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 reservoir 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 usage 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

<table>
<thead>
<tr>
<th>Coring fluid</th>
<th>Filtrate</th>
<th>Sw</th>
<th>So</th>
</tr>
</thead>
<tbody>
<tr>
<td>Water base mud</td>
<td>water</td>
<td>higher</td>
<td>lower</td>
</tr>
<tr>
<td>Oil base mud</td>
<td>oil</td>
<td>constant</td>
<td>higher</td>
</tr>
<tr>
<td>Oil Emulsion</td>
<td>water</td>
<td>higher</td>
<td>lower</td>
</tr>
<tr>
<td>Gas</td>
<td>gas</td>
<td>constant</td>
<td>replaced</td>
</tr>
<tr>
<td>Air (Water)</td>
<td>uncertain</td>
<td>uncertain</td>
<td>lower</td>
</tr>
</tbody>
</table>
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:

**Figure 1**
Interpretation of reservoir fluids zones
\[ RQI \text{ (mikrons)} = 0.0314 \sqrt{\frac{k}{\theta}} \] (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 follows:

\[ HI = \log \left[ \frac{\alpha \cdot \theta / RQI}{RQI} \right] \] (2)

where:
\[ \alpha = 3.238 \times 10^{-9} \cdot \beta \cdot k \]
\[ \beta = 1.092 \times 1011 k^{-1.8872} \]
\[ RQI = 0.0314 (k \cdot \theta) \]

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

Figure 2 indicates plot of \( K \) versus \( \theta \). This plot data can be used to select representative core samples for special core analysis.

Figure 3 shows 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...
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>
<thead>
<tr>
<th>No</th>
<th>Aman</th>
<th>k (mD)</th>
<th>θ</th>
<th>RQI</th>
<th>β</th>
<th>α</th>
<th>HI</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>9645</td>
<td>37</td>
<td>27.04</td>
<td>0.03673</td>
<td>1.2E+08</td>
<td>14.3612</td>
<td>4.02417</td>
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<tr>
<td>2</td>
<td>9648</td>
<td>197</td>
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<td>0.07818</td>
<td>5106296</td>
<td>3.25723</td>
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<tr>
<td>3</td>
<td>9651</td>
<td>155</td>
<td>29.32</td>
<td>0.07222</td>
<td>8028394</td>
<td>4.02937</td>
<td>3.21389</td>
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<tr>
<td>4</td>
<td>9854</td>
<td>116</td>
<td>33.53</td>
<td>0.0584</td>
<td>1.4E+07</td>
<td>5.2109</td>
<td>3.4759</td>
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<tr>
<td>5</td>
<td>9657</td>
<td>103</td>
<td>28.77</td>
<td>0.05941</td>
<td>1.7E+07</td>
<td>5.79042</td>
<td>3.4777</td>
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<tr>
<td>6</td>
<td>9660</td>
<td>88</td>
<td>32.48</td>
<td>0.05168</td>
<td>2.3E+07</td>
<td>6.65816</td>
<td>3.62161</td>
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<tr>
<td>7</td>
<td>9663</td>
<td>50</td>
<td>36.86</td>
<td>0.03857</td>
<td>6.8E+07</td>
<td>10.9944</td>
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<td>8</td>
<td>9666</td>
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<td>9</td>
<td>9669</td>
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<td>3.6E+07</td>
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<td>3.65905</td>
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<td>3.52848</td>
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<td>11</td>
<td>9676</td>
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<td>0.07563</td>
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<td>12</td>
<td>9678</td>
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<td>7.22</td>
<td>0.0181</td>
<td>2.1E+10</td>
<td>162.621</td>
<td>4.81195</td>
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<tr>
<td>13</td>
<td>9681</td>
<td>5.5</td>
<td>15.08</td>
<td>0.01896</td>
<td>4.4E+09</td>
<td>77.9201</td>
<td>4.79214</td>
</tr>
<tr>
<td>14</td>
<td>9684</td>
<td>6.5</td>
<td>17.32</td>
<td>0.01924</td>
<td>3.2E+09</td>
<td>67.1868</td>
<td>4.78172</td>
</tr>
<tr>
<td>15</td>
<td>9687</td>
<td>4.4</td>
<td>13.47</td>
<td>0.01795</td>
<td>6.7E+09</td>
<td>94.9791</td>
<td>4.85302</td>
</tr>
</tbody>
</table>
Mercury injection capillary pressure is performed by two basic processes (Drainage and Inhibition processes).

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

$$PTS = \left( \frac{P_3}{P_1} \right)^{0.5} \quad \text{(3)}$$

where:
- $P_1$ = 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.

Effective porosity indicated by mercury injection curve. The area above the curve indicates the effectiveness 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 types 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:

\[ RE = \frac{SHg_1 - SHg_2}{SHg_1} \times 100\% \] \hspace{1cm} (4)

where: 
- \( RE \) = recovery efficiency, %
- \( SHg_1 \) = maximum volume of mercury injected at maximum pressure
- \( SHg_2 \) = volume of mercury remaining in pores after pressure 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 (DSI) calculation

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

\[ RI = \frac{2 \times \sigma \cos \theta}{PC} \] \hspace{1cm} (5)

where: 
- \( \sigma \) = Interfacial Tension, dynes/cm
- \( \theta \) = Contact Angle, degrees
- \( C \) (Kozeny Number) = \( 145 \times 10^{-3} \)

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

\[ DRI = \frac{PC \cdot dSw}{RI \cdot dPC} \] \hspace{1cm} (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.

\[ RE = \frac{SHg_1 - SHg_2}{SHg_1} \times 100\% \]

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 the 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

Pc = entry pressure, is the minimum pressure at which mercury first enters the pore system of the sample

P1 = 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 calculate recovery efficiency (RE)
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.

\[ J(\text{Sw}) = \frac{P_c}{\sigma \cos \theta} \sqrt{\left( \frac{k}{\Phi} \right)} \]  

\( \Phi \) = Porosity, fraction
\( \sigma \) = Interfacial tension, dyne/cm

If units of \( k \) in md and \( P_c \) in psi, the equation can be simplified such as:

\[ J(\text{Sw}) = \frac{F \times P_c}{\sigma \cos \theta} \sqrt{\left( \frac{k}{\Phi} \right)} \]  

\( F = 0.2166 \) as units conversion factor

\[ \text{where: } H = \frac{(Pcr)/(Sw - Sh)}{Pcr} \]  

\( H \) = Height in feet above 100 % water level corresponding to Zero Capillary Pressure.
\( Pcr \) = Capillary pressure 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

<table>
<thead>
<tr>
<th>Clay mineral groups</th>
<th>CEC meq/100 gr</th>
<th>Resistivity ohm.m @ 77°F</th>
</tr>
</thead>
<tbody>
<tr>
<td>Montmorillonite</td>
<td>60 - 150</td>
<td>0.7 - 1.5</td>
</tr>
<tr>
<td>Illite</td>
<td>10 - 40</td>
<td>1.0 - 3.0</td>
</tr>
<tr>
<td>Kaolinite</td>
<td>3 - 15</td>
<td>&gt; 3</td>
</tr>
<tr>
<td>Chlorite</td>
<td>10 - 40</td>
<td>&gt; 3</td>
</tr>
</tbody>
</table>

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

1. Application of resistivity and C.E.C data in water saturation ($S_w$) 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 capillary 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 referred to as conductive solids. The conductivity 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 Exchange 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:

\[ Sw^* = n^* \sqrt{ \frac{F^* \cdot RW}{Rt (1 + Rw \cdot \beta \cdot Qv) / Sw} } \]  
(9)

where : Sw* = Water saturation of the shally sand  
F* = Formation Resistivity Factor of brine  
n* = Saturation exponent of shally sand  
\( \beta = \) Specific Counterion Activity, Ohm\(^{-1}\)/ (equiv/L) 
= (- 0.140 CEC/PV - 0.008)  
\( Qv = \) Clay concentration, meq/ml

\[ Qv = CEC (1 - \theta ) GD \]  
(10)

where : \( \theta \) = Porosity, fraction  
CEC = Cation Exchange Capacity, meq/100 g  
GD = Grain Density, gr/cc

J. Averaging relative permeability data

The purpose of averaging relative permeability data is to obtain one correlation for the reservoir to facilitate reservoir performance.

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 relative permeability data.

\[ Swi \quad Kro(Swi) \quad Krg(Swi) \]
\[ Sor \quad Kro(Sgr) \quad Krw(Sor) \]
\[ Sgr \quad Krg(Swr) \quad Krg(Sgr) \]

3. Accurate determination of end points is most critical

* Plot means hydraulic radius 0.0314 (kg/\( \phi \)) vs Swi and Sor for all samples.
* Draw the best curve through all data points.

4. Determination reduced saturations.

* On the basis of hydrocarbon pore volume

Water-Oil System :

\[ Sw^* = (Sw-Swi) / (1-Swi) \]  
(11)

\[ So^* = 1 - Sw^* \]  
(12)

* On the basis of displaceable hydrocarbon pore volume.

\[ Sw^{**} = (Sw - Swi) / (1-Swi-Sor) \]  
(13)

\[ So^{**} = (So - Sor) / (1-Swi-Sor) \]  
(14)

| Table 5 | Relative permeability data sample no.1 ; Swi = 10 % |
|----------|-------------|--------------|---------------|
| Swi, %   | Kro         | Krw          | Sw*           |
| 10       | 1           | 0            | 0             |
| 34       | 0.23        | 0.004        | 0.287         |
| 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         |
5. Plot Kro and Krw versus Sw* or Sw** on semi-log for all samples.

Example:

Averaging Relative Permeability 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 8
Normalized Sw calculation

<table>
<thead>
<tr>
<th>Rel. Perm. Values</th>
<th>Sw* 10%</th>
<th>Sw* 22%</th>
<th>Sw* 35%</th>
<th>Sw** (%) at Kro</th>
<th>Sw** (%) at Krw</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.005</td>
<td>49</td>
<td>48</td>
<td>35</td>
<td>52.3</td>
<td>32.5</td>
</tr>
<tr>
<td>0.01</td>
<td>47</td>
<td>47</td>
<td>57</td>
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<td>0.02</td>
<td>42</td>
<td>56</td>
<td>57</td>
<td>48.7</td>
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<td>0.05</td>
<td>34</td>
<td>56</td>
<td>57</td>
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<td>0.01</td>
<td>34</td>
<td>38</td>
<td>44</td>
<td>38.7</td>
<td>40.7</td>
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<tr>
<td>0.2</td>
<td>28</td>
<td>32</td>
<td>37</td>
<td>32.3</td>
<td>54.7</td>
</tr>
</tbody>
</table>

If Swi = 18 %

Sw (%) = (100 - Swi) (Sw*/100) + Swi
b. Tabulate values of $Sw^*(\text{average})$ or $S^*(\text{average})$ 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 reported from sieve analysis include graphical and tabular data which show cumulative percent 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). Calcometry 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:
Table-10
Acid concentration used base on acid solubility data

<table>
<thead>
<tr>
<th>Formation solubility (%)</th>
<th>Acid strength (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0 – 10</td>
<td>3 – 5</td>
</tr>
<tr>
<td>10 – 20</td>
<td>5 – 7.5</td>
</tr>
<tr>
<td>20 – 40</td>
<td>7.5 – 10</td>
</tr>
<tr>
<td>&gt; 40</td>
<td>10 – 28</td>
</tr>
</tbody>
</table>

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.

Damage factor = $\frac{k(\text{brine}) - k(5\% \text{ CaCl}_2)}{k(\text{brine})}$

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 conclusions can be drawn from the application techniques of core analysis data discussed:

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 qualitative aid in locating possible oil productive zone (Fig-1).

- The porosity and permeability relationships varies with 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 $RQI$ 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. $PTS \geq 1$ indicates a good sorting, however $PTS \leq 5$ 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 porosity (Fig-5).

2. The performance of a hydrocarbon bearing reservoir is largely 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 theoretical 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, particularly the estimation of water saturation in shaly 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 usually used to evaluate formation sensitivity to injected water during waterflood operation.

REFERENCES


Symbols

\[ \beta = \text{Specific Conterion Activity, Ohm}-1/(\text{Equiv/L}) \]
\[ C = \text{Kozeny Number} \]
\[ CEC = \text{Cation Exchange Capacity, ml/100mg} \]
\[ Dri = \text{Pore Size Distribution} \]
\[ F = \text{Unit Coversion Factor} \]
\[ GD = \text{Grai Density, g/cc} \]
\[ H = \text{Height above free water level, ft} \]
\[ HI = \text{Heterogeneity Index} \]
\[ J(\text{Sw}) = J-\text{fuction, dimensionless} \]
\[ K = \text{Permeability, md} \]
\[ K_{rw} = \text{Relative Permeability to Water, fraction} \]
\[ K_{ro} = \text{Relative Permeability to Oil, fraction} \]
\[ K_{rg} = \text{Relative Permeability to Gas, fraction} \]
\[ P_c = \text{Capillary Pressure, psi or dyne/sq.cm} \]
\[ P_c = \text{Reservoir Capillary Pressure, psi or dyne/sq.cm} \]
\[ PTS = \text{Pore Throat Sorting} \]
\[ Qv = \text{Clay concentration, meq/ml} \]
\[ RQI = \text{Reservoir Quality Index, microns} \]
\[ RE = \text{Efficiency Recovery} \]
\[ Ri = \text{Pore Radius, microns} \]
\[ SHg = \text{Mercury Saturation, \% pore space} \]
\[ Swi = \text{Initial Water Saturation, \% pore space} \]
\[ Sor = \text{Residual Oil Saturation, \% pore space} \]
\[ Sgr = \text{Residual Gas Saturation, \% pore space} \]
\[ \alpha = \text{Geometrical factor} \]
\[ \beta = \text{Forchheimer Factor} \]
\[ \sigma = \text{Interfacial Tension, Dyne/cm} \]
\[ \Phi = \text{Porosity, fraction} \]
\[ \theta = \text{Contact angle, degrees} \]