APPLICATION OF CORE ANALYSIS DATA FOR FORMATION EVALUATION

by

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ABSTRACT

The primary goal of most reservoir evaluation studies is the integration of data from various sources to indentify zones with similar fluid flow characteristics, and to define the areal and lateral continuity of such zones.

Core data developed on rock samples recovered from a formation or interest zone which play a vital role in exploration programs, well completion and workover operations and in well and reservoir evaluation. Coring is the only mean of obtaining an actual sample of an oil bearing formation to study. These cores, with proper handling and preservation, are used to obtained data which permit accurate evaluation of the oil or gas reservoirs.

This paper presents a practical used of core analysis data for formation evaluation of reservoir hydrocarbon and to provide information that will be of practical value to geologists and engineers involved with the interpretation of core analysis data.

I. INTRODUCTION

Core analysis should be established early in the drilling program. Managerial, drilling, geological, and engineering requirements must all be considered.

The application of core analysis to provide data for reser- voir evaluation is not a new science but has seen continued research activity over along period.

Core analysis is complex containing many stages between the reservoir and the final measurements and interpretation. To ensure whether the data produced is valid every step along this phase must be handled with equal attention. Regular core analysis data obtained in conventional and whole core analysis provide the range of values and average values for porosity (storage capacity) and permeability (general flowability) and an estimate of oil and water saturation in the reservoir.

The study of a representative sample of an oil bearing formation, as obtained by coring, provides the only means for direct measurement of many important properties of the formation.

Many of the basic principles used in core analysis today are the same as those originally established by the pioneers in the field. Techniques have been expanded and improved and instrumentation has undergone change, however, attention to detail and selection of the proper analytical techniques for the rock type recovered are still essential to secure valid data.

Core analysis data, used in formation evaluation are essential for :

- Determination of reservoir fluid zones
- Determination of distribution of porosity
- Determination of distribution of permeability
- Prediction of reservoir perfomance
- Prediction of reservoir quality
- Prediction of rock heterogeneity index
- Determination of pore throat sorting
- Determination quality of effective porosity
- Prediction of recovery efficiency
- Pore size distribution
- Etc.

Attached are some brief method informations and application of core data in evaluating oil and gas reservoirs.

II. APPLICATION OF CORE ANALYSIS DATA

Core analysis still remains a basic tool for obtaining the most direct and reliable information concerning the rocks penetrated by the drill.

A. *Application of fluid saturation data to predict the reservoir type*

The recommended method for determining water and oil saturations is the Dean-Stark extraction, which can be used to determine the saturation of both plug samples and full core samples. Another advantage of the Dean-Stark technique is that it also cleans the sample. If plug sample are used, the bit lubricant should be the same as the mud used to take the core. In other words, if the core was drilled with a water-based mud, the plug samples should be drilled with an appropriate brine.

Many factors influence on the results of fluid saturations at the laboratory, however the most influencing factor is the effect of coring fluids during coring operation (Table 1).

Observation and analysis of a fresh core remain the best available means to evaluate a potential reservoir if used in conjunction with other tools such as testing and electric logging. Careful useage of the parameters provided by core analysis allow electric logs to be calibrated so as to afford reliable estimations of actual reservoir properties.

It should be remembered that actual reservoir saturations are altered by filtrate invasion during coring and by the pressure reduction and gas expansion as the rock is brought to surface conditions. Laboratory data will indicate the presence or absence of oil and normally an upper limit (in water base core) of water present in the reservoir for comparison with other data. Rough interpretation data for determining of reservoir type presented in Table 2.

Example application of fluid saturation data, as shown in Figure 1

B. *Application of porosity and permeability data to calculate the reservoir quality index (RQI) and level heterogeneity index (HI)*

An important aspect of reservoir description is to describe the reservoir quality index and level of heterogeneity of the pore network. Reservoir porosity and permeability will tend to be lower than those

Table-2
Rough interpretation of reservoir type

So (Average)	Sw (Average)	Reservoir type expected
3%	50%	Gas
2 - 5 %	60%	Oil & Gas
5%	50 - 70 %	Oil
1%	70	Water

Table 1
Effect of coring fluids

Coring fluid	Filtrate	Sw	So
Water base mud	water	higher	lower
Oil base mud	oil	constant	higher
Oil Emulsion	water	higher	lower
Gas	gas	constant	replaced
Air (Water)	uncertain	uncertain	lower

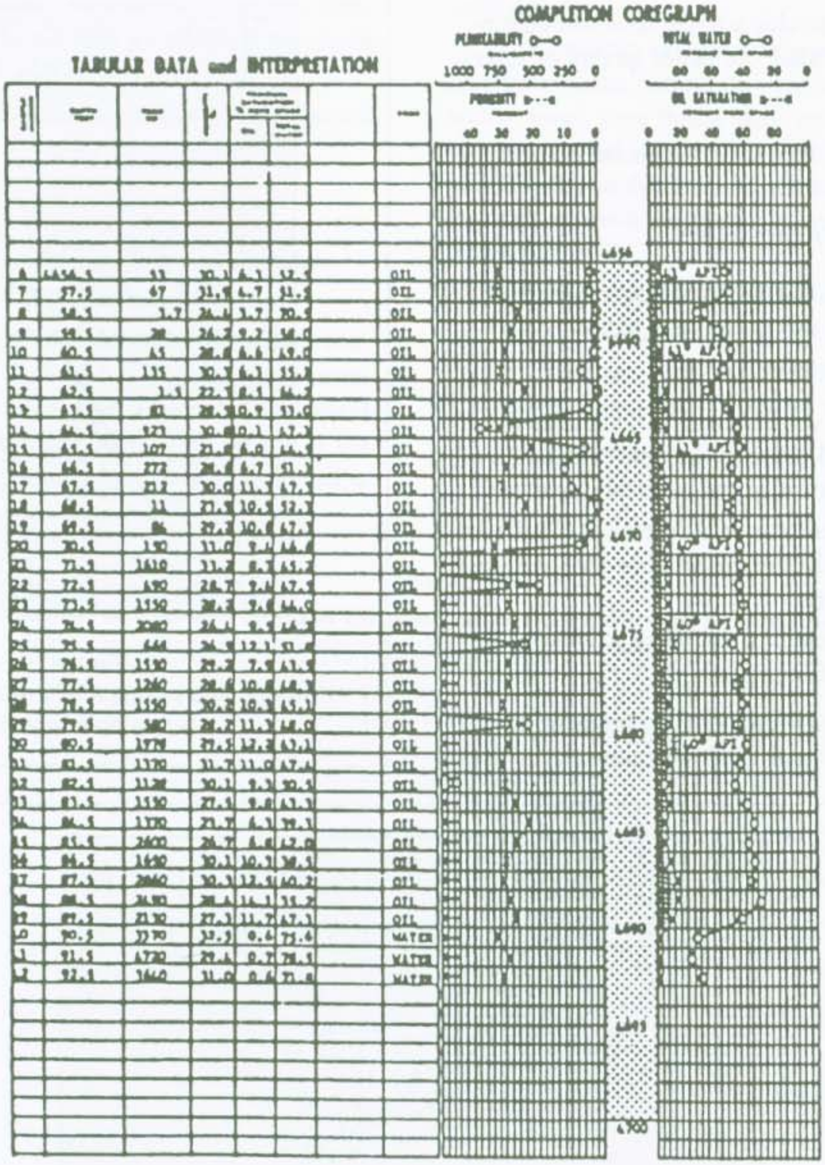


Figure 1
Interpretation of reservoir fluids zones

measured in the laboratory due to the presence of more than one fluid and the effect of overburden pressures. It is, however, recommended to obtain porosity and permeability data at reservoir conditions.

1. Porosity and permeability data determined at various net overburden pressures, are used to calculate Reservoir Quality Index (*RQI*), using Kozeny-Carmen equation :

RQI (mikrons) = $0.0314\sqrt{(k/\theta)}$ .... (1)

RQI can be used to characterize reservoir quality. The higher *RQI* value, the better quality of reservoir.

2. A Heterogeneity Index (*HI*), can be defined as follow :

$HI = \log [\, a \,.\, \theta / RQI \,] / RQI \,]$ ....(2)

where : α = 3.238 x 10-9 . β . k
β = 1.092 x 1011 k-1.8872
RQI = 0.0314 (k / θ)

Samples with HI values less than 1 indicate much better quality. Table 3 presents the data calculation of *RQ* and *HI* base on porosity and permeability data.

Figure 2 indicates plot of *K* versus θ. This plot data can be used to select representative core samples-for special core analysis.

Figure-3 show graphical of *HI* vs *RQI* from deltaic shally sandstone formation.

This figure presents functional relationship for *HI* vs *RQI* for the upper and the lower zones. It is note

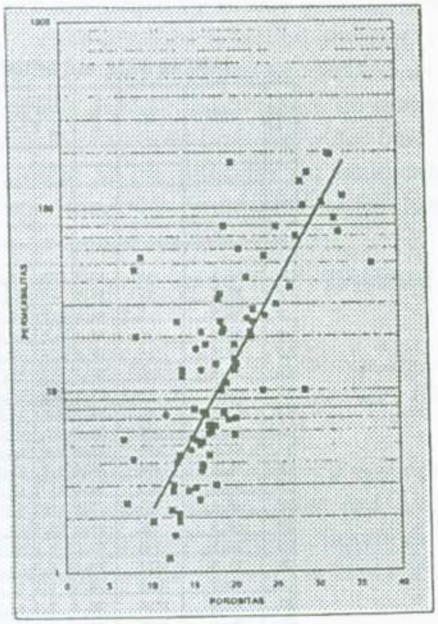


Figure 2
Porosity and permeability relations required for sample selection

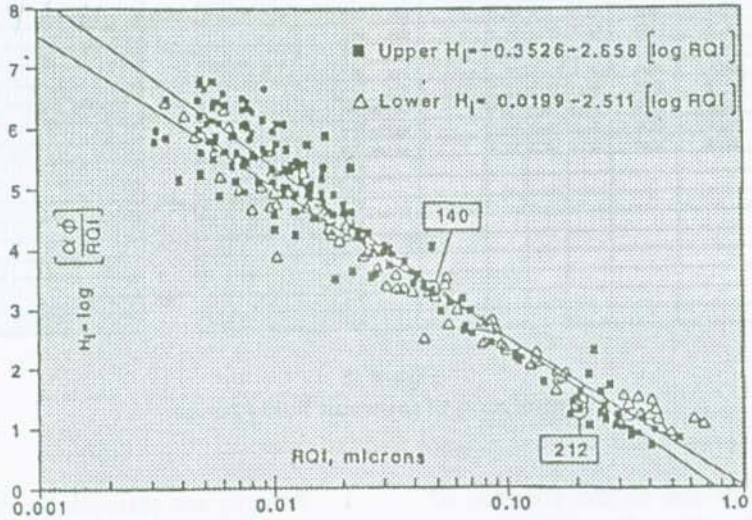


Figure 3
RQI and HI relations

worthy that sample 140 (clay type: chlorite) behaved quite differently from sample 212 (clay type: kaolinite). Sample 212 showed an identical but much lower *HI* than sample 140.

Samples with *HI* values less than 1 have much better quality.

C. *Application of mercury capillary pressure data to calculate pore throat sorting (PTS)*

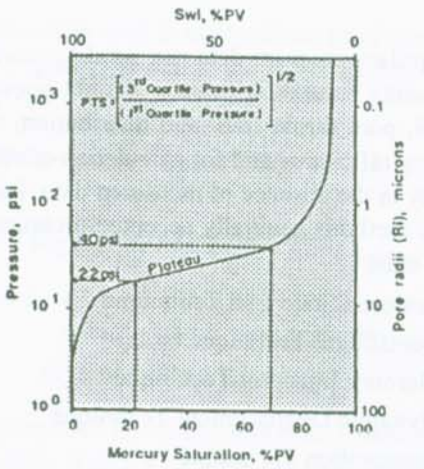
Pore geometry varies from reservoir to reservoir, and changes with lithology, depositional environment,diagenesis and rock type. The most important variable in the commercial production of oil is the size and distribution of the pores in which the oil is stored and through which it must flow to reach the wellbore.

The capillary pressure data are used to compute reservoir water saturation versus height above the water level, pore throat size and distribution, reservoir recovery efficiency and for calculation of relative permeability in the absence of measured data. Following are five methods generally accepted measurement techniques exist :

(a) Restored State Cell Technique
(b) Centrifugal Technique
(c) Mercury Injection Technique
(d) Dynamic Displacement Technique
(e) Evaporation Technique

Table 3
Data calculation of RQI and HI base on overburden porosity and permeability data

No	Aman	k (mD)	θ	RQI	β	α	HI
1.	9645	37	27.04	0.03673	1.2E+08	14.3612	4.02417
2.	9648	197	31.78	0.07818	5106296	3.25723	3.12192
3.	9651	155	29.32	0.0722	8028394	4.02937	3.21389
4.	9854	116	33.53	0.0584	1.4E+07	5.2109	3.4759
5.	9657	103	28.77	0.05941	1.7E+07	5.79042	3.4777
6.	9660	88	32.48	0.05168	2.3E+07	6.65816	3.62161
7.	9663	50	36.86	0.03657	6.8E+07	10.9944	4.04459
8.	9666	139	28.43	0.06943	9861094	4.4383	3.25944
9.	9669	70	27.84	0.04979	3.6E+07	8.15696	3.65905
10.	9672	79	25.48	0.05529	2.9E+07	7.32698	3.52848
11.	9675	54	9.26	0.07583	5.9E+07	10.2688	3.09831
12.	9678	2.4	7.22	0.0181	2.1E+10	162.621	4.81195
13.	9681	5.5	15.08	0.01896	4.4E+09	77.9201	4.79214
14.	9684	6.5	17.32	0.01924	3.2E+09	67.1866	4.78172
15.	9687	4.4	13.47	0.01795	6.7E+09	94.9791	4.85302



Mercury saturation = 92%

Q_1 = 0.25 x 92% = 23% P_1 = 22 psi

Q_3 = 0.75 x 92% = 69% P_3 = 40 psi

PTS = $(40 psi/22 psi)^{1/2}$ = 1.35

Figur 4

Calculating pore throat sorting using mercury injection capillary pressure curve (from Jennings, 1967)

Mercury injection capillary pressure is performed by two basic processes (Drainage and Inbibition processes).

PTS can be defined by mercury injection capillary pressure data using equation :

$$PTS = [\frac{P_3}{P_1}]^{0.5} \quad .... (3)$$

where : $P1$ = First quartile

P_3 = Third quartile

PTS = Pore Throat Sorting

P_1 and P_3 are defined from Pc vs Shg *curve*. $PTS = 1$ indicates a good sorting, however $PTS > 5$ indicating poor pore throat sorted.

Figure 4 shows the Drainage Mercury Injection Capillary Pressure curve and explanation for PTS calculation. (After Jennings, 1967)

D. *Application of mercury capillary pressure data to define effective porosity sorting*

The quality of effective porosity can be defined from Pc vs Mercury saturation (SHg) curve. Quality of effective porosity is indicated by area above each curve.

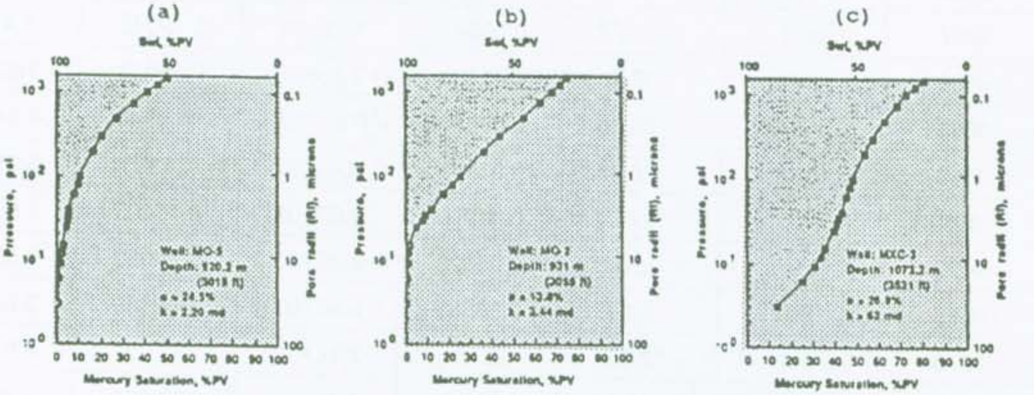


Figure 5

Effective porosity indicated by mercury injection curve. The area above the curve indicates the effectivess of the interconnected pores within the rock sample. (a) has the least effective porosity, while (c) has the most effective porosity among the three samples

The larger area, the better effective porosity.

Figure 5 presents plot data of three different type of effective porosity sorting.

E. *Application of mercury capillary pressure data for predicting recovery efficiency (RE)*

Recovery Efficiency of oil reservoir can be predicted from Mercury Injection Capillary Pressure data using the equation :

$$RE = \frac{SHg_1 - SHg_2}{SHg_1} x\ 100\% \text{..................} \quad (4)$$

where : RE = recovery efficiency, %
SHg_1 = maximum volume of mercury injected at maximum pressure
SHg_2 = volume of mercury remain in pores afterpressure is reduced to zero point

Plot data in Figure 6 can be used for recovery efficiency calculation. The higher value, the better recovery.

F. *Application of mercury capillary pressure data for pore entry radii (RI) and pore size distributions (DRI) calculation*

Pore entry radii (*Ri*) in the rock can be calculated from mercury injection capillary pressure data using the following equation :

$$Ri = \frac{2.\ \sigma \cos\theta\ .\ C}{Pc} \quad \text{..................}(5)$$

where : σ = Interfacial Tension, dynes/cm
θ = Contact Angle, degrees
C (Kozeny Number) = 145×10^{-3}

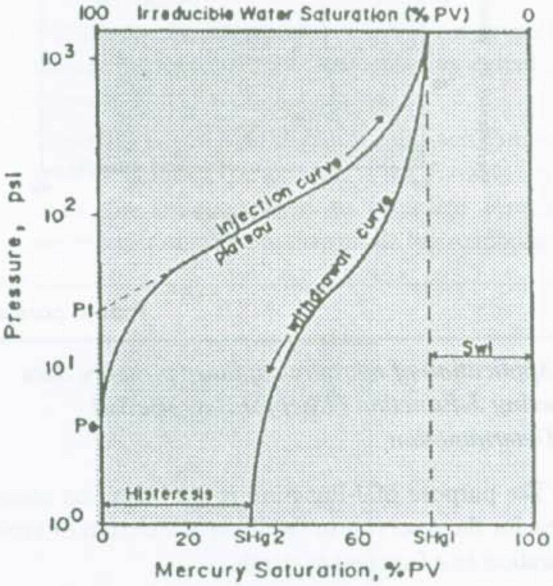
Pore size distribution can be calculated from Mercury injection capillary pressure data using equation :

$$Dri = \frac{Pc}{Ri}\frac{d\,Sw}{d\,Pc} \quad \text{..................} \quad (6)$$

where : $dSw = Sw(n+1) - Sw(n)$
$dPc = Pc(n+1) - Pc(n)$

Pore size distribution can be defined using incremental mercury injected (*Shg*) versus pore radii (*Ri*).

Figure-7 shows Pore Size Distribution plot data.



RE = (SHg1 - SHg2)/SHg1 x 100%

RE - recovery efficiency
SHg1 - maximum volume of mercury injected into the pore volume of the sample at maximum pressure (1500 psi)
SHg2 - volume of mercury remaining in the pore volume of sample when pressure is reduced from 1500 psi to zero pressure
Swi - irreducible water saturation, is the percentage of pore volume not entered by mercury at 1500 psi
Pe - entry pressure, is the minimum pressure at which mercury first enters the pore system of the sample
Pt - threshold pressure, is extended from the plateau to the pressure scale and is defined as the pressure at which first mercury imbibes into the rock at reservoir conditions

Hysteresis reflects the residual non-wetting fluid saturation.

Figure 6
Injection-withdrawal mercury saturation curves versus capillary pressure showing the terminology and the way to calculte reccovery efficiency (RE)

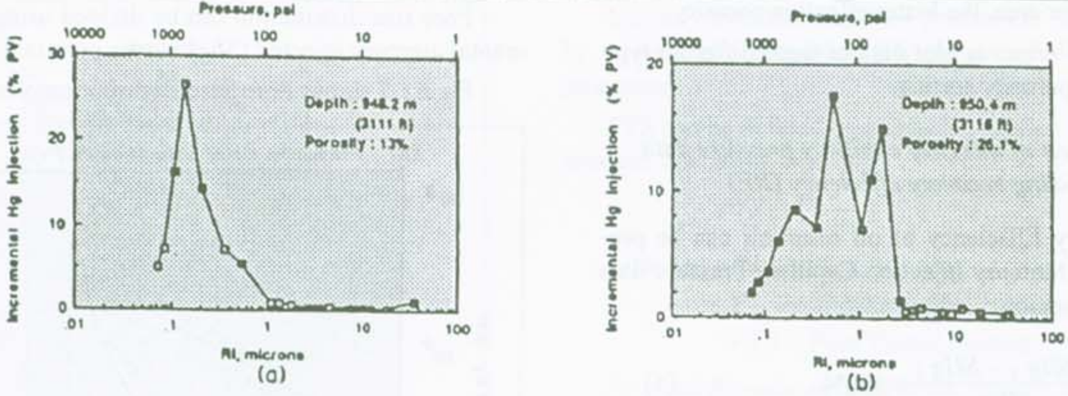


Figure 7
Plot of pore size distribution curve

G. *Application of mercury capillary pressure data using J-Function (JSw) for Average Swi Determination*

The purpose of J-Function is to obtain one correlation for the reservoir to facilitate calculation of brine saturation as a function of depth.

$$J(Sw) = \frac{Pc}{\sigma \cos \theta} \sqrt{(\frac{k}{\Phi})} \quad () \quad \text{.............} \quad (7)$$

where : Pc = Capillary Pressure, dyne/cm^2
k = Absolute Permeability, cm^2
Φ = Porosity, fraction
σ = Interfacial tension, dyne/cm

1 Darcy = 9.896×10^{-9}

1 Atm. = 1.0133×10^{6}

If units of k in md and Pc in psi, the equation can be simplified such as :

$$J(Sw) = \frac{F \ x \ Pc}{\sigma \cos \theta} \sqrt{(\frac{k}{\Phi})} \quad () \quad \text{..................} \quad (7a)$$

where : $F = 0.2166$ as units conversion factor

H. *Application of capillary pressure curve and relative permeability data to predict transition zone*

The oil-water contact usually is define as the lowest level in reservoir that will produce water-free oil. The transition zone is the vertical interval between lowest water-free oil and the highest leveel that will produce 100 % water.

Arps defined the oil-water transition zone by comparing various reservoir saturation levels to capillary pressure curves and relative permeability data. The capillary pressure data from core samples are used to confirm transition zone thickness.

Conversion of capillary pressure data to equivalent heights above 100 % water saturation level is by the following equation :

$$H = (Pcr)/(Sw - Sh) \quad \text{....................} \quad (8)$$

where : H = Height in feet above 100 %% water level corresponding to Zero Capillary Pressure.
Pcr = Capillarypressure at initial reservoir conditions, psi
Sw = Water Gradient in psi/ft at initial reservoir conditions
Sh = Hydrocarbon Gradient in psi/ft at initial reservoir conditions.

Table 4
CEC and resistivity of several clay minerals

Clay mineral groups	CEC meq/100 gr	Resistivity ohm.m @ 77° F
Montmorillonite	80 - 150	0.7 - 1.5
Illite	10 - 40	1.0 - 3.0
Kaolinite	3 - 15	> 3
Chlorite	10 - 40	> 3

A composite plot of these data are shown on Figure 8.

I. *Application of resistivity and C.E.C data in water saturation (Sw) calculations*

1. Resistivity measurements define for a given formation parameters used in electric log calculation of porosity and water saturation.

   These measurements define for a given formation with its unique pore geometry, the variables, a, m, n in the equation used to calculate formation water saturations from downhole log response.

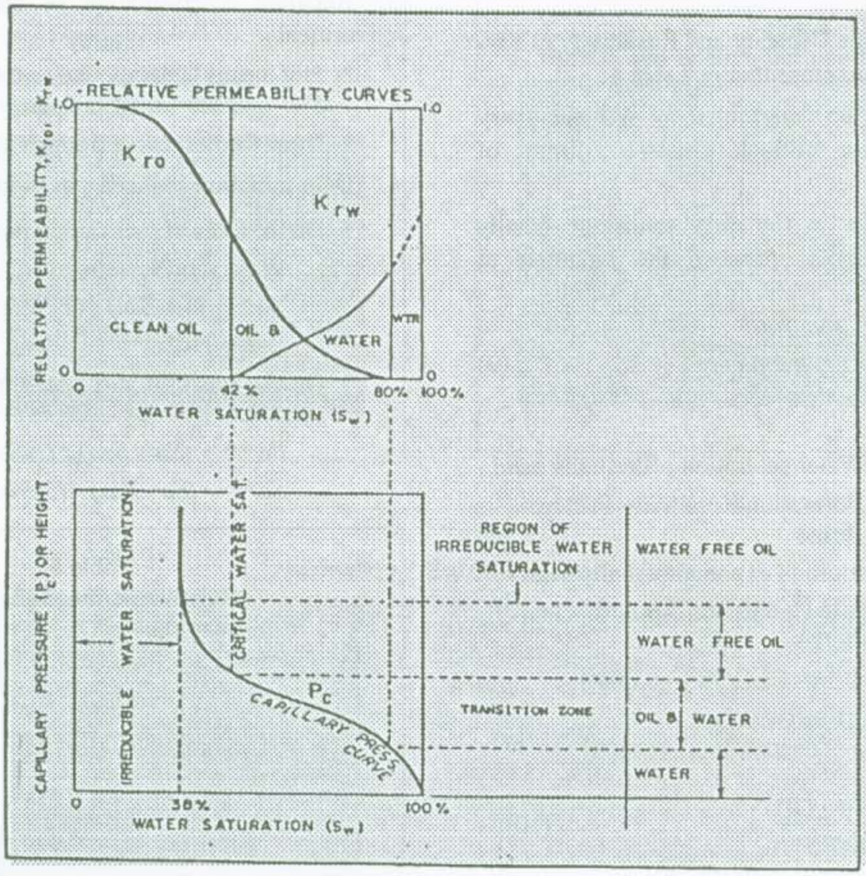


Figure 8
Combination plot of capilary pressure with Kw-Ko Relative permeability curves to predict transition zone

The clay minerals present in a natural rock act as separate conductor and are sometimes refered to as coductive solids. The coductivity of clay is related to the cation exchange capacity (CEC). The higher the CEC, the lower the formation factor at any salinity. Fresh water yields low F values and low in n values.

2. Cation Exhange Capacity (CEC) is determined on formation samples and varies with the type and quantity of clay. This ion exchange may alter formation porosity, reduce permeability, reduce formation resistivity and result in erroneously high calculated water saturation from downhole logs.

Cation Exchange Capacity and Resistivity of several clay minerals are presented in Table 4.

The CEC may be determined by wet chemistry techniques. Unit are milliequivalents/100 grams of dry rock.

To calculate Sw in the dirty sandstone (shally sand), Waxman-Smits propose the equation as follow:

$$Sw^* = \sqrt[n^*]{\left[\frac{\dfrac{F_*\ .\ RW}{Rt\,(1 + Rw\ \beta\ Qv)}}{Sw}\right]} \quad \text{.....................} \quad (9)$$

where : Sw^*= Water saturation oftheshally sand

Fa = Formation Resistivity Factorof brine

n^* = Saturation exponentofshally sand

β = Specific Counterion Activity, Ohm^{-1}/(equiv./L)

= (- 0.140 CEC/PV) - 0.008)

F^* = Fa (1 + Rw.β.Qv)

Qv = Clay concentration, meq/ml

$$Qv = \frac{CEC\ (1 - \theta\ )\ GD}{\theta - 100} \quad \text{.............................} \quad (10)$$

where : θ = Porosity, fraction

CEC = Cation Exchange Capacity, meq/100g

GD = Grain Density, gr/cc

J. *Averaging relative permeability data*

The purpose of averaging relative permeability data is to obtain one correlation for the resevoir to fasilitate resevoir perfomance.

1. Samples with data to be averaged must be texturally similar as evident from a Leverett *"J"* function plot of capillary pressure data.
2. Allowable end points for normalizing relativepermeability data.

Swi	*Kro (Swi)*	*Krg (Swi)*
Sor	*Kro (Sgr)*	*Krw (Sor)*
Sgr	*Krg (Swr)*	*Krg (Sgr)*

3. Accurate determination of end points is most critical
   - * Plot means hydraulic radius 0.0314 (k/ φ) vs ***Swi*** and ***Sor*** for all samples.
   - * Draw the best curve through all data points.
4. Determination reduced saturations.
   - * On the basis of hydrcarbon pore volume

Water-Oil System :

$Sw^* = (Sw\text{-}Swi)\ /\ (1\text{-}Swi)$ .... (11)

$So^* = 1 - Sw^*$ .... (12)

* On the basis of displaceable hydrocarbon pore volume.

$Sw^{**} = (Sw - Swi)\ /\ (1\text{-}Swi\text{-}Sor)$ .... (13)

$So^{**} = (So - Sor)\ /\ (1\text{-}Swi\text{-}Sor)$ .... (14)

Table 5
Relative permeability data
sample no.1 ; Swi = 10 %

Sw, %	Kro	Krw	Sw*
10	1	0	0
34	0.23	0.004	0.267
36	0.190	0.011	0.289
40	0.120	0.030	0.333
42	0.070	0.070	0.356
50	0.022	0.160	0.444
55	0.004	0.285	0.500

Table 6
Relative permeability data sample no.2 ; Swi = 22 %

Sw, %	Kro	Krw	Sw*
40	0.420	0.0001	0.231
46	0.220	0.0050	0.308
50	0.130	0.1900	0.359
52	0.090	0.0300	0.385
60	0.005	0.1300	0.487

Table 7
Relative permeability data sample no.3 ; Swi = 35 %

Sw, %	Kro	Krw	Sw*
60	0.165	0.0045	0.385
67	0.050	0.0500	0.492
70	0.025	0.0870	0.538
74	0.007	0.1500	0.600
75	0.002	0.1750	0.615

5. Plot *Kro* and *Krw* versus *Sw** or *Sw*** on semi-log for all samples.

Example :

Averaging RelativePermeability data

Given water-oil relative Permeability data or three samples. (Table-5, Table-6 and Table-7)

Solutions:

a. At selected values of *Kro* and *Krw* (e.g., 0.001; 0.01; 0.1; 0.25; 0.5; 1) determine values of *Sw** or *Sw*** for each sample and average value arithmetically.

Table 9
Normalized relative permeability calculation

Kr	Sw (Kro)	SW (Krw)
0.005	60.9	44.7
0.01	59.2	46
0.02	57.9	48.2
0.05	53.3	51.6
0.1	49.7	56.3
0.2	44.5	62.9

Table 8
Normalized Sw calculation

Rel.Perm. Values	Swi			Sw*(%) at Kro	Swi			Sw*(%) at Krw
	10%	22%	35%		10%	22%	35%	
0.005	49	48	35	52.3	27.5	31	39	32.5
0.01	47	47	57	50.3	28.5	33	31	34.2
0.02	45	46	55	48.7	30.5	36	44	36.8
0.05	39	42	48	43.0	34	40	49	41.0
0.01	34	38	44	38.7	39	46	55	46.7
0.2	28	32	37	32.3	46	54	64	54.7

If Swi = 18 % ——— Sw (%) = (100 - Swi)(Sw* / 100) + Swi

b. Tabulate values of Sw^* (average) or S^* (average) at each *Kro* and *Krw* value.
With average value of (k/) versus *Swi* and *Sor* and determine representative values of *Swi* and *Sor*.

c. Using value of *Swi* or *Sor* and average values of Sw^* or Sw^{**} recompute *Sw* on the basis of total pore space as follows :

$$Sw = (1-Swi)\,Sw^* + Swi$$

$$Sw = (1-Swi-Sor)\,Sw^{**} + Swi$$

Figure-9 shows a normalized water saturation, *Sw* percent hydrocarbon pore volume. Figure-10 shows Normalized Relative Permeability data.

J. *Addition data*

Additional laboratory data for supporting formation evaluation include as follows :

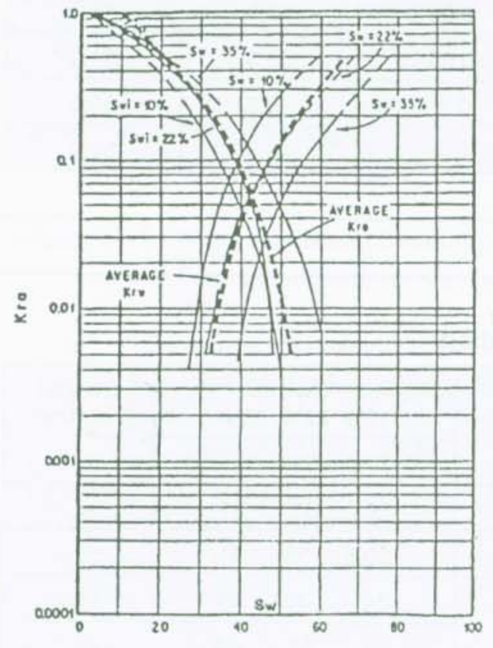
1. Sieve analysis data

This data yields grain size distribution and can be used to gain insight into transportation prior to deposition. It is also used to assist in screen or slotted liner selection when completing poorly consolidated formations. Data repoted from sieve analysis include graphical and tabular data which show cummulative per cent of sample (by weight) for various grain (screen) sizes.

2. Acid solubility data

This test is performed to measure the carbonate ($CaCO_3$) contents in the core sample or any material that soluble in the acid (HCl). Calcimetry is the apparatus which is usually used in the laboratory for the test above.

The application data can be used for acidizing information in the field, as follow :



Figur 9
Anormalized water saturation, % PV

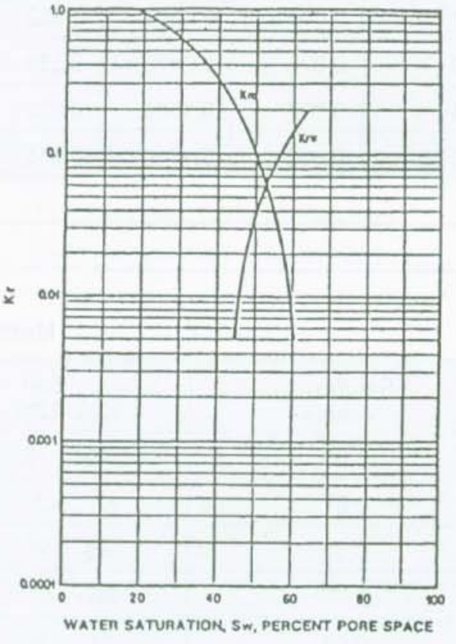


Figure 10
Anormalized relative permeability data

Table-10
Acid concentration used base on acid solubility data

Formation solubility (%)	Acid strength (%)
0 – 10	3 – 5
10 – 20	5 – 7.5
20 – 40	7.5 – 10
> 40	10 – 28

3. Liquid permeability data

These data are used to evaluate formation sensitivity to water used for drilling, coring, workover and injection.

Permeability reduction may be due to clay particle migration or clay hydration. Montmorillonite is most likely to swell and Kaolinite most likely to migrate. For further complete study the Scanning Electron Microscope (SEM) and X-Ray diffraction data are necessary. In the laboratory tests are conducted on direct measurement of permeability during the flow through a saturated sample.

$$\text{Damage factor} = \frac{k\ (brine) - k'(5\%\ CaCl)}{k\ (brine)}$$

Ca, Mg or K often stabilize the Clay.

5 % solution (50.000 ppm) of $CaCl_2$, $MgCl_2$ and KCl are suitable for initial screening plans.

III. CONCLUSION

The following conlusions can be drawn from the application techniques of core analysis data discused:

1. The core analysis should be established early in the drilling program and managerial, drilling, geological, and engineering requirements must be all considered.
   - The application of fluid saturation data, in some instances, may be a valuable qualitatif aid in locating possible oil productive zone (Fig-1).
   - The porosity and permeability relationships varieswith formation and rock type and reflects the variety of pore geometry present. (Fig-2).
   - An index for correlating microscopic pore space attributes with reservoir macroscopic petrophysical parameters. ***RQI*** can be used to characterize rock quality. The higher ***RQ***I value, the better quality of reservoir.
   - An important aspect of reservoir evaluation is to describe the heterogeneity of pore network. Sample with HI 1 have much better quality (Fig-3).
   - The pore throat sorting (***PTS***) index can be used to characterize the size and distribution with the pore space. ***PTS*** 1 indicates a good sorting, however ***PTS*** 5 indicating poor pore throat sorted. (Fig-4).
   - Quality of effective porosity is indicated by area above each drainage capillary pressure curve. The larger area, indicates the better effective porosty (Fig-5).
2. The performance of a hydrocarbon bearing reservoir is largerly controlled by certain intrinsic properties of the reservoir porous medium.
   - An index for correlating recovery efficiency (*RE*) of oil reservoir can be predicted from capillary pressure data, where the higher *RE* value, the better recovery (Fig-6).
   - A theoritical oil-water transition zone, predicted from capillary pressure and relative permeability curve, in some instance, may be a valuable qualitative aid in estimating possible transition zone (Fig-8).
   - The use of the CEC data in conjunction with resistivity data can improve several log analysis parameters, particularlythe estimation of water saturation inshaly sand formation.
   - The averaging relative permeability data is to obtain one correlation for the reservoir to facilitate reservoir performance (Fig-9 and Fig-10).

3. The accurate core analysis data largely support the geologists and engineering in formation evaluation.
   - Sieve analysis data, in some instances can be used to assist in screen selection and acid solubility data can be used for informations in acidizing field operations.
   - Liquid permeability data is usualy used to evaluate formation sensitivity to injected water during waterflood operation.

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Symbols

β = Specific Conterion Activity, Ohm-1/(Equiv./L)
C = Kozeny Number
CEC = Cation Exchange Capacity, ml/100mg
Dri = Pore Size Distribution
F = Unit Coversion Factor
GD = Grai Density, gr/cc
H = Height above free water level, ft
HI = Heterogeneity Index
$J(Sw)$ = J-fuction, dimensionless
K = Permeability, md
Krw = Relative Permeability to Water, fraction
Kro = Relative Permeability to Oil, fraction
Krg = Relative Permeability to Gas, fraction
Pc = Capillary Pressure, psi or dyne/sq.cm
Pcr = Reservoir Capillary Pressure, psi or dyne/sq.cm
PTS = Pore Throat Sorting
Qv = Clay concentration, meq/ml
RQI = Reservoir Quality Index, microns
RE = Efficiency Recovery
Ri = Pore Radius, microns
SHg = Mercury Saturation, % pore space
Swi = Initial Water Saturation, % pore space
Sor = Residual Oil Saturation, % pore space
Sgr = Residual Gas Saturation, % pore space
α = Geometrical factor
β = Forchhimer Factor
σ = Interfacial Tension, Dyne/cm
Φ = Porosity, fraction
θ = Contact angle, degrees.□