of sand or clay lithology. Photographs and the increment histogram suggest any core plug to whole core error is negligible. A further concern is that small sand lenses which may be isolated from the reservoir gas column are included by this method. Although this is not feasible with gas reservoirs, in similarly laminated oil reservoirs core fluorescence can be used to

identify unfilled sand lenses. This should be examined.

Does laboratory preparation and conditions alter P_c - S_w from reservoir conditions? Clays collapsing during plug preparation will decrease S_w for a given capillary pressure. Total porosity for correct density log calibration³ required that plugs were dried to 105°C for three days under vacuum, which may have collapsed clays. This possibility has been investigated on 10 plugs from 1-400mD, cleaned with cool toluene solvent and dried at 60°C and 40° relative humidity. Helium porosity and Klinkenberg permeabilities were measured at 1325; 1586; 1847 and 2108 psia net confining pressures (hydrostatic loading) and again after standard routine core analysis drying. Lower permeabilities were enhanced more by the 105°C drying, but the change remains small, with a 1% increase at 20mD and 3% at 1mD (**Fig. 11**). The changes in S_w these permeability changes imply for core-log calibration intervals is less than 1 saturation unit, indicating this problem to be minor.

Stress was corrected for. However, porous plate capillary pressures on eight, preserved, 0.3-100mD (low permeability) samples at reservoir stress and temperature, and with reservoir fluids has been proposed to further quantify possible reservoir to laboratory P_c - S_w effects.

Conclusions

1. Providing core plugs are machine sampled, capillary pressure data, routine core data and wireline formation pressures may be used to provide log independent estimates of the petrophysical input to reserves: $EHC = h \times \emptyset \times Sh$. However, the ability of routine core data to represent whole core must be examined.

2. The integration of image-logs, core capillary pressures and conventional logs exploits pre-existing data cost effectively to increase reserves certainty and reduce capital investment risk.

3. Increased reserves are achieved by circumventing classic log analysis shaly sand, excess-conductivity problems which suppress log analysis Sh . Such problems are characteristic of the freshwater stacked Tertiary clastics of S.E. Asia.

4. Individual facies suggest the change from a conventional Waxman Smits analysis to the core-image-log-log integration described here increases with clay content and increases with clay continuity.

5. Enhanced R_t resolution is desirable, but is not essential. The integration calibrates the available log data, regardless of resolution, to log independent EHC . However, enhanced resolution R_t will lessen the sensitivity to clay volume (gamma ray) and hence reduce the range of the required n^* prediction.

6. This method may be applied through a simpler modified Archie approach in which water zone m is derived as a function of $\emptyset$ and V_{clay} . n or n^* should then be derived from all reliable log independent values of S_w , plotted against the log data R_t/R_o . Log independent S_w 's include oil mud core, low invasion core, the commonly available core capillary

pressures described here, and routine core data with chart K-4⁶. These core-log n values should then be critically assessed against electrical special core n , and the appropriate n selected.

7. This method may be used as a general template for complete $\emptyset Sh$ core-log integration. Each field's core and log data, and geology and fluids, must be examined case by case in the quest for the n^* derivation which generates actual reservoir saturations.

Nomenclature

B	= WS equivalent conductivity of clay exchange cations, mho/m per meq/cc
C_t	= $1/R_t$, 'true' formation conductivity, mmho/m
<i>Equivalent hydrostatic stress</i>	= the stress applied hydrostatically in the laboratory which is equivalent to the reservoir's uniaxial stress, psia
ghc	= hydrocarbon gradient, 0.055 psi/ft (from well test gas compositions)
gw	= water gradient, 0.423 psi/ft (fm. pressure data)
h	= netpay thickness, feet
<i>Height</i>	= equivalent height above FWL, feet
m^*	= WS porosity (cementation) exponent
n^*	= WS saturation exponent
P_c	= measured capillary pressure, psi
P_c^*	= stress corrected capillary pressure, psi
P_{cab}	= laboratory air/brine capillary pressure, psi
Q_v	= WS effective concentration of clay exchange cations per unit pore fluid volume, meq/cc (meq of CEC per cc of pore fluid)
ρ_{hog}	= core grain density, g/cc
ρ_{hof}	= apparent fluid density, g/cc
R_t	= 'true' resistivity of formation, ohmm
R_w	= resistivity of formation water, ohmm
Sh	= hydrocarbon saturation of evaluated porosity, dec
S_{nw}	= laboratory saturation of non wetting phase (air)
S_{nw}^*	= stress corrected saturation of non wetting phase (air)
S_w	= water saturation of the evaluated porosity, decimal
S_{wpc}	= core data's prediction of S_w from P_c , k and $\emptyset$, per facies group
T	= temperature, °C
$T \cos \theta$	= interfacial tension $\times$ cosine (assumed contact angle), reservoir ~ 48 dynes/cm, air-brine ~ 72 dynes/cm
V_{clay}	= clay volume, decimal
WS	= Waxman and Smits (equation)
$\emptyset_{lab}$	= laboratory measured porosity
$\emptyset_{res}$	= reservoir porosity from laboratory uniaxially corrected overburden data, decimal
$\emptyset_t$	= total porosity, decimal

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Tables

Table 1 Petrophysical uncertainties, ranked

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Table 3 Lumping of 12 original core-image log facies to 4 petrophysical facies groups

Table 4 Facies group, number of routine core analysis plugs and average *Height*

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Figures

Fig. 1 The complex network of clay distribution suggests: 1) the inadequacy of resistivity modeling and, 2) the machine sampled core plugs must be investigated for their ability to represent whole core

Fig. 2 Whole core would provide a log independent direct measure of *EHC* over the gross interval

Fig. 3 Features of interest during facies based core-log n^* integration. Logs show little indication of pay

Fig. 4 Schematic of the facies based core-log n^* integration

Fig. 5 Methane and water interfacial tensions

Fig. 6 Special core data multiple linear regression predictions of S_w ('*Swpck*') from P_c , ϕ and k for each facies group

Fig. 7 Projected gas water contact and reservoir capillary pressure from wireline formation pressures for the *Pc-Height* conversion

Fig. 8 Regularly sampled routine core data. Standard 1.00 foot plug increment or 1.20 upon failure

Fig. 9 Example of derivation of *rhof* per facies group and fluid zone

Fig. 10 S_{wws} from core-log n^* and S_{wsca} from special core n^*

Fig. 11 The increase in permeability due to 105°C drying over 60°C / 40 RH humidity drying is negligible

Table 1 Petrophysical uncertainties, ranked			
<i>Feature</i>	<i>Relevance to log data</i>	<i>Log analysis result</i>	<i>Addressed by this study</i>
dm scale clay network conductivity	Excess conductivity inadequately modelled by core plug BQv	Sw error, high Sw	Yes: core-log n*
Laminated sands	Logged Ct only partially influenced by Sw	High Sw, Sw error	Yes: core-log n*
Variable clay distribution	Variable relationship between logged Ct and Sw. Improperly matched Ct, Ø and BQv inputs	Sw error	Yes: image-log facies groups
High Rw	Poor HC/water differentiation	Misidentification of pay	Yes if Rw_cored = Rw_uncored
Poorly known Rw	Poorly known Ct:Sw relationship	Sw error	Yes if Rw_cored = Rw_uncored
Invasion	Apparent Rt < True Rt	High Sw, low pay thickness, low EHC	Yes if invasion_cored = invasion_uncored, Else no

Excess conductivity = Conductivity not modelled by Archie equation

Table 2 Data for facies based core-log n* integration	
Conventional logs	Essential
Formation pressures (<i>Height</i>)	Essential
Machine sampled routine core data	Essential
<i>Pc-Sw</i> special core data	Essential
Image-logs facies / other log facies	Essential
Core overburden Ø and <i>m</i> *	Desirable
Core <i>CEC</i> / <i>Qv</i>	Desirable
NMR logs	Desirable
Log independent <i>Rw</i>	Desirable
Whole core <i>Pc-Sw</i>	Desirable

Table 3 Lumping of 12 original core-image log facies to 4 petrophysical facies		
<i>Facies Group</i>	<i>= Core-image log Facies</i>	<i>Character</i>
1. Clean Sands	4. Massive ssts 7. Cross-bedded ssts 1. Mudclast-rich ssts	High reservoir quality
2. Sands w. Discontinuous Clay	11. Sand-rich heterolithics 12. Laminated sandstones	If Vclay > 70% sand is discontinuous
3. Bioturbated + cm Heteroliths	5. Bioturbated heterolithics 8. Rippled heterolithics	High Ct
4. Poor Reservoir	6. Bioturbated ssts 2. Bioturbated mudstones 3. Coal 9. Paleosoils 10. Mudstones	High Ct Biot sd has contin. tortuous k path

Table 4 Facies group, number of routine core analysis plugs and average Height

<i>Facies Group</i>	<i>Mean calib. Height, ft</i>	<i>No of calib. plugs</i>
1. Clean Sands	29	70
2. Sand w. Discontinuous Clay	63	190
3. Bioturbated + cm Heterolithic Sands	94	270
4. Poor Reservoir	57	362

Table 5 Facies group changes, n* and EHC

<i>Facies Group</i>	<i>SCA n*</i>	<i>Mean core-log n*</i>	<i>% change EHC</i>
1. Clean Sands	1.76	1.53	9
2. Sand w. Discontinuous Clay	1.93	1.55	16
3. Bioturbated + cm Heterolithic Sands	2.03	1.40	31
4. Poor Reservoir	1.54	1.24	20



Fig. 1 The complex network of clay distribution suggests: 1) the inadequacy of resistivity modeling and, 2) the machine sampled core plugs must be investigated for their ability to represent whole core

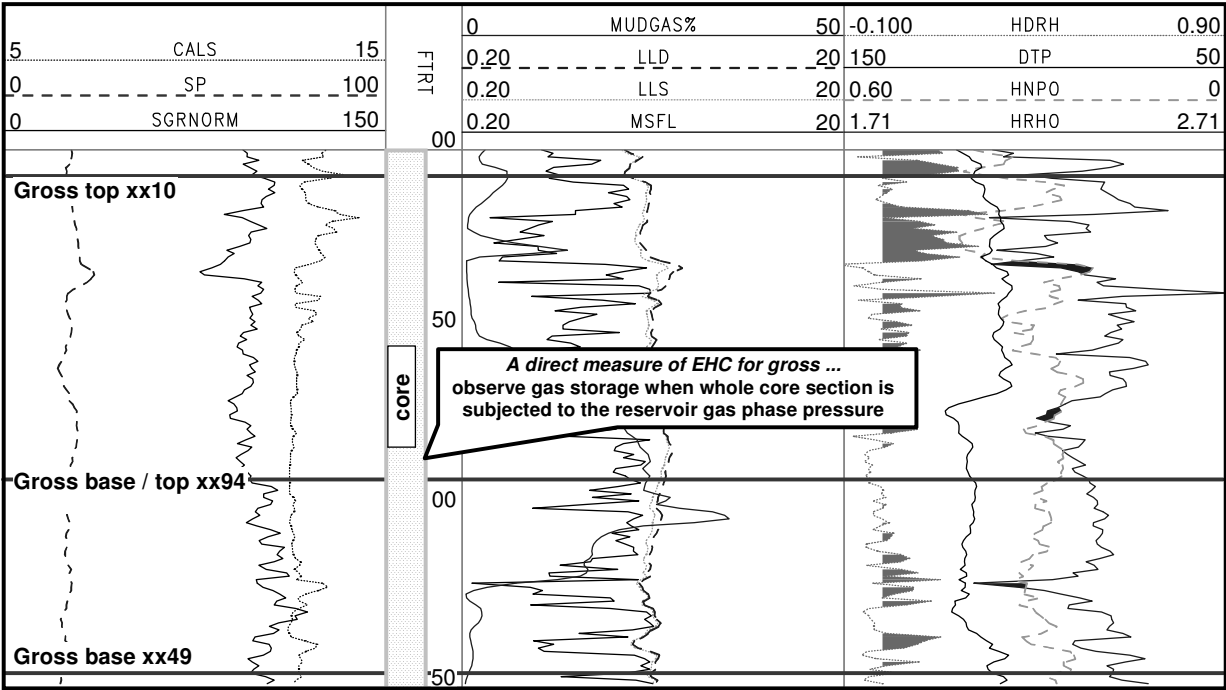


Fig. 2 Whole core would provide a log independent direct measure of *EHC* over the gross interval

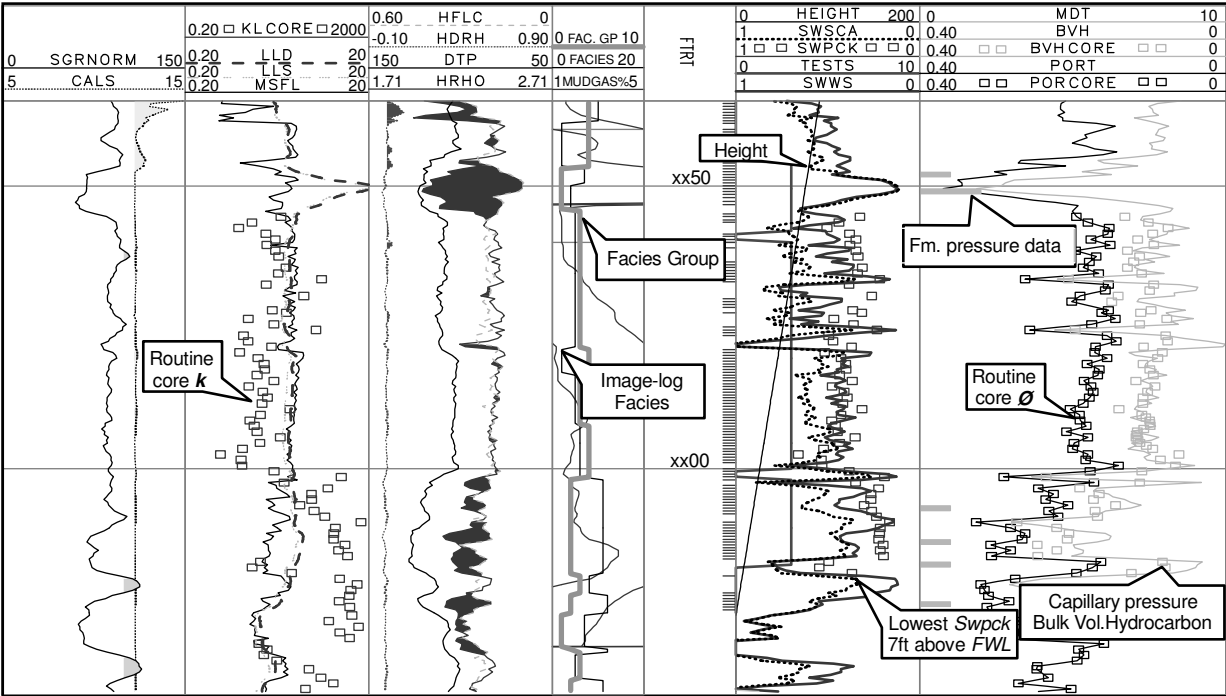


Fig. 3 Features of interest during facies based core-log n^* integration. Logs show little indication of pay

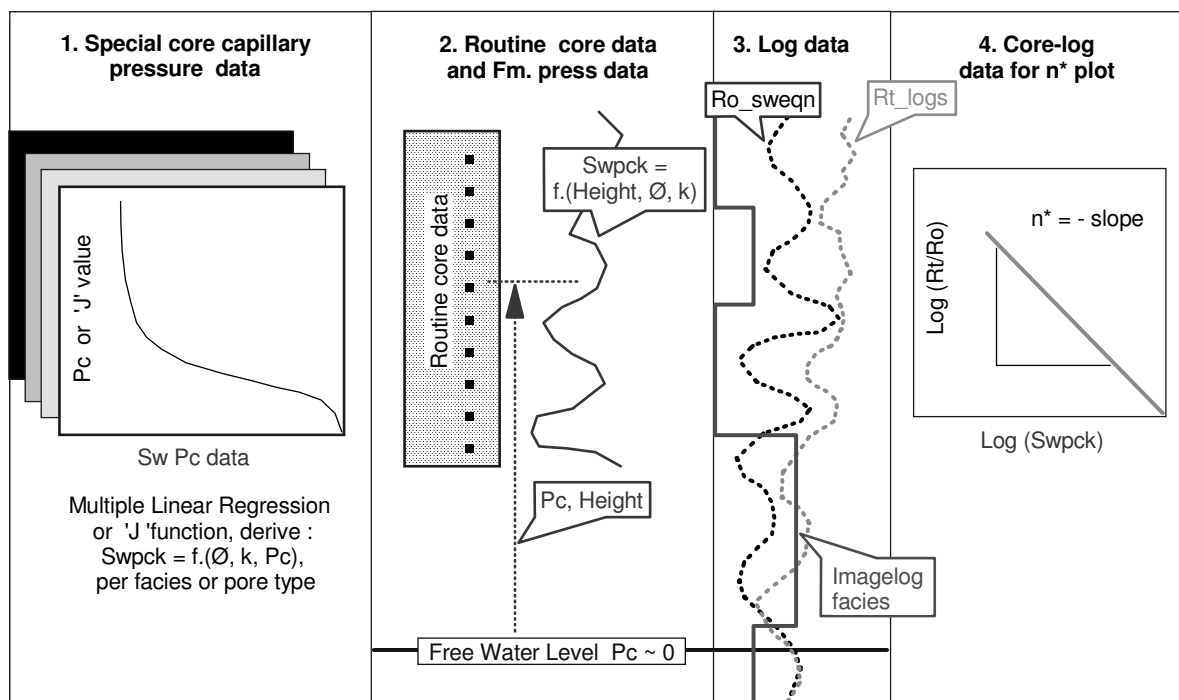
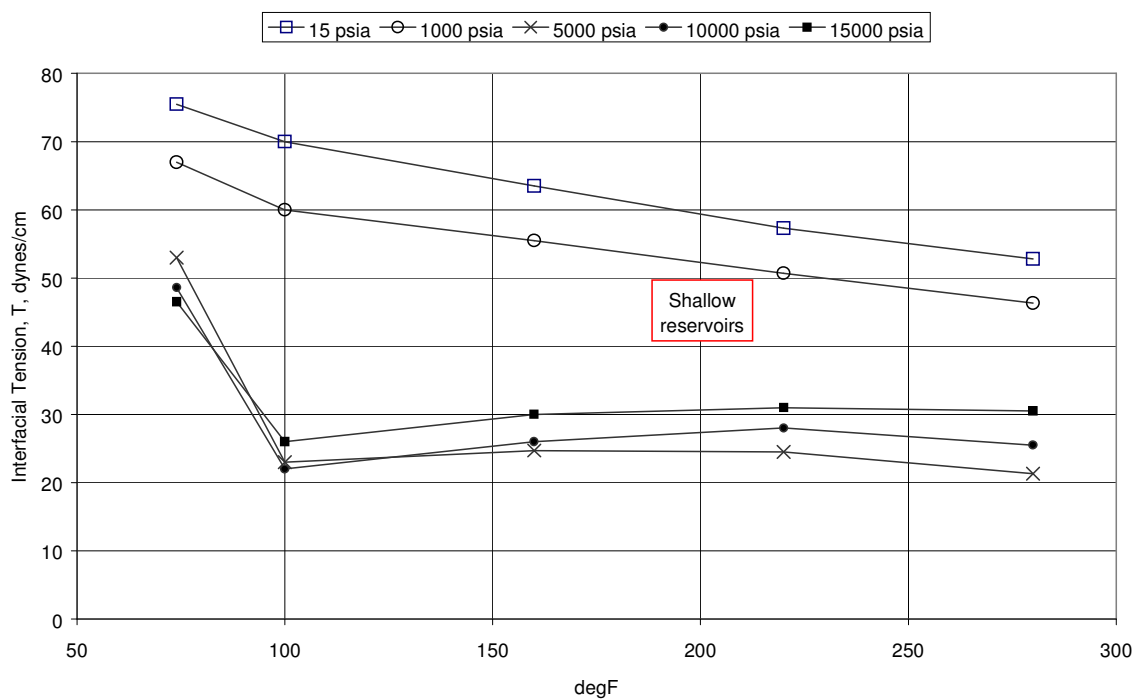
Fig. 4 Schematic of the facies based core-log n^* integration

Fig. 5 Methane and water interfacial tensions

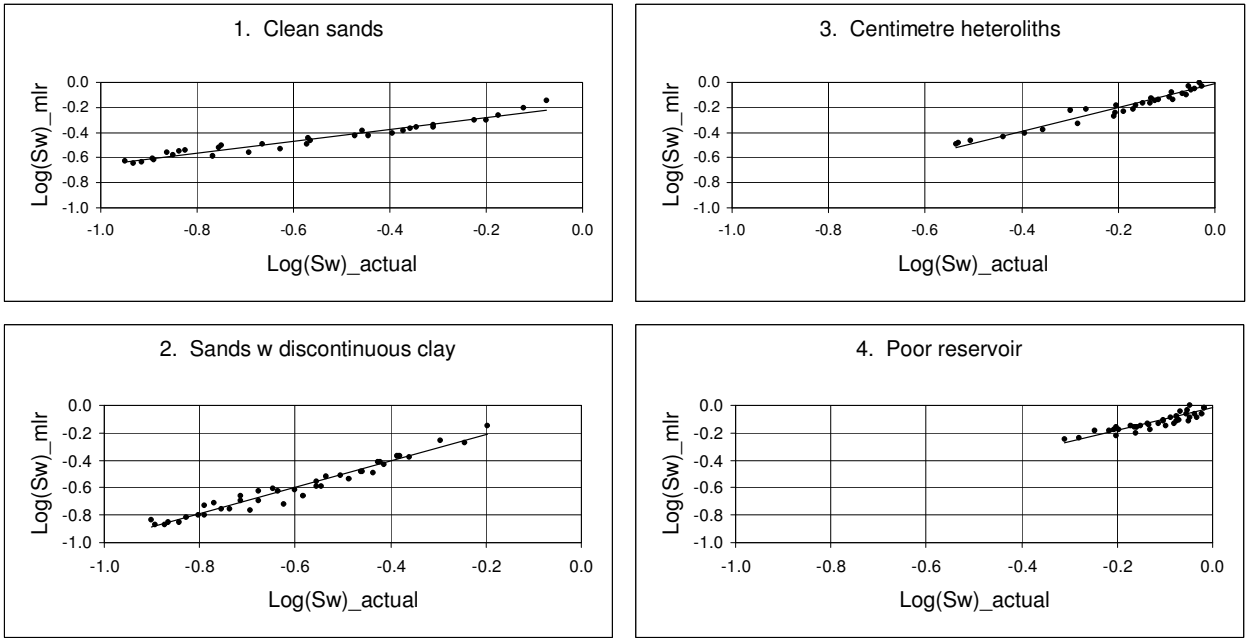


Fig. 6 Special core data multiple linear regression predictions of Sw ('Sw_{pck}') from P_c , ϕ and k for each facies group

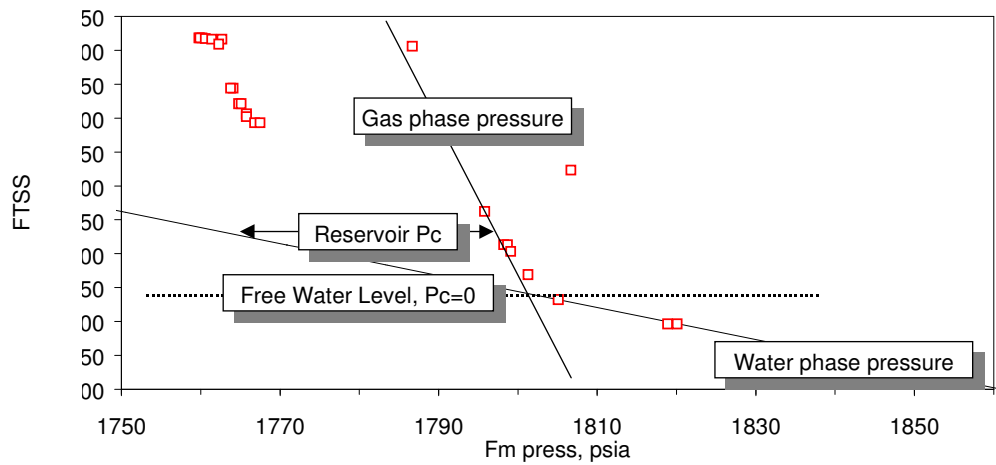


Fig. 7 Projected gas water contact and reservoir capillary pressure from wireline formation pressures for the P_c -Height conversion

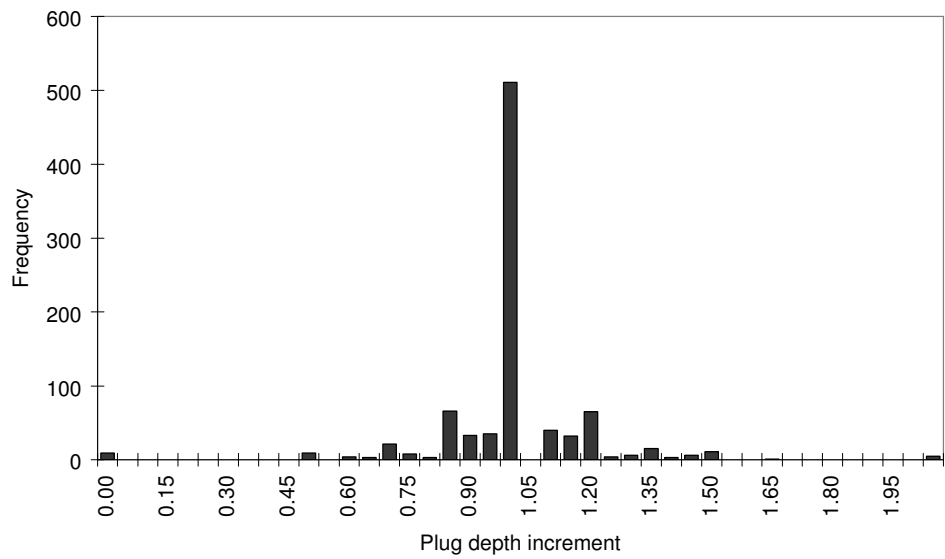


Fig. 8 Regularly sampled routine core data. Standard 1.00 foot plug increment or 1.20 upon failure

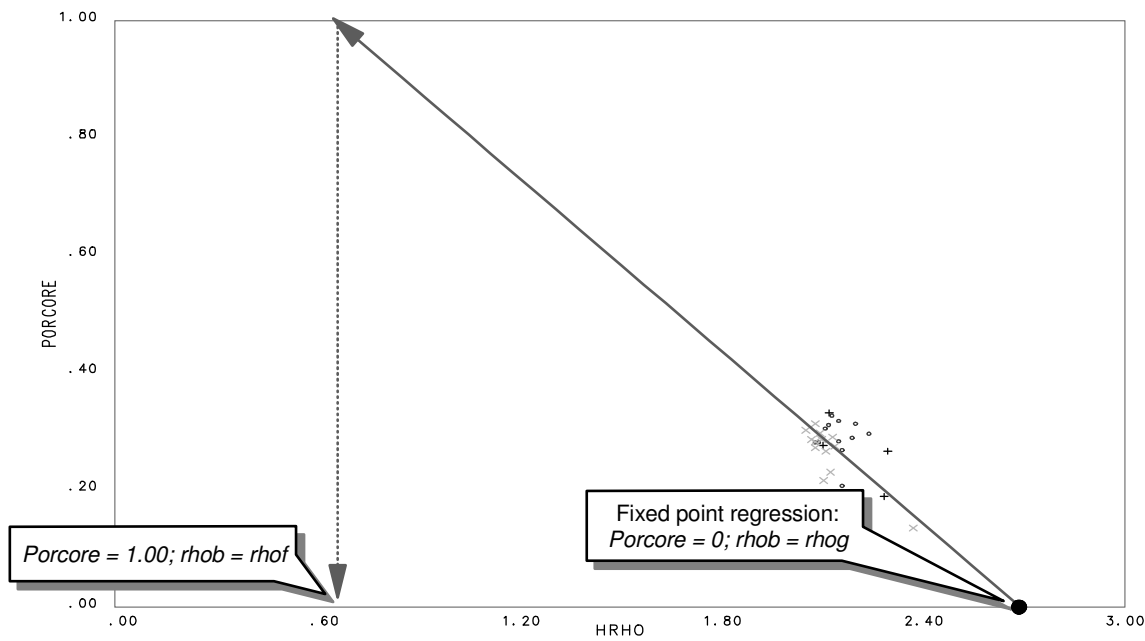


Fig. 9 Example of derivation of $rhof$ per facies group and fluid zone

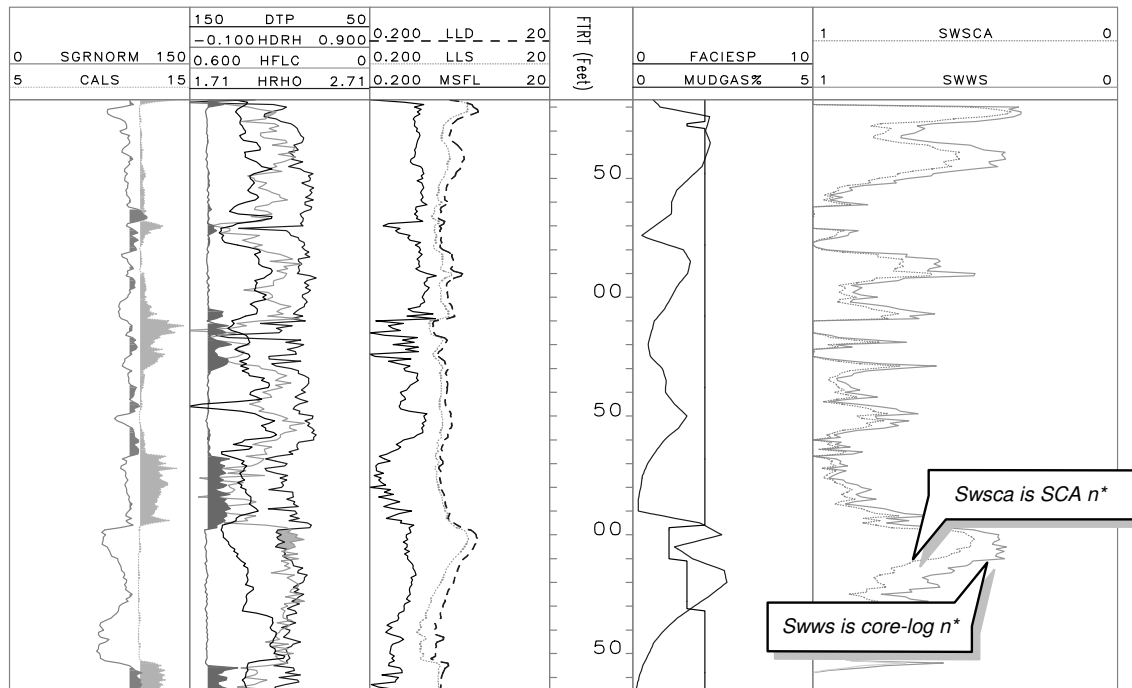


Fig. 10 $S_{w_{ws}}$ from core-log n^* and $S_{w_{sca}}$ from special core n^*

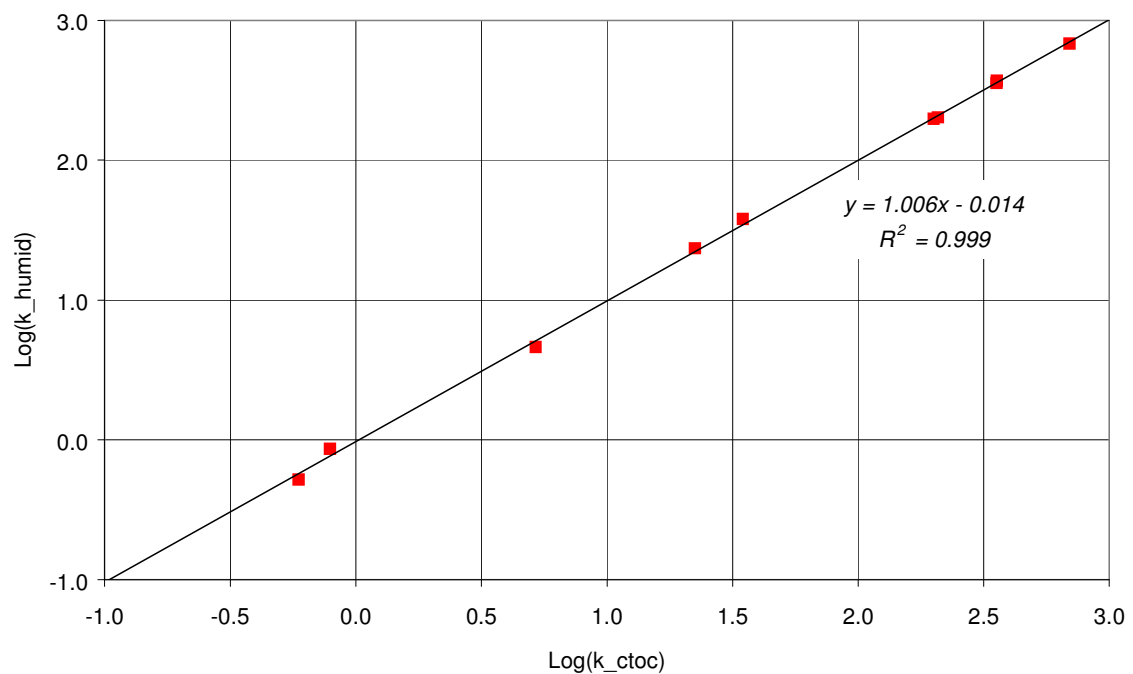


Fig. 11 The increase in permeability due to 105°C drying over 60°C / 40 RH humidity drying is negligible

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