BASIC CONCEPTS

- In the oil exploration process, the hydrocarbon bearing rock structure is defined based on *seismic* and *geological surveys*, and a drilling location is then located and the well is drilled.
- Many sub-surface data are obtained from *drill coring* and *cuttings*, but the method is highly expensive and has many limitations.
- Here comes the role of Well Logging Technique.
- Well logging provides a cheaper, quicker method of obtaining accurate sub-surface petrophysical data.
- Well Logging measurements can:
  - ✓ Determine the hydrocarbon potential of the well.
  - ✓ Determine hydrocarbon type and volume.
  - ✓ Determine what types of fluid will flow and at what rate.
  - ✓ Serves to identify Hydrocarbon Reservoirs.

❖ **Well Logging ….**

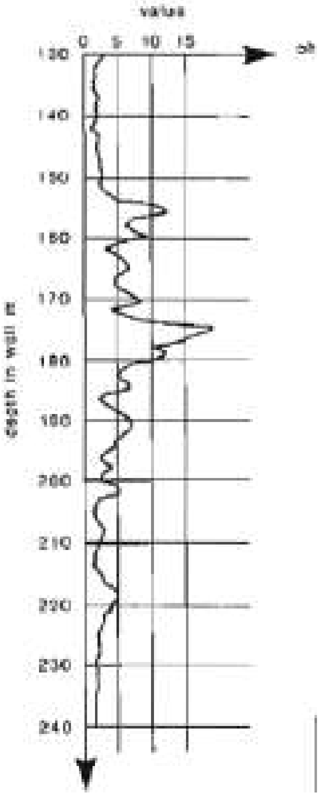
- Well Logging is the technique of making petrophysical measurements in the sub-surface earth formations through the drilled borehole in order to determine both the physical and chemical properties of rocks and the fluids they contain.

❖ **Objectives of Well Logs**

✓ Lithology identification (limestone, dolomite, dolomitic limestone, …).
✓ Determination of reservoir petrophysical properties (e.g. porosity, saturation, permeability).
✓ Identification the reservoir and non-reservoir rocks (e.g. sandstone and shale).
✓ Identification the fluid type in the pore space of reservoir rock (gas, oil, water).
✓ Identification of productive zones.
✓ Determination the depth and thickness of productive zones.
✓ Locating reservoir fluid contacts(such as OWC and GOC).

- ✓ Well to well correlation for determining the lateral extension of subsurface geologic cross sections.

❖ **Well Logging Techniques**



- A ***log*** is a continuous recording of a geophysical parameter along a borehole.
- The value of the measurement is plotted continuously against depth in the well.
- The well logs are taken between drilling stop episodes and at the end of drilling..
- Nowadays there are measurements taken during drilling, by attaching the log tools to the drill string behind the bit, such logging is called ***MWD*** **(*measurement while drilling*)** or ***LWD*** **(*logging while drilling*)**.

- Well Logging Measurements are carried out through the **<u>drilled borehole.</u>**
- The drilled borehole may be either an **Open Hole** or a **Cased Hole.**
  - o **Open Hole:** A borehole available immediately after drilling.
- ✓ Measurements concern with formation evaluation.
  - o **Cased Hole:** A borehole after placed the casing pipes and cementing.
- ✓ Measurements concern with reservoir development & production
- Well logs are made when the drill-bit is removed from the borehole. This can be either between drilling episodes, before casing is set, or at the end of drilling.

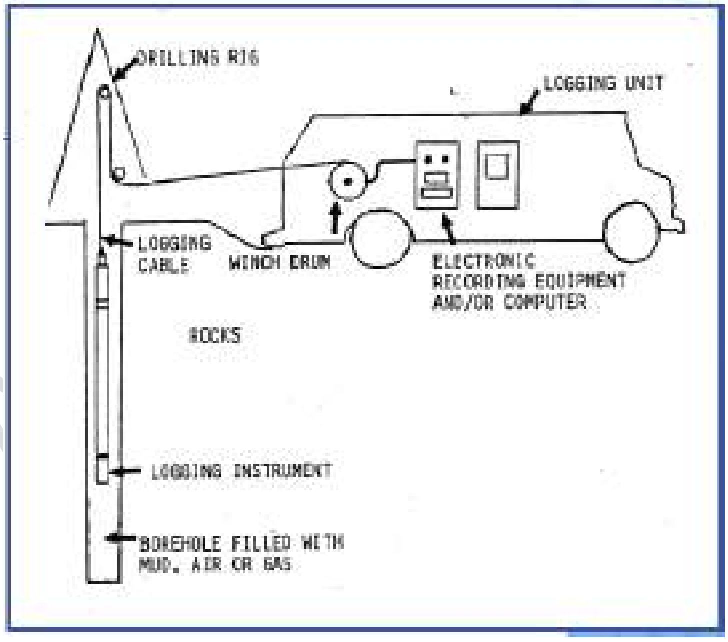
❖ **Basic Well Logging Equipment** consists of;

✓ **Logging Unit**. A special truck installed with a full computer system.

✓ **Logging cable or the Wireline**

✓ **Logging Tool or Sonde**

- The logging tool (sonde) is *lowered* into the wellbore by the logging cable (wireline).
- When it reaches the bottom of the interval to be logged, it is slowly <u>*withdrawn*</u> at a pre-determined speed.
- Log measurements are made continually during this process.
- Data acquired by the sonde are transmitted to the surface system by the logging.
- The surface computer records, processes and plots these data as a function of well depth.



❖ <u>**Types Of Open Hole Well Logs**</u>

1) Electrical
- Spontaneous Potential (SP) Log.
- Resistivity Log.

2) Radioactive
- Gamma Ray Log.
- Density Log.
- Neutron Log.

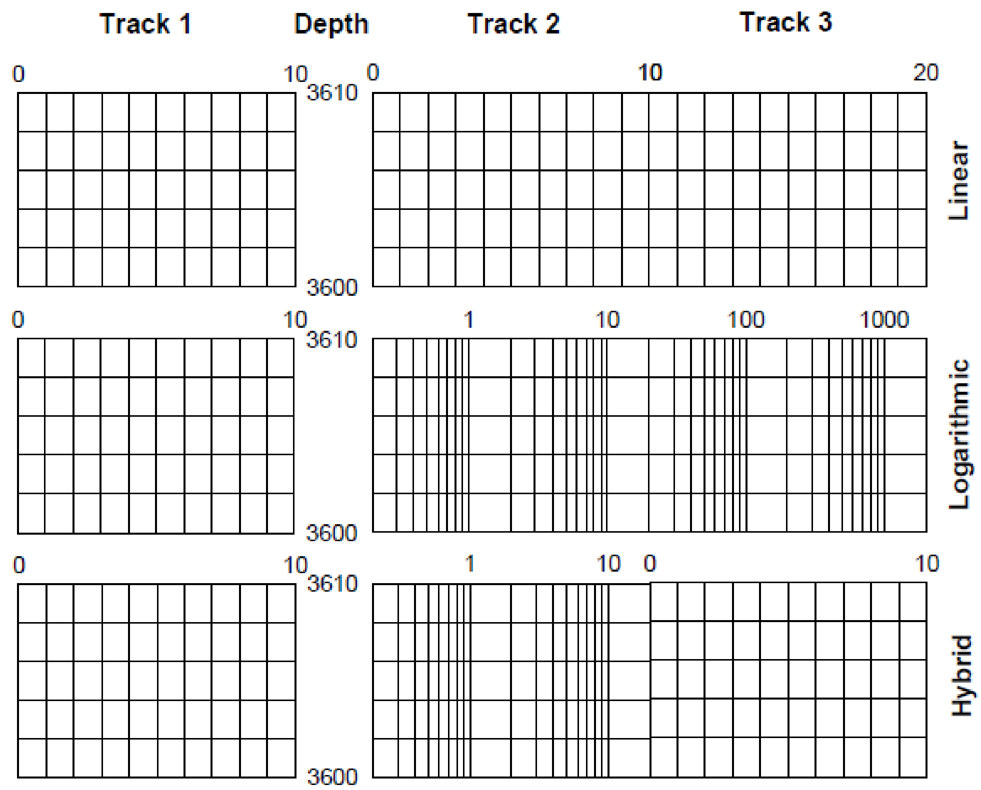
3) Acoustic
- Transit time (sonic) Log

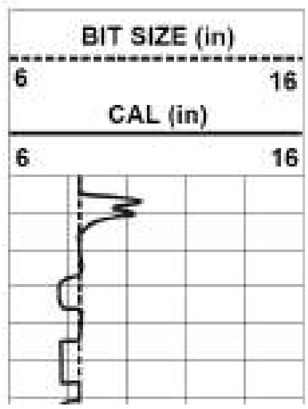
4) Mechanical
- Caliper Log

5) Thermal and Magnetic logs
- Pressure Log.
- Temperature Log.

❖ <u>The Presentation of Log Data</u>

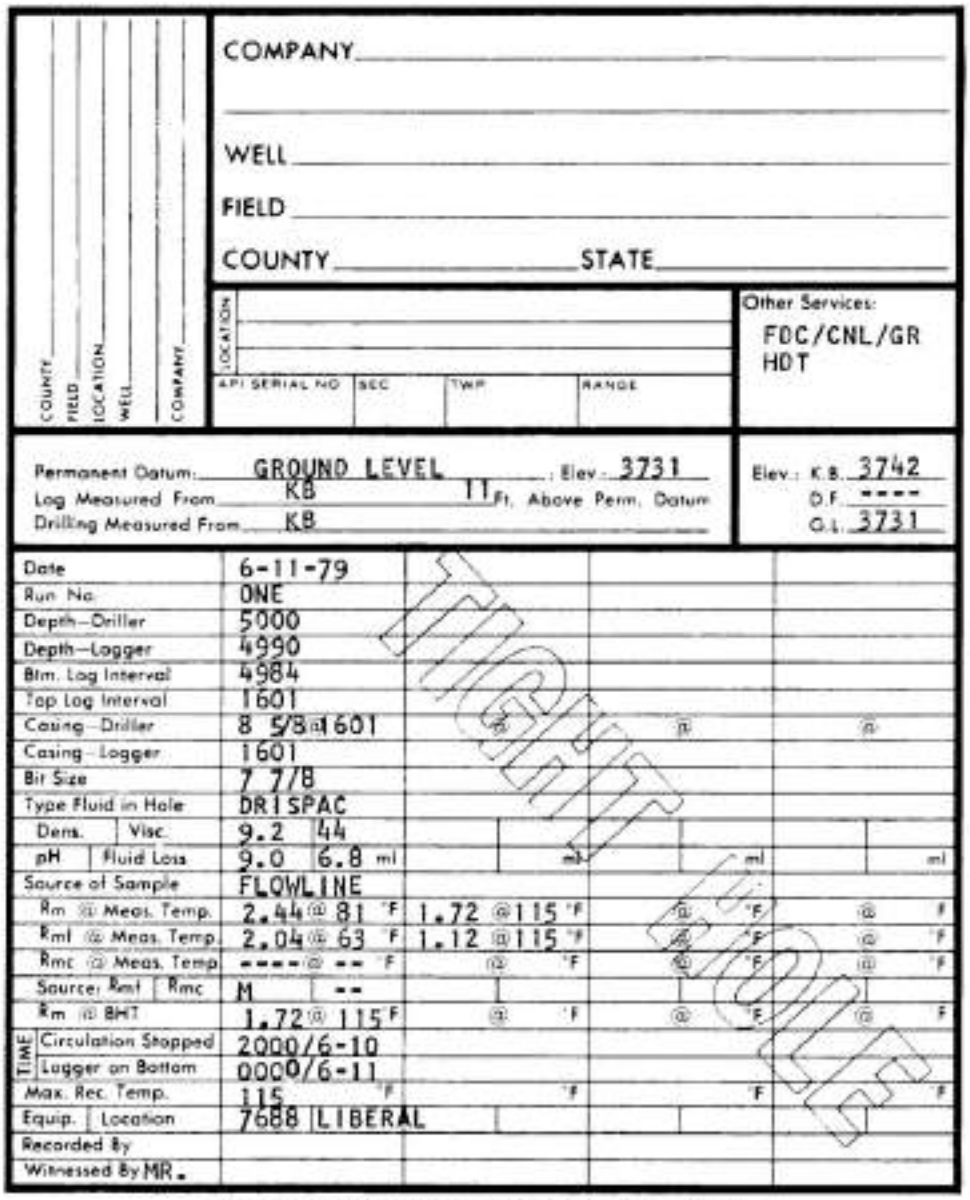
Conventionally, logs are presented on a standard grid defined by the *American Petroleum Institute* (API).





1. The grid consists of 3 tracks and a depth column.
2. The API grid format has specific dimensions for each track, and an overall width of 8.25 inches.(2.5 inches wide for each track).
3. <u>Track 1</u> is always **linear** and is often used for *drill bit size*, *caliper* log, SP log and *gamma ray* log .
4. <u>Depth column</u> (0.75 inches wide) may be in feet or meters.
5. A range of depth scales(such as 1:1200. 1:600 and 1:240) are used depending upon the resolution required for analysis.
6. <u>Tracks 2 and 3</u>, which may have either a **linear** or a **logarithmic** scale. These tracks are used for <u>density</u>, <u>neutron</u>, and <u>sonic</u>, and <u>resistivity</u> log.

7. All tracks can take multiple log curves, and the code for the curve, its style (i.e., dashed line).
8. the scale units are given at the top of the log.
9. every log grid is headed by a log heading which allow the suitable interpretation of the log.



COMPANY
WELL
FIELD
COUNTY STATE
COUNTY FIELD LOCATION WELL COMPANY
LOCATION
API SERIAL NO SEC TWP RANGE
Other Services: FDC/CNL/GR HDT

Permanent Datum: GROUND LEVEL ; Elev.: 3731
Log Measured From KB 11 Ft. Above Perm. Datum
Drilling Measured From KB
Elev.: K.B. 3742 D.F. ---- G.L. 3731

Date	6-11-79			
Run No.	ONE			
Depth—Driller	5000			
Depth—Logger	4990			
Btm. Log Interval	4984			
Top Log Interval	1601			
Casing—Driller	8 5/8 @ 1601	@	@	@
Casing—Logger	1601			
Bit Size	7 7/8			
Type Fluid in Hole	DRISPAC			
Dens. / Visc.	9.2 / 44			
pH / Fluid Loss	9.0 / 6.8 ml	ml	ml	ml
Source of Sample	FLOWLINE			
Rm @ Meas. Temp.	2.44 @ 81 °F	1.72 @ 115 °F	@ °F	@ °F
Rmf @ Meas. Temp.	2.04 @ 63 °F	1.12 @ 115 °F	@ °F	@ °F
Rmc @ Meas. Temp.	---- @ -- °F	@ °F	@ °F	@ °F
Source: Rmf / Rmc	M / --			
Rm @ BHT	1.72 @ 115 °F	@ °F	@ °F	@ °F
TIME Circulation Stopped	2000/6-10			
TIME Logger on Bottom	0000/6-11			
Max. Rec. Temp.	115 °F	°F	°F	°F
Equip. / Location	7688 / LIBERAL			
Recorded By				
Witnessed By	MR.			

*BHT = Bottom Hole Temperature

❖ Logging Environment

- Logging operation can cover a wide range of measurements and surveys, but they are costly. So , not all the measurement are needed on every well. It is most important to have a good understanding of the geological conditions expected to be encountered and to design the logging program to evaluate the formations in the most effective and economic way.
- In log analysis, there are several reasons why it is important to know the lithology of a zone (i.e., sandstone, limestone, or dolomite).
  - ✓ Porosity logs require a lithology or a matrix constant before the porosity (Ø) of the zone can be calculated.
  - ✓ The formation factor (*F*), a variable used in the Archie water saturation equation, also varies with lithology.
  - ✓ As a consequence, the calculated water saturation changes as *F* changes.
- Therefore, we need to review certain fundamentals of rock characteristic which may be encountered during a logging operation.

A) Rocks

- Rocks are classified into three groups based on their origin: *Igneous, Sedimentary and Metamorphic* rock**.**
- Sedimentary rocks are closely linked with the occurrence of petroleum.
- Sedimentary Rocks formed from weathered and eroded material, transported and deposited by water or wind, as sediments that is later cemented together.

Sediment	Rock
Sand	Sandstone
Lime mud	Limestone
Clay	Shale

- Sedimentary rocks can be classified into;

(1) **Clastic Rocks;** subdivided into;

a) Sandstone.
b) Siltstone.
c) Clay.
d) Shale.

(2) **Carbonate Rocks**; subdivided into;

a) Limestone.
b) Dolomite.
c) Marl
d) Chalk

1) Clastic Rocks

- ✓ **Sandstone :** Sandstones are usually composed of quartz mineral (SiO_2**).**
- ✓ **Siltstone :** Siltstone is composed of quartz mineral the same as sandstone, but the grain size is finer and may contain other minerals.
- ✓ **Clay** : Clay is very complex set of minerals. It is made up of very small individual grains which can only be seen by electron microscope.
- ✓ **Shale :** it is a mixture of clay and silt. Shale may have good porosity, but it's permeability is zero.

2) Carbonate Rocks

- ***Limestone*** and ***dolomite*** are the most common of carbonate rocks, and making up about a quarter of all sedimentary rocks.
- Limestone are very subjected to cementation, thus primary porosity is often reduced or destroyed.
- Limestone may commonly be altered to dolomite with the formation of secondary porosity.
- The main reservoir rocks are made up of sandstones and/or carbonates (99% of the total).

B) Reservoir Rocks

- Reservoir rocks must be porous and permeable, i.e. there must be spaces between the fragments or grains of the rock and these pores must be interconnected to provide a continuous path for fluid movement·
- The most common rocks that combine porosity and permeability as effective reservoir rocks are sandstones and carbonates.
- We can classify the reservoir according to reservoir rock into;

1) <u>Sandstone Reservoirs</u>

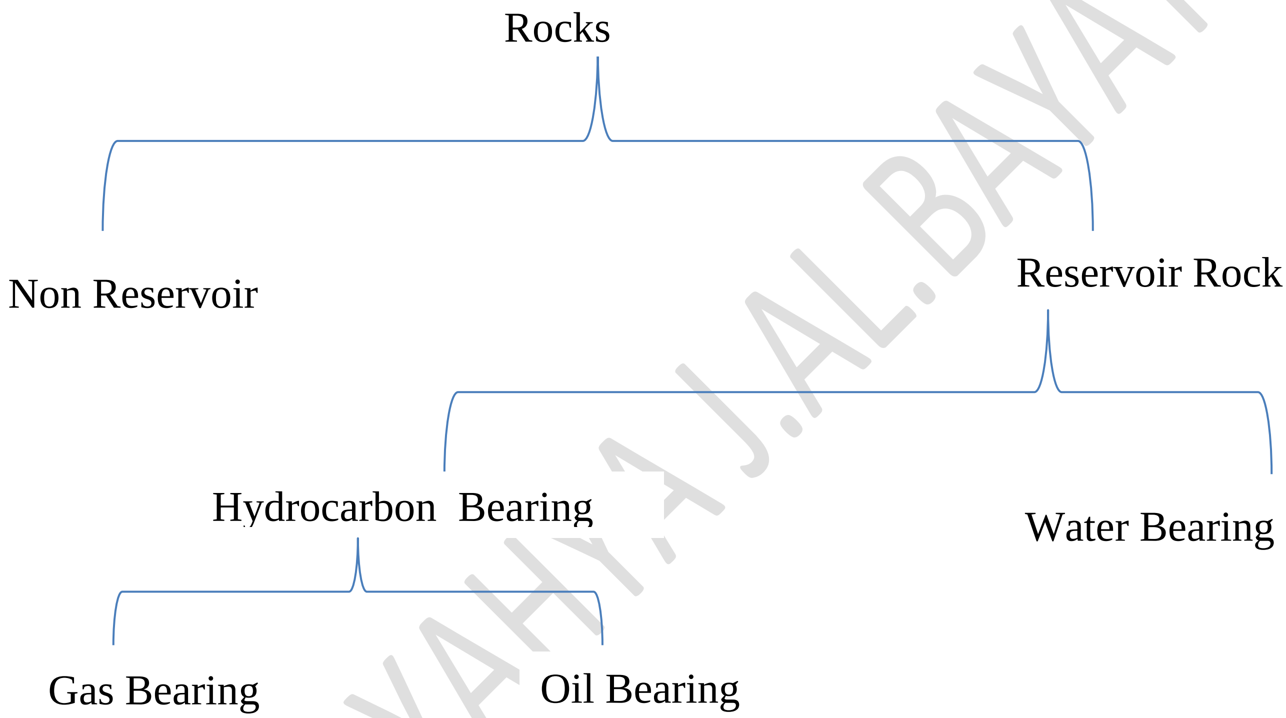
These are by far the most common, accounting for 80% of all reservoirs and 60% of oil reserves. The rock is formed of grains of quartz (silica $Si0_2$). If the grains are free, they form sand. If the grains are cemented together, they form sandstone. Shaly sandstone also exist.

2) <u>Carbonate Reservoirs</u>

They consist of limestone ($CaCO_3$) and/or dolomite ($CaCO_3$, $MgCO_3$). Shaly carbonates also exist. The "marls", which contain between 35 and 65% shale, are not reservoirs rock. This is because a small proportion of shale, binding the grains together, and decreases the permeability.
The 'chalk' is also not reservoirs rock, although it's porosity is high, but the permeability is low or very low (about 1 millidarcy), because it's grains are very small.

- The fundamental questions that has to find answers during *Well Logging Analysis* are;
    - ✓ **What kind of rock is present ?**
        - o reservoir or non-reservoir rock?
    - ✓ **If Reservoir rock exists.**
        - o Are any hydrocarbon present ?
    - ✓ **Type of hydrocarbon present.**
        - o whether oil or gas?
    - ✓ **How much hydrocarbon is there ?**
        - o (pay thickness, porosity, saturation etc.)

- To estimate Hydrocarbon potential of a reservoir, we need to know three main petrophysical properties of the reservoir rock;
  - ✓ **Porosity**
  - ✓ **Permeability**
  - ✓ **Water Saturation**
- Well Logging measurements aim at determining **these three main Petrophysical parameters** of the rock.



- **Reservoir Rocks**
  - ✓ Low Gamma Ray
  - ✓ Good SP development
- **Non Reservoir Rocks**
  - ✓ High Gamma Ray
  - ✓ Flat SP development
- **Water Bearing Zone**
  - ✓ Low Deep Resistivity
- **Hydrocarbon Bearing zone**
  - ✓ High Deep Resistivity
- **Gas Bearing Zone**
  - ✓ Density – Neutron logs Shows Very Good Crossover Indicating.

C) Petrophysical Rock Properties

1) Porosity

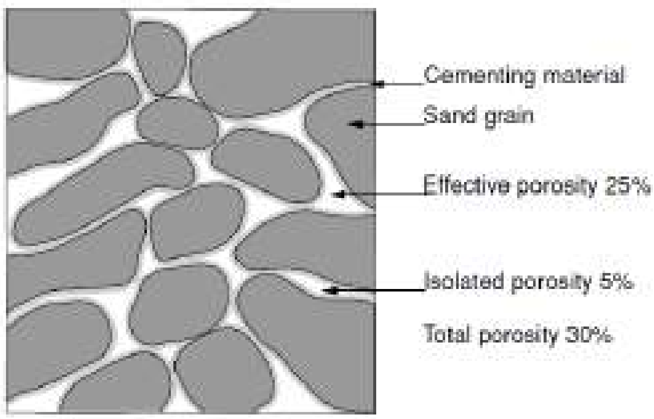
- The porosity of a rock is a measure of the amount of internal space that is capable of holding fluids.

$$\varphi = \frac{pore\ volume\ V_p}{bulk\ volume\ V_b}$$
$$= \frac{bulk\ volume(Vb) - grain\ volume(Vg)}{bulk\ volume(Vb)} \ldots\ldots\ldots(1)$$

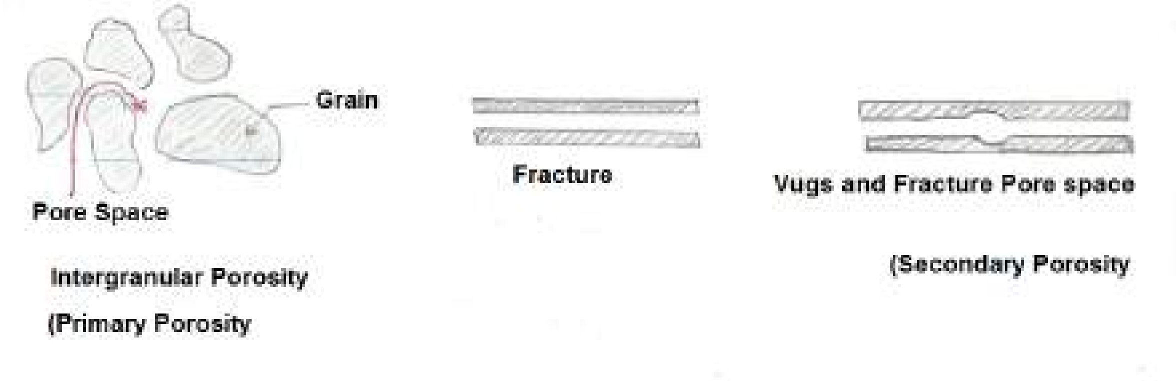
- It is important because it represents a potential storage volume for hydrocarbons.
- <u>A commercial oil bearing sandstones should contain at least 8 to 10 percent porosity.</u>
- <u>In granular limestones it is possible to have as little as 4 to 6 percent porosity associated with commercial production.</u>
- Sedimentary rocks rarely contain more than 35 percent pore space.
- Porosity classify into;
  - ✓ **Absolute (total) porosity** φ_t : ratio of the total pore space in the rock to that of the bulk volume.
  - ✓ **Effective porosity** φ_e : ratio of the interconnected pore space in the rock to that of the bulk volume.

Clean sandstones: $\phi_e = \phi_t$

Carbonate, cemented sandstones: $\phi_e < \phi_t$



- ✓ **Primary Porosity:** The porosity of the rock resulting from its original deposition (such as Intergranular porosity). **porosity of limestone rocks.**
- ✓ **Secondary porosity :** The porosity resulting after original deposition, such as fracture or vugs. **Porosity of dolomite rocks**.



Porosity Logs

The porosity of reservoir rocks may be determined by direct measurement on core samples in the lab or estimated in situ by well log analysis. Porosity log are;

- ❖ Density Log.
- ❖ Neutron Log.
- ❖ Sonic Log.

➢ **Some real values of measured porosity**

1) Sand stone: Ø=(10-40)%
2) Limestone: Ø=(5-25)%
3) Clay: Ø=(20-45)%

It is generally said that the porosity is;

a. Negligible if Ø < 5%
b. Low if 5% < Ø < 10%
c. Good if 10% < Ø < 20%
d. Very good if Ø > 20%

2) **Fluid Saturation**

- Saturation is defined as fraction, or percent, of the pore volume occupied by a particular fluid (oil, gas, or water), and is expressed as:

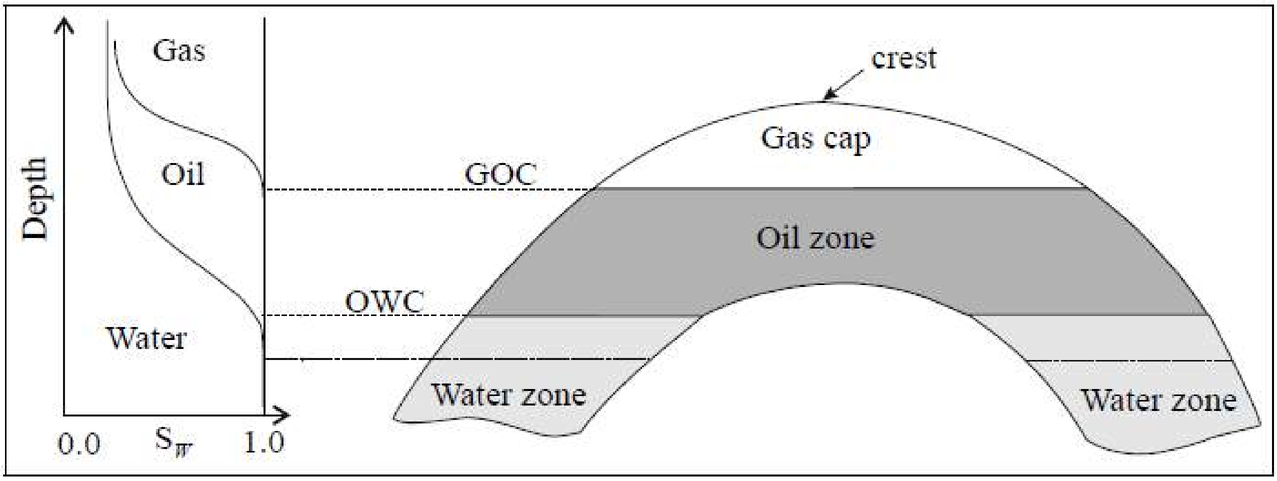
$$fluid\ saturation = \frac{total\ volume\ of\ fluid}{pore\ volume} \ldots\ldots\ldots (2)$$

$$pore\ volume = vol.of\ gas + vol.of\ oil + vol.of\ water$$
$$= 1\ \ or\ 100\%$$

$$S_o = \frac{volume\ of\ oil}{pore\ volume},$$

$$S_g = \frac{volume\ of\ gas}{pore\ volume},\quad S_w = \frac{volume\ of\ water}{pore\ volume}$$

- The gravitational forces (density difference) makes the gas accumulate at the top of the reservoir, and the oil directly below. Water underlies the petroleum, as an aquifer.



- The **Gas-Oil Contact (GOC)** – a surface separating the gas cap from the underlying oil zone (also referred to as oil "column"). Below the GOC, gas can be present only as a dissolved phase in oil.
- The **Oil-Water Contact (OWC)** – a surface separating the oil zone from the underlying water zone. Below the OWC, oil is generally absent.
- The migration and accumulation of petroleum in a reservoir leads to the replacement of the original pore water by gas and oil.

- Between the oil zone and the water zone, an oil-water transitional zone exists.
- Between the oil zone and the gas zone, an oil-gas transitional zone exists.
- The pore space of the rock in the oil zone and gas cap zone contain a small amount of water commonly called **connate water saturation S_{wc}** or **irreducible water saturation S_{wirr}** or **initial water saturation S_{wi}**.

❖ **Methods of Determining Water Saturations**

1. Conventional core analysis
2. Capillary pressure measurements
3. **Well log analysis (Depends on Electrical Rock Properties).**

Water saturation determination from resistivity logs is based on Archie's equation. The equation is;

$$S_w^n = \frac{a \cdot R_w}{\Phi^m \cdot R_t} \quad ....(3)$$

Parameter	Source	Parameter	Source
Rt	Deep resistivity log	**m**	• Assumed m = 2 • From crossplots
Rw	From SP log	**n**	• Assumed n = 2 • From crossplots
a	a = 1 (carbonate) a = 0.81 (sandstone)	$\boldsymbol{\varphi}$	· Sonic log · Density log · Neutron log

S_w: the water saturation (fraction).

R_w: formation water resistivity (ohm-m).

R_t : formation resistivity (ohm-m) determined from deep induction or deep laterolog .

a: Tortuosity factor

n:saturation exponent

m: cementation factor

❖ Volumetric In Place Hydrocarbon Estimation

- For an oil zone with reservoir area *A in* acres and reservoir thickness h in feet, the volume of oil in place is;

$$OOIP = 7758Ah\varphi(1 - S_w) \; \dots\dots(4) \qquad (bbl)$$

- For a gas zone with the same dimensions, the volume of initial gas in place is;

$$GOIP = 43560Ah\varphi(1 - S_w) \dots\dots(5) \qquad (ft^3)$$

- Convert the volume of oil and gas from the reservoir conditions to the stock tank conditions (stander conditions at the surface), by ***formation volume factors (B)***.

$$STOOIP = \frac{7758Ah\varphi(1 - S_w)}{B_o} \dots\dots\dots(6) \qquad STB$$

Similarly;

$$STGOIP = \frac{43560Ah\varphi(1 - S_w)}{B_g} \; \dots\dots(7) \qquad SCF$$

Where Bo = oil formation volume factor (bbl/STB)

Bg = gas formation volume factor (ft^3/scf)

- OOIP Calculation Required the Following Data;

✓ Reservoir Bulk Volume.(obtained from structural or depth map, isopach map)

✓ Average Porosity.

✓ Average water saturation.

✓ OFVF or GFVF (Bo or Bg).

✓ OWC and GOC.

✓ Other parameters such as cut off values, pay thickness to gross thickness value.

❖ **Average Porosity and Water Saturation** : Average Porosity and water saturation are obtained from weighed or arithmetic average calculation as;

From weighed average porosity;

$$\varphi_{avg} = \frac{\sum \varphi_i h_i}{\sum h_i} \dots\dots\dots.(8)\ \ if\ h_i \neq h_{i+1} \neq \cdots \dots\dots h_n$$

From arithmetic average porosity;

$$\varphi_{avg} = \frac{\sum \varphi_i}{n}\ ,\ \ if\ h_i = h_{i+1} = \cdots \dots\dots h_n$$

From weighed average water saturation;

$$S_{w\,avg} = \frac{\sum \varphi_i h_i S_w}{\sum \varphi_i h_i} \dots\dots\dots.(9)\ if\ h_i \neq h_{i+1} \neq \cdots \dots\dots h_n$$

From arithmetic average water saturation;

$$S_{w\,avg} = \frac{\sum S_{wi}}{n}\ \ ,\ \ if\ h_i = h_{i+1} = \cdots \dots\dots h_n$$

Example: Calculate the arithmetic average and thickness-weighted average from the following measurements:

Sample	Thickness, ft	Porosity, %
1	1.0	10
2	1.5	12
3	1.0	11
4	2.0	13
5	2.1	14
6	1.1	10

Solution:

• Arithmetic average

$$\phi = \frac{10+12+11+13+14+10}{6} = 11.67\%$$

• Thickness-weighted average

$$\phi = \frac{(1)(10)+(1.5)(12)+(1)(11)+(2)(13)+(2.1)(14)+(1.1)(10)}{1+1.5+1+2+2.1+1.1}$$

$$= 12.11\%$$

Example: Calculate average oil and connate water saturation from the following measurements:

Sample	h_i, ft	ϕ, %	S_o, %	S_{wc}, %
1	1.0	10	75	25
2	1.5	12	77	23
3	1.0	11	79	21
4	2.0	13	74	26
5	2.1	14	78	22
6	1.1	10	75	25

Solution:

Sample	h_i, ft	ϕ	ϕh	S_o	$S_o\phi h$	S_{wc}	$S_{wc}\phi h$
1	1.0	.10	.100	.75	.0750	.25	.0250
2	1.5	.12	.180	.77	.1386	.23	.0414
3	1.0	.11	.110	.79	.0869	.21	.0231
4	2.0	.13	.260	.74	.1924	.26	.0676
5	2.1	.14	.294	.78	.2293	.22	.0647
6	1.1	.10	.110	.75	.0825	.25	.0275
			1.054		0.8047		0.2493

$$S_o = \frac{\sum_{i=1}^{n} \varphi_i h_i S_{oi}}{\sum_{i=1}^{n} \varphi_i h_i} = \frac{0.8047}{1.054} = 0.7635$$

$$S_w = \frac{\sum_{i=1}^{n} \varphi_i h_i S_{wi}}{\sum_{i=1}^{n} \varphi_i h_i} = \frac{0.2493}{1.054} = 0.2365$$

Gross and Net Pay Thickness

- The thickness of the reservoir zone used in this calculation is the ***net pay thickness***.
- The ***net pay thickness*** is the clean, permeable, hydrocarbon-containing zones, from which hydrocarbons can be produced at economic rates.
- The **gross thickness,** is the total thickness of the reservoir interval, that contains *produced* and *non-produced hydrocarbon* zones.

- The ***net to gross ratio*** is thickness of net pay divided by the gross thickness, and is often used to represent the quality of a reservoir zone. Net pay thickness can be calculated depending on *porosity* , *water saturation* and sometimes *shale volume cut off* values.

Sandstones
$\phi_{cutoff} \approx 7\%$ gas
$\phi_{cutoff} \approx 8\%$ oil
Carbonates
$\phi_{cutoff} \approx 4\%$

Sandstones
$Sw_{cutoff} \approx 60\%$
Carbonates
$Sw_{cutoff} \approx 50\%$

$V_{shcutoff} \approx 20 \text{ to } 30\ \%$

- ***cut off* values** used to distinguish between pay and non-pay intervals. So; for an interval to be regarded as **pay zone in carbonate reservoir**, it must have ;

porosity value ≥ 4 % , clay volume ≤ 30 % and water saturation ≤ 50 %

- Consider net and gross thickness, hydrocarbon in place calculated as;

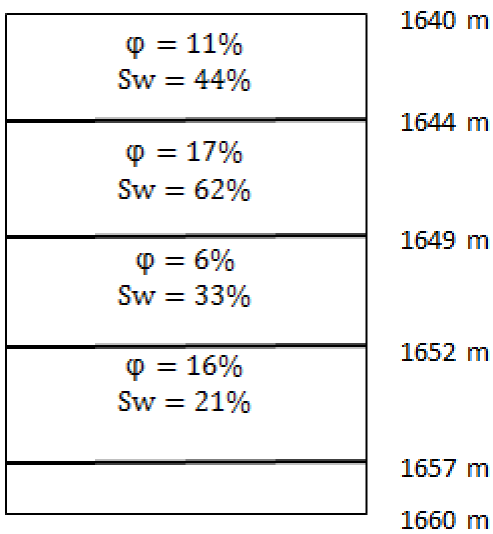
$$OOIP = \frac{7758Ah\varphi(1 - S_{wi})(\frac{h_{net}}{h_{gross}})}{B_{oi}} \quad STB \qquad (10)$$

$$OGIP = \frac{43560Ah\varphi(1 - S_{wi})(\frac{h_{net}}{h_{gross}})}{B_{gi}} \quad SCF \qquad (11)$$

Example: Given**;** Porosity cut off = 9% ,

Water saturation cut off = 55%

Calculate the net pay and gross thickness.



Solution:

This reservoir contain from *four* zones.

Gross thickness = 1657-1640 = 17 m

Zone 1:

Thickness = 1644-1640=4m

Porosity of this zone > cut off porosity (9%)

Water saturation < cut off water saturation(55%)

This zone is net pay zone with thickness of 4 m

Zone 2:

Thickness = 1649-1644=5m

Porosity of this zone > cut off porosity(9%)

Water saturation > cut off water saturation(55%)

This zone is non-pay zone.

Zone 3:

Thickness = 1652-1649=3m

Porosity of this zone < cut off porosity (9%)

Water saturation < cut off water saturation(55%)

This zone is non-pay zone.

Zone 4:

Thickness = 1657-1652=5m

Porosity of this zone > cut off porosity (9%)

Water saturation < cut off water saturation(55%)

This zone is net pay zone with thickness of 5 m

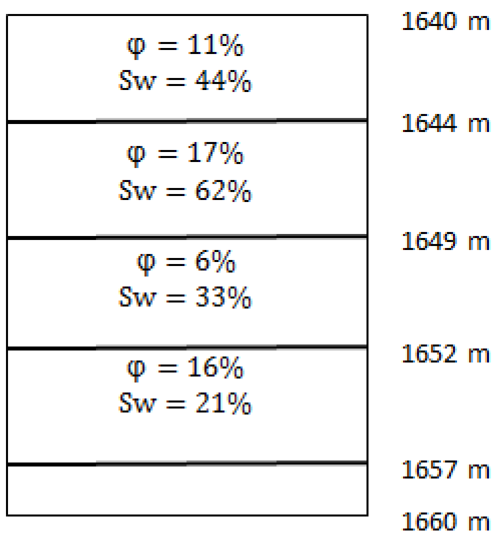
- Net pay thickness = Zone 1 thick.+ Zone 4 thick.= 4+5= 9 m

$$\left(\frac{h_{net}}{h_{gross}}\right) = \frac{9}{17} = 0.53$$

❖ Process of Interpretation

- ✓ Identify potential reservoir intervals; distinguish non-permeable, non-reservoir intervals from porous potential intervals.
- ✓ Estimate thickness of the potential reservoirs.
- ✓ Determine lithology (rock type) of the potential reservoirs.
- ✓ Calculate porosity (Φ) using **porosity log**.
- ✓ Calculate shale volume (V_{sh}) using **GR log**.
- ✓ Determine resistivity of formation water (R_w).
- ✓ Calculate water saturations (S_w) using **resistivity log**.
- ✓ Estimate original oil in place OOIP.

Example: Given;
Porosity cut off = 9%
Water saturation cut off = 55%
Oil Formation Volume Factor = 1.4 Bbl/Stb
RF= 37%
Reservoir Bulk Volume = 174301 acre.ft
Calculate ;



1. Nep pay thickness
2. Gross thickness
3. Pore volume in (ft^3) and (bbl)
4. IOIP in reservoir and tank conditions.
5. Recoverable oil reserve

Solution:
Nep pay thickness = 9 ft
Gross thickness = 17 ft
N/G = 9/17 = 0.53

Depth ft	h ft	φ	Sw	φ*h	φ*h*Sw
1640-1644	4	0.11	0.44	0.44	0.1936
1652-1657	5	0.16	0.21	0.8	0.168
sum	9			1.24	0.3616

$$\varphi_{avg} = \frac{\sum \varphi_i h_i}{\sum h_i} = \frac{1.24}{9} = 0.1378$$

$$S_{w.avg} = \frac{\sum \varphi_i h_i S_{wi}}{\sum \varphi_i h_i} = \frac{0.3616}{1.24} = 0.29$$

$$PV = \varphi avg.\ BV = (43560)(0.1378)(174301) = 1046253605\ ft^3$$

$$= 1046.25\ MM\ \ ft^3$$

$$PV = (7758)(0.1378)(174301)$$

$$= 186336902.4\ bbl$$

$$= 186.34\ MM\ \ bbl$$

$$OOIP = 7758(BV)\varphi avg.\left(1 - S_{w.avg}\right)\left(\frac{N}{G}\right) = 70118576.4\ bbl$$

$$OOIP = \frac{7758\ (BV)\varphi avg.\left(1 - S_{w.avg}\right)\left(\frac{N}{G}\right)}{B_o} = \frac{70118576.4}{1.4}$$

$$= 50084697\ STB$$

ELECTRICAL PROPERTIES OF ROCK

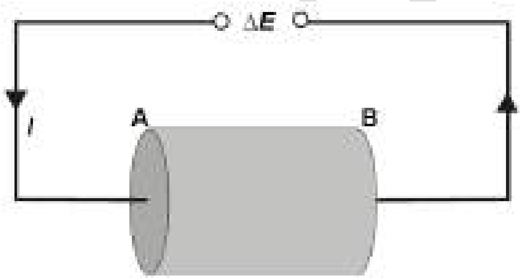
❖ Flow of Electrical Current Through the Reservoir Rocks

- Reservoir rocks consist of grain(matrix) and cement, and these components are *non-conductive* for electrical currents.
- An electrical current will flow only through the connate water saturating the porous of the rock, and then only if the connate water contains dissolved salts.
- Hydrocarbons (oil and gas) are *non-conductive* for electrical currents.

❖ Resistance and Resistivity

Ohm's Law states that;

The current(***I***) flowing from *point* ***(A)*** to *point* ***(B)*** in a conductor is proportional to the *electrical potential difference* ***(ΔE)*** between point A and point B.



$$I = c\,\Delta\boldsymbol{E} \qquad (1)$$

C = the constant of proportionality (called the electrical conductance *(c*), measured in Siemens (S).

I = Current measured in amperes (A).

ΔE =potential difference measured in volts (V).

Electrical **resistance** (*r)*, is the inverse of conductance, so;

$$r = \frac{1}{C} \qquad (2)$$

Resistance is measured in **ohms** (Ω). Hence, we can rewrite Eq. (1) as;

$$I = \frac{\Delta\boldsymbol{E}}{\boldsymbol{r}} \qquad (3)$$

- The *resistance is a property of the material* ….. **How?** If the material has a **low conductivity** to the current, the material **resistance** is **high (**from **Eq.2)…** when the **material resistance** is **high,** the **current** will be **low (**from **Eq.3)**, vice versa.
- The resistance depends on the **length** and **area** of end face of the sample……**How**?
  - If the sample length is doubled, the resistance of the sample will be double.
  - If the perpendicular area to the current flow doubles the current will increase, the resistance of the sample will decrease(see eq.3).

$$i.e. \qquad r \propto \frac{L}{A}$$

Proportionality constant is called **Resistivity (R)**

$$r = R\left(\frac{L}{A}\right)$$

Or we can say;

The resistance per unit length and area is called the ***resistivity*** *R*, and can be expressed as;

$$r = R\left(\frac{L}{A}\right) \quad \rightarrow \quad R = \frac{A}{L}r \quad \rightarrow \quad and \qquad r = \frac{\Delta E}{I}$$

$$\therefore \quad R = \frac{\Delta E}{I}\frac{A}{L} = (r)\frac{A}{L} \qquad (4)$$

Where:

R = the resistance of the sample (Ωm or ohm.m)

Δ*E* = the potential difference across the sample (volts, V)

I = the current flowing through the sample (amperes, A)

A = the cross-sectional area of the sample perpendicular to the current flow(m^2)

L = the length of the sample (m).

- Note that a conductivity ***(C)*** can also be defined as the reciprocal of the resistivity *R*,

$$C = \frac{1}{R} = \frac{I}{\Delta E}\frac{L}{A} \qquad (5)$$

Where: *C* = the conductivity of the sample (siemens per metre S/m or millisiemens per metre mS/m), or (moh/m or mmoh/m)

R= resistivity in $\Omega.m$

- In log evaluation the resistivity of the formation is the principal indicator of hydrocarbons, therefore emphasis has been put on the precise determination of resistivity.
- That is why quite a number of tools and techniques have been designed and developed to make a very accurate measurements of this parameter.
- There are two main types of tool are measure the electrical rock properties.
  - <u>tool measures resistivity directly</u>, and the result is given in ohm.m (Ω.m).
  - <u>tool measures conductivity directly</u>, and the result is given in siemens per metre (S/m), or in millisiemens per metre (mS/m). The two measurements are measuring the same property of the rock, and can be interconverted using;

$$C\left(\frac{s}{m}\right) = \frac{1}{R(\Omega.m)} \qquad or \qquad C\left(\frac{ms}{m}\right) = \frac{1000}{R(\Omega.m)} \qquad (6)$$

Proof:

$$R = r\frac{A}{L} \quad , \qquad R = ohm.\frac{m^2}{m} = ohm.m$$

$$R = r\frac{A}{L} = \frac{\Delta E}{I}\frac{A}{L} \quad , \ and \ \ C = \frac{1}{R} = \frac{I}{\Delta E}\frac{L}{A} = \frac{1}{r}\frac{L}{A}$$

$$C = \frac{1}{ohm}.\frac{m}{m^2}, \qquad \frac{1}{ohm} = mho$$

$$C = \frac{mho}{m} \quad , \quad or \ \ \frac{s}{m}$$

❖ Resistivity of the Reservoir Rocks

- Reservoir rocks consist of
  - Matrix material (low or not conductive to current) High resistivity.
  - Formation waters (conductive to current) Low resistivity.
  - Oil (low or not conductive to current) High resistivity.
  - Gas (low or not conductive to current) High resistivity.
  - Water-based mud filtrate (conductive) Low resistivity.
  - Oil-based mud filtrate High resistivity.
- Resistivity of formation waters depends on salinity.
- Fresh water have high resistivity (about $10^6\ \Omega.m$).
- Saturated salt water have low resistivity (less than $0.1\ \Omega.m$).
- The main salt exists in formation water is NaCl.
- Formation water salinity unit represented in part per million of Nacl **ppm NaCl**.

❖ Factors Affecting Resistivity of the Reservoirs Rocks

1) Salinity ∞ 1/R
2) Temperature ∞ 1/R
3) Presence of hydrocarbons ∞ R

❖ Resistivity Variation with Salinity and Temperature

- The resistivity varies greatly with temperature but little with pressure.
- The temperature in a borehole can be found directly from temperature log and called bottom hole temperature BHT.
- **Formation temperature** (T_f) or temperature at any depth, can be calculated by Knowing the following parameters;
  - ✓ Formation depth.
  - ✓ Bottom hole temperature (BHT).
  - ✓ Total depth of the well.
  - ✓ Surface temperature.
- Formation temperature can be calculated by using the following steps;

1. Calculate the geothermal gradient.

$$G.G = 100\left(\frac{BHT - T_o}{TD}\right) \qquad (7)$$

2. Calculate the formation temperature;

$$T_f = \frac{G.G}{100}\left(D_f\right) + T_o \qquad (8)$$

G.G = geothermal gradient (F^o/100 ft) or (C^o/100m)

T_f = formation temperature at any depth(F^o).

T_{BHT}= Bottom hole temperature (F^o).

T_o= annuls mean surface temperature = 80^{o}F

D_f = formation depth(ft).

D_T = Total well depth (ft).

- Formation temperature also can be calculated by using by using **chart** (Fig.1)

Converting

$$1\,\frac{F^o}{100ft} = 1.823\,\frac{C^o}{100m}$$

$$1\,\frac{C^o}{100m} = 0.5486\,\frac{F^o}{100ft}$$

Example: If BHT = 200 F^{o} at depth 11000 ft,

1) Calculate the geothermal gradient, assume the annulus surface temperature is 80 F^{o}.
2) Calculate the temperature at depth 5000 ft.

Solution:

$$G.G = 100\left(\frac{T - T_o}{D}\right) = 100\left(\frac{200 - 80}{11000}\right) = 1.09^{o}F/100ft$$

$$T_f = \frac{G.G}{100}\left(D_f\right) + T_o \quad \rightarrow \; T_f = \frac{1.09}{100}(5000) + 80 = 134.5^{o}F$$

- By Using Chart (Fig.1)

G.G= 1.1^{o}F , T_f = 135^{o} F

- Measured resistivity at surface conditions can be corrected to the subsurface or well conditions by using;

1) Arp's Formula;

$$R_2 = R_1 \left[\frac{T_1 + 6.77}{T_2 + 6.77}\right] ;^{\circ}F \qquad (9)$$

$$R_2 = R_1 \left[\frac{T_1 + 21.5}{T_2 + 21.5}\right] ;^{\circ}C \qquad (10)$$

Where;

R_1 = resistivity @ temperature T_1 , R_2 = resistivity @ temperature T_2

2) (Fig.2) , which is based upon **Arp's** equation. This chart relates between the resistivity, NaCl salinity, and temperature.

Example ; If the formation temperature is 166^{o} F, and the water resistivity at laboratory condition equal to 0.04 $\Omega.m$ @ 70^{o} F, calculate water resistivity @ T_f

Sol: R1 = 0.04 , T1 = 70^{o} F , R2 = ? , T2= 166^{o} F

$$R_2 = 0.04 \quad \left[\frac{70 + 6.77}{166 + 6.77}\right]$$

$$\therefore Rw = R_2 = 0.01777 \approx 0.018 \;\; \Omega.m$$

Examples

1. Resistivity of water sample @ 250°F is 0.26 Ω.m calculate ;
   a. Salinity of the water sample.
   b. Resistivity of sample @ 140°F
2. A brine (solution of water and Nacl) with salinity (55000 ppm) have resistivity equal to (0.1 Ω.m), calculate the brine temperature in F° and C°.
3. Calculate the resistivity of brine at (300°F) with salinity (350 ppm) and (100000 ppm). Discuss the results.

❖ **Equivalent NaCl Salinity of Salts**

- Salinity represents the total amount of salts in the brine, estimated by part per million of salts (ppm).
- Formation water consist of many types of salts in different concentrations dissolved in it as well as NaCl salt.
- Types of salts in formation water are;
  $NaCl$, $CaSo_4$, Na_2SO_4 , KCl , $CaCl_2$, $MgSO_4$, Na_2SO_4 and others.
- The brine salinity in **chart (Fig-2)** is based on NaCl salt only, therefore the other salts in formation water must be convert to the equivalent NaCl salts.
- For this purpose we use **chart (Fig.3)**.

Example: Formation water sample consist of $MgCl_2$ salt, concentration of Mg^{+2} ions are (2400 ppm) and concentration of Cl^- ions are (4600 ppm), calculate

- the equivalent NaCl concentration of $MgCl_2$ salt
- the resistivity of the sample at (100°F).

Solution;

- calculate the total solids concentration

$$total\ solids\ concentration\ = 2400\ +\ 4600\ = 7000\ ppm$$

- From **chart (Fig-3),** enter the x-axis at 7000 ppm and read the multiplier value for each of the solids curves from the y-axis:

$$k \rightarrow (cl)\ =\ 1 \qquad , \qquad k \rightarrow (Mg)\ =\ 1.32$$

ion	original ionic concentration C_o (ppm)	multiplier k	Eq. NaCl concentration =(k).(C_o) ppm
Mg^{+2}	2400	1.32	3168
Cl^-	4600	1.00	4600
Total	7000		7768

- Multiply each concentration by its multiplier

$$\text{For } Mg^{+2} \text{ the equivalent } = (2400).(1.32) = 3168\ \text{ppm}$$

$$\text{For } Cl^{-} \text{ the equivalent } = (4600).(1) = 4600\ \text{ppm}$$

- Calculate the equivalent NaCl concentration of $MgCl_2$ salt

$$\therefore \text{ Equivalent NaCl } = 3168 + 4600 = 7768\ \text{ppm}$$

- From **chart (Fig-2)** the resistivity is 0.55 $\Omega.m$

Examples

1. Table below represents the analysis results for two samples of formation water taken from the field X , for each sample calculate the water resistivity (R_w) at 100°F , 160°F and 200°F

ion	original ionic concentration C_o (ppm)	multiplier k	Eq. NaCl concentration =(k).(C_o) ppm
Mg^{+2}	1457		
Cl^-	3860		
Na^+	1683		
CO_3^{-2}	2153		
SO_4^{-2}	2277		
k^+	1858		
Ca^{+2}	1835		
Total			

❖ **Formation Water Resistivity (Rw) Determination Methods**

- Formation water, sometimes called *connate water* or *interstitial water*, is the water, uncontaminated by drilling mud, that saturates the porous formation rock.
- The water sample can be obtain from a production test, drill stem (DST) test or from well logs.
- The resistivity of the formation water, Rw is an important interpretation parameter since it is used in the calculation of the saturations (water and/or hydrocarbon).
- There are several methods for estimating Rw. These include;
  - Direct measurements method in the laboratory.
  - chemical analyses. (chart Gen-6)
  - the spontaneous potential (SP) log.
  - Archie’s equation.
  - Cross plots method.
  - Apparent R_w method.

❖ Formation Factor (Archie's First Law)

- Let; R_o is the resistivity of rock, 100% saturated with formation water.
  R_w is the resistivity of formation water.
- It has been established experimentally that the resistivity of rock, 100% saturated with formation water is proportional to the resistivity of formation water.

$$R_o \propto R_w$$

The constant of proportionality is called the formation resistivity factor, F.

$$R_o = F \cdot R_w \qquad (11)$$

$$F = \frac{R_o}{R_w}$$

- If the rock porosity was 100% , i.e. (there is no matrix or grain just 100% fluid) .. The formation factor =1
- If we slowly add grains to this rock, the porosity decreases, and formation factor increase , also rock resistivity R_o will increase because the grains of rock will decrease the conductivity. So the formation factor depends on the porosity, and is always **greater than 1** in a porous medium.
- Archie examined the way that the formation factor F changes from rock to rock by the rock porosity,

$$F = \frac{a}{\Phi^m} \qquad (12)$$

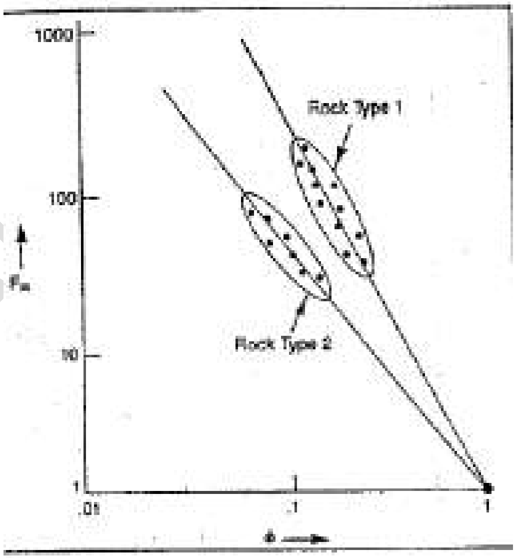
Where;
m = cementation factor (no units).
a = tortuosity factor, represents complexity of the paths between pores , i.e the electrical current flow paths.

- Equations (**11**) and (**12**) are often combined and called **Archie's first law**.

- The resulting equation is ;

$$R_o = R_w \frac{a}{\Phi^m} \qquad (13)$$

- The cementation factor (m) is the factor that describes the increase in resistivity that results from the increasing rock grains .
- Cementation factor depends on;
  - ✓ tortuosity factor. $\boldsymbol{a \propto m}$ $(\,as\ a\ increase\ the\ m\ increase)$
  - ✓ grain size.
  - ✓ grain size distribution.
- Archie stated that "the slope, m, appeared to vary for different rock types as a function of the degree of cementing of the rock". Hence, this slope, m, is generally referred to as the "cementation factor", which is a misnomer since it varies as a function of many factors.

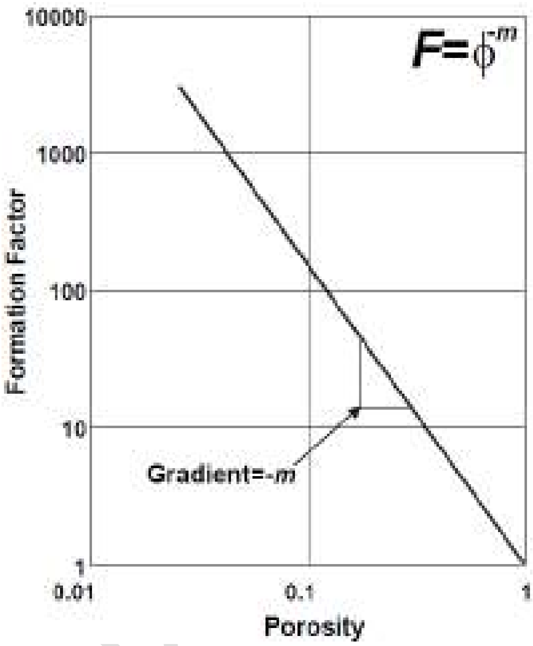


- Table below show the values of (m) and (a) according to rock types.

Type of rock	m	a	F.F Equation
Carbonates (Hard formations)	2	1	$F = \frac{1}{\varphi^2}$ (14)
unconsolidated sandstone (Soft formations)	2.15	0.62	$F = \frac{0.62}{\varphi^{2.15}}$ (15) **(Humble formula)**
consolidated sandstone (Soft formations)	2	0.81	$F = \frac{0.81}{\varphi^2}$ (16)

- Also we can use **chart (Fig.4)** to find formation factor graphically.
- Typically , m= (1.4 – 2) in sandstone.
  m= (2 – 2.8) in carbonate.

- Both the formation factor and the cementation exponent can be measured on core plugs in the laboratory. A mean cementation exponent can be obtained graphically by plotting *F* against φ on log-log graph paper, which intersects *F*=1 when φ =1, and with a gradient equal to –*m*..



$$\log F = log\left(\frac{R_o}{R_t}\right) = -m \log \varphi$$

❖ Partial Water Saturation (Archie's Second Law)

- Let; $\mathbf{R_o}$ is the resistivity of rock, **100% saturated** with formation water. (i.e. there is only formation water inside the rock porous)

  $\mathbf{R_t}$ is the true resistivity of rock, **partially saturated** with formation water.
  (i.e. there are formation water and hydrocarbons inside the rock porous)

- It has been established experimentally that the resistivity of rock, partially saturated with formation water (R_t) is proportional to the resistivity of rock, 100% saturated with formation water R_o.

$$R_t \; \alpha \quad R_o$$

$$R_t \;=\; I \; R_o \qquad\qquad (17)$$

- The constant of proportionality *I* is called the ***resistivity index*** and describes the effect of partial desaturation of the rock.
  - ✓ If the rock is fully saturated, *I*=1.00.
  - ✓ If the rock is full of dry air (i.e., not saturated with a conductive fluid), $I \rightarrow \infty$.

- The resistivity index therefore varies between 1 and infinity depending upon the *degree of saturation* of the rock. So;

$$I = S_w^{-n} \qquad (18) \qquad \textbf{(for sandstone)}$$

where: *Sw* = the fractional water saturation of the rock

I = the resistivity index

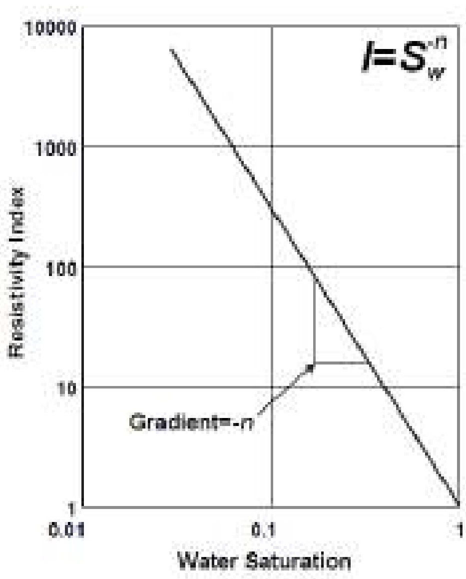
n = the saturation exponent. (range from 1.8 to 2.0)

- Equations (**17**) and (**18**) are often combined and called **Archie's second law**. The resulting equation is ;

$$R_t = \frac{R_o}{S_w^n} \qquad (19)$$

$$S_w^n = \frac{R_o}{R_t}$$

- From equation above we observed;
- R_o is special case of R_t.
- Always $R_t \geq R_o$.
- In 100% water saturated zone , $R_t = R_o$.
- Decreasing in water saturation indicates the presence of hydrocarbons which are nonconductive , therefore the rock true resistivity R_t increase and become greater than R_o.
- We conclude that, always the ratio $\frac{R_o}{R_t} \leq 1$, thus $S_w \leq 1$.
- A mean saturation exponent can be obtained graphically by plotting resistivity index *I* against the water saturation *Sw*, on log-log paper. The result is a straight line intersecting *I*=1 when *Sw*=1, and with a gradient equal to –*n*.



❖ Combining Archie's Laws

The two equations for each of the Archie laws can be combined into one controlling equation. Combining Eq. (13) and (19) gives;

$$S_w^n = \frac{a \cdot R_w}{\Phi^m \cdot R_t} \qquad (20)$$

Table below summarizes the sources of the parameters that go into this equation to calculate the water saturation.

Parameter	Source	Parameter	Source
Rt	Deep resistivity log	**m**	Assumed m = 2 From crossplots
Rw	From SP log chemical analyses other methods	**n**	Assumed n = 2 From crossplots
a	a = 1 (carbonate) a = 0.81 (sandstone)	**φ**	Sonic log - Density log Neutron log

$$S_w = \sqrt[n]{\frac{R_w \phi^{-m}}{R_t}} = \sqrt[n]{\frac{R_w F}{R_t}} = \sqrt[n]{\frac{R_o}{R_t}}$$

Examples

1. Complete the table below depending on Archie general laws (assume a=1), solve each unknown in details.

S_w(%)	Φ(%)	m	n	R_w(Ω.m)	R_t(Ω.m)
	10	2	2	0.25	250
32	15	1.7	1.7		357
14	9	2		0.05	465
	14	1.8	1.8	0.24	92
(S_h = 56)	15		2	0.07	13.5

2. If the porosity is 12% , and water resistivity equal to (0.15 ohm.m) , assume m = n = 1.8 , find;

a. Formation true resistivity in case of 100% saturated with water.

S_w(%)	Φ(%)	m	n	R_w(Ω.m)	R_t(Ω.m)

b. Formation true resistivity in case of contains 60% hydrocarbons.

S_w(%)	Φ(%)	m	n	R_w(Ω.m)	R_t(Ω.m)

❖ Determination of Saturation Exponent (*n*)

- Saturation Exponent is water saturation exponent in Archie Equation(Eq.20), its values ranges between 1.8 and 2.5, sometime it is assumed (n=2).
- But the actual value of (n) is differ from assumed value which leads to errors in water saturation calculation, thus errors in OOIP calculations.
- Saturation Exponent depends on **wettability**

$n > 2$ in oil-wet systems

$n < 2$ in water-wet systems

❖ The value of the saturation exponent can be obtained from laboratory experiments on core samples. The procedure is as follows for a single core sample:

- ✓ Prepare the core sample.
- ✓ Saturate the sample in water, i.e. Sw = 100%.
- ✓ Measure the true resistivity R_t of the sample.
  In this case $R_t = R_o$, because $S_w = 100\%$.
- ✓ Measure the true resistivity R_t at different water saturation values, for example at S_w= 75% , 50% , 25% , ………..
- ✓ Calculate R_o/R_t ratio in each water saturation and true resistivity value.

Serial #	S_w (decimal)	R_t (Ω.m)	R_o/R_t
1	$S_{w1} = 1.0$	$R_{t1}=R_o$	$R_o/R_{t1}=1.0$
2	$S_{w2} = 0.75$	R_{t2}	R_o/R_{t2}
3	$S_{w3} = 0.60$	R_{t3}	R_o/R_{t3}
4	$S_{w4} = 0.50$	R_{t4}	R_o/R_{t4}
5	$S_{w5} = 0.25$	R_{t5}	R_o/R_{t5}

Theoretical Foundation:

$$S_w^n = \frac{R_o}{R_t}$$ By taking log. for each side

$$Log\left(\frac{R_o}{R_t}\right) = Log\left(S_w^n\right)$$

Apply logarithm rule $Log\,(x^y) = y\,.\,Log\,(x)$, to obtain;

$$Log\left(\frac{R_o}{R_t}\right) = n \cdot Log\,(S_w)$$

Compare the above equation with equation of straight line { $y = b\,x + c$ }

$Y = Log\left(\frac{R_o}{R_t}\right)$ $X = Log\,(S_w)$ b=slope = n c=intercept=0

Example: Calculate Saturation Exponent from the experimental laboratory data;;

Serial #	S_w (%)	R_t (Ω.m)	R_o/R_t
1	100	1.00	
2	75	1.73	
3	50	3.73	
4	25	14.00	

❖ The Effect of Errors in Resistivity Calculations

- The accurate determination of the water saturation is key to being able to calculate an accurate value for the amount of oil in place.
- Errors of a few percent in the determination of the water saturation result in errors worth billions of dollars when transferred into errors in the determination of STOOIP.
- In attempting to reduce errors we ensure that the five parameters in Eq. (20) are measured using independent methods.
- Laboratory determined *m* and *n* values are the best ones to take, however early in a reservoirs life these are not available, and so guesses are used instead.
- Table below shows the propagation of errors in Eq. (20) for the calculation of water saturation.

Propagation of errors in water saturation calculations.

Data			
	-20%	Base Case	+20%
R_t	32	40	48
R_w	0.32	0.4	0.48
ϕ	0.18	0.2	0.22
m	1.8	2	2.2
n	1.8	2	2.2

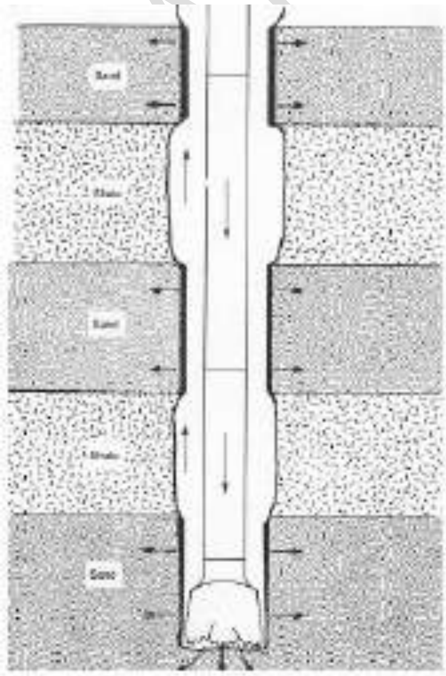
Saturations from changing individual parameters

R_t	0.56	0.50	0.46
R_w	0.45	0.50	0.55
ϕ	0.56	0.50	0.45
m	0.43	0.50	0.59
n	0.46	0.50	0.53

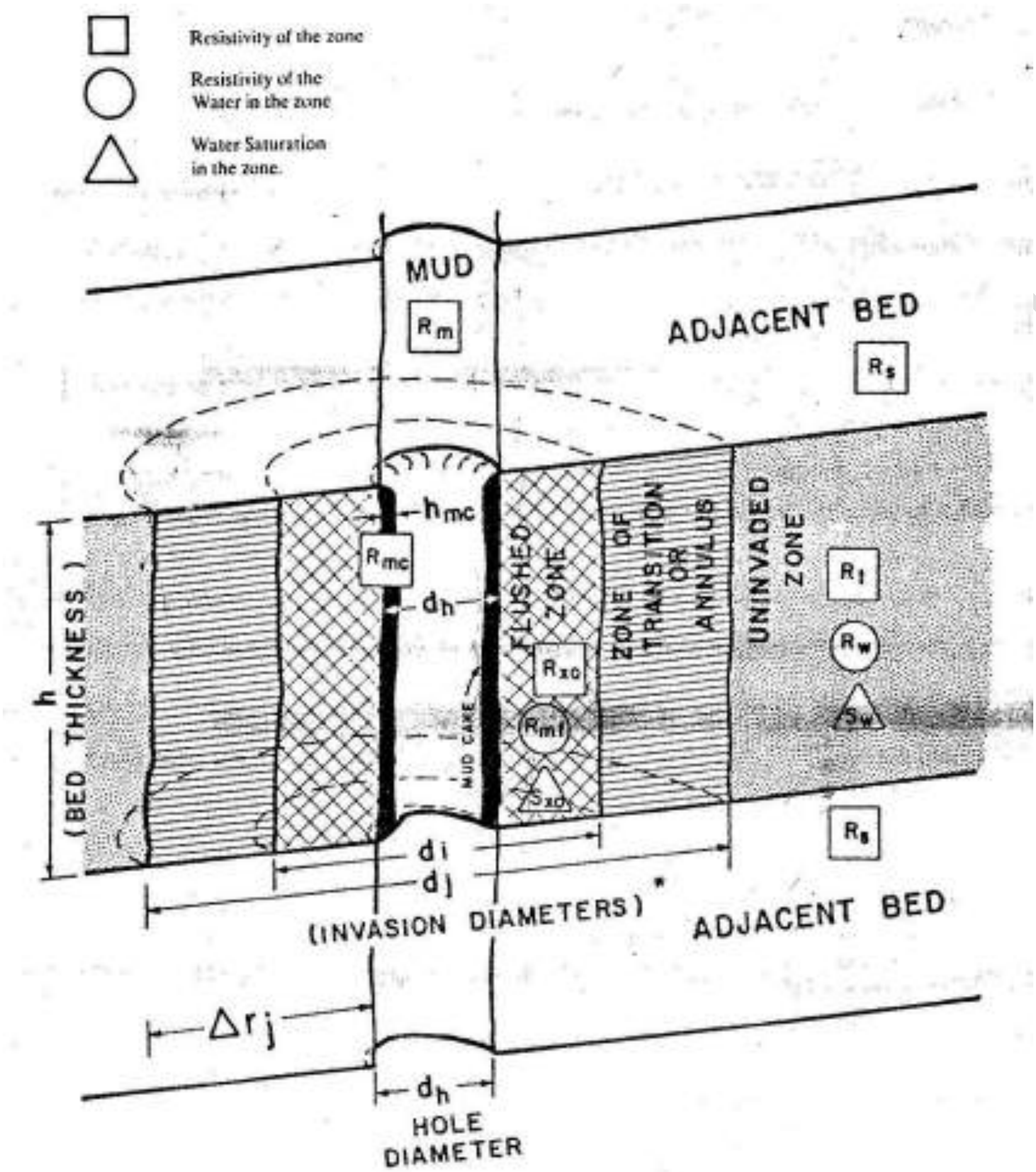
❖ Invasion & Borehole Environment

- When the borehole is drilled in a formation, the rock and the fluid in the rock undergoes alteration in the vicinity of the borehole.
- All logging measurements are then affected by the borehole and the altered rock around it.
- Borehole conditions affecting the log measurement are:

a. hole size **b. drilling mud** **c. mud cake** **d. mud filtrate**



- During drilling the mud pressure in the annulus must be kept greater than the hydrostatic pressure of fluid in the formation pores to prevent a well blowout.
- The pressure differential between the mud column pressure and the formation fluid pressure, forces drilling fluid into the formation.
- As this happens solid particles in the drilling mud will be left on the formation wall and form a mud cake, which reduce the diameter of the borehole.
- The liquid phase of mud will enter to the permeable formation pushing back the reservoir fluids.
- This part of the drilling mud is called the ***mud filtrate***.
- The zone where the mud filtrate has complete replaced the reservoir fluids is called the ***flushed zone.***
- The zone where the mud filtrate has incomplete replaced the reservoir fluids is called the ***transition zone.***
- The zone where the mud filtrate has not replaced the reservoir fluids is called the ***un-invaded zone.***



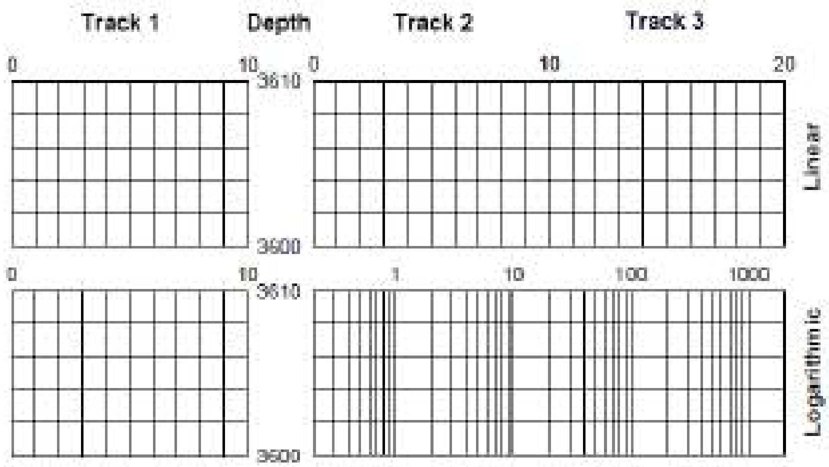
- dh – hole diameter
- di – diameter of invaded zone (inner boundary; flushed zone)
- dj – diameter of invaded zone (outer boundary; invaded zone)
- Drj – radius of invaded zone (outer boundary)
- h_{mc} – thickness of mud cake
- R_m – resistivity of the drilling mud
- R_{mc} – resistivity of the mud cake
- R_{mf} – resistivity of mud filtrate
- R_s – Resistivity of surrounding bed

- R_t – resistivity of un-invaded zone (true resistivity)
- R_w – resistivity of formation water
- R_{xo} – resistivity of flushed zone
- S_w – water saturation of uninvaded zone
- S_{xo} – water saturation of flushed zone

	Flushed Zone	Transition Zone	Un-invaded Zone
Rock resistivity	R_{xo}	R_i	R_t
porosity	φ	φ	φ
Water resistivity	R_{mf}	R_z	R_w
Water saturation	S_{xo}	S_{xi}	S_w

RESISTIVITY LOGS

- Resistivity is ability to impede the flow of an electric current through a substance.
- **Resistivity logs** measure the ability of rocks to conduct electrical current and are scaled in units of ohm- meters.
- Resistivity is the inverse of conductivity. The ability to conduct electric current depends upon:
  - The **Volume** of water.
  - The **Temperature** of the formation.
  - The **Salinity** of the formation
- Resistivity logs are electrical logs used to:
  - ✓ determine hydrocarbon-bearing versus water bearing zones.
  - ✓ indicate permeable zones.
  - ✓ determine water saturation.
- Typical formation resistivity are usually from 0.2 to 1000 ohm-m.
- Resistivity higher than 1000 ohm-m are uncommon in permeable formations but are observed in Evaporates impermeable formation(salt, anhydrites).
- Resistivity of soft formations i.e. shaly sands range from 0.5 Ω-m to about 50 Ω-m and 10Ω-m to 100 Ω-m for hard formations (carbonates).
- Because resistivity cannot be read correctly over the entire measurement range when displayed on a linear scale, all resistivity logs are presented on logarithmic scale, usually in 4 cycle across two log tracks. This allows the display of readings from 0.2 to 2000 ohm.m.



❖ Resistivity Log Tools Types

- In general, resistivity logs are classified into four groups;

A. **Conventional Electrical Surveys (ES)**

- o Short Normal devices 16"N
- o Long Normal devices 64"N
- o Lateral devices, (18'8")

B. Focusing Electrode Logs

- ▪ Laterologs (LL)
  - ✓ Basic laterologs, (LL3 , LL7 , LL8)
  - ✓ Dual laterologs DLL (LLd + LLs)
- ▪ Spherically Focussed Log SFL

C. Micro-Resistivity Logs

- o Microlog ML
- o Microlatero log MLL
- o Proximity Log PL
- o Micro Spherically Focussed Log MSFL

D. Induction logs

- o The Dual Induction Laterolog DIL (ILD + ILM).
- o The Induction Spherically Focussed Log ISF, combines; 6FF40, SFL and SP.

❖ Resistivity Log Tools Uses

- Measuring the resistivity of formations is complicated by the invasion of drilling fluids into permeable rocks. In wireline logging we make all measurement through the borehole. There are three main regions surrounding the wellbore:
  - ✓ The flushed zone.
  - ✓ The transition zone.
  - ✓ The undisturbed (un-invaded) zone.
- The purpose of all resistivity devices is to measure True Resistivity (Rt) or the resistivity of the flushed zone (Rxo).

	Flushed Zone	Transition Zone	Un-invaded Zone
Rock resistivity	R_{xo}	R_i	R_t
Water resistivity	R_{mf}	R_z	R_w
Water saturation	S_{xo}	S_{xi}	S_w

- The resistivity devices (tools) used in these regions are:
  - ✓ Deep Resistivity Tool….(measures Rt in un-invaded zone).
  - ✓ Medium/ Shallow Resistivity Tool.. (measures Ri, in transition zone).
  - ✓ Micro Resistivity Tool….{ measures Rxo in flushed zone}.

Tools	Flushed Zone R_{xo}	Transition(invaded) Zone R_i	Un-invaded Zone R_t
	0.084-0.5 ft	0.5 – 3 ft	+ 3 ft
Laterolog3 *LL3*			●
Laterolog shallow *LLS*		●	
Spherically Focussed Log SFL		●	
Laterolog7 *LL7*			●
Laterolog8 *LL8*		●	
Laterolog deep *LLD*			●
Microlog ML	●		
Microlaterolog MLL	●		
Proximity Log PL	●		
Micro Spherically Focussed Log MSFL	●		
Induction Log deep ILD			●
Induction Log medium ILM		●	
Induction Log 6FF40			●
Lateral 18'8"			●
Long Normal (64"N)			●
Short Normal (16"N)		●	

A) Conventional Electric Logs/ Electrical Survey Log (ES)

- ES logs were the first wireline logs, and are no longer used.
- These logs used 4-electrode system;
  - current electrode A and current electrode B to create currents.
  - potential electrode M and potential electrode N to measure potential difference.
- A surface current electrode (B) send an electrical current to an electrode (A) on the tool through formation. The potential difference is measured between potential electrode (M) on the tool and potential electrode (N) at the surface.
- The surface detector will measure the formation's resistance to the current.
  {The current(***I)*** flowing in a conductor is proportional to the *electrical potential difference* ***(ΔE)*** }.
- The potential difference is proportional to the resistivity of formation**.**

$$\Delta E \propto R$$

- Many factors affect the reading of a conventional electric log.
  - ✓ Hole diameter (d_h).
  - ✓ Diameter of invaded zone (di).
  - ✓ Mud resistivity Rm.
  - ✓ Bed thickness.
- Since the material surrounding the electrode system is not uniform, the logs read only an *apparent resistivity (Ra)*.

- There must be conductive fluid in the borehole for the tool to function properly. So this tool does not work in oil or air-filled holes.

- The conventional **electrical survey (ES)** usually consisted of;
  - ✓ Short Normal devices 16"N {16"N = 16 inch normal}
  - ✓ Long Normal devices 64"N { 64"N = 64-inch normal}
  - ✓ Lateral devices, (18'8") {18'8" = 18 foot 8 inch lateral}

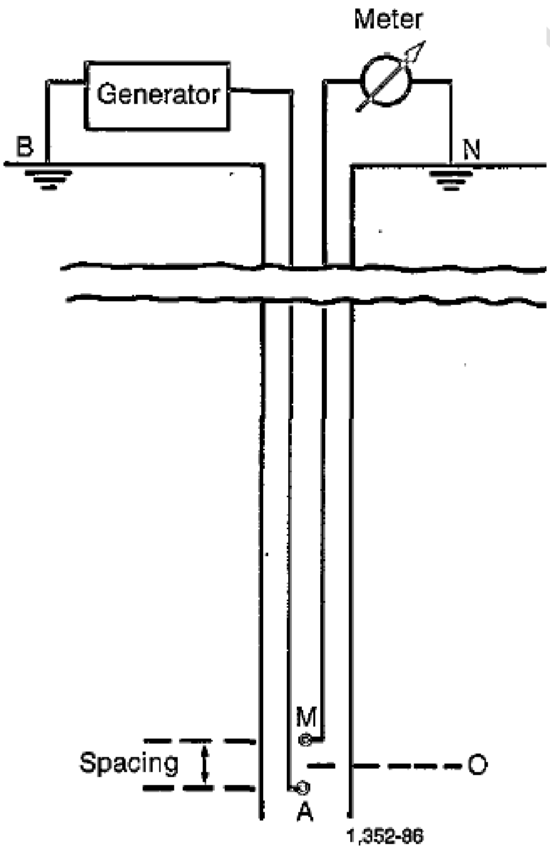
A. **Normal Device**

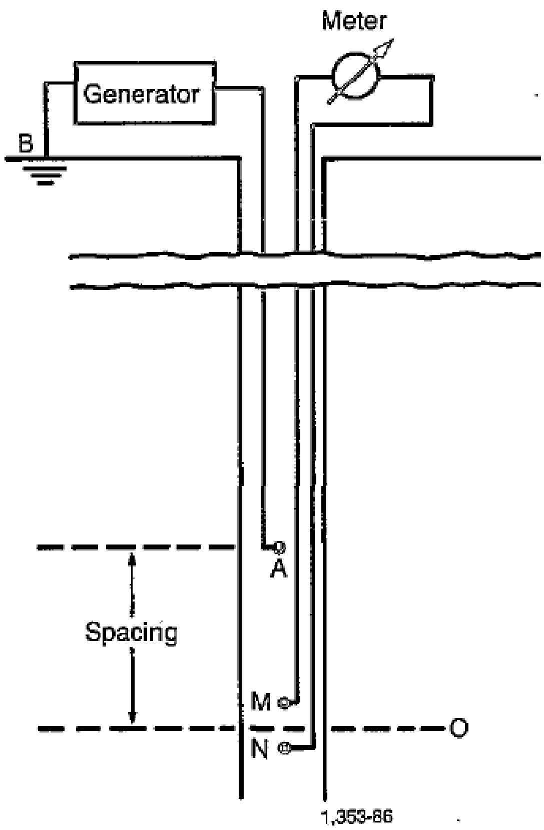
- The electrode spacing of a short normal is usually 16 inches (16"N) and the long normal is 64 inches (64"N).

B. Lateral Device

Here the electrode spacing is defined as the distance between the electrode (A) and the midpoint between the two potential electrodes (O).

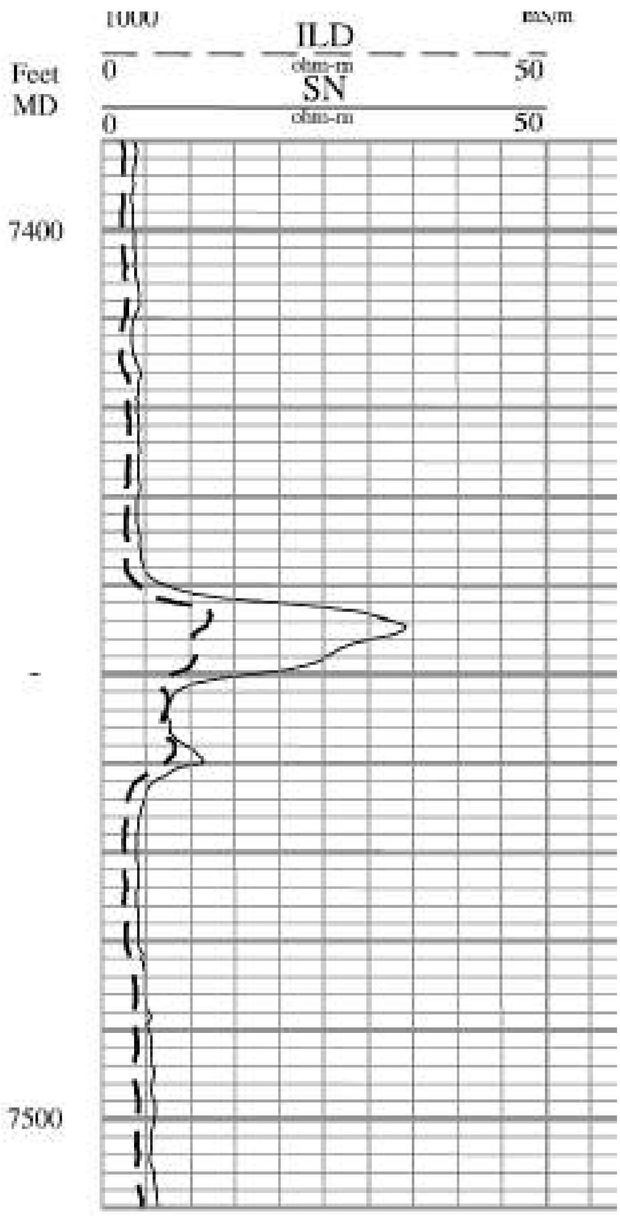
- Generally, the large the spacing, the deeper the device investigates into the formation and measurement . Thus, in the ES resistivity logs, the lateral log has the deepest investigation from the normal log.
- ES logs are rarely used today since these logs has largely been replaced by Induction- Electrical logs





❖ Conventional Electric Log Presentation

The log is presented starting with the third track. The scale is **linear** and often goes from 0 to 10 and then 0-100. The units for resistivity is ohm-meter (Ω - m). Typically speaking, the deep dashed line, if present, is the deepest reading curve. Sometimes there is an expanded scale for the short normal. This is used to help pick bed boundaries.

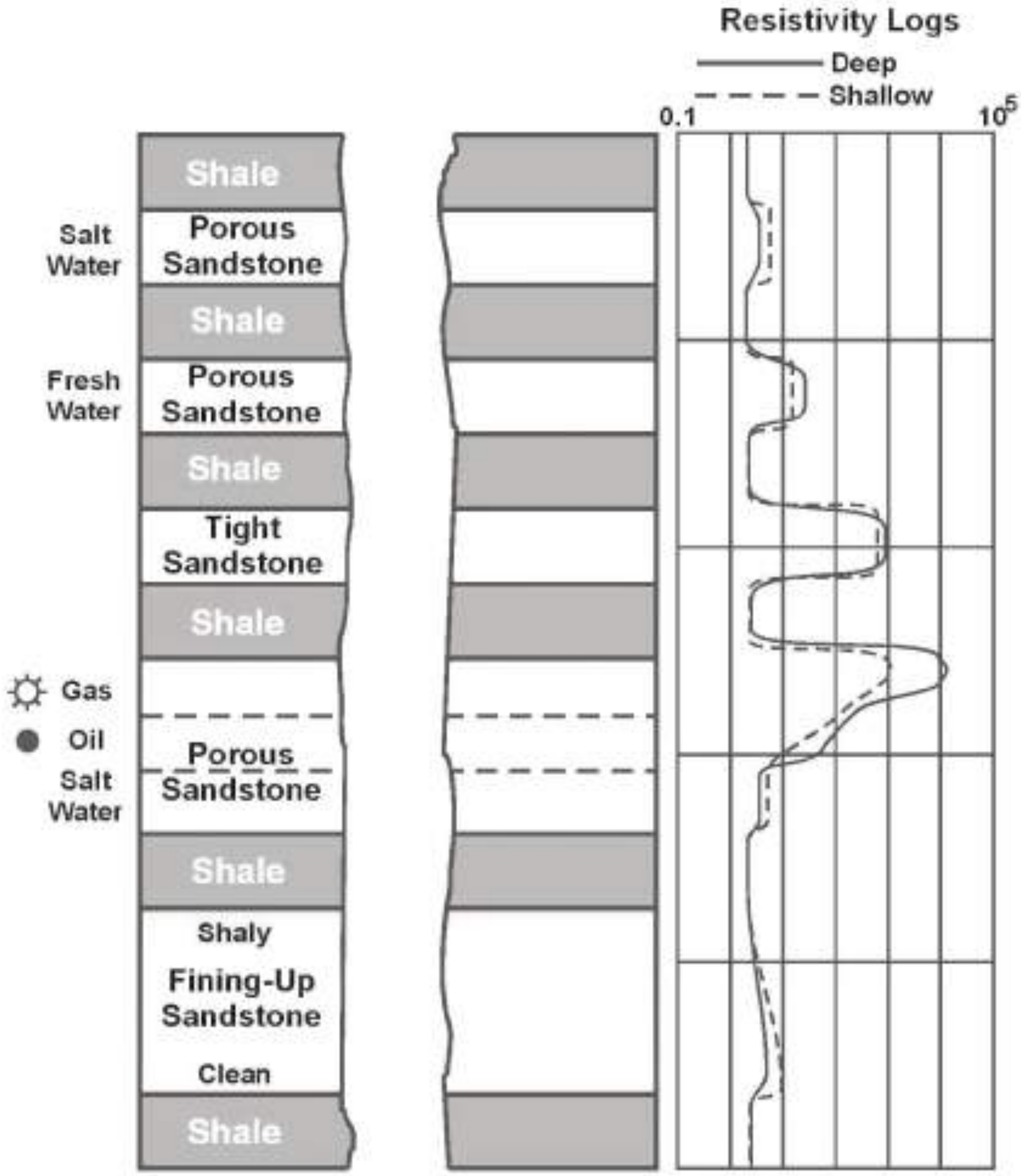


Typical Resistivity

- 0.5Ω-m to 1000 Ω-m for typical formations.
- Soft formations i.e. shaly sands range from 0.5 Ω-m to about 50 Ω-m
- 10Ω-m to 100 Ω-m for hard formations (carbonates)
- Evaporites (salt, anhydrites) may have several thousand Ω-m
- Formation water will range from 0.015 Ω-m (very salty brines)
- Several Ω-m, fresh water reservoirs
- Sea water has a resistivity of 0.35 Ω-m at 75 degrees Fahrenheit

❖ Typical Responses of an Resistivity Tool

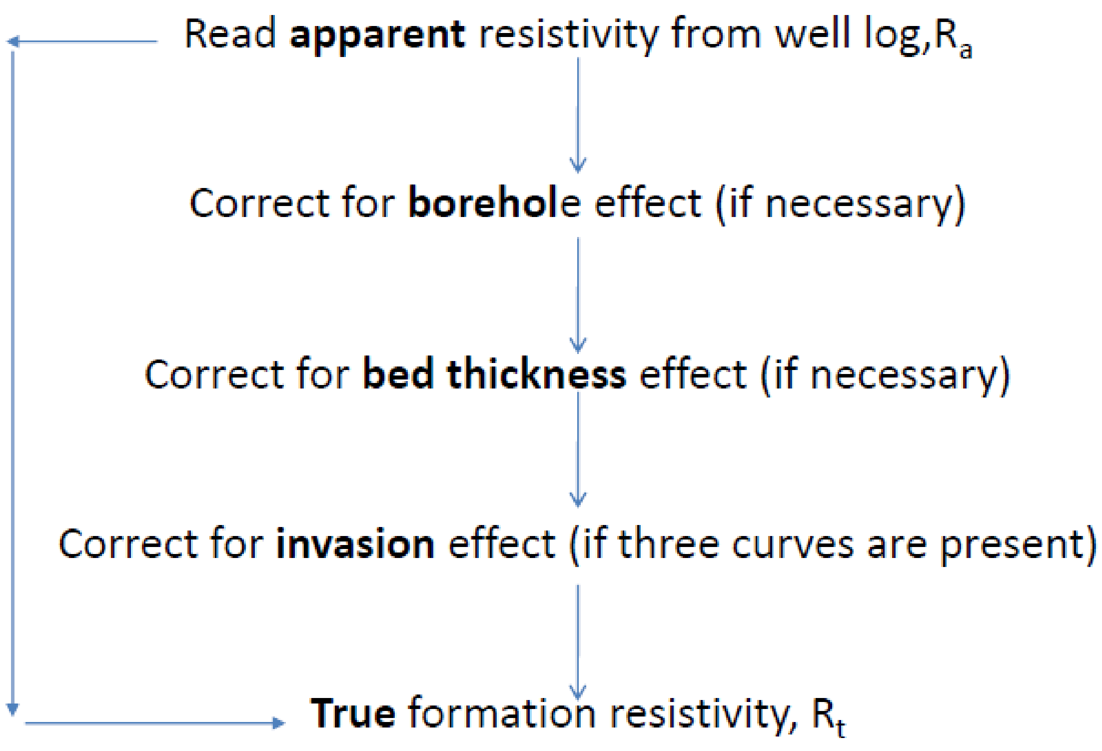
Figure below shows the typical response of an electrical tool in a sand/shale sequence. Note the lower resistivity in shales, which is due to the presence of bound water in clays that undergo surface conduction. The degree to which the sandstones have higher resistivities depends upon (i) their porosity, (ii) their pore geometries, (iii) the resistivity of the formation water, (iv) the water, oil and gas saturations (oil and gas are taken to have infinite resistivity).



Note: Assume Deep Resistivity Reads Rt If;

1) Rt/Rm is greater than about 10.
2) Rt/Rs is greater than about 10.
3) Hole diameter (dh) is greater than about 12 inches.
4) The bed is thinner than about 15 ft.
5) Invasion diameter (di) is greater than about 40 inches

- dh – hole diameter
- di – diameter of invaded zone (inner boundary; flushed zone)
- R_m – resistivity of the drilling mud
- R_s – Resistivity of surrounding bed
- R_t – resistivity of un-invaded zone (true resistivity)



B. Focused Resistivity Logs / Laterologs

- To overcome the limitations of the original electrode logs **(Electrical Survey Log**) the *laterolog* device was developed.
- Laterologs are electrode logs designed to measure formation resistivity in boreholes filled with saltwater muds (where *Rmf* ~ *Rw*) and resistivity > 200 Ω.m.
- Focused resistivity devices use "guard electrodes" to force current deeper into the formation (but they can have deep, medium and shallow depths of investigation).
- Focused devices were developed due to problems with;
  i) conductive muds.
  ii) large Rt (true resistivities of the formation)
  iii) deep invasion of borehole fluid
  iv) thin beds (but may be used in moderately thick beds).
- In focused devices Ra (apparent Resistivity) is within 10% of the Rt (true Resistivity).
- **Utility and Limitations of Focused Resistivity Devices**
  - Good Points - best in resistive, thin, interbedded sequences with a low borehole fluid resistivity (Rm) (therefore focused resistivity devices are well suited for salt-mud, carbonate logging programs.
  - Limitations - affected by invasion of borehole fluid and tough to run properly in the field.
- Invasion can influence the laterolog, because the resistivity of the mud filtrate is approximately equal to the resistivity of formation water (*Rmf* ~ *Rw*) when a well is drilled with saltwater muds, invasion does not strongly affect *Rt* values derived from a laterolog. But, when a well is drilled with freshwater muds (where *Rmf* > 3 *Rw*), the laterolog can be strongly affected by invasion. Under these conditions, a laterolog should not be used.

- The borehole size and formation thickness affect the laterolog, but normally the effect is small enough so that laterolog resistivity can be taken as *Rt*.

EXAMPLE of a laterolog and microlatero log.

- ✓ This log illustrates the curves and provides an example for picking log values. These logs are used when *Rmf* ~ *Rw*.
- ✓ **Track 1**: The log track on the far left contains gamma ray (GR) and caliper (CALI) curves, shown as solid and dashed lines respectively. Gamma ray logs commonly accompany laterologs. This one is recorded in units that predate API units, microgram-Radium equivalents per ton (µgRa-eq/ton).
- ✓ **Track 2**: This displays the laterolog (LL3), which measures the deep resistivity or true resistivity (*Rt*) of the formation. Note that the scale increases linearly from left to right in increments of 5 ohm-m from 0 to 50. <u>At the depth of **3948 ft**, the laterolog value reads **21 ohm-m**</u>.
- ✓ **Track 3**: The microlaterolog (MLL) measures the resistivity of the flushed zone (*Rxo*). Note that the scale starts with zero at the left edge of track 3. The scale ranges from 0 to 50 ohm-m in increments of 5 ohm-m. At the depth of **3948 ft** the microlaterolog reads 8 ohm-m.

Note: To correct the laterolog (for invasion) to true resistivity (*Rt*), use the following formula from (Hilchie, 1979). Using the example at 3948 ft:

$$R_t = 1.67\ (R_{LL}) - 0.67\ (R_{xo})\quad R_t = 1.67\ (21) - 0.67\ (8)$$

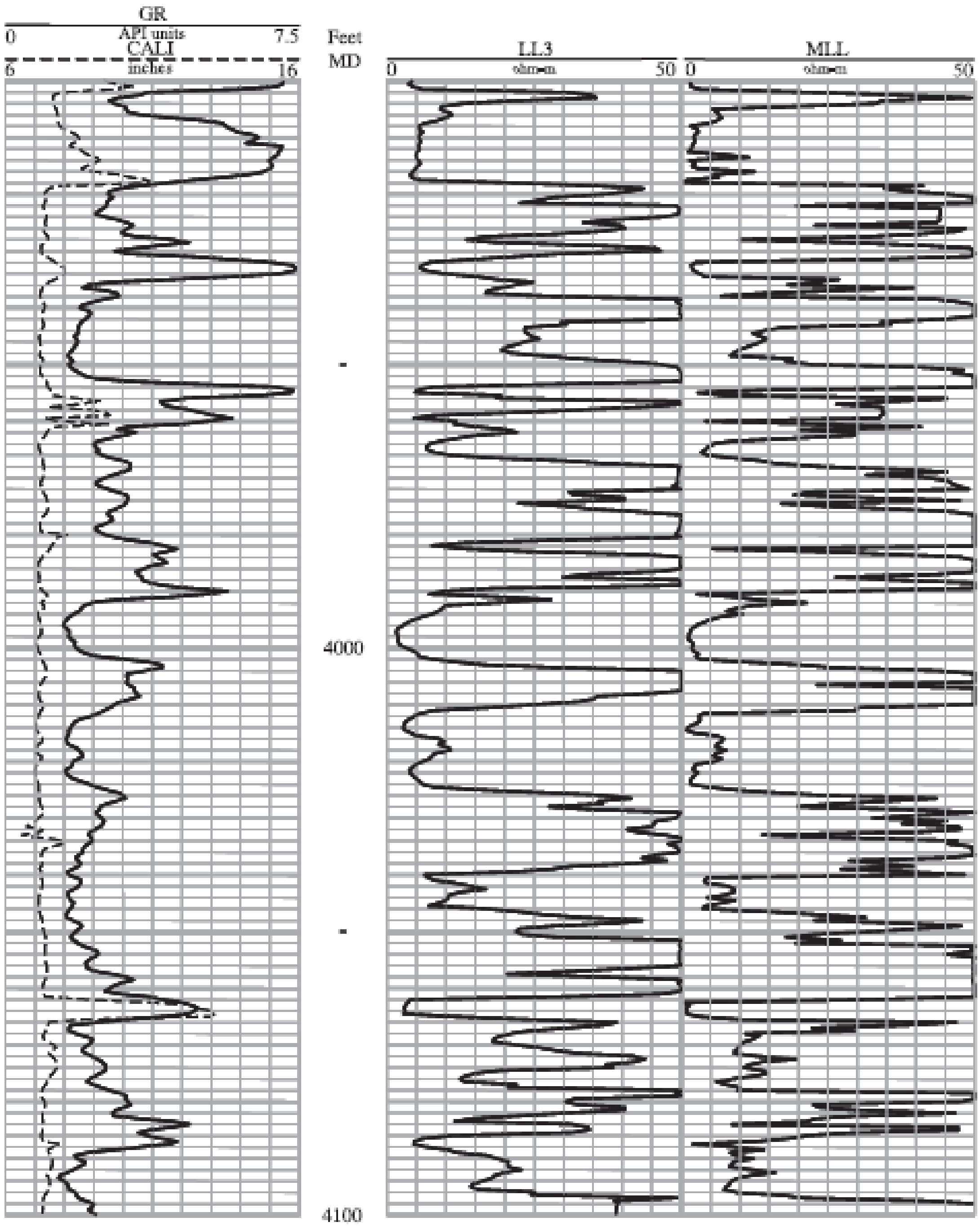
$$R_t = 29.7 \text{ ohm-m}$$

where:

R_t = resistivity of the uninvaded zone

R_{LL} = laterolog resistivity (21 ohm-m at 3948 ft)

R_{xo} = microlaterolog resistivity (8 ohm-m at 3948 ft)


GR
0
API units
7.5
CALI
6
inches
16
Feet
MD
4000
4100
LL3
0
ohm-m
50
MLL
0
ohm-m
50

❖ Dual Laterolog

- The dual laterolog consists of a deep-reading measurement (*RLLD*) and a shallow-reading measurement (*RLLS*).
- Both curves are displayed in tracks 2 and 3 of the log, usually on a four-cycle logarithmic scale ranging from 0.2 to 2000 ohm-m.
- A natural gamma ray log is often displayed in track 1.
- The third resistivity measurement is the microspherically focused resistivity (*RMSFL*), a focused electrode log that has a very shallow depth of investigation and measures the formation resistivity very close (within a few inches) of the wellbore.

EXAMPLE of dual laterolog with microspherically focused log.

- These logs are used when *Rmf* ~ *Rw* and invasion is deep.
- The resistivity scale in tracks 2 and 3 is a four-cycle logarithmic scale ranging from 0.2 to 2000 ohm-m; the values increase from left to right.

Deep laterolog resistivity:

- The LLD (long-dashed line) measures the deep resistivity of the formation, If invasion is not deep and the bed of interest is thick **(>2 ft),** the deep reading commonly approximates true formation resistivity (*Rt*).
- At the depth of **9324 ft**, the deep laterolog resistivity (*RLLD*) is **16 ohm-m**.

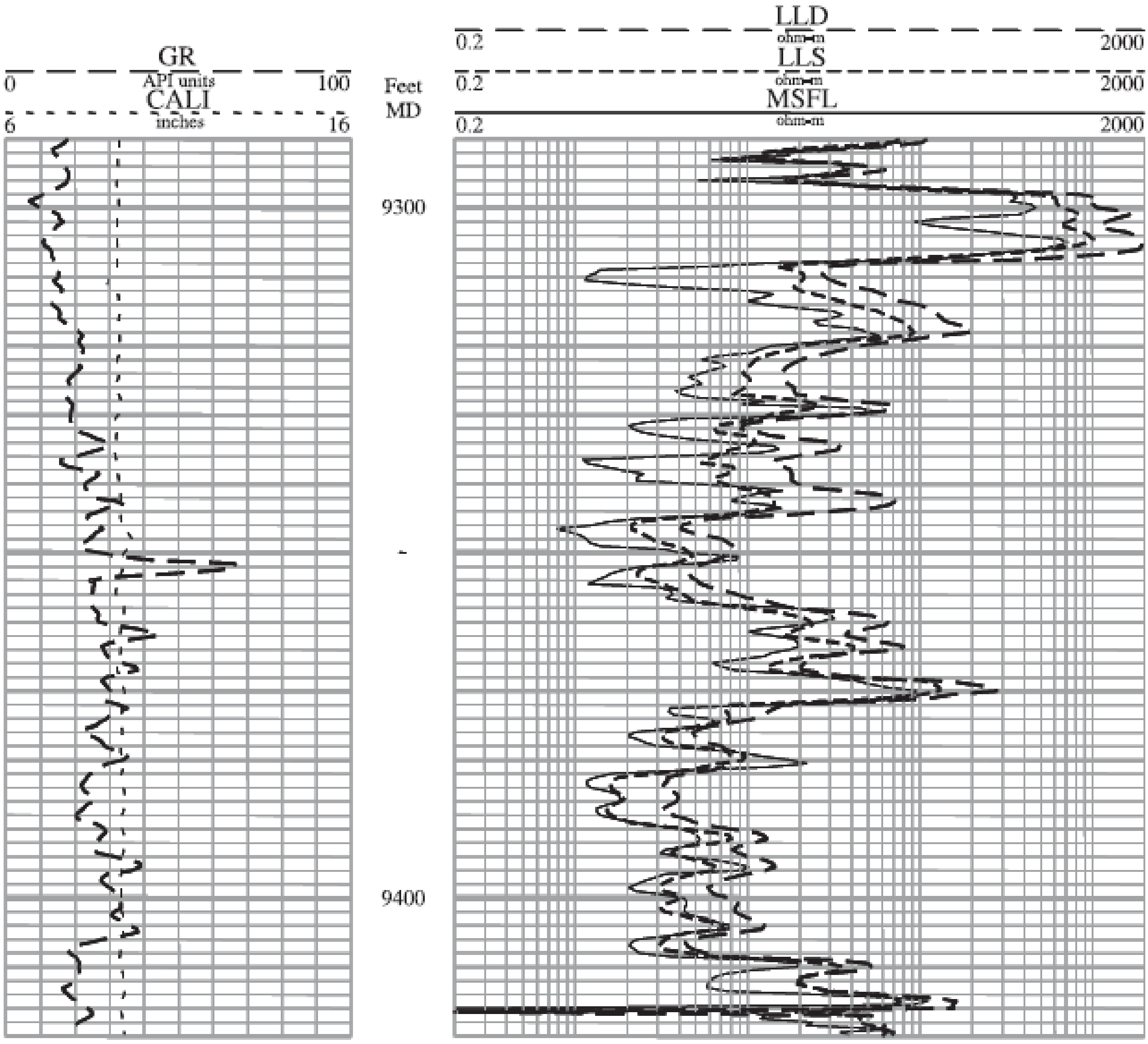
Shallow laterolog resistivity:

- The LLS (short-dashed line) measures the shallow resistivity of the formation or the resistivity of the invaded zone (*Ri*).
- At **9324 ft**, the shallow laterolog resistivity (*RLLS*) is **10 ohm-m**.

Microspherically focused log (MSFL) resistivity:

- The MSFL (solid line) measures the resistivity of the flushed zone (*Rxo*).
- At **9324 ft**, the MSFL resistivity (*RMSFL*) is **4.5 ohm-m**.

- When this three resistivity-curve combination (i.e., deep, shallow, and very shallow) is used, the deep laterolog curve can be corrected for invasion effects to produce *Rt*.
- A ***tornado chart*** (**CHART Rint-9b**) is used to graphically correct *RLLD* to *Rt* and to determine the diameter of invasion (*di*) and the *Rxo*.



- The following ratios are needed for work on the **tornado chart** (Figure 6), and the values represented are picked from the log as shown above:

LLD/MSFL = *RLLD*/*RMSFL* = 16/4.5 = 3.6

LLD/LLS = *RLLD*/*RLSS* = 16/10 = 1.6

- **EXAMPLE;** Dual laterolog-*Rxo* tornado chart for correcting deep resistivity to *Rt*. Log values in this exercise are picked from the example dual laterolog-MSFL in previous example.

- **TORNADO CHART Rint-9b (Fig.6)** consists of from the following parameters**;**

✓ RLLD/Rxo vertical axis of chart

✓ RLLD/RLLS horizontal axis of chart.

✓ Rt/RLLD ratio: The scale for this value is represented by the solid red lines. The scale values are in red and range from 1.1 to 1.8.

✓ di: The diameter of invasion around the borehole is picked from the chart by following the dashed, blue lines to the scales at the top of the chart. The scale from 20 to 120 gives di in inches, and the scale from 0.50 to 3.04 gives di in meters.

✓ *Rt*/*Rxo* ratio: The scale for this ratio value is represented by the heavy, blue, solid lines. The scale values are in black, increase from bottom to top, and range from 1.5 to 100.

- Given:

LLD = *RLLD* = 16.0 ohm-m

LLS = *RLLS* = 10.0 ohm-m

MSFL = *RMSFL* = 4.5 ohm-m

RLLD/*RMSFL* = *RLLD*/*Rxo* = 3.6

RLLD/*RLLS* = 1.6

Procedure:

1. Plot *RLLD*/*Rxo* (= 3.6) on the vertical axis and *RLLD*/*RLLS* (= 1.6) on the horizontal axis. Plot the intersection of these values on the tornado chart, and determine *Rt/RLLD*, Ri and *Rt*/*Rxo* values.
   - ***Rt/RLLD*** *value falls between the scale values 1.3 and 1.4, so we assign a value of* ***1.32****.*
   - **di** value falls between the scale values of 40 and 50 inches, so we assign a value of **43 inches**.
   - ***Rt*/*Rxo*** value falls between the scale values 3 and 5 (much closer to 5), so we assign a value of **4.8**.
2. Finally, corrected values for true resistivity of the formation (*Rt*) and resistivity of the flushed zone (*Rxo*) are determined using these ratios.

$$\mathbf{(Rt/RLLD) \times (RLLD)_{log} = Rt\ (corrected)}$$

1.32 x 16.0 ohm-m = 21.1 ohm-m = *Rt*, true formation resistivity.

$$\mathbf{Rt\ (corrected)/(Rt/Rxo)_{chart} = Rxo}$$

21.1 ohm-m/4.8 = 4.4 ohm-m = *Rxo*, resistivity of flushed zone.

When the deep laterolog log reading is corrected for invasion via the tornado chart, the resulting estimate of true formation resistivity is always greater than the deep laterolog reading.

C. **INDUCTION LOGS**

- Unlike the original (unfocused) electrode logs and laterologs, induction logs measure formation conductivity rather than resistivity. Formation conductivity is related to formation resistivity through the following equation;

$$C = \frac{1000}{R}$$

where:

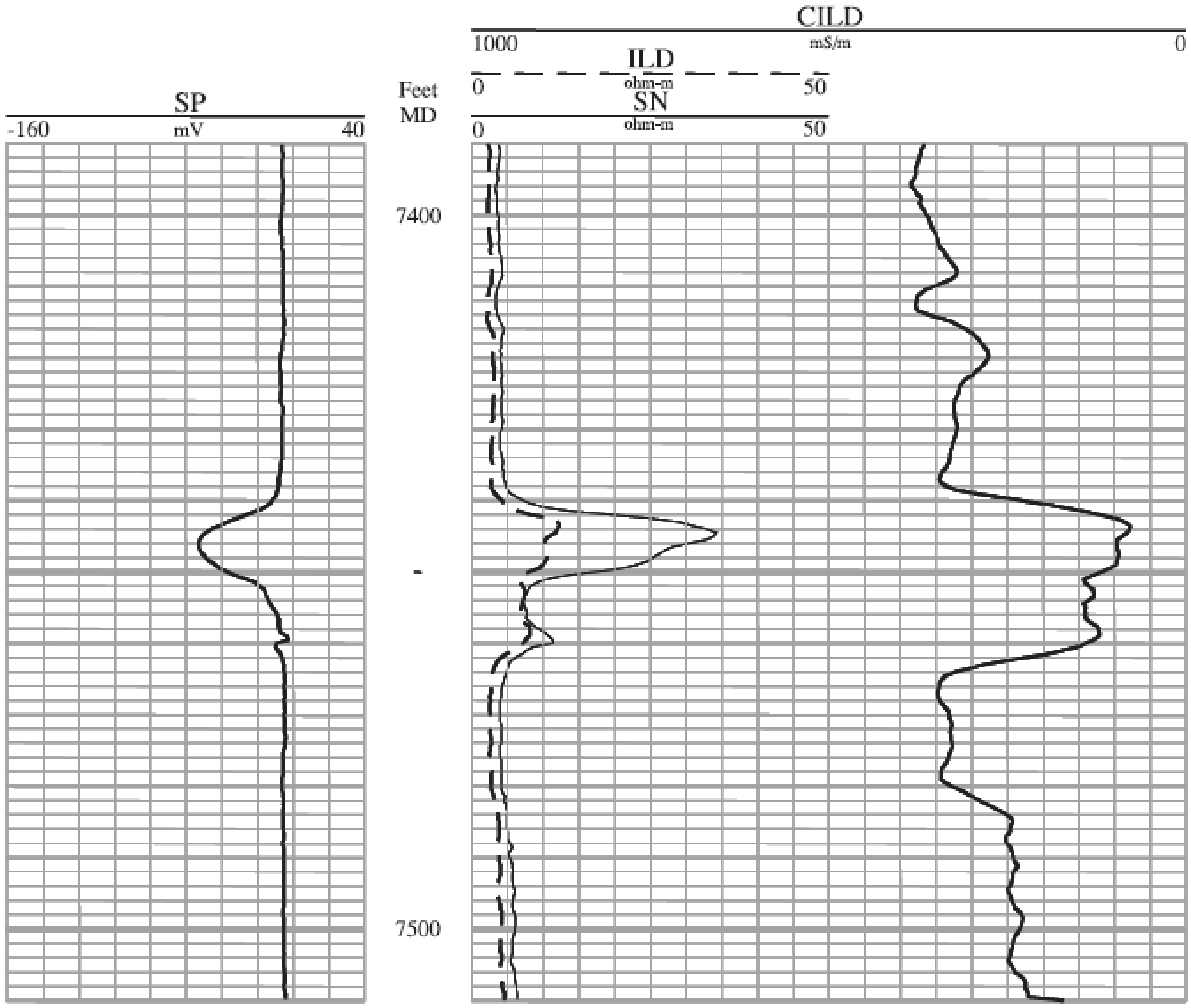
C = conductivity in milli mho/m (= milli Siemens)

R = resistivity in ohm-m

- By design, induction logs work well in wells containing non-conducting fluids in the borehole (such as air and oil-based mud) or in freshwater muds (where $Rmf > 3\ Rw$).
- They are most affected by salty muds. Induction logs work best in low to moderate formation resistivities.
- The uncertainty in the measurement increases at high formation resistivities, making induction logs less desirable than the laterolog for highly resistive formations (resistivities greater than about 100 ohm-m).
- Like the laterolog, the first version of the induction log, the induction electric log, had a single deep induction measurement (*RIL*). It, however, was combined with the earlier (electrode-type) short-normal measurement (*RSN*) to measure the resistivity of the formation at two distances from the borehole. The SP measurement was a common correlation measurement in this suite.
- The short-normal measurement interrogated the formation at a shallow distance from the wellbore, and comparison of the two measurement values, *RSN* and *RIL*, was an indication of invasion and, thus, formation permeability.

EXAMPLE of Induction Electric Log.

- The Induction Electric Log is normally used when *Rmf* > *Rw*.
- **Track 1:** The log track on the far left contains the spontaneous potential (SP) log. The SP scale increases from -160 mV on the left to +40 mV log on the right and has 10 increments of 20 mV. The value at the depth of 7446 ft is about -50 mV. The value of the SP in is measured from the shale baseline (i.e., the SP value in the shales where the SP value is zero), and the deflection from the baseline is negative.
- **Track 2:** The middle log track contains two resistivity curves. The short normal (SN, also called the 16-inch normal) represented by the solid line, measures the invaded zone resistivity (*Ri*). The induction log (ILD), represented by the dashed line, measures the uninvaded zone resistivity (*Rt*). At 7446 ft, the short normal has a value of 30 ohm-m. The induction value at the same depth is 10 ohm-m.
- **Tracks 2 and 3**: These tracks contain the conductivity curve (CILD) which is the basic induction-log measurement. The conductivity curve can be used to convert values to resistivity. In this way, track 2 resistivity values can be checked for accuracy, or values can be derived more accurately at low resistivities. For example, to convert track 3 values to resistivity the procedure is as follows:
  - ✓ The values on the conductivity scale increase from right to left, from 0 to 1000 are marked in 50 mmhos/meter increments. At a depth of 7446 ft, the curve in track 3 is nearly 2 increments from the right and shows a value of 97 mmhos/meter. Because resistivity equals 1000/conductivity, the resistivity = 1000/97 = 10.3 ohm-m. When the logs are displayed on linear scales, as in this example, resistivity can determined more accurately from conversion of the conductivity curve than from reading the resistivity curve itself.



❖ **Utility and Limitations**

- induction logs are used most effectively in holes filled with moderately- to non-conductive drilling muds, or in empty holes

- operates to advantage when the borehole fluid is an insulator (oil or gas), but also works well when the borehole contains conductive mud (if the mud is not too salty, the formations are not too resistive, and the borehole diameter is not too large)

- vertical focusing is good (down to approximately 5 feet thick)

- **Problems** - for resistive thin beds (less than 5 ft thick), an induction log may not be reliable for determining True Resistivity

- Induction logs are conductivity devices, and perform best in higher conductivities (lower resistivities); therefore if the resistivities of the bed are greater than 100 ohm-meters the use of induction logs is questionable.

❖ *Dual Induction Log*

- The second-generation induction log is called the dual induction. This log consists of a deep-reading induction device, which attempts to measure *Rt*, and a medium-reading induction device which measures *Ri*.
- The dual induction log also has a third resistivity curve, a shallow-reading, focused, laterolog-type measurement which may be either a laterolog-8 (LL8) or a spherically focused log (SFL).
- The dual induction log is useful in formations that are deeply invaded by mud filtrate. Because of deep invasion, the deep reading induction may not accurately measure the true resistivity of the formation (*Rt*).
- Resistivity values obtained from the three curves on a

dual induction log are used to correct deep resistivity to true resistivity (*Rt*) from a ***tornado chart (Rint-2b*** *and* ***Rint-2c)*** **(Fig.7-8)**. This tornado chart can also help determine the diameter of invasion (*di*) and the ratio of *Rxo*/*Rt*.

- **EXAMPLE** of a dual induction log. The dual induction log is normally used when *Rmf* is much greater than *Rw* and also where invasion is deep.

Track 1 in this log suite contains gamma ray and SP curves. The resistivity scale in tracks 2 and 3 is a logarithmic scale from 0.2 to 2000 ohm-m, increasing from left to right. Note the following logs.

Deep induction log resistivity:

The dashed ILD curve measures the deep resistivity of the formation, or close to true resistivity (*Rt*). At the depth of **13591 ft**, the deep resistivity (ILD) is **70 ohm-m**.

Medium induction log resistivity:

The dotted ILM curve measures the medium resistivity of the formation or resistivity of the invaded zone (*Ri*). At **13,591 ft**, the medium resistivity (ILM) is **105 ohm-m**.

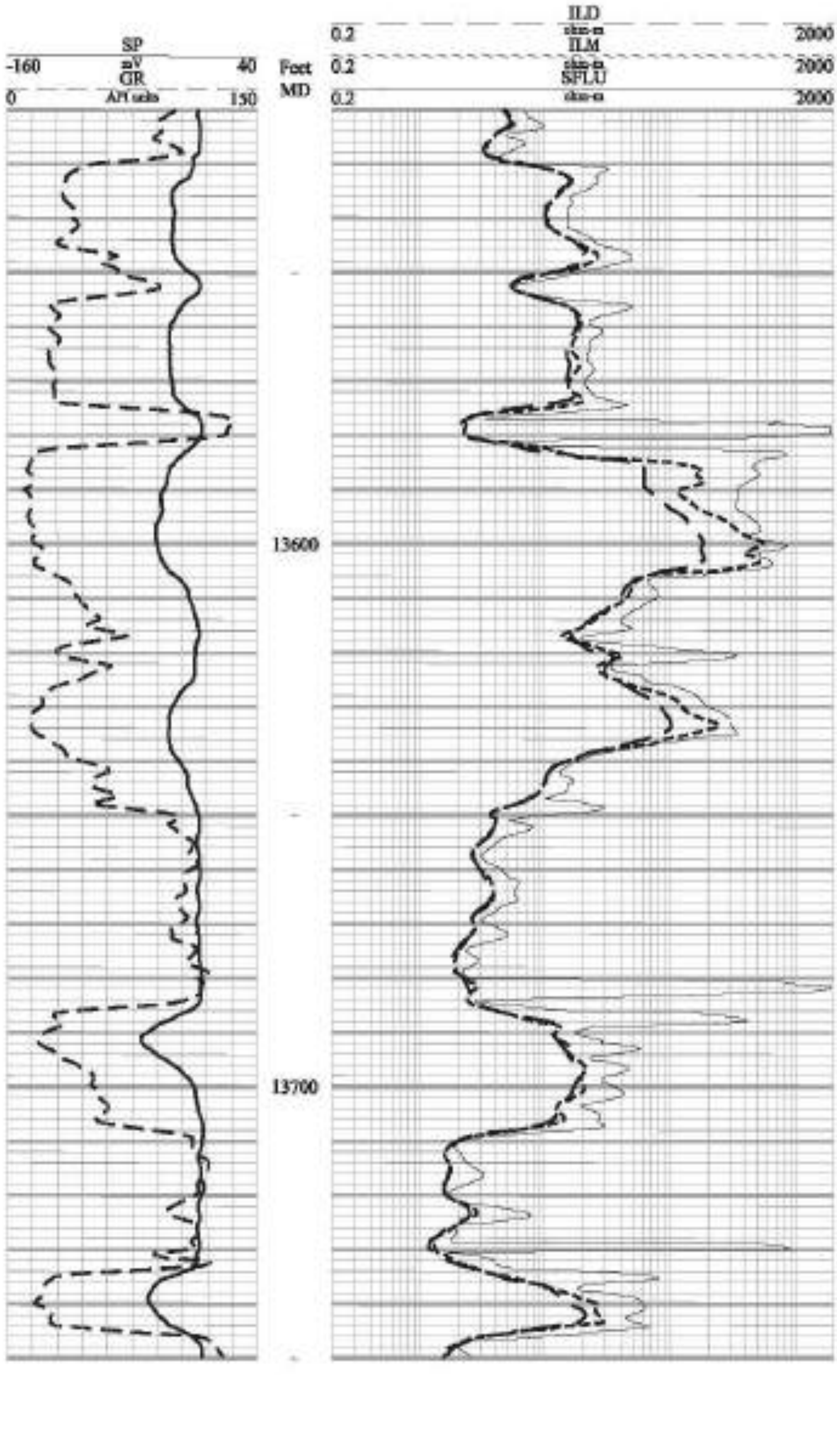
Spherically focused log resistivity:

The solid SFLU curve measures the shallow resistivity of the formation or resistivity of the flushed zone (*Rxo*). At **13,591 ft**, the resistivity of the flushed zone is **320 ohm-m**.

The following ratios are needed for work on the tornado chart, and the values are picked from the example log:

SFLU/ILD = *RSFLU*/*RILD* = 320 ohm-m/70 ohm-m = 4.6

ILM/ILD = *RILM*/*RILD* = 105 ohm-m/70 ohm-m = 1.5


SP
-160 mV 40
GR
0 API units 150
Feet
MD
13600
13700
ILD
0.2 ohm-m 2000
ILM
0.2 ohm-m 2000
SFLU
0.2 ohm-m 2000

EXAMPLE; Dual Introduction-SFL tornado chart used for correcting *RILD* values to *Rt*, true formation resistivity. Log values in this exercise are picked from the example dual laterolog-MSFL in previous example.

- **TORNADO CHART Rint-2c** consists of the following from the parameters**;**

✓ **RSFL/RID ratio** vertical axis of chart

✓ **RIM/RID ratio** horizontal axis of chart.

✓ **Rt/RID ratio**: The scale for this value is represented by the solid red lines. The scale values are in red and range from 1.0 to 0.8, decreasing from left to right.

✓ di: The diameter of invasion around the borehole is picked from the chart by following the dashed, blue lines to the appropriate scale. Note that the *di* scale is in inches across the top of the tornado and is in meters through the middle part of the tornado chart; both scales increase from left to right.

✓ ***Rt/Rxo ratio***: This is the ratio of resistivity of the flushed zone (*Rxo*) over the true resistivity of the formation (corrected *Rt*). This ratio, derived from the chart, is used in later calculations. The scale is represented by the heavy, blue, solid lines, and the scale values are shown as whole numbers midway across the lines.

- Given:

ILD = *RILD* = 70 ohm-m

ILM = *RILM* = 105 ohm-m

SFLU = *RSFL* = 320 ohm-m

RSFL/*RILD* = 4.6

RILM/*RILD* = 1.5

Procedure:

1. Plot the *RSFL*/*RILD* ratio (= 4.6) on the vertical axis) and the *RILM*/*RILD* ratio (=1.5) on the horizontal axis. Plot the intersection of these values on the tornado chart, and pick the following values:
   - ✓ *Rt*/*RILD* value; falls on the 0.80 line.
   - ✓ *di*: the value is between the 60-inch and 70-inch lines, and *di* is about 68 inches.
   - ✓ Rxo/Rt: the plotted sample falls on the line with a value of 7.0.
2. Finally, with values taken from the chart, calculate corrected values for *Rt* and *Rxo*.

(*Rt/RILD*)$_{chart}$ X *(RILD)$_{log}$* = *Rt* (corrected)

0.80 X 70 = 56 ohm-m (*Rt* corrected, or true formation resistivity)

(*Rxo/Rt*)$_{chart}$ X *Rt* (corrected) = *Rxo* (corrected)

7 X 56 = 392 ohm-m (*Rxo*, corrected resistivity of the flushed zone).

When the deep induction log reading is corrected for invasion via the tornado chart, the resulting estimate of true formation resistivity is always less than the deep induction reading.

- The deep induction log does not always record an accurate value for deep resistivity in thin, resistive zones (where *Rt* > 100 ohm-m). Therefore, an alternate method to determine true resistivity (*Rt*) should be used.
- The technique is called ***Rt minimum*** (*Rt min*) and is calculated by the following formula:

$$Rt_{min} = R_i x \frac{R_w}{R_{mf}}$$

where:

Rt min = true resistivity (also called *Rt minimum*)

Rmf = resistivity of mud filtrate at formation temperature

Rw = resistivity of formation water at formation temperature

Ri = resistivity tool measuring in the invaded zone, usually laterolog-8 or spherically focused log.

❖ The rule for applying *Rt min* is to determine *Rt* from both the dual induction log tornado chart and from the *Rt min* formula, and use whichever value of *Rt* is the greater. In addition to the Rt min method for determining *Rt* in thin resistive zones, correction curves (Schlumberger) or forward modeling algorithms are available to correct the deep induction log resistivity to *Rt*.

❖ MICRORESISTIVITY LOGS

- These tools are designed to;
  - ✓ define permeable beds by detecting presence of a mud cake.
  - ✓ obtain the resistivity of the flushed zone (Rxo).
- Rxo (Resistivity of "Flushed Zone") is used to;
  - ✓ Calculate residual oil saturation left after flushing the flushed zone

$$\text{residual oil saturation} = \text{Sor} = \{\varphi * (1 - \text{Sxo})\}$$

$$S_{xo}^{n} = \frac{F\ R_{mf}}{R_{xo}} = \frac{a\ R_{mf}}{\varphi^{m}\ R_{xo}}$$

F = formation resistivity factor (no units).
m = cementation factor (no units).
a = tortuosity factor (no units).
n = saturation exponent (no units).
R_{mf} – resistivity of mud filtrate. Ω m
S_{xo} – water saturation of flushed zone. Ω m
R_{xo} – resistivity of flushed zone. Ω m (from Micro resistivity log)

  - ✓ Calculate formation porosity.

$$\frac{Rxo}{Rmf} = F = \frac{a}{\varphi^{m}}$$

Note: The following conditions must be exists when calculating porosity from Rxo tools;

☒ Rxo/Rmc > 15
☒ Mud cake thickness > 0.5 inch

$$mud\ cake\ thickness = \frac{bit\ size - hole\ size}{2}$$

☒ Invasion diameter > 4 inch

✓ Recognize (by comparing Rxo with Rt) which zones have sufficient permeability to be invaded by mud filtrate

✓ Calculate *movable hydrocarbon saturation*.

$$\text{movable hydrocarbon saturation} = \text{Shr} = \{\varphi * (\text{Sxo} - \text{Sw})\}$$

◈ *Microlog (ML)*

- The microlog is a micro resistivity device that detects mudcake.
- Two resistivity measurements are made; the micro-normal (R_2) and the micro-inverse (R_{1x1}).
- The micro-normal device investigates 3 to 4 inches into the formation (measuring *Rxo*) and the micro-inverse investigates approximately 1 to 2 inches into the formation and is significantly affected by the resistivity of the mud cake (R_{mc}).
- The detection of mud cake by the microlog indicates that invasion has occurred and the formation is permeable.

Case 1: permeable zones / *hydrocarbon zone*

micro-normal curve R_2 > micro-inverse curve R_{1x1}

positive separation (occur when $R_{mc} > R_m > R_{mf}$)

Case 2: Shale zones

micro-normal curve R_2 < micro-inverse curve R_{1x1}

negative separation

micro-normal curve R_2 ≈ micro-inverse curve R_{1x1}

no separation

Case 3: permeable zones / *water zone*

micro-normal curve R_2 < micro-inverse curve R_{1x1}

negative separation

Case 4: permeable zones / *no invasion*

micro-normal curve R_2 ≈ micro-inverse curve R_{1x1}

no separation

note: Resistivity values of the mud cake Rmc , drilling mud Rm, and mud filtrate Rmf are obtained from log heading information .

- The microlog tool also has a caliper log that measures the borehole diameter.
- A decrease in borehole diameter can indicate mud cake and support the interpretation of permeability.

Caliper log curve < Bit Size (BS)

borehole size smaller than the diameter of the drill bit used to drill the hole.

Indicated mud cake (permeable formation)

- **Remember that** even though the resistivity of the mud filtrate (*Rmf*) is less than the resistivity of the mud cake (*Rmc*), the micronormal curve reads a higher resistivity in a permeable zone than the shallower reading micro-inverse curve.??? why
- This is because the filtrate has invaded the formation, and part of the resistivity measured by the micronormal curve is read from the rock matrix, whereas the microinverse curve measures only the mudcake (*Rmc*) which has a lower resistivity than rock.
- In enlarged boreholes, a shale zone can exhibit as positive separation. To detect zones of erroneous positive separation, a microcaliper log is run in track 1, so that borehole irregularities are detected.
- Nonporous and impermeable zones have high resistivity values on both the micronormal and microinverse curves.
- Hilchie (1978) states that resistivities of approximately ten times the resistivity of the drilling mud (R_m) at formation temperature indicate an impermeable zone.

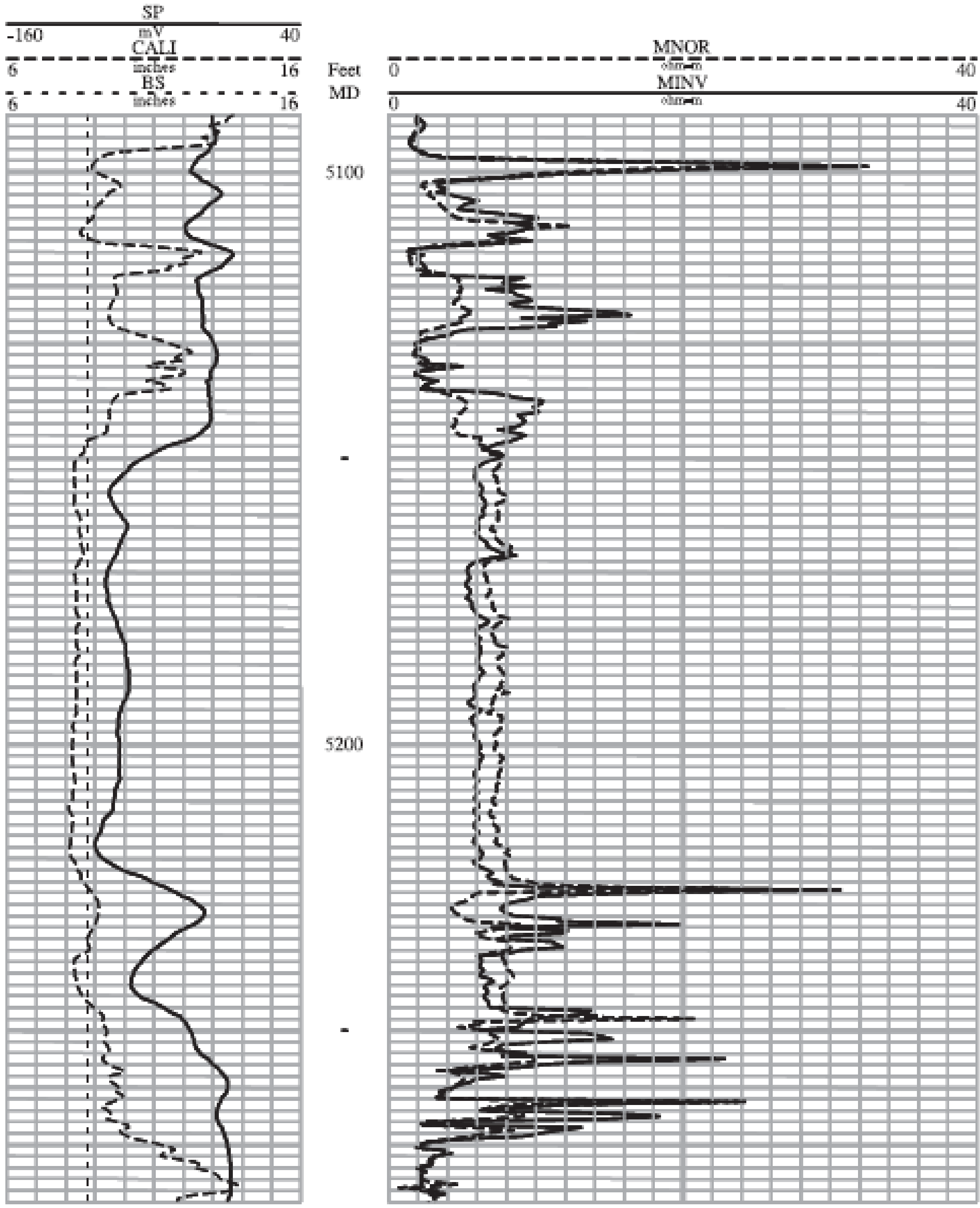
EXAMPLE; Microlog with SP log and caliper.

- This log demonstrates permeability two ways: by *positive separation* between the micronormal and microinverse logs (MNOR > MINV) in tracks 2 and 3 and by decreased borehole diameter due to mudcake, detected by the caliper log in track 1.
- Examine the interval from 5147 to 5246 ft.
- **Track 1**: The caliper measurement is shown by the long-dashed line in track 1. The short-dashed line shows the bit size (BS), which is 8.75 inches. Just above 5147 ft, the caliper shows a borehole diameter of approximately 11 inches, but the hole size decreases to about 8.5 inches from 5147 to 5224 ft, indicating the presence of mud cake and a permeable zone. Mudcake is also present at 5237 to 5245 ft. Note how the SP corresponds with these two mudcake intervals.
- **Tracks 2 and 3**: The micro-normal log (MNOR, shown by the dashed line) measures the resistivity of the flushed zone, and the micro-inverse (MINV, shown by the solid line) measures the resistivity of any mud cake that might be present.
- Mud cake and permeability are indicated by *positive separation*, which occurs where micro-normal log shows a higher resistivity than the micro-inverse log.

  Note the **positive separation** from **5150 to 5224 ft** and from **5237 to 5246 ft**.
- The separation is about 0.5 ohm-m.
- The fluid in the flushed zone is a combination of mud filtrate, formation water, and possibly residual hydrocarbons. The fluid in the mud cake is just mud filtrate, which has a higher resistivity than the fluids in the flushed zone. Based on this alone, we might expect the micro-inverse to show a higher resistivity than the micro-normal over intervals of mud cake.
- Remember, however, that rock generally has a higher resistivity than the fluids in it or around it. The rock in the flushed zone is compacted

and cemented, but the rock part of the mud cake (cuttings and mud solids) is not compacted or cemented.

- Mud cake contains much more fluid and much less rock than an equal volume of the formation in the flushed zone. The higher concentration of fluid in the mud cake gives the mud cake a lower resistivity than the flushed zone.

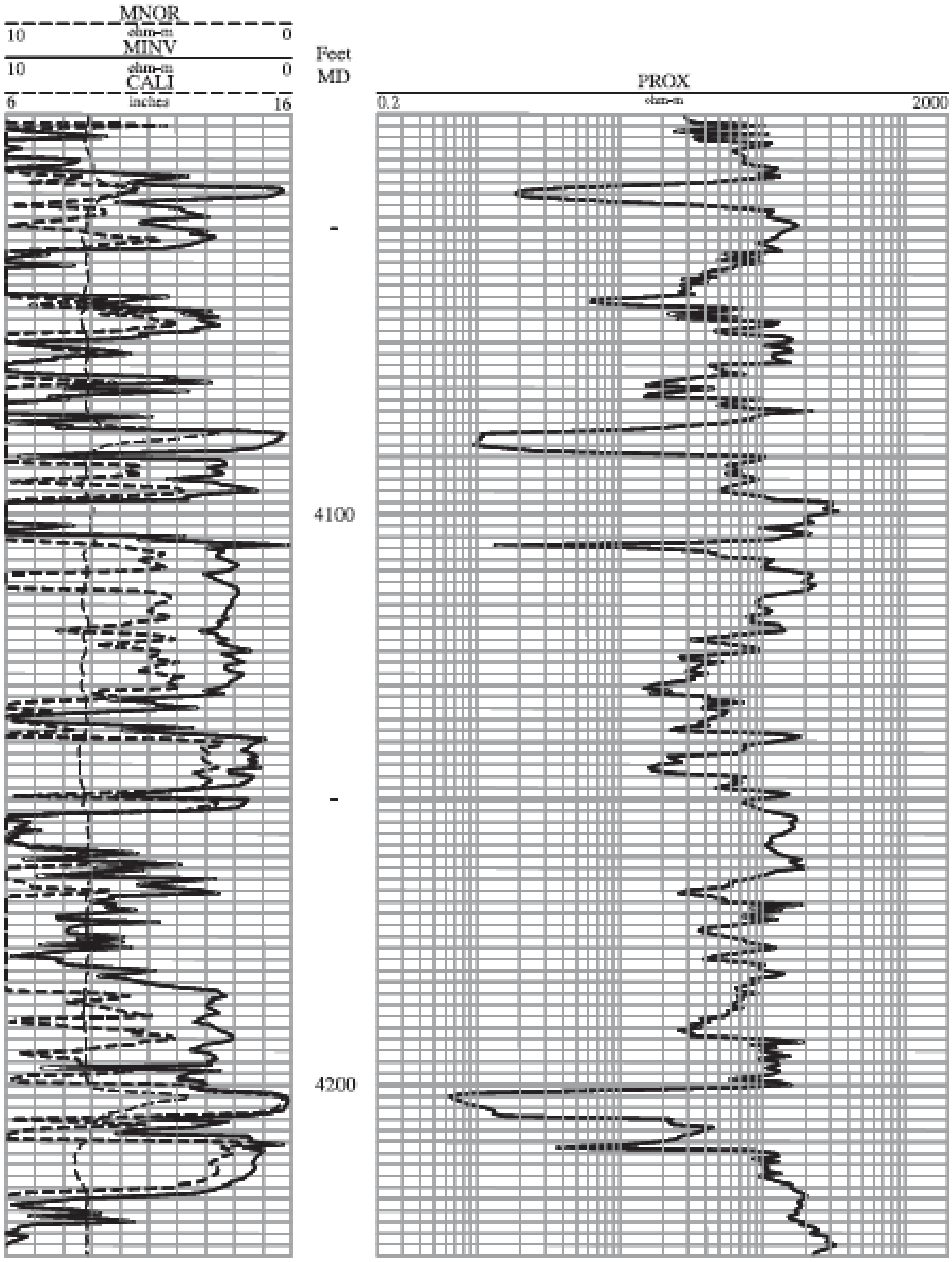


❖ Other Microresistivity Logs

- The microlaterolog (MLL), the proximity log (PL), and the microspherically focused log (MSFL) are focused, electrode logs designed to measure the resistivity in the flushed zone (*Rxo*).
- Unlike the micrologg, all produce a single resistivity curve, but because of their focused design they are more accurate predictors of flushed-zone resistivity.
- Because the microlaterolog is strongly influenced by mud cake thicknesses greater than 1/4 inch, the microlaterolog should be run only with saltwater muds.
- The proximity log, which is more strongly focused than the microlaterolog, is designed to investigate deeper so it can be used with freshwater muds where mud cake is thicker, but with low invasion it might measure beyond the invaded zones.
- The microspherically focused log, introduced by Schlumberger in 1972, and other tools of similar design seem to generally be very good at determining flushed-zone resistivity (*Rxo*).

- **Example** of a proximity log with a microlog and caliper.
- The proximity log is designed to read the resistivity of the flushed zone (*Rxo*). This particular log package includes a proximity log to read Rxo, a microlog to determine permeable zones, and a caliper to determine the size of the borehole.
- Examine the log curves at 4144 ft.
- **Track 1**: Track 1 shows both a microlog and a caliper log. On this example, the resistivity values for micronormal and microinverse increase from right to left, so that the positive separation shows the same pattern with respect to the depth track as it does when displayed in track 2. At the depth of 4144 ft, the micronormal (MNOR, shown by the dashed line) shows higher resistivity than microinverse (MINV, shown by the solid line). The microinverse has a value of about

1.5 ohm-m, and the micronormal has a value of about 3.0 ohm-m. The microlog indicates a permeable zone.



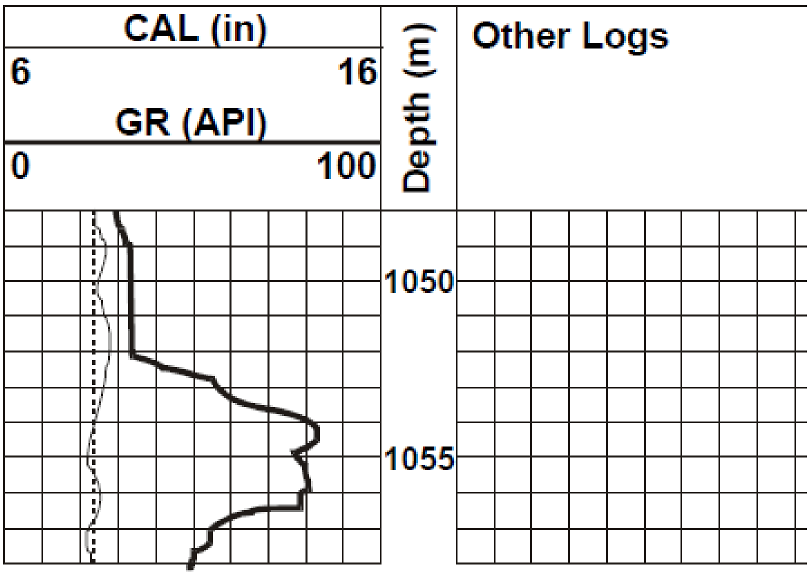
- The caliper log indicates a borehole slightly less than 9 inches.
- **Tracks 2 and 3**: The proximity log measures resistivity of the flushed zone (*Rxo*). In this example the scale is logarithmic, reading from left to right. At 4144 ft, we read a proximity curve value (*Rxo*) of 18 ohm-m.

GAMMA RAY LOG

- The gamma ray (GR) log measures the natural radioactivity emanating from the formations.
- There are three naturally radioactive elements in nature:
  - ✓ **Uranium U** series – fixed by fine-grained organic material.
  - ✓ **Thorium Th** series – absorbed by clay minerals.
  - ✓ **Potassium** K^{40} – part of clay mineral composition.
- **Total gamma ray (GR) log** measures total (cumulative) response of U, Th, and K^{40}.
- In sedimentary formations the GR log normally reflects the shale content of the formations. This is because the radioactive elements tend to concentrate in clays and shales and these elements are more radioactive than sand or carbonate.
- Shale-free (clean) formation have low concentrations of radioactive elements therefore give low gamma ray readings.
- As shale/clay content increases, the gamma ray log response increases because of the concentration of the radioactive elements in shale/clay.
- Gamma Ray log unit recorded in API Units (American Petroleum Institute).

▪ The total gamma ray log is usually recorded in *track 1* with the *caliper* log, *bit size* and *SP* log.

▪ The API scale goes from 0 to 100 API, and 0 to 150 API used in log presentations.

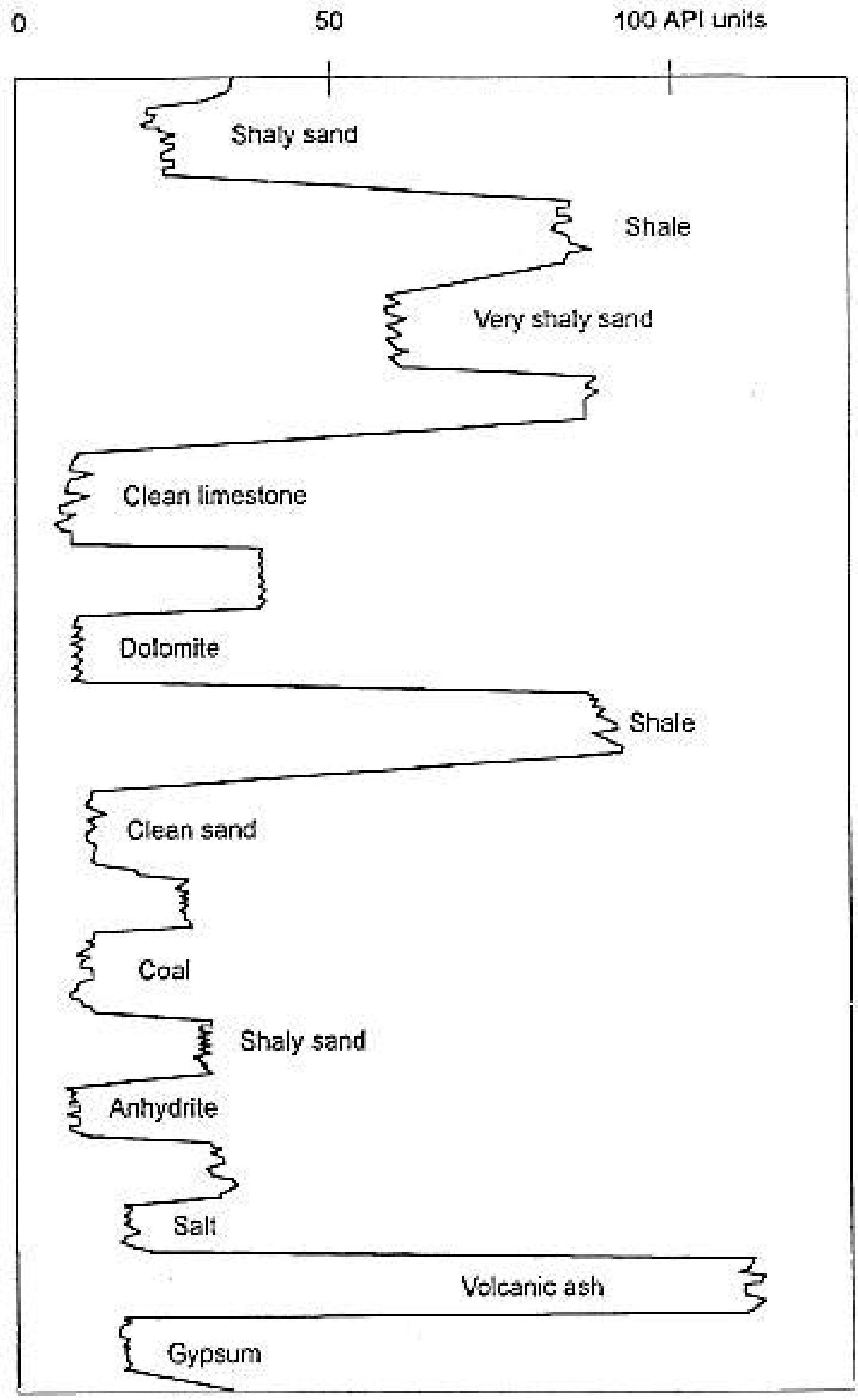


o *GR response in Typical Formations*

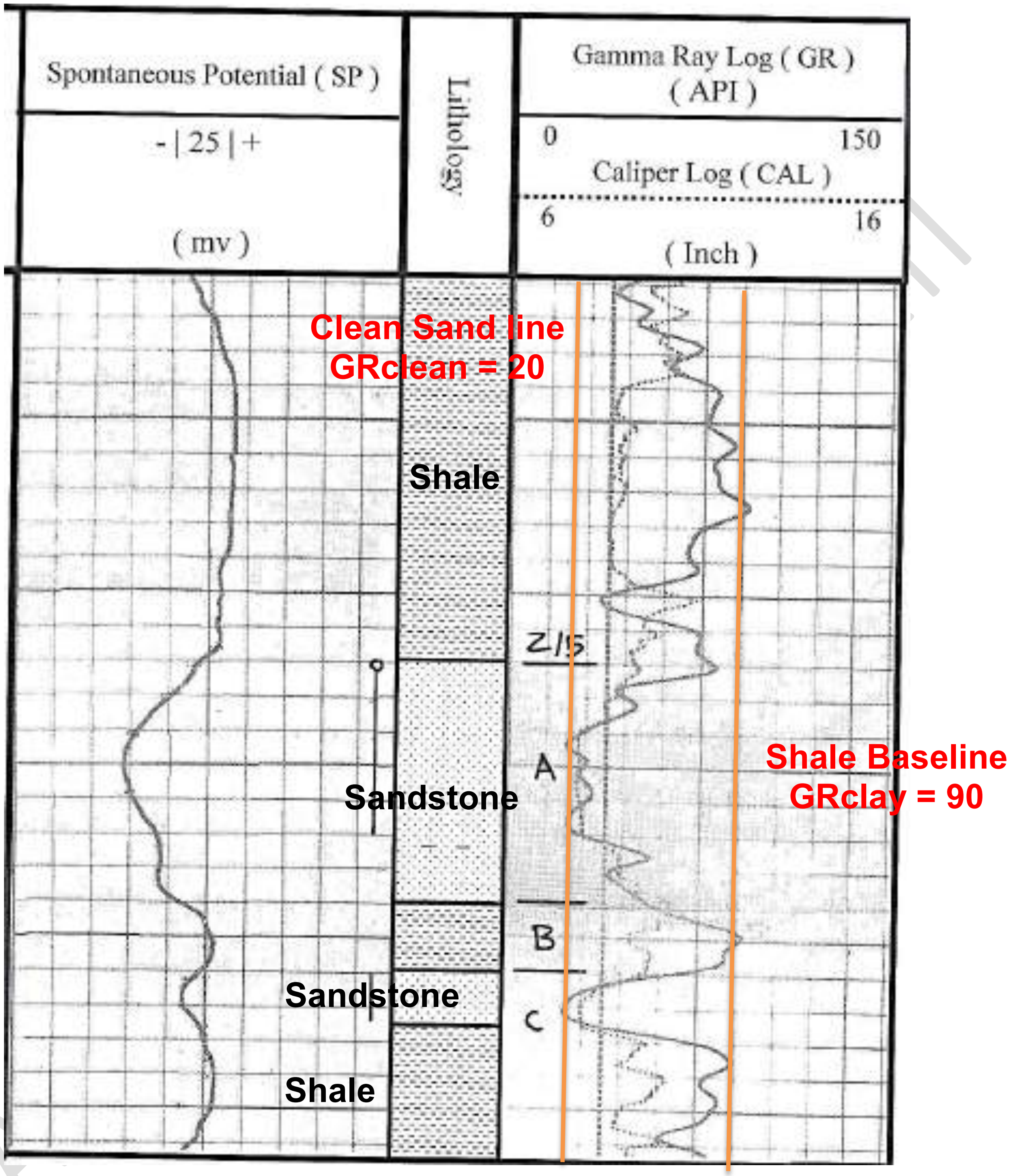
Lithology:	**API**
Limestone	5-10
Dolomite	10-20
Sandstone	10-60
Shale	80-140

Minerals:	**API**
Calcite	0 - 15
Dolomite	0 - 15
Quartz	0 - 15

Evaporates	**API**
Halite(NaCl)	Low
Anhydrite	Low
Coal	



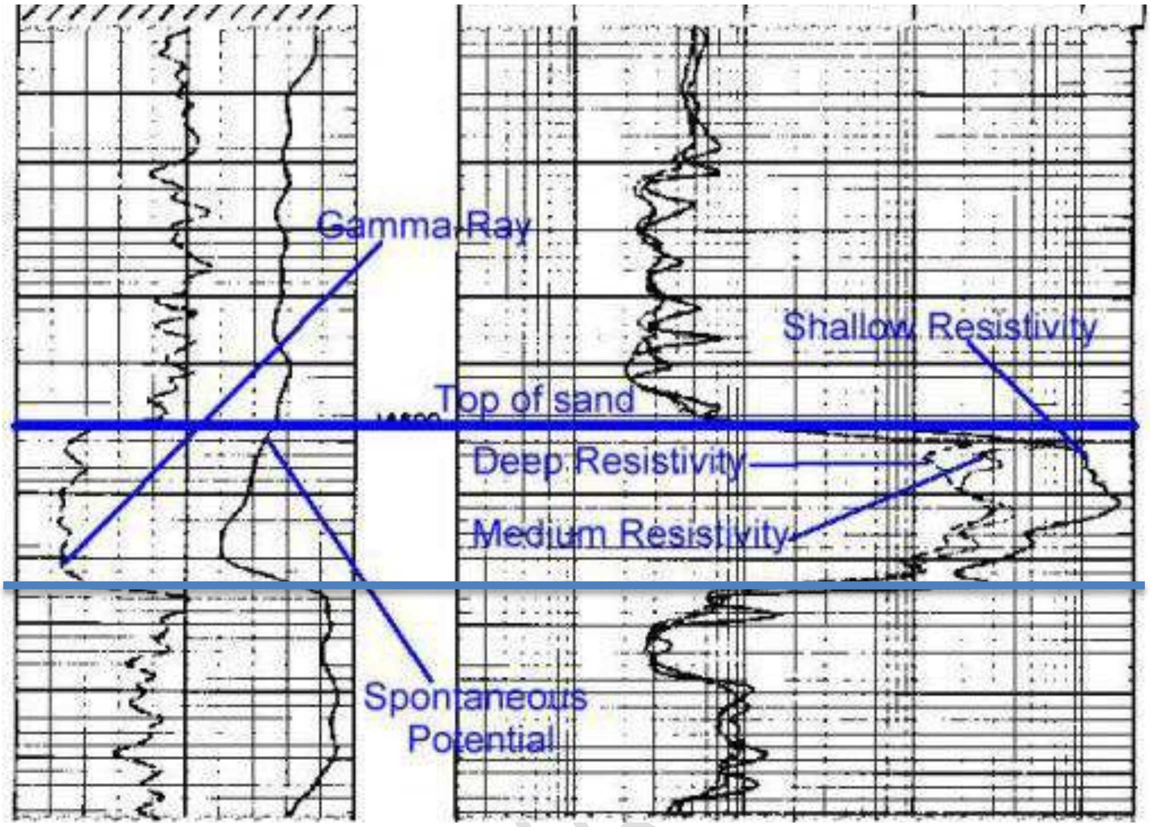
o Example of GR Log



GR is high in shale/ clay formation, because shale/clay is more radioactive than sand or carbonate (high concentrations of radioactive elements in shale / clay)

GR is low in sand or carbonate formation because low concentrations of radioactive elements in sand or carbonate formation.

o GR Log Correlations with Other Logs



Identification hydrocarbon reservoir

Low GR

Low SP

high resistivity

large separation between shallow, medium, & deep resistivity

o Uses of GR Log

1) Shale/ Clay Volume Calculations **(**Quantitative use**).**
2) Shale / Clay Zone Identification (Qualitative use).
3) Well to Well Correlation / Log tops, stratigraphic correlations.
4) Net thickness to gross thickness estimation (NET PAY).
5) Lithology indicator. (shaly sand evaluation – effective porosity)

1) Shale Volume(Content) Estimating

- The GR log measurement obtained from the formation is often used to calculate a shale/clay volume since naturally radioactive elements tend to have greater concentrations in shale/clay than in clean sandstones.

✓ **Clay** : Clay is very complex set of minerals. It is made up of very small individual grains which can only be seen by electron microscope.

✓ **Shale :** it is a mixture of clay and silt. Shale may have <u>good porosity</u>, but it's <u>permeability is zero</u>.

- The presence of shale in a reservoir can cause erroneous values for water saturation and porosity derived from logs. These erroneous values are not limited to sandstone but also occur in limestone and dolomites.
- Presence of shale in a formation lead to;
  - ✓ Porosity logs (sonic. density. and neutron) will record too high a porosity.
  - ✓ Resistivity log record too low resistivity.
- The most significant effect of shale in a formation is to reduce the resistivity contrast between hydrocarbon and water zone.
- Hilchie (1978) suggests that for shale to significantly affect log-derived water saturations (i.e. water saturation from Archie equation), <u>shale content must be greater than 10 to 15 %</u>.
- The first step in shaly sand analysis is to determine the volume of shale from a gamma ray log.
- After the volume of shale (V_h) is determined, it can then be used to correct the porosity log for shale effect.
- Remember that all shaly sandstone formulas reduce the water saturation value from the value that would be calculated if shale effect was ignored. However, this lowering of water saturation can be a problem in log evaluation, because. *if* an *engineer overestimates shale content,* a water-*bearing zone may calculate like a hydrocarbon zone.*

- Shale volume is the bulk volume of shale (exactly the volume of silt, dry clay, and bound water) to the rock bulk volume.
- Calculation of the ***gamma ray index*** is the first step needed to determine the volume of shale from a gamma ray log.
- The ***gamma ray index IGR*** is calculated from the gamma ray log data using the relationship;

$$I_{GR} = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}} \qquad (1)$$

where:

IGR = the gamma ray index

$GR_{\log}$ = the gamma ray reading at the depth of interest

$GR_{\min}$ = the minimum gamma ray reading. (Usually the mean minimum through a clean sandstone formation.)

$GR_{\max}$ = the maximum gamma ray reading. (Usually the mean maximum through a shale or clay formation).

The relationship between gamma ray magnitude and shale content may be linear or non-linear.

1. Linear Gamma Ray - clay volume relationship:

$$V_{sh} = I_{GR} = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}} \qquad (2)$$

2. Non-linear Gamma Ray - clay volume relationships:

(a) Larionov [for *older rocks* /**cretaceous**(consolidated) rocks] use;

$$V_{sh} = 0.33(2^{2xI_{GR}} - 1) \qquad (3)$$

(b) Larionov **[for tertiary** (unconsolidated) rocks] use;

$$V_{sh} = 0.083(2^{3.7x\, I_{GR}} - 1) \qquad (4)$$

All the above relationships are empirical. If there is no enough information known, the linear relationship is probably the best choice, although it is the most pessimistic. All the non-linear relationships predict less clay volume than the linear response, in varying amounts depending on the GR reading and the clean and shale values.

Example: Example of gamma ray log with density and neutron logs. This example illustrates the curves and scales of a gama ray log, and is also used to pick values to estimate the value of (Vsh) from (IGR).

In **track-1**, the gamma ray log is the only one represented on this track. Note that the GR scale increases from left-to-right, and ranges from (0-150 API).

At the depth of (13570 ft), pick the gamma ray reading of the formation. It is (28 API) gamma ray units (the scale measures in increments of (15 API) units; slightly less than two units from (0 API)).

Next, pick the minimum gamma ray reading from the log which is (GR_{min}, clean =15 API gamma ray unit) at the depth of (13590 ft). and the maximum gamma ray reading from the log is (GR_{max}, shale = 128 API gamma ray units) at the depth of (13720 ft).

Given Data:

From the figure: GR_{log}=28

GR_{min}, clean = 15

GR_{max}, shale = 128

Calculate the shale volume?

Solution:

$$I_{GR} = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}} = \frac{28 - 15}{128 - 15} = 0.115$$

Linear

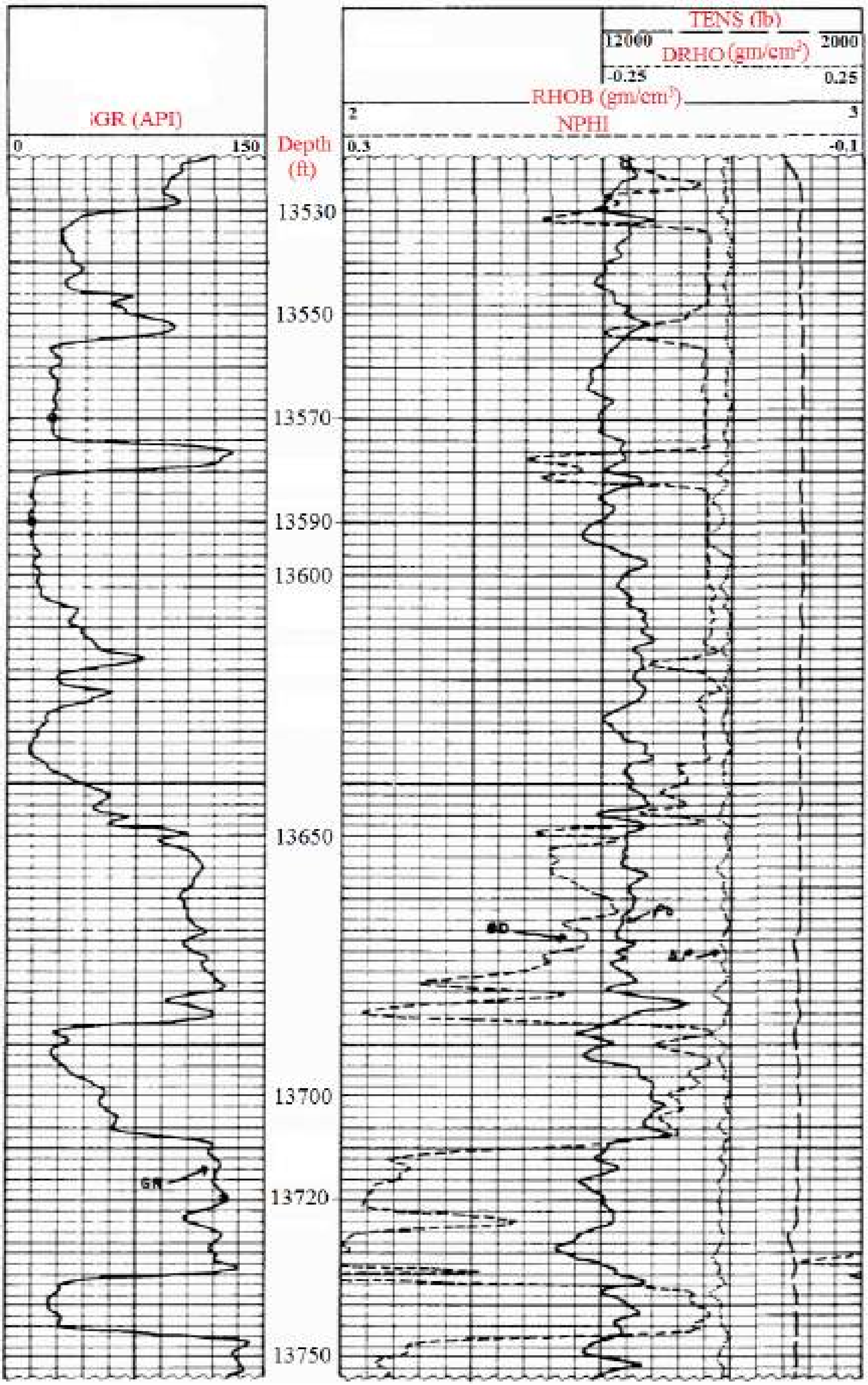
$$V_{sh} = I_{GR} = 0.115 \ or \ 11.5\%$$

Non-Linear (*older rocks*)

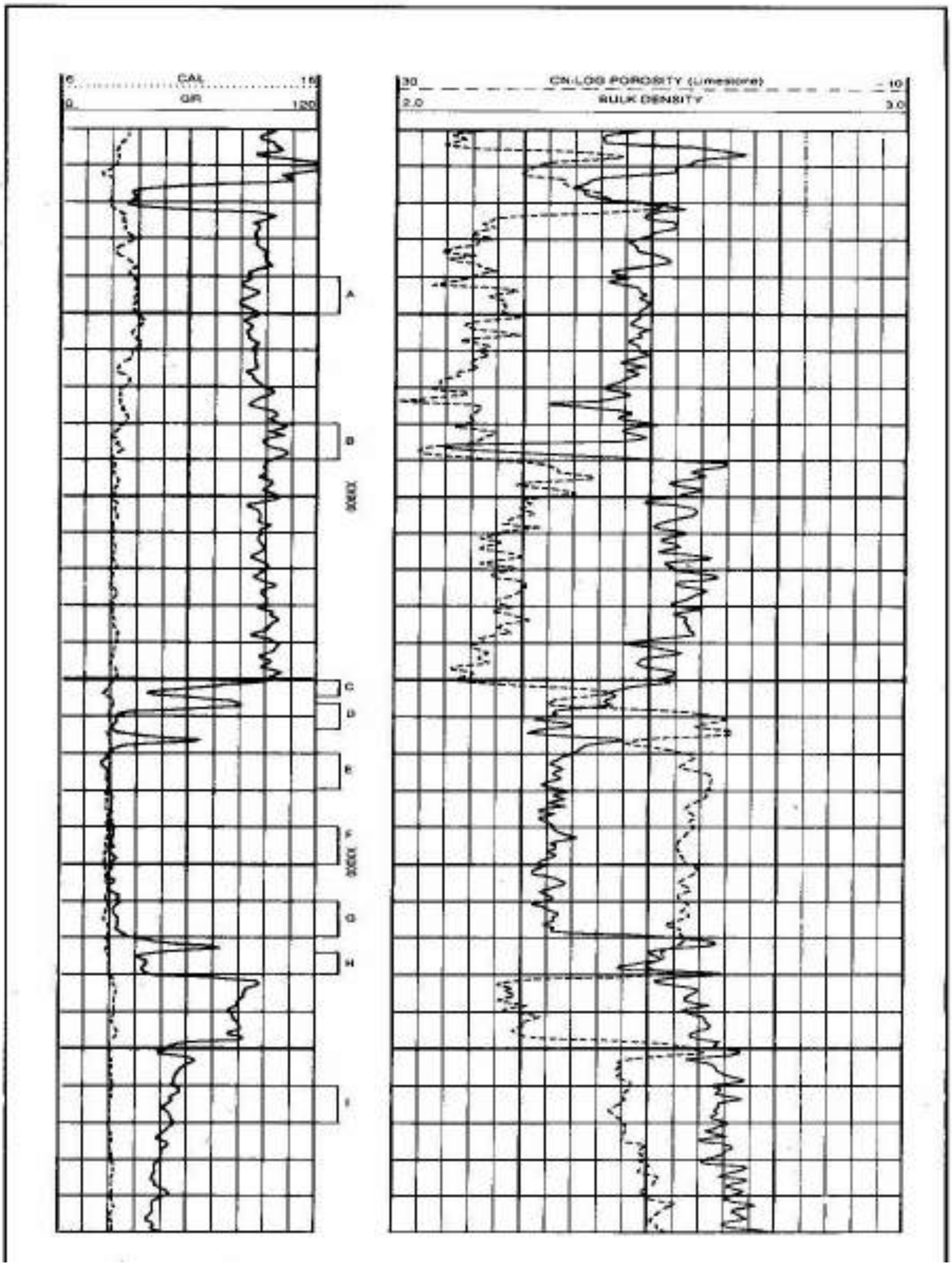
$$V_{sh} = 0.33(2^{2xI_{GR}} - 1) = 0.33(2^{2*0.115} - 1) = 0.057 \ \ or \ \ 5.7\%$$

Non-Linear (tertiary rocks**)**

$$V_{sh} = 0.083(2^{3.7x\ I_{GR}} - 1) = 0.083(2^{3.7*0.115} - 1)$$
$$= 0.0284 \ \ or \ \ 2.84\%$$

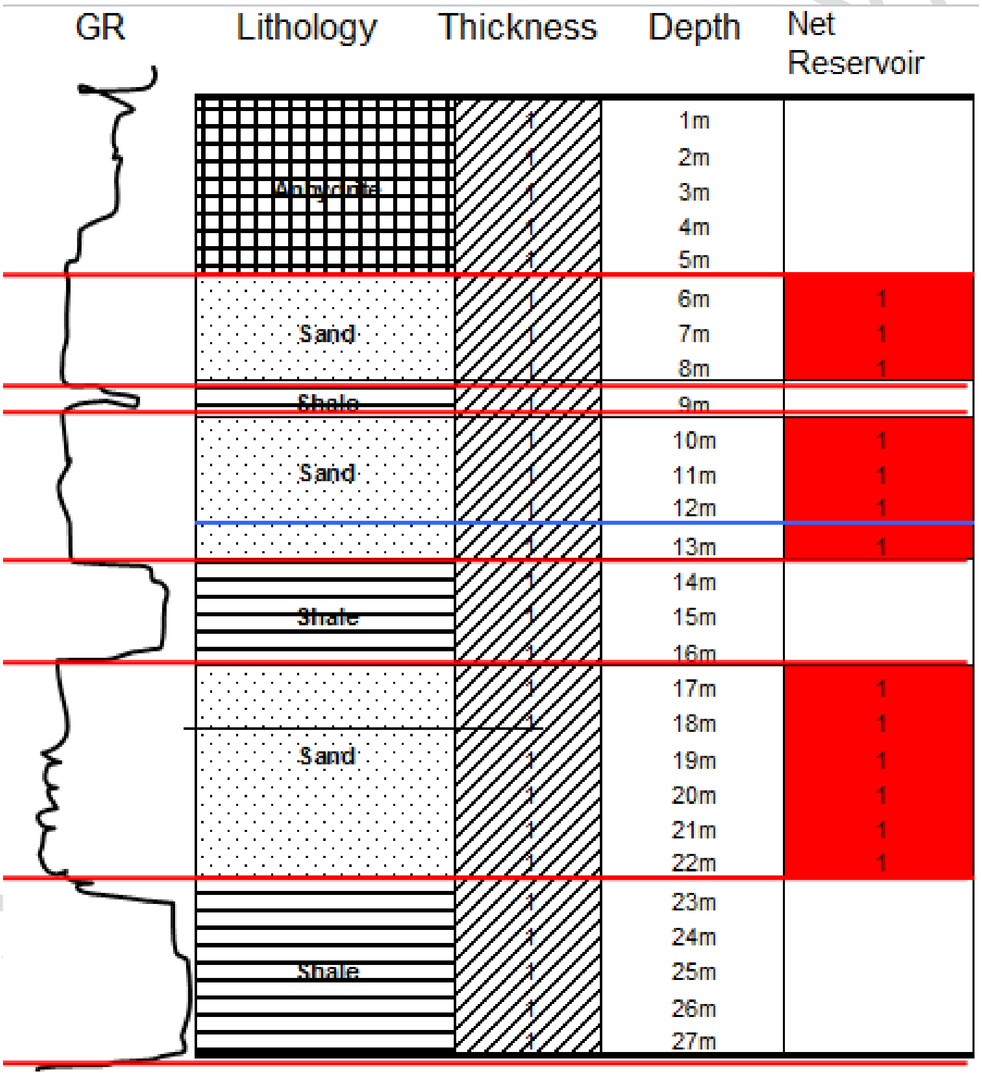

GR (API)
0
150
Depth
(ft)
13530
13550
13570
13590
13600
13650
13700
13720
13750
GR
TENS (lb)
12000
2000
DRHO (gm/cm³)
-0.25
0.25
RHOB (gm/cm³)
2
3
NPHI
0.3
-0.1

H.W; A Tertiary sand and shale sequence is represented by the interval shown on the accompanying log. Determine **Vsh** for the indicated zones.



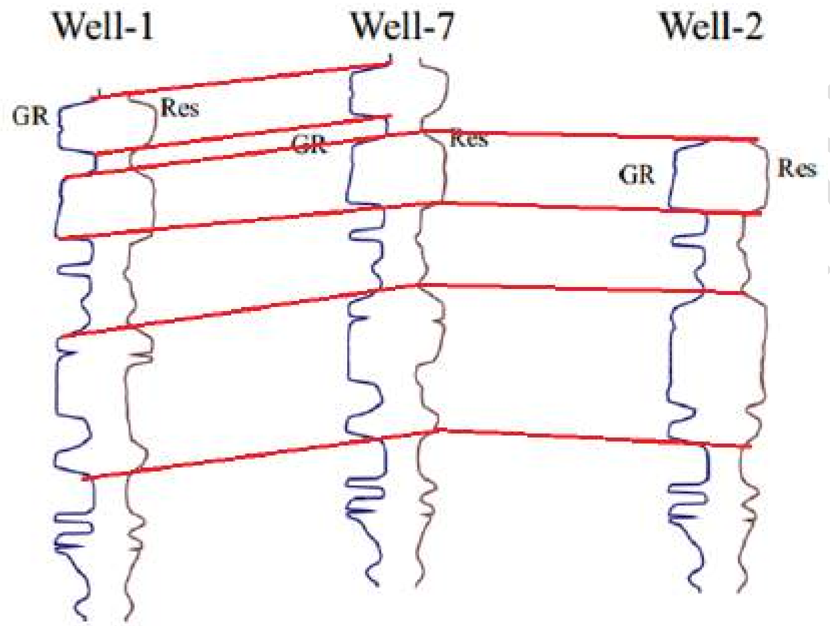
2) Net-To-Gross Calculation

- The ***net pay thickness*** is the clean, permeable, hydrocarbon-containing zones, from which hydrocarbons can be produced at economic rates.
- The **gross thickness,** is the total thickness of the reservoir interval, that contains *produced* and *non-produced hydrocarbon* zones.
- The ***net to gross ratio*** is thickness of net pay divided by the gross thickness, and is often <u>used to represent the quality of a reservoir zone</u>.



3) Well to Well Correlation

Total gamma ray log is used for correlation between wells were being logged for determining the lateral extension of subsurface geologic cross sections. Because there is a similarity between log readings.



Because of drilling operations is too expensive, so that relatively fewer wells will be drilled, and hence the maximum data must be squeezed out of each well regardless almost of the cost. If there are no hydrocarbon shows, the well data will still be very useful for correlation with other wells that do show hydrocarbons, will help to constrain the extent of neighboring reservoirs, as well as adding to the information about the general geological structure of the area.

o GR Log Corrections For Borehole Effects

- Borehole conditions that affects GR log are;

1) Borehole size.
2) Mud weight (mud density).
3) Tool Eccentricity.

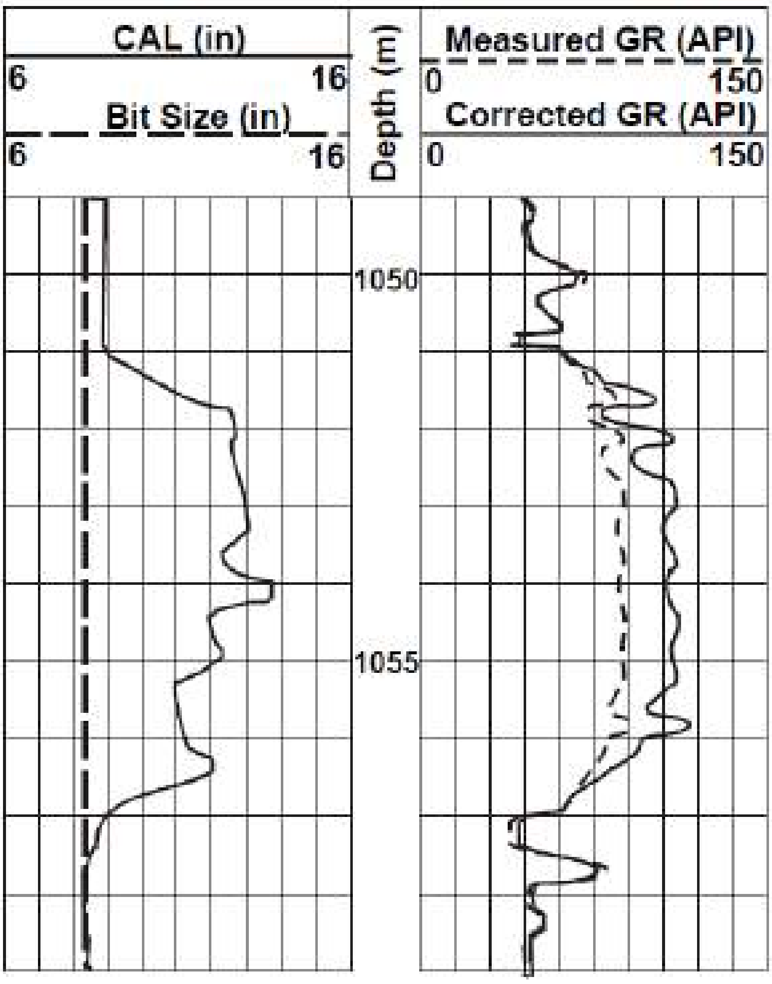
✓ Large holes **(caving)**, and **heavy muds** *reduce* the gamma ray log response.

✓ In caved intervals there is more drilling mud between the formation and the gamma ray detector which is reduce the gamma rays response, hence, the log is underestimated, as shown in Fig. below.

✓ The denser mud, increase the gamma rays scattering in the mud.

✓ Air drilling increases the log response.

✓ KCl mud increase GR log response, because of potassium containing.



Use **chart GR-1** to correct the GR log for mud density and hole size.

H.W: From the following given data, find the corrected GR.;

1. GR = 36 API units (gAPI), dh = 12 in., mud weight = 12 lb/gal, tool OD = $3\frac{3}{8}$ in., and the tool is centered. (**ANS; 58 API**)
2. Borehole diameter = 6.0 in., tool OD = $3\frac{3}{8}$ in., the tool is centered, mud weight = 12 lbm/gal, measured, GR = 36 gAPI. (**ANS; 45.4 API**)

- **Log Correction Steps Without Using Charts**

$$N'_{GR} = N_{GR} \times A \times 10^{x}$$

$$N'_{GR} = \text{Corrected Gamma Ray Response (API Units)}$$

$$N_{GR} = \text{Measured Gamma Ray Response (API Units)}$$

Where :

$$A = \begin{cases} 1 \text{ for } 3\frac{5}{8} \text{ in. diameter instrument} \\ 1.05 \text{ for } 3\frac{7}{8} \text{ in. diameter instrument} \\ 0.95 \text{ for 2 in. diameter instrument} \\ 0.92 \text{ for } 1\frac{11}{16} \text{ in. diameter instrument} \end{cases}$$

$$x = \left(\frac{d_{bh} - d_{inst}}{k}\right)\left[0.047(\rho_m - 8) + 0.38\right] - 0.1548$$

$$d_{bh} = \text{Borehole diameter (inches)}$$

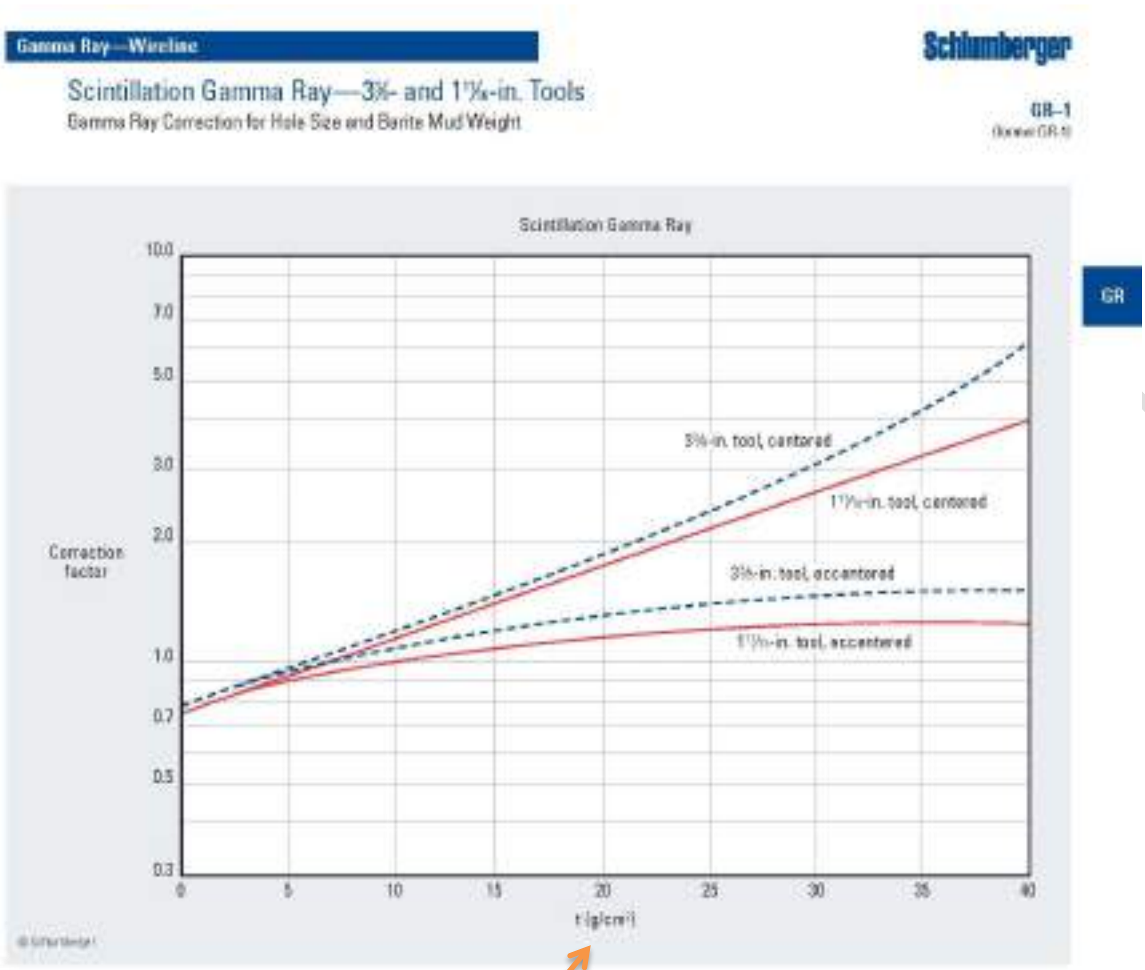
$$d_{inst} = \text{Instrument diameter (inches)}$$

$$\rho_m = \text{Mud density (lb/gal)}$$

$$k = \begin{cases} 16, \text{ instrument centered} \\ 20, \text{ instrument uncentered} \end{cases}$$

H.W: From given data correct the GR log, then estimate the shale volume.

Depth	=	4300 ft	GR_{log}	=	36 API
Caliper Log	=	8.799 inch	Mud Density	=	9.878 lb/gal
GR_{min}	=	6 API	GR_{max}	=	62 API
$d_{instument}$	=	3.625 inch	Instrument Uncentered		



$$t = \frac{W_{mud}}{8.345}\left(\frac{2.54(d_h)}{2} - \frac{2.54(d_{sonde})}{2}\right), \quad g/cm^2$$

Covert to gm/cm^3

Covert to cm

Example: Given: GR = 36 API units (gAPI), dh = 12 in. mud weight =12 lbm/gal, tool OD = 3 ⅜ in., and the tool is centered. Find: Corrected GR value.

Sol:

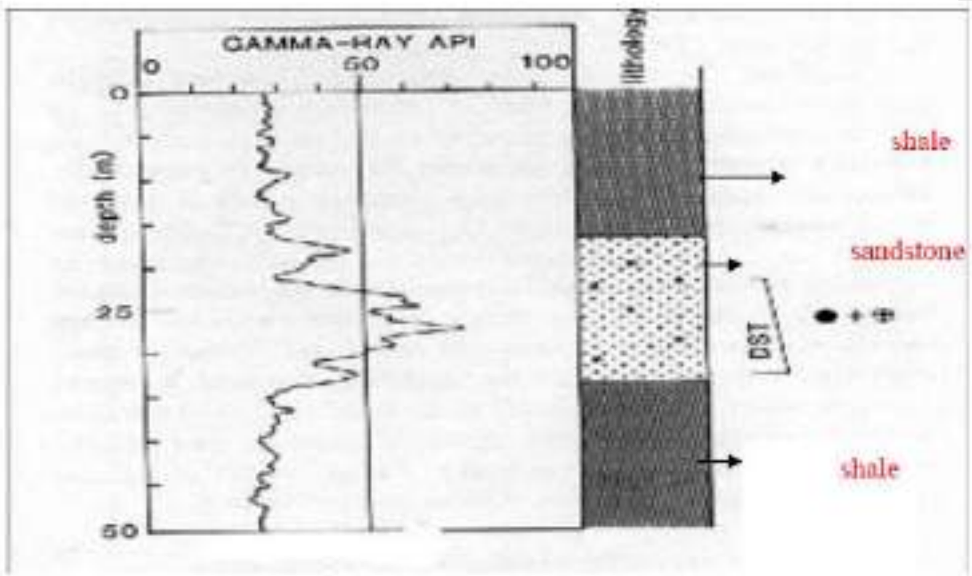
$$t = \frac{12}{8.345}\left(\frac{2.54(12)}{2} - \frac{2.54(3.375)}{2}\right) = 15.8 \text{ g/cm}^2.$$

Enter the chart at 15.8 on the x-axis and move upward to intersect the 3⅜ in. centered curve. The corresponding correction factor is 1.6.

Grcorr = 1.6 × 36 gAPI = 58 gAPI

o **Spectral Gamma Ray (SGR) Log**

- The total gamma ray log in clean sands can sometimes produce high gamma ray readings which would confuse them with shales.
- Such sandstones include radioactive contaminant such as feldspars, micas , volcanic ash, granite wash **or** the formation waters contain dissolved radioactive salts.

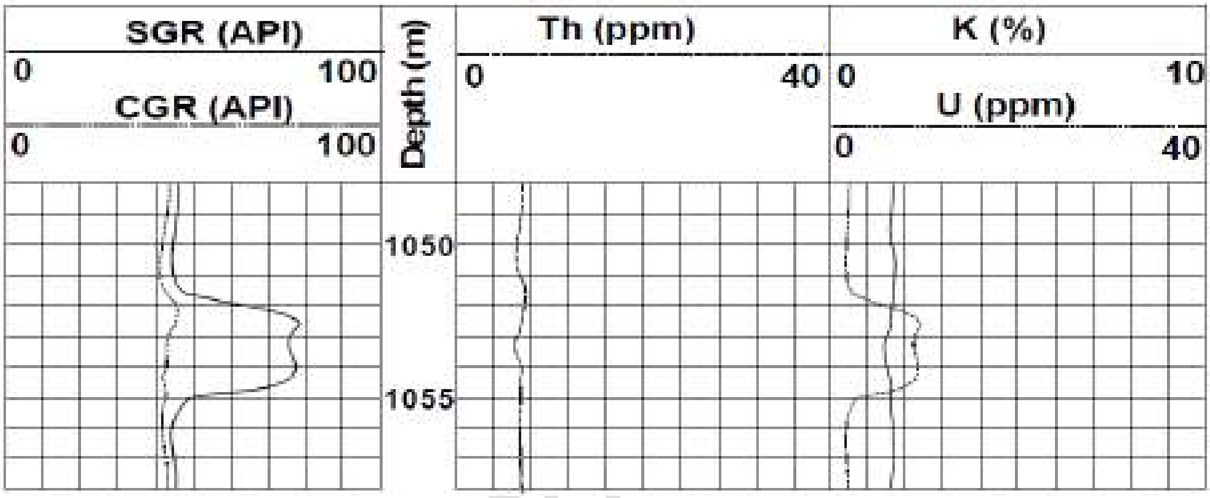


- The extra information supplied by the *spectral gamma ray* tool can, in most cases, help recognize these situations, and give us information about the composition and possible lithology of the formation.
- The ***spectral gamma ray* SGR log** measures the natural gamma radiation emanating from the formations separated into different types of radio-isotopic sources : (1) thorium, (2) potassium, and (3) uranium.
- The format for reporting the spectral gamma ray data is more complex than for the total gamma ray log because it contains much more detailed information.
  - **Track 1** is used to record;

✓ The spectral gamma ray log (*SGR*), which is a sum of all the radiation contributions.

✓ the computed gamma ray log (*CGR*), which is the sum of the **potassium and thorium** responses, leaving out the contribution from uranium.

- **Tracks 2 and 3** are used to record the calculated abundances associated with the radiation from the individual contributions from each of K^{40}, U^{238}, and Th^{232}.
- It should be noted that potassium is reported as a percentage, while U^{238} and Th^{232} are reported in parts per million (ppm).
- The spectral gamma ray log (*SGR*) is also called *Natural Gamma Ray Spectrometry Tool* (NGS).



o Uses of the Spectral Gamma Ray Log

Uses	Knowing
Lithology identification	Radioactive content for the minerals
Identification of organic material and source rocks.	Uranium content of organic material
Fracture identification.	Uranium contribution to radioactivity
Correction of the GR for clay content evaluation.	
Identification of clay minerals .	Th, U, K content of individual clay mineral.
Study of depositional environments.	Th/K content of shale depositional environments
Volume of shale determination.	Th (max.) and Th(min) for pure shale

o SGR Log Interpretation

- The three radioactive elements measured by the SGR log occur in different parts of the reservoir. If we know the lithology, we can obtain further information.

A) In Carbonates:

U - indicates phosphates, organic matter.

Th - indicates clay content.

K - indicates clay content, radioactive evaporates.

B) In Sandstones:

Th - indicates clay content, heavy minerals.

K - indicates micas, micaceous clays and feldspars.

C) In Shales:

U - in shale, suggest a source rock.

Th - indicates the amount of detrital material or degree of shaliness.

K - indicates clay type and mica.

- We can calculate the **shale volume** from the individual readings of the spectral gamma ray log (K, Th, and U), and from the computed gamma ray log (*CGR*).

$$V_{sh}\big|_{CGR} = \frac{CGR - CGR_{min}}{CGR_{max} - CGR_{min}} \quad \text{............(5)}$$

$$V_{sh}\big|_{K} = \frac{K - K_{min}}{K_{max} - K_{min}} \quad \text{............(6)}$$

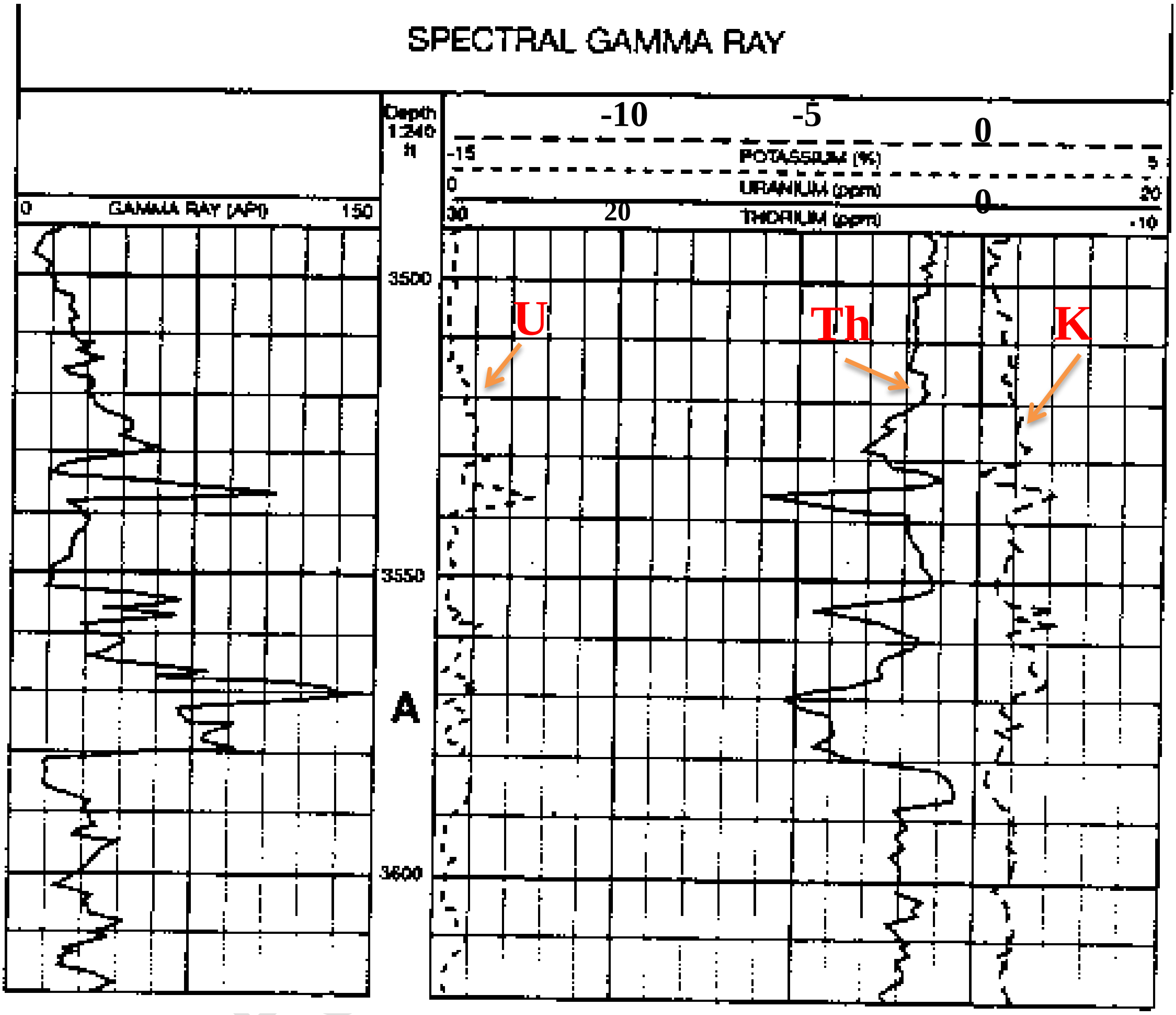
$$V_{sh}\big|_{Th} = \frac{Th - Th_{min}}{Th_{max} - Th_{min}} \quad \text{............(7)}$$

$$V_{sh}\big|_{U} = \frac{U - U_{min}}{U_{max} - U_{min}} \quad \text{............(8)}$$

Note

Equation (5) is better shale indicators than Eq. (1), since the random contribution of U is eliminated. Equation (8), is almost never used.

o Spectral Gamma Logs: Example

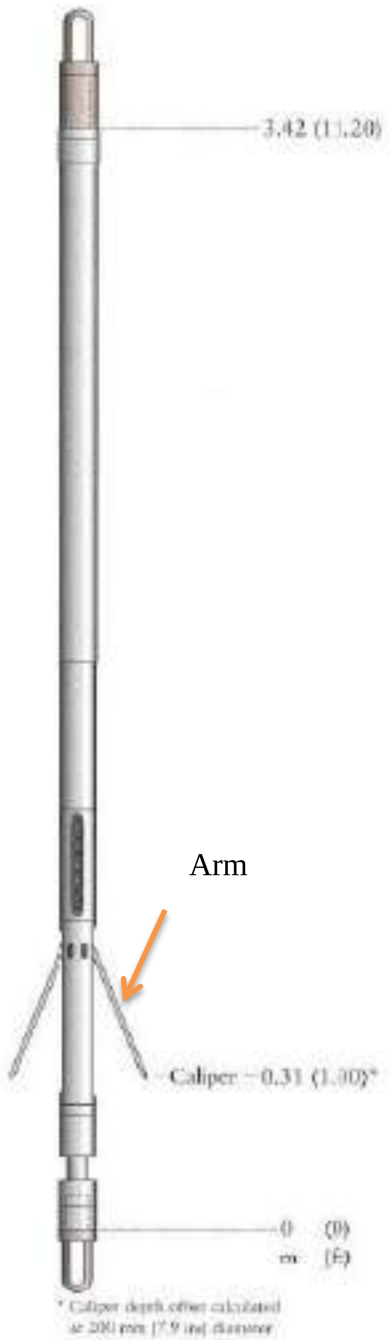


	Min	Max
GR	15	139
Th	1.2	11.5
K	0.22	1.9
U	0.21	2.5

- In clay-bearing carbonate rocks high total gamma readings are not related only to the clay fraction, but are also due to the presence of uranium series minerals of organic origin.
- High total gamma ray readings are therefore not a reliable indicator of the shaliness of a carbonate.
- If the spectral gamma ray log indicates the presence of K and Th together with the U, it may be said that the K and Th contributions are associated with the clay content of the shaly carbonate, while the U is associated with some organic source.
- Thus, when calculating the shaliness of a carbonate, it is better to use the *CGR* (Eq. 5).
- Table below show interpretation of spectral gamma ray data in carbonates.

K	Th	U	Explanation
Low	Low	Low	Pure carbonate, no organic matter
Low	Low	High	Pure carbonate, organic matter
High	High	Low	Shaly carbonate, no organic matter
High	High	High	Shaly carbonate, organic matter
Low	High	Low	Not a carbonate, or shaly carbonate rare low K high Th clay minerals
Low	High	High	Not a carbonate, or shaly carbonate rare low K high Th clay minerals

CALIPER LOGS



- The *Caliper Log* is a tool for measuring the <u>diameter</u> and <u>shape</u> of a borehole.
- It uses a tool which has 2, 4, or more extendable arms.
- The arms can move in and out as the tool is withdrawn from the borehole, and the movement is converted into an electrical signal by a potentiometer.

o **Types Of Caliper Log Tools**

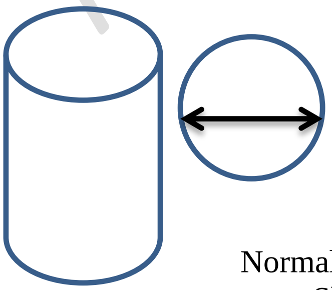
1. Two Arm Caliper Tool

✓ Measures the borehole diameter.

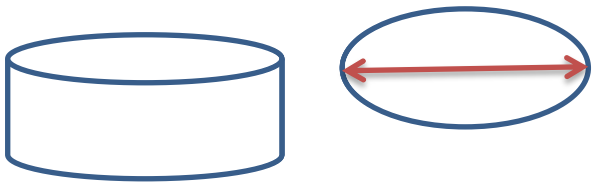
✓ Plotted in track 1 of the master log together with the bit size for reference.

✓ Borehole diameters larger and smaller than the bit size are possible.

<u>Limitations</u>: Many boreholes can attain an <u>oval shape</u> after drilling. This is due to the effect of the pressures in the crust being different in different directions as a result of tectonic forces. In oval holes, the two arm caliper will lock into the long axis of the oval cross-section, giving larger values of borehole diameter than expected. In this case tools with more arms are required.



Normal Borehole Shape



Oval Borehole Shape

2. **Four Arm Caliper Tool (Dual Caliper)**

- ✓ The two opposite pairs arms work together to give the borehole diameter in two perpendicular directions.
- ✓ An example of a 4 arm tool is the **Borehole Geometry Tool (BGT)**.
- ✓ **BGT** has 4 arms that can be opened to 30 inches (40 inches as a special modification), and give two independent perpendicular caliper readings.
- ✓ The tool also calculates and integrates the volume of the borehole and includes sensors that measure the direction (azimuth) and dip of the borehole.
- ✓ This information(borehole volume, direction and dip) is useful to;
  - Estimate the amount of drilling mud in the borehole
  - Estimate the amount of cement required to case the hole.
  - Plot the trajectory of the borehole.

3. **Multi-Arm Caliper Tools**

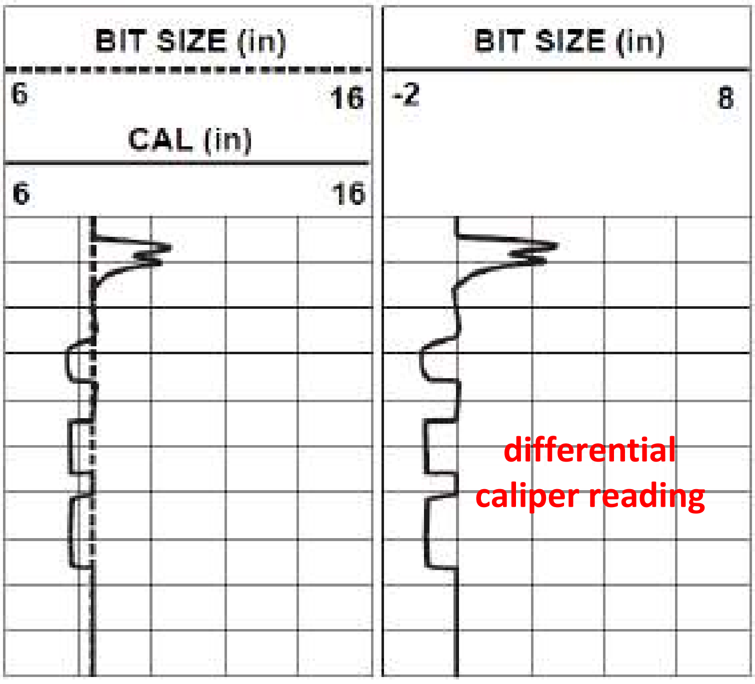
- ✓ Up to 30 arms are arranged around the tool allowing the detailed shape of the borehole to be measured.

o **Log Presentation**

- ✓ The caliper logs are plotted in track 1 with the drilling bit size for comparison.

Or

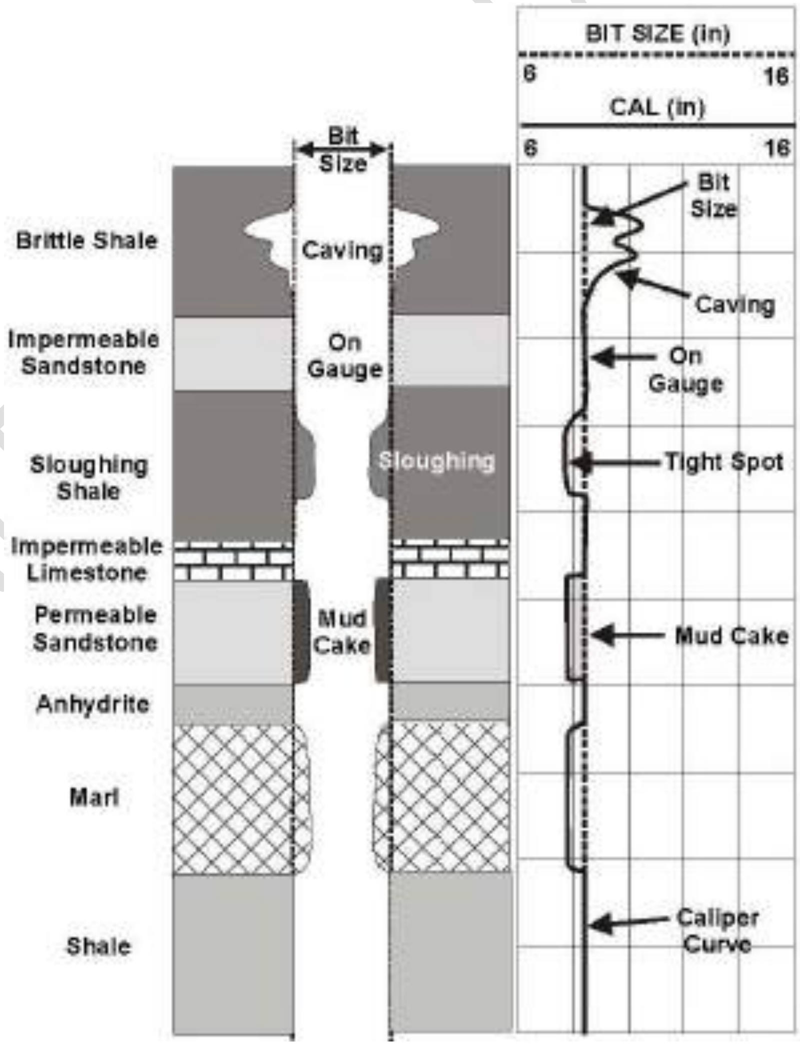
- ✓ Plotted as <u>differential caliper reading</u>, where the reading represents the caliper value minus the drill bit diameter.
- ✓ The scale is generally given in <u>inches</u>, which is standard for measuring bit sizes.



o **Caliper Log Interpretation**

- when a hole is the same diameter as the bit-size it is called ***on gauge***.

Hole Diameter	**Cause**	**Possible Lithologies**
On Gauge **Cal = BS**	1.Well consolidated formations. 2.Non-permeable formations.	1.Massive sandstones 2.Shaly Limestone 3.Igneous rocks 4.Metamorphic rocks
Larger than Bit Size **Cal > BS**	1. Formation soluble in drilling mud. 2. Formations weak and cave in.	1. Salt formations drilled with fresh water. 2. Unconsolidated sands, gravels, weak shales.
Smaller than Bit Size **Cal < BS**	1. Formations swell and flow into borehole. 2. Development of mud cake for porous and permeable formations.	1. Swelling shales. 2. Porous, permeable sandstones.



o **Uses of the Caliper Log**

1. Gives information about formation lithology.
2. Used with the GR log to indicate the permeability and porosity zones (reservoir rock) due to development of mud cake.
3. Calculation of mud cake thickness.

$$h_{mc} = \frac{d_{bit} - d_{hole}}{2} \qquad in$$

4. Measurement of borehole volume.

$$V_h = \left(\frac{d_{hole}^2}{2}\right) + 1.2\% \qquad litter/meter$$

5. Measurement of required cement volume.

$$V_h = (0.5)\left(d_{hole}^2 - d_{casing}^2\right) + 1\% \qquad litter/meter$$

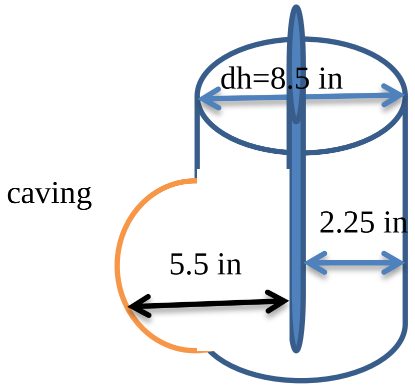
6. Selection of consolidated formations for;
   A. wireline pressure tests.
   B. Recovery of fluid samples.
   C. Packer seating for well testing purposes
   D. Determining casing setting depths.
7. Measurement casing setting depths. (where caliper log inside casing string read straight line).
8. Indication of hole quality for the assessment of others logs whose data quality is degraded by <u>holes that are out of gauge</u>.

- Other log data can often be corrected for bad hole conditions using the caliper log readings, but the larger the correction, the less reliable the final data will be.

Caliper and Bit size(BS) logs	**Others Logs Readings**
Caliper – BS = 0 %	Excellent condition, no need for correction
Caliper – BS < 10 %	Logs are good quality,
Caliper – BS =10 – 30%	Logs probably need to be corrected
Caliper –BS >30 – 50%	Logs incorrect, need to correct
Caliper – BS > 50 %	Very bad borehole conditions. incorrect logs

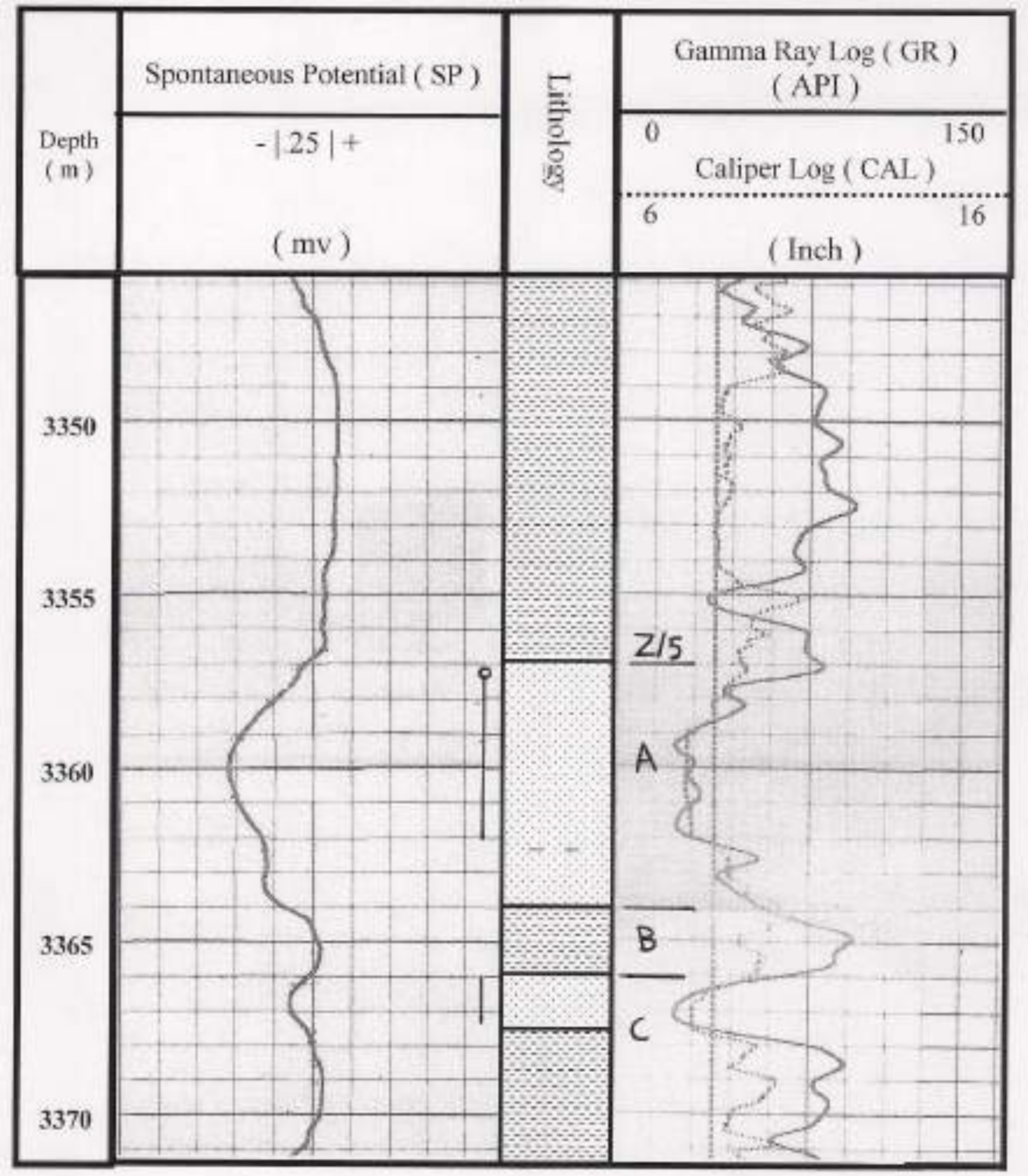
(Yan et al., 2008)

- Well logging tools are designed to be about 4 inches in diameter for a standard 8.5 inch hole, and they are designed to work with 2.25 inches of drilling mud between them and the formation.



- If the hole caves to 14 inches, which is not uncommon, the distance to the formation becomes 5.5 inches and the tool responses are degraded.
- This can be corrected for to some extent if the caliper value is known.
- Tools that work by being pressed up against the side of the borehole wall have even greater problems because the irregularity of the borehole wall makes it impossible to obtain reliable readings.
- In both cases the recognition that a borehole has bad caving or thick mud cake can help us judge the reliability of other tool's readings.

o Caliper Log Example:



التفسير :

① نلاحظ من خلال شكل منحني مجس الكاليبر عند العمق (3366.3 – 3367.7) م تضيق في قطر البئر أمام صخرة الحجر الرملي وهذا يعني وجود Mud Cake امام هذه الطبقة بسبب حدوث عملية الترشيح مقابل هذه الطبقة لنفاذيتها مما يجعل تجمع المواد الصلبة على الجدار وبناء Mud Cake

② عند العمق (3367.7 – 3371) م نلاحظ توسع في قطر البئر أمام صخرة Shale وهذا يعني وجود هدم أمام هذه الطبقة وهكذا .

THE SPONTANEOUS POTENTIAL LOG

- The spontaneous potential (SP) log was one of the earliest electric log and has a significant role in well log interpretation.
- The SP log used to:

  I. Detect permeable beds.
  II. Determine formation water resistivity R_w.
  III. Determine the volume of the shale in permeable beds.
  IV. Correlate between the wells.

2 Electrodes

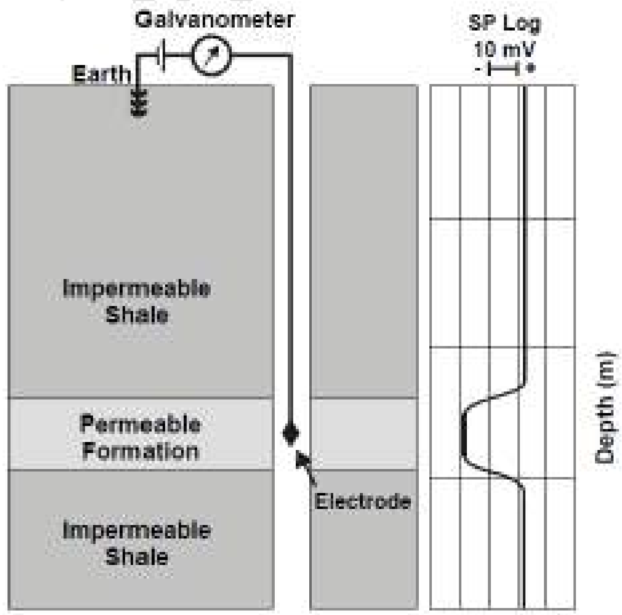
- ✓ Electrode A moveable

Move Up or Down in the borehole filled with conductive mud.

- ✓ Electrode B Fixed

Placed in the mud pit at the surface.

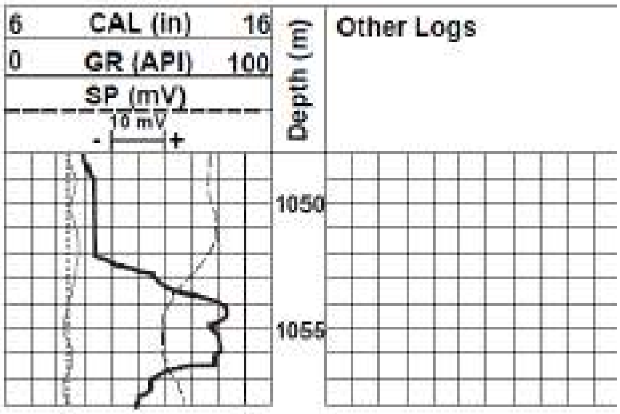
- ✓ Galvanometer



- The SP log response created by direct electric current (DC) voltage differences between the potential of a moveable electrode in the well bore and the potential of a fixed electrode at the surface.
- Differences between the potentials of electrode A and electrode B arising mainly from ***electrochemical factors*** within the borehole.

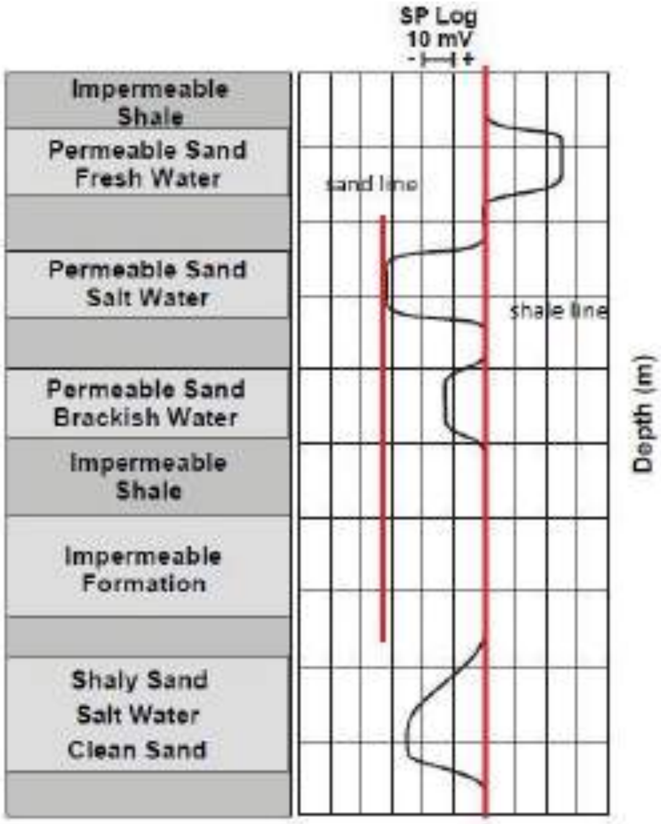
- These ***electrochemical factors*** are brought by differences in salinities between mud filtrate resistivity (R_{mf}) and formation waters resistivity (R_w) in permeable beds.
- There are three requirements for the existence of an SP current:

✓ A conductive borehole fluid (i.e., a water based mud).
✓ A porous and permeable bed·
✓ A difference in salinity between the borehole mud and the formation water.

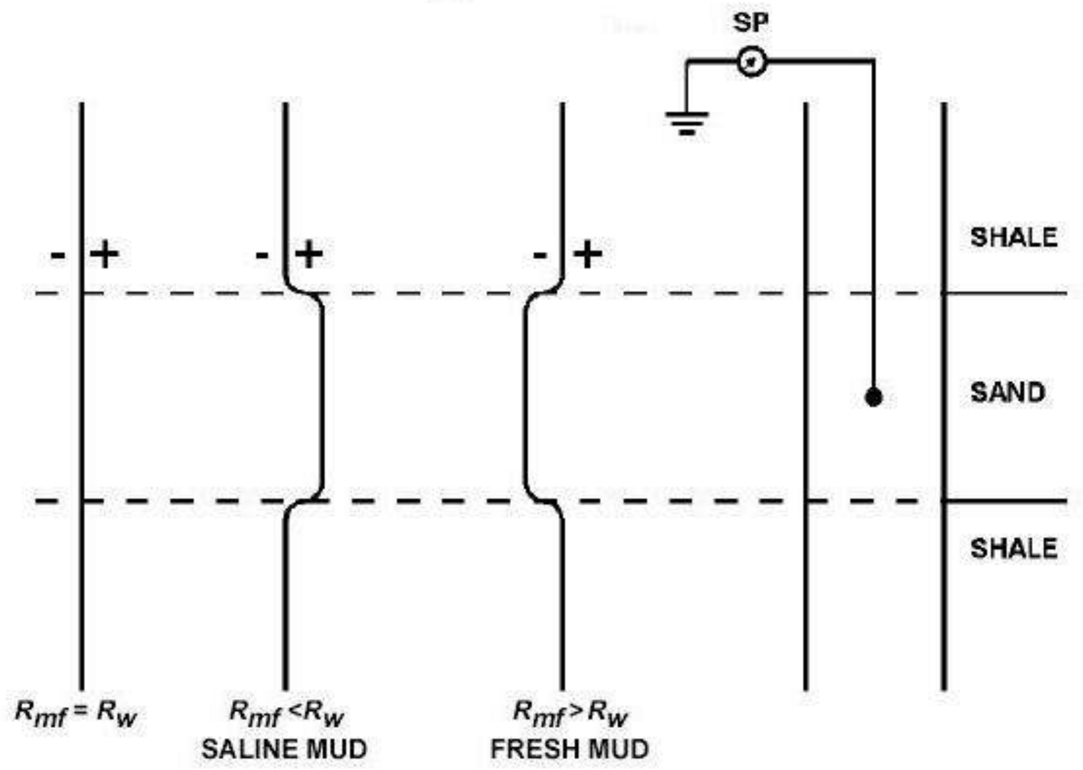


o **SP Log Curve Response Analysis**

- SP log in millivolts recorded in the track #1 in millivolts with Gamma ray log in API, and Caliper log in inch.
- In shale formation the SP curve is relatively constant and follows a straight line called a **shale baseline**. SP curve deflections are measured from this shale baseline.
- The position of the shale baseline on the log has no useful meaning, only used for interpretation purposes.
- In permeable sandstone formations, the curve shows deflections from the shale baseline to reach constant deflection defining a **sand line**.

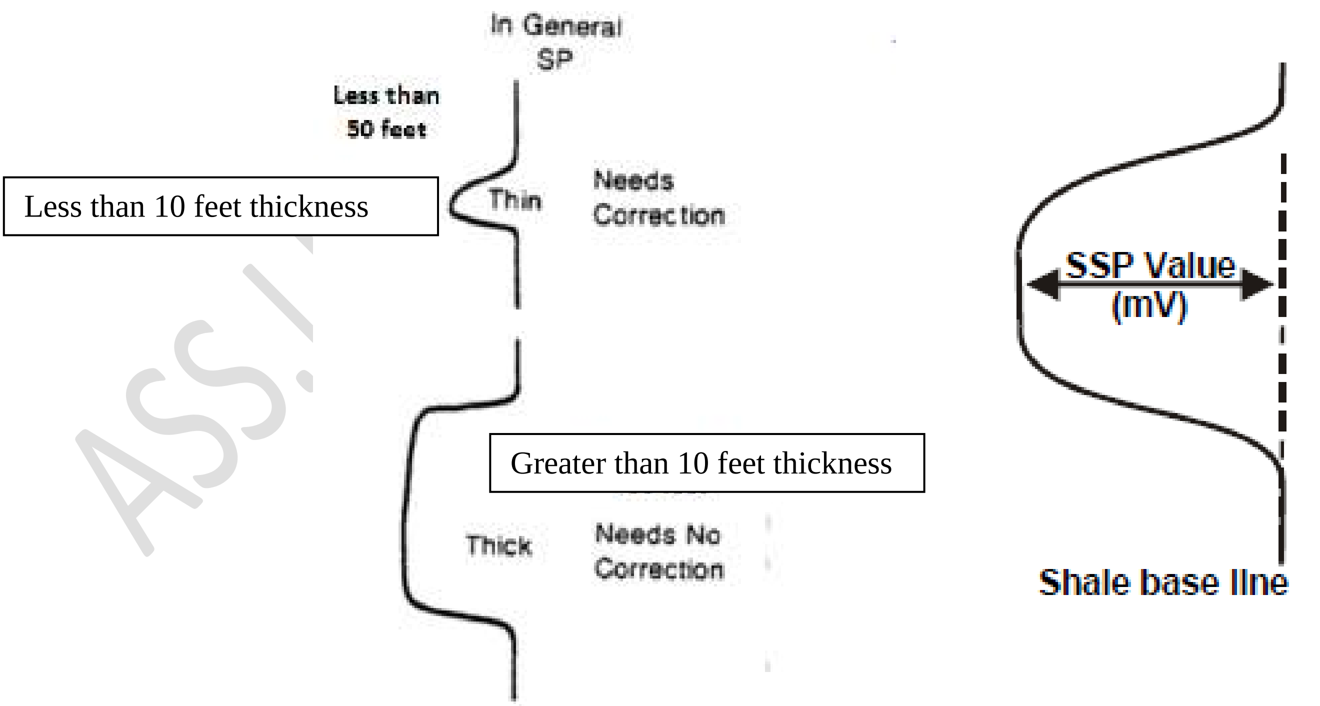


- The deflection may be either to the left shale line (*negative*) or to the right shale line (*positive*), depending mainly on the relative salinities of the formation water and the mud filtrate.
- If the formation water salinity is greater than the mud filtrate salinity,(or $R_w < R_{mf}$) the deflection is to the *left*. (Fresh Mud Using).
- If the formation water salinity is less than the mud filtrate salinity,(or $R_w > R_{mf}$) the deflection is to the *right*. (Saline Mud Using).
- If the salinities of the mud filtrate and formation water are about similar or **equal** (i.e. $R_w = R_{mf}$), there is no SP deflection opposite a permeable bed. (Note that ; $Salinity \propto \frac{1}{resistivity}$)



o Static SP (SSP)

- The **static SP**, or **SSP**, is the maximum SP deflection opposite a thick, clean, porous, permeable formation. { **thick formation ≥ 10 feet thick** }
- The SSP is the difference between the SP log at the shale base line and that in the center of the thick clean formation.
- SP (spontaneous potential) is the SP response due to the presence of thin beds and/or the presence of gas and/or the presence of the shale.
- The SSP is important concept because it is a necessary element for determining accurate values of R_w and volume of shale.
- *As* a formation is shaly or thins (i.e. < 10 feet thick) the SP measured in the borehole will record an SP value less than SSP , in this case the SP must be corrected to find a value of SSP.



- The SP curve can be corrected by chart for the effects of bed thickness.

(use **chart SP-5** for **thickness** in feet, or **chart SP-6** for **thickness** in meter)

- *As a general rule whenever the SP curve is narrow and pointed in shape, the SP should be corrected for bed thickness*.

  - **pseudo-static SP**

- ***Pseudo-Static Spontaneous Potential* (PSP) is** the SP deflection obtained for homogeneous shaly formations and/or thin shaly beds after correction for bed thickness, i.e. is the SP response if shale is present.

❖ **Factors Influencing The SP Log Responses**

1. **R_{mf}/R_w Ratio**.

   $R_{mf}/R_w > 1$ deflection to the left shale line (*negative*)

   $R_{mf}/R_w = 1$ no deflection

   $R_{mf}/R_w < 1$ deflection to the right shale line (*positive*)

2. Bed thickness

   Thin beds (<3m or 10 ft) reduce the deflection of the SP curve

3. formation resistivity (Rt).

   Higher Rt both reduce the deflection of the SP curve

4. Invasion

   Usually very small and can, in general, be ignored

5. Shale content

   increased shale content reduces SP deflection

6. Borehole diameters.

   Usually very small and can, in general, be ignored

7. Hydrocarbon Content

   In hydrocarbon-bearing zones, the SP curves deflection is reduced

Example// SP Log Deflection From The Shale Baseline.

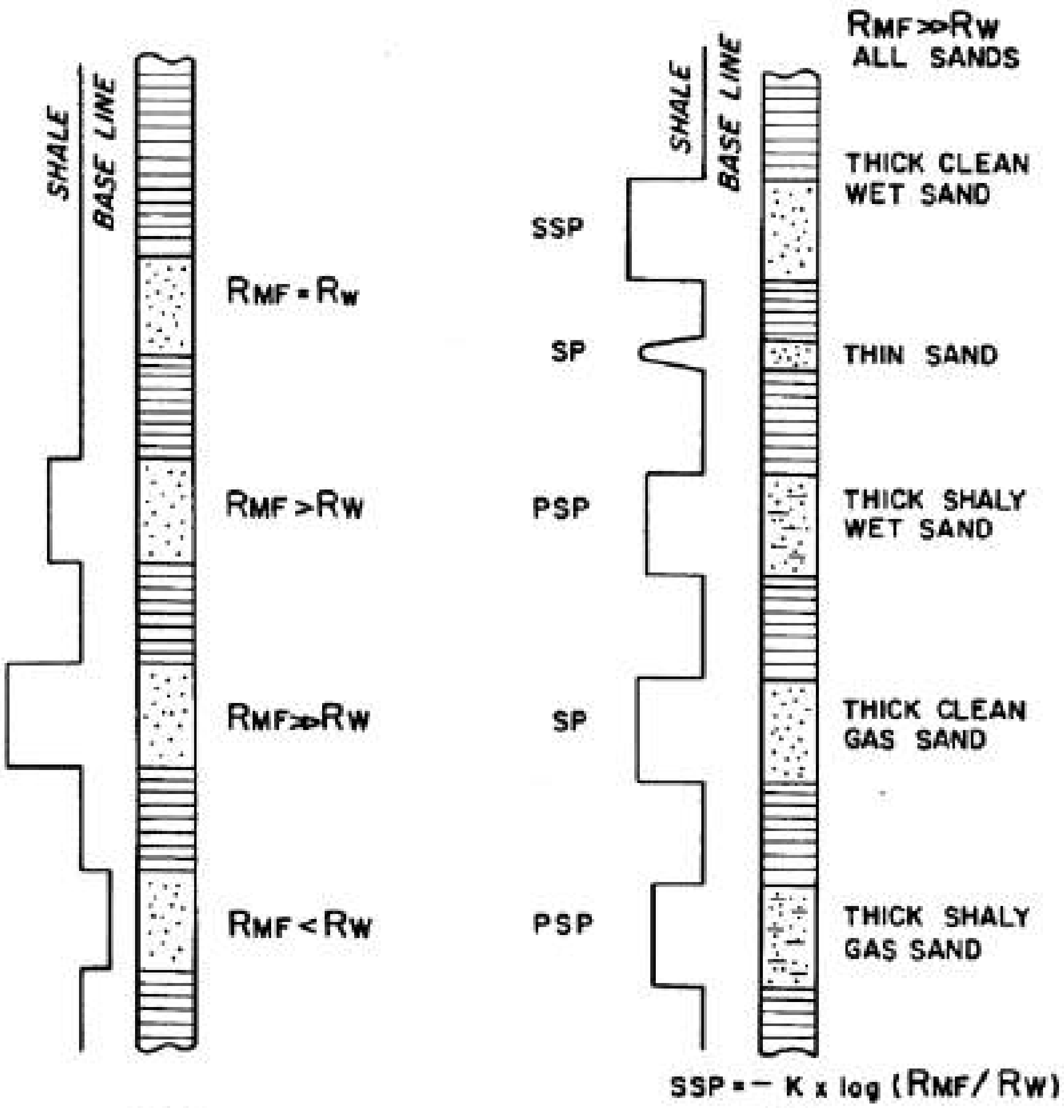
Figure A / SP log deflection with different resistivity of mud filtrate (R_{mf}) and formation water (R_w).

- ✓ When $R_{mf} = R_w$ there is no deflection.
- ✓ When $R_{mf} > R_w$ SP log deflects to the left of shale line (negative deflection).
- ✓ When $R_{mf} >> R_w$ the deflection is proportionately greater.
- ✓ When $R_{mf} < R_w$ SP log deflects to the right of shale line (positive deflection).

Remember, the spontaneous potential log (SP) is used only with conductive (salt water based) drilling muds.

Figure B / SP deflection with resistivity of the mud filtrate (R_{mf}) much greater than formation water (R_w).

- ✓ SSP (static spontaneous potential) at the top of the diagram, is the maximum deflection possible in a thick, shale free, and water bearing ("wet ") sandstone for a given ratio of R_{mf}/R_w. All other SP log deflections are less, and are relative in magnitude.

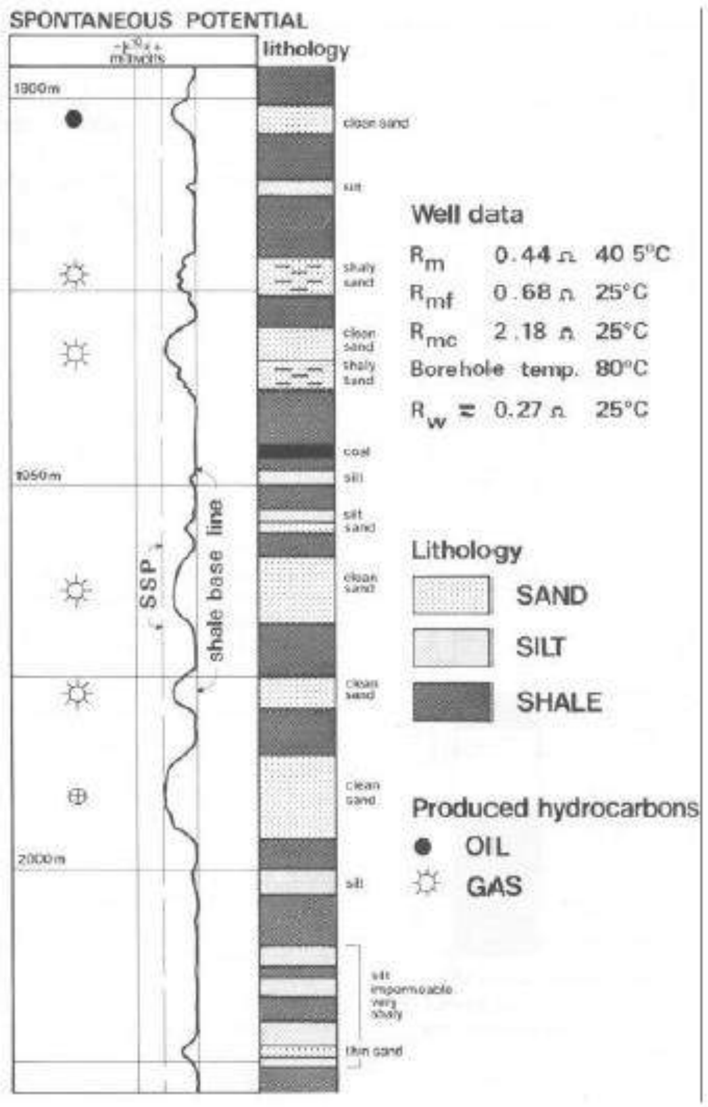

SHALE
BASE LINE
RMF = Rw
RMF > RW
RMF >> RW
RMF < RW
RMF >> RW
ALL SANDS
SSP
SP
PSP
SP
PSP
THICK CLEAN WET SAND
THIN SAND
THICK SHALY WET SAND
THICK CLEAN GAS SAND
THICK SHALY GAS SAND
SSP = − K x log (RMF/ RW)

10A 10B

SP Log Applications

1) The detection of permeable beds.

- Permeable zones are indicated if there is a small deflection in the SP log from the shale baseline.
- Permeable bed boundaries are detected by the point of the inflection from the shale baseline.
- It should be noted that some permeable beds might give no deflection, such as those where there is no difference in salinity between the formation fluids and the mud filtrate.



2) Calculation of Water Resistivity (Rw) from SP Log

1. Identify the *shale baseline* and *clean sand lines* on the SP log. The difference is SP.
2. Correct the SP reading to SSP for bed thickness.

(use **chart SP-5** for **thickness** in feet, or **chart SP-6** for **thickness** in meter).

$$SSP = correction\ factor\ \ x\ Sp \qquad (1)$$

3. Calculate the formation temperature.

- **By using equation;**

$$T_f = \left(\frac{BHT - T_o}{D_T}\right)(D_f) + T_o \qquad (2)$$

T_f = formation temperature at any depth.
BHT = Bottom hole temperature.
T_o= annuls mean surface temperature = 80^o F
D_f = formation depth and D_T = total well depth

- **Or by using chart Gen-2**

4. Convert R_{mf} at measured temperature to $\mathbf{R_{mf}}$ at formation temperature.

$$R_2 = R_1\left(\frac{T_1 + 7}{T_2 + 7}\right) \dots\dots\dots\dots(3)$$

Note; R_{mf} and R_m obtained from log heading (i.e. given),,,, if R_{mf} not given in log heading, we can calculate it from;

$$R_{mf} = 0.75\, R_m \dots\dots\dots..(4)$$

$$R_{mc} = 1.5\, R_m \dots\dots\dots\dots\dots(5)$$

5. If formation water salinity is **low** (less than 80000 ppm NaCl)

$$ssp = -k \log\frac{R_{mf}}{R_w} \qquad (6)$$

$$R_w = \frac{R_{mf}}{10^{-(SSP/K)}} \dots\dots\dots.(7)$$

Where, K = constant

$$k = 0.133\, T_f + 61 \qquad (8)$$

6. If formation water salinity is **high** (greater than 80000 ppm NaCl) we must calculate R_{mf} equivalent, or R_{mfe}.

$$A.\ \ If \quad R_{mf}\ @\ 75^o\ F\ (24^o C)\ < 0.1\ \Omega.m$$

- **Use Chart SP-2(T in F^o) , or chart SP-3(T in C^o)**

This chart using to convert $R_{mf} \longrightarrow R_{mfe}$

$R_{we} \longrightarrow R_w$

Do not use the dashed lines, they are for gypsum based muds.

- **Or use the following eq**.

$$R_{mfeq} = \frac{(146 \text{ x } R_{mf}) - 5}{(337 \text{ x } R_{mf}) + 77} \text{ ....(9)}$$

$$B.\ \ If \quad R_{mf}\ @\ 75^o\ F(24^o C) = 0.1\ \Omega.m \ \ to \ \ 0.25\ \Omega.m$$

$$R_{mfe} = 0.85\ \ R_{mf\ @TF} \qquad (10)$$

$$C.\ \ If \quad R_{mf}\ @\ 75^o\ F(24^o C)\ >\ 0.25\ \Omega.m$$

$$R_{mf} = R_{mfe}$$

7. Calculate the equivalent formation water resistivity, Rwe

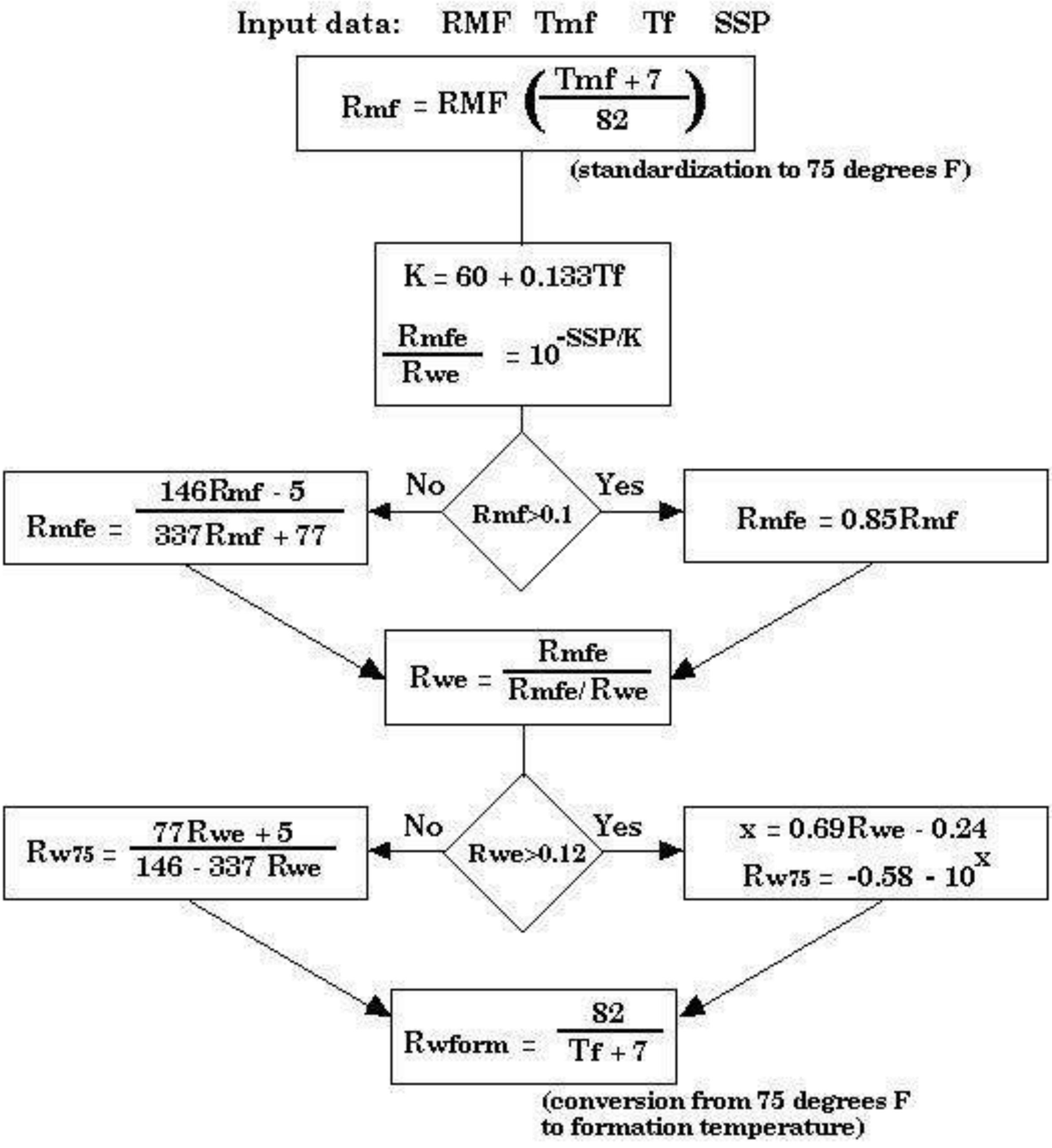
$$ssp = -k \log \frac{R_{mfe}}{R_{we}} \qquad (11)$$

$$R_{we} = \frac{R_{mfe}}{10^{-(SSP/K)}} \text{ ....(12)}$$

Or find R_{we} using **chart SP-1**

8. Calculate the formation water resistivity, R_w

Use Chart SP-2 (T in F^o) , or chart SP-3 (T in C^o)


Input data: RMF Tmf Tf SSP
Rmf = RMF ((Tmf + 7) / 82)
(standardization to 75 degrees F)
K = 60 + 0.133Tf
Rmfe / Rwe = 10^-SSP/K
No
Rmf>0.1
Yes
Rmfe = (146Rmf - 5) / (337Rmf + 77)
Rmfe = 0.85Rmf
Rwe = Rmfe / (Rmfe/Rwe)
No
Rwe>0.12
Yes
Rw75 = (77Rwe + 5) / (146 - 337 Rwe)
x = 0.69Rwe - 0.24
Rw75 = -0.58 - 10^x
Rwform = 82 / (Tf + 7)
(conversion from 75 degrees F
to formation temperature)

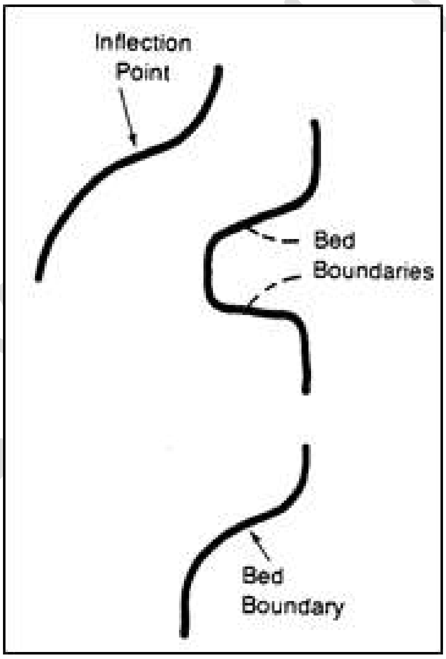
3) Calculation The Volume Of Shale In Permeable Beds.

The shale volume is sometimes calculated from the SP log using the relationship:

$$V_{sh} = 1 - \frac{PSP}{SSP} \qquad (13)$$

PSP = SP log read in a thick homogeneous shaly sand zone.

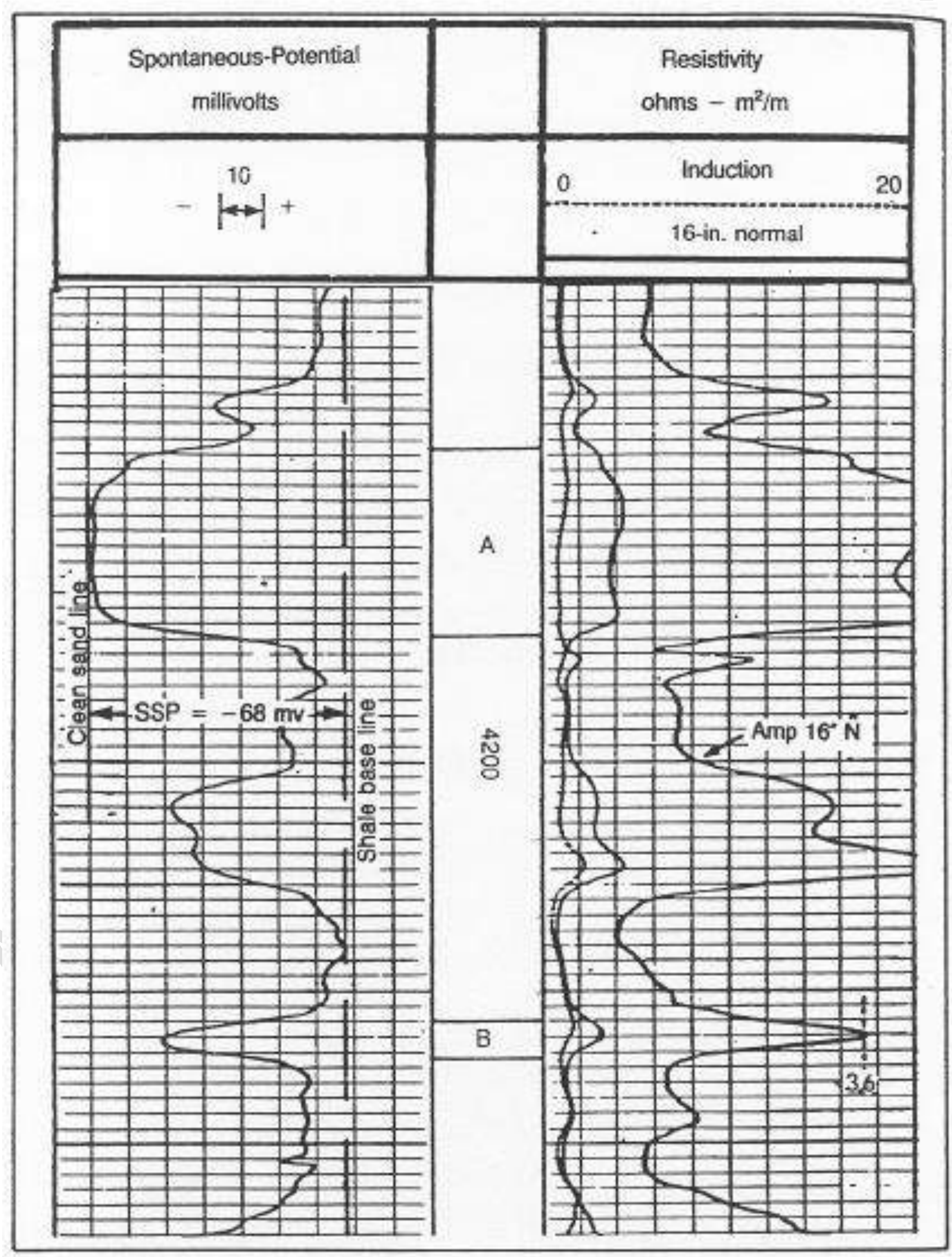
SSP = SP log read in the thick clean sand zone.



Example; Given;

T_{TD}= 196 deg F @ TD = 9,400 ft.
Gulf Coast well
R_{mf} = 0.71 @ T_m =68 deg. F
R_m = 1.00 @ T_m =68 deg. F

Calculate R_w for zones A and B.



Solution;

Step 1: *The shale baseline and clean sand line are drawn on the figure.*
SP = -68 mV is the potential difference.

Step 2: *The formation temperature can be computed by:*

$$T_f = (196 - 75)\frac{4170}{9400} + 75 = 129\,°F$$

Step 3: *The R_{mf} at formation temperature is:*

$$(R_{mf})_f = 0.71\left(\frac{68 + 6.77}{129 + 6.77}\right) = 0.39\,\Omega\text{-}m$$

Similarly, R_m = 0.55 ohm-m @ T_f

Step 4: *Bed thickness = 24ft.; R_i, = 4 ohm-m from the 16" short normal; thus R_i/R_m = 7.2 ≈7.5. From the figure the correction factor = 1.00.*

Step 5: *Since R_{mf} > 0. 25 then R_{mfe} = 0.39 ohm-m.*

Step 6: *Calculate the equivalent formation water resistivity.*

$$R_{we} = 0.39 * 10^{\left(\frac{-68}{61 + 0.133(129)}\right)} = 0.052\,\Omega\text{-}m$$

Step 7: *Since R_{we} < 0. 1, R_w = 0. 060 ohm-m*

<u>**Note ;**</u> we can obtain the Rw value from the following equations depending on Rwe;

1. If $R_{we} < 0.12$

$$R_{w75} = \frac{(77 \text{ x } R_{we}) + 5}{146 - (377 \text{ x } R_{we})}$$

2. $R_{we} > 0.12$

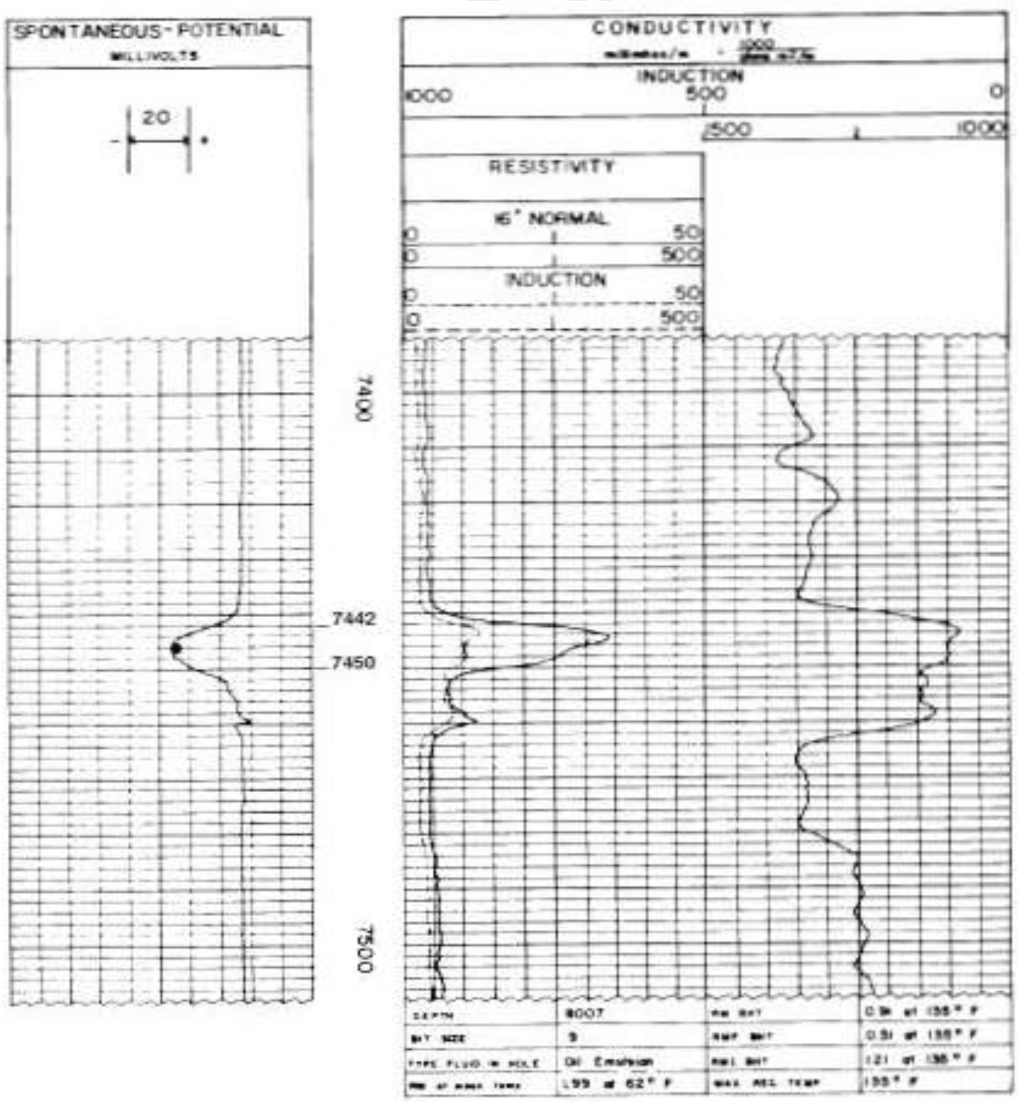
$$R_{w75} = -0.58 + 10^{(0.69 R_{we} - 0.24)}$$

3. Correct Rw @ 75° F to Rw @ T_f

Problem 1: Given: R_w = **0.22** ohm-m at **250°F** and resistivity of the mud filtrate (R_{mf}) = **0.7** ohm-m at **100°F**, converted to **0.33** at **250°F**.
Find:

1) SP or ESSP .
2) Salinity.

Problem 2: Determination of formation water resistivity (R_w) from SP log shown in figure below.
Given:
R_{mf} = **0.51@ 135^o F**
R_m = **0.91@ 135^o F**
Surface temperature (T_{sc})= **60^o F**
Total depth = **8007 ft**
Bottom hole temperature (BHT) = **135^o F**
R_i = **28 Ω – m.**
Bed thickness = **8 ft**.



Problem-3: Figure below show conventional resistivity logs with SP log for limestone formation below **7000** ft.

Given data:

R_m **= 0.4 Ω-m @183 °F**.

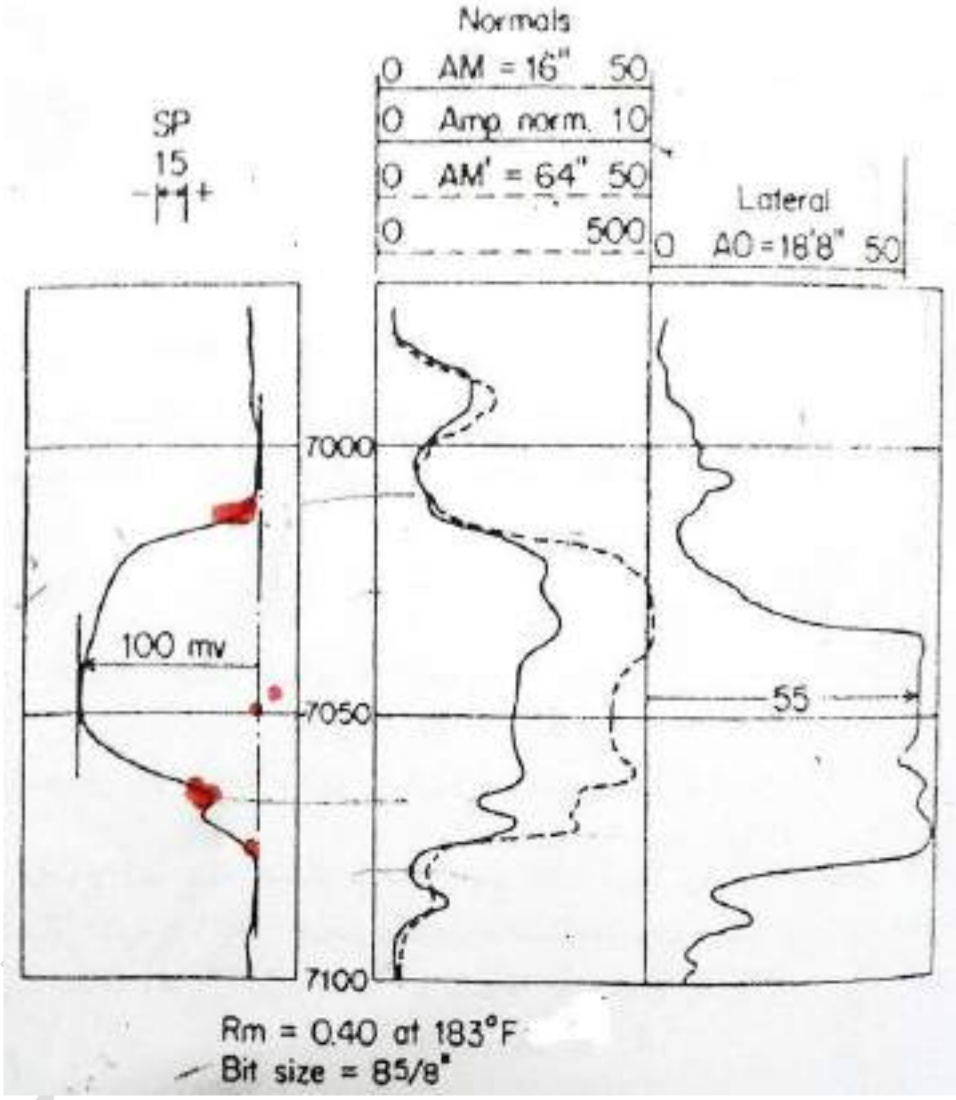
Bit size **= 8 5/8"**.

R_o **= 0.9 Ω-m**.

T_f **= 185 °F**.

Calculate:

1- R_t
2- S_w
3- R_w
4- Φ
5- Salinity.



POROSITY LOGS

- Rock porosity can be obtained from the;
  - Sonic log
  - Density log
  - Neutron log
- For all these devices, the tool response is affected by the formation porosity, fluid and matrix.
- If the fluid and matrix effects are known or can be determined, the tool response can be related to porosity. Therefore, these devices are usually referred to as ***porosity logs***.
- None of these logs measure porosity directly.
- The density and neutron logs are nuclear measurements. The sonic log use acoustic measurements.
- A combination of these logs gives good indications for lithology and more accurate estimates of porosity.
- Porosity calculating from porosity log is not very accurate method, but has the advantage of providing continuous porosity data.
- When the porosity are obtained from porosity log, they can be calibrated with porosity data obtained from core-sample and serve as additional dependable source of porosity distribution evaluation.

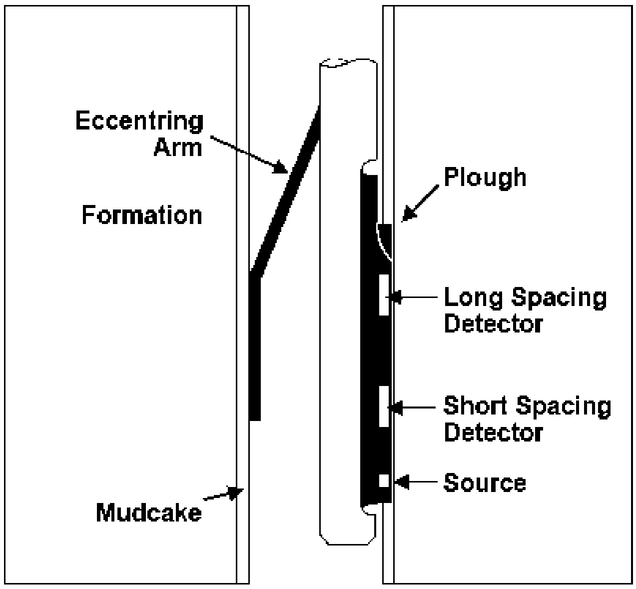
Density Log

- The formation density compensated (FDC) log is a porosity log that measures *bulk density* of the formation.

❖ ***FDC Log Uses***

– Porosity/Lithology Determination.
– Detect gas-bearing zone.
– Evaluation of shaly sands and complex lithology.
– Determination of hydrocarbon density.

▪ **Principle**

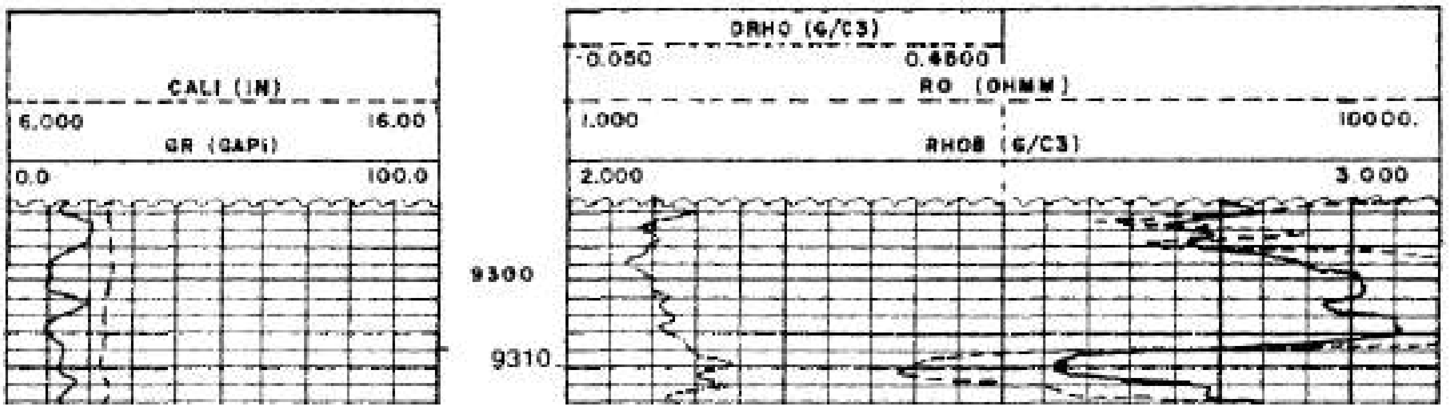


- The density logging device is a contact tool which consists of a medium-energy gamma ray source that emits gamma rays into a formation. The gamma ray source is either Cobalt-60 or Cesium-137.
- Gamma ray collides with electrons in the formation. <u>At each collision</u> a gamma ray particle <u>loses some of its energy to the electrons.</u>
- The interaction between incoming gamma ray particles and electrons in the formation called "***Compton Scattering***".
- Two detectors, located a fixed distance from the gamma ray source, are counted the number of scattered (returning) gamma rays as an indicator of formation density.

- The number of Compton Scattering collisions is a direct function of the number of electrons in a formation (electron density).
- So, electron density can be related to bulk density *(ρ_b)* of a formation in (gm/cm^3).

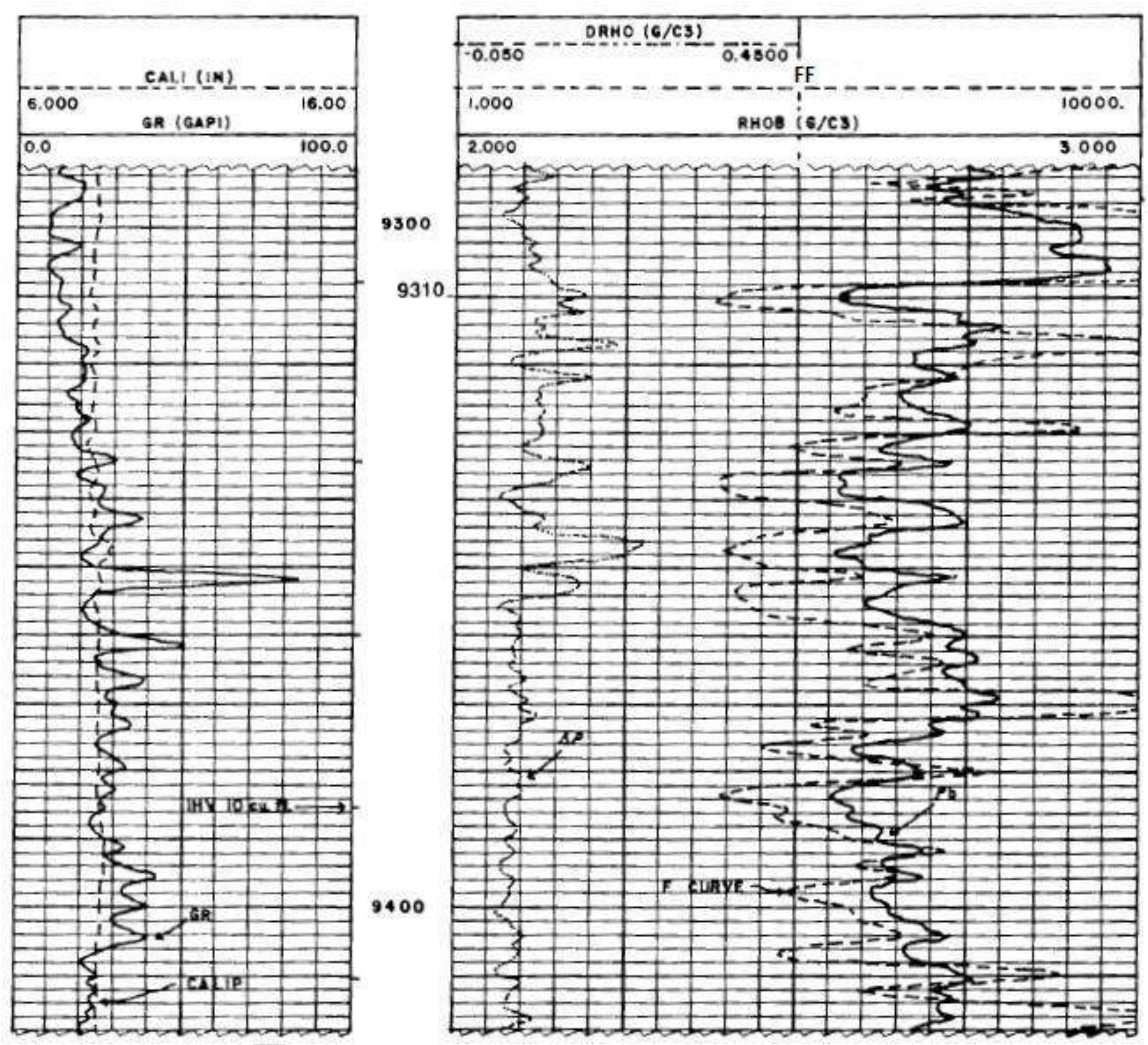
- **FDC Log Presentation**

- The bulk density curve is recorded in tracks #2 and #3 along with a correction curve *($\Delta\rho$).*
- Because the modern density log is a compensated log (dual detectors), the correction curve *($\Delta\rho$)* records how much correction has been applied to the bulk density curve (ρ_b), due to borehole irregularities.
- *When the* correction curve *($\Delta\rho$)* e*xceeds 0.2 gm/cc, the value of the bulk density obtained from the bulk density curve* (ρ_b) *should be considered invalid.*
- A density derived porosity curve is sometimes present in tracks #2 and #3 along with the bulk density (ρ_b) and correction *($\Delta\rho$)* curves. Track # 1 contains a gamma ray log and a caliper log.



Example…1: bulk density log with a gamma ray and caliper and formation factor curve (F).

- **Track #1**-This track includes both the gamma ray and caliper logs. Note that both scales read left to right: the gamma ray values range from 0 to 100 API gamma ray units. and the caliper measures the bore hole size from 6 to 16 inches.
- **Tracks #2 and #3**-The bulk density curve *(ρ_b),* correction curve *(Δ*ρ) and formation factor curve (FF) are recorded in this track, where the scales increase in value from left to right.
- The bulk density (ρ_b) scale ranges in value from 2.0 gm/cc to 3.0 gm/cc and is represented by a solid line.
- The density correction curve *Δ*ρ ranges in value from -0.05 gm/cc to +0.45 in increments of 0.05 gm/cc, but only uses the left half of the log track.
- The formation factor curve (F) ranges in value from 1 to 1000 and is represented by a dashed line.
- For example at depth 9310 ft. read a bulk density value (ρ_b) of *2.56* gm/cc.


CALI (IN)
6.000
16.00
GR (GAPI)
0.0
100.0
9300
9310
9400
DRHO (G/C3)
-0.050
0.4500
FF
1.000
10000.
RHOB (G/C3)
2.000
3.000
GR
CALIP
F CURVE

▪ Porosity from Density Log

- Formation bulk density(ρ_b) is a function of matrix density(ρ_{ma}), porosity and formation fluid density(ρ_f) (salt mud, fresh mud. or hydrocarbons).
- To determine porosity, either by **chart** (**por-5**) or by equation, the matrix density and type of fluid in the borehole must be known.
- The formula for calculating density porosity is:

$$\varphi_D = \frac{\rho_m - \rho_b}{\rho_m - \rho_f} \dots\dots\dots..(1)$$

Where;

ρ_{ma} = matrix (or grain) density

ρ_b = Bulk density as measured by the log.

ρ_f = Fluid density

Fluid/lithology Type		ρ (gm/cc)
fresh water mud	ρ_f gm/cc	1
Salt water mud		1.15
Oil		0.85 (If unknown.)
Gas		0.7 (If unknown.)
Sandstone	ρ_m gm/cc	2.65
Limestone		2.71
Dolomite		2.87
Anhydrite		2.96
Salt (Halite) NaCl		2.165

Example….2: Using **chart por-5** for converting bulk density *(ρ_b)* to porosity using values picked from a density log in **Example..1**.

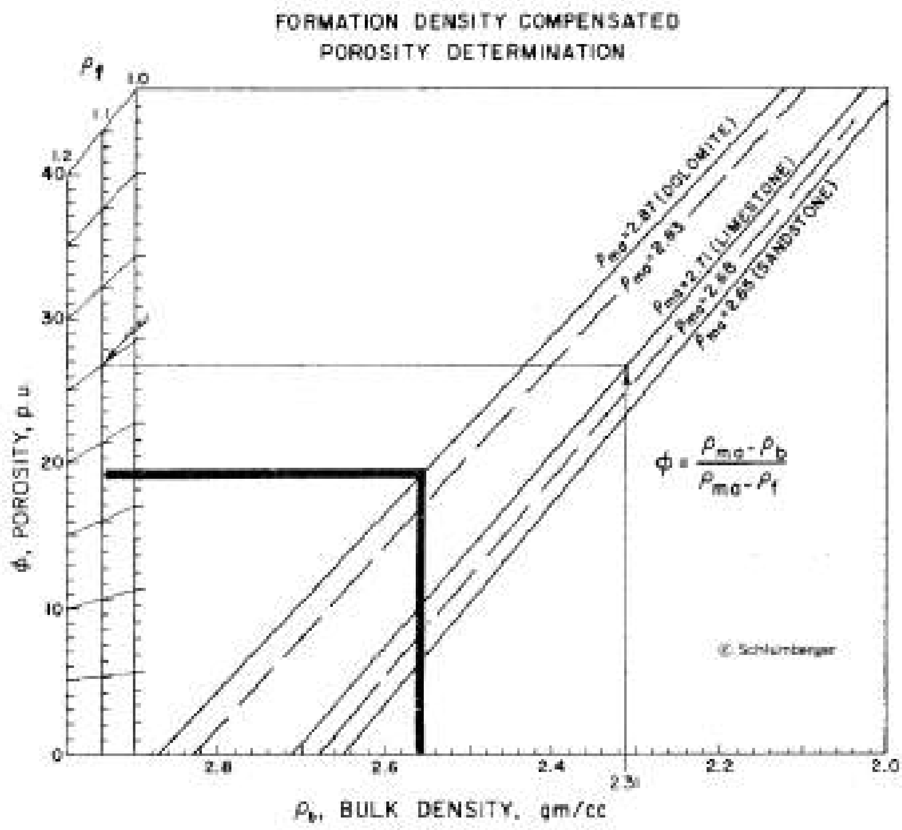
Given; ρ_{ma} = 2.87 gm/cc (dolomite; from table)

ρ_f = 1.1 gm/cc (fluid density for salt mud)

ρ_b = 2.56 gm/cc at a depth of 9310 ft (from log: Fig. above)

Procedure:

1. Find a value for bulk density *(ρ_b)=2.56 gm/cc* on the horizontal scale.
2. Follow the value vertically until it intersects the diagonal line representing the matrix density *(ρ_{ma})* used (in this case 2.87 for dolomite).
3. From that point, follow the horizontal line to the left where the porosity value is represented on the porosity scale at a fluid density (ρ_{fl}) of 1.1 In this case, the porosity is 18%.



Shaly Formation

- After the volume of shale (V_{sh}) is determined from GR log, it can be used to correct the porosity obtained from density log for shale effect.
- Hilchie (1978) suggests that for shale to significantly affect log-derived water saturations (i.e. water saturation from Archie equation), shale content must be greater than 10 to 15 %.
- Remember that, porosity is one of the Archie's Eq. parameters, therefore, porosity determined from porosity log must be corrected to shale effect.

$$Sw^n = \frac{a\,R_w}{\varphi^m\,R_t} \qquad (Archie\ Eq)$$

- The first step in shaly sand analysis is to determine the volume of shale from a gamma ray log.
- After the volume of shale (V_h) is determined, it can then be used to correct the porosity log for shale effect.
- Porosity from density log in a shaly formation is calculated using the following equation:

$$\varphi_{Dc} = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f} - V_{cl}\left(\frac{\rho_{ma} - \rho_{cl}}{\rho_{ma} - \rho_f}\right) \ldots \ldots (2)$$

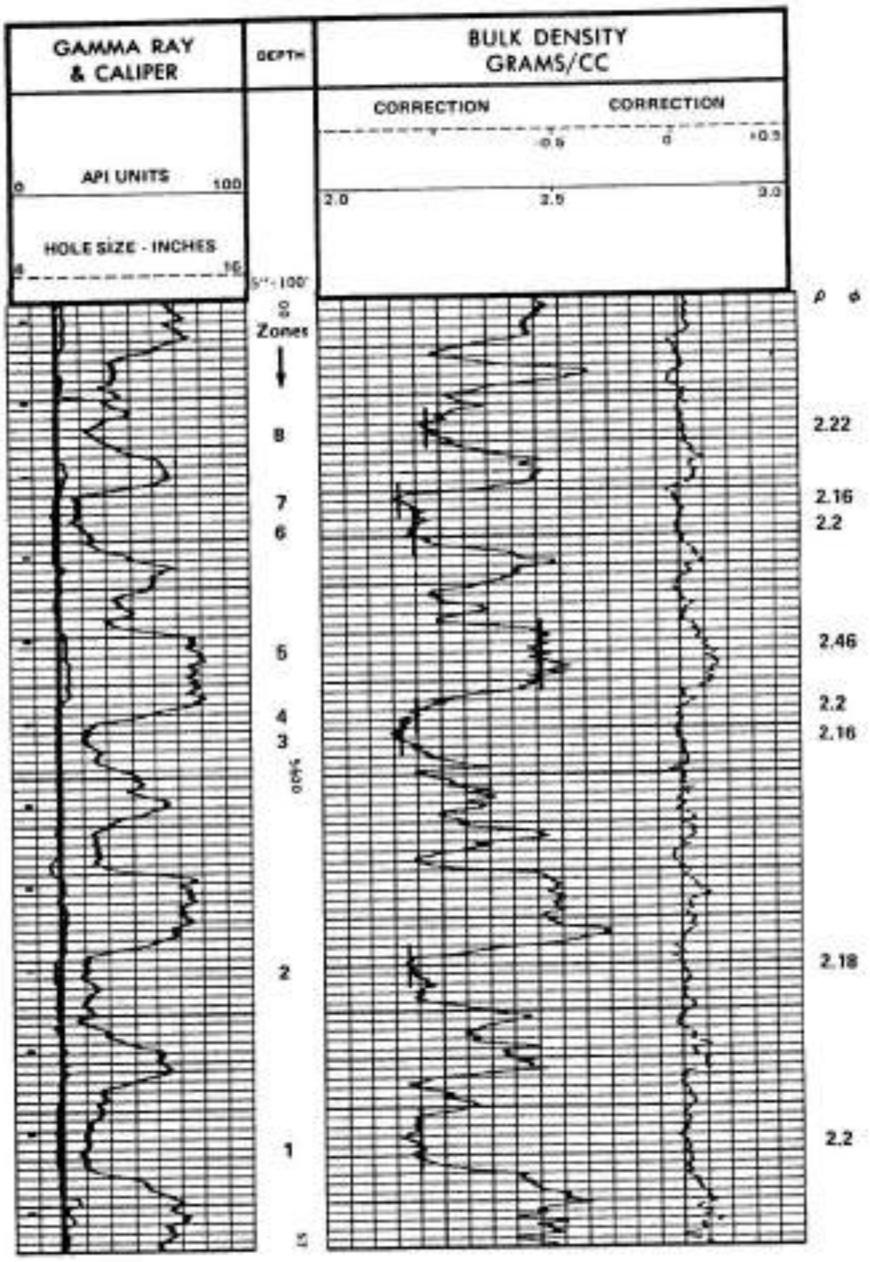
Where;

φ_{Dc}= Corrected density for clay effect.

V_{cl} = Volume of clay.

ρ_{cl} = Density value of adjacent clay formation. (i.e. at maximum GR reading). From figure of **Example….1,** GR max. at depth 9352 ft = 82 API, so $\rho_{cl} = 2.725\ gm/cc$

Example…3: calculate formation porosity at depth 5600 ft.



Steps:

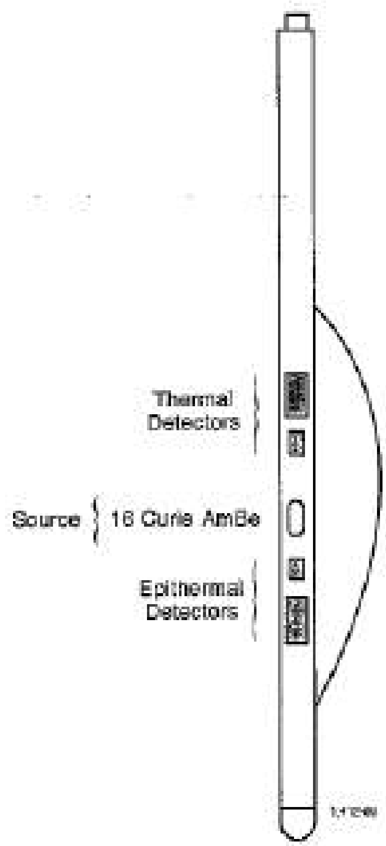
1. *Read* ρ_b *value at depth 5600 ft*
2. *Read GRmin and GRmax from GR log.*
3. *Calculate Vsh at depth 5600 ft.*
4. *Calculate porosity using chart por-5 or using Eq.(1).*
5. *If Vsh at depth 5600 ft less than 10% , porosity, go to step 4.*
6. *If Vsh at depth 5600 ft greater than 10%, read the value of* ρ_{cl} *, go to step 7.*
7. *Correct the porosity value from step(4) to shale effect using Eq(2).*

Neutron Log

- Neutron log is porosity log that measure the *hydrogen ion concentration* in a formation.
- In clean formations (i.e. shale-free) where the pores are filled with water or oil, the neutron log reflects the amount of liquid-filled porosity.

❖ **Principle**

- Neutrons are created from a *chemical source* in the neutron logging tool.
- The *chemical source* may be a mixture of *americium* and *beryllium* which will continuously emit neutrons.
- These neutrons collide with the nuclei of the formation material, and result in a neutron losing some of its energy.
- Because the hydrogen atom is almost equal in mass to the neutron, maximum energy loss occurs when the neutron collides with a hydrogen atom. Therefore, the maximum amount of energy loss is a function of a formation's hydrogen concentration.
- Because hydrogen in a porous formation is concentrated in the fluid-filled pores, energy loss can be related to the formation's porosity.



- When pores are filled with the gas, rather than oil or water, neutron porosity will be lowered. This occurs because there is less concentration of hydrogen in gas compared to oil or water. A lowering of neutron porosity by gas is called *gas effect.*

- Neutron log responses vary depending on:
  - ✓ differences in detector types.
  - ✓ spacing between source and detector.
  - ✓ lithology--i.e. sandstone, limestone. and dolomite.
- These variations in response can be compensated for by using the appropriate chart (**Neutron Porosity Equivalence Curves**).

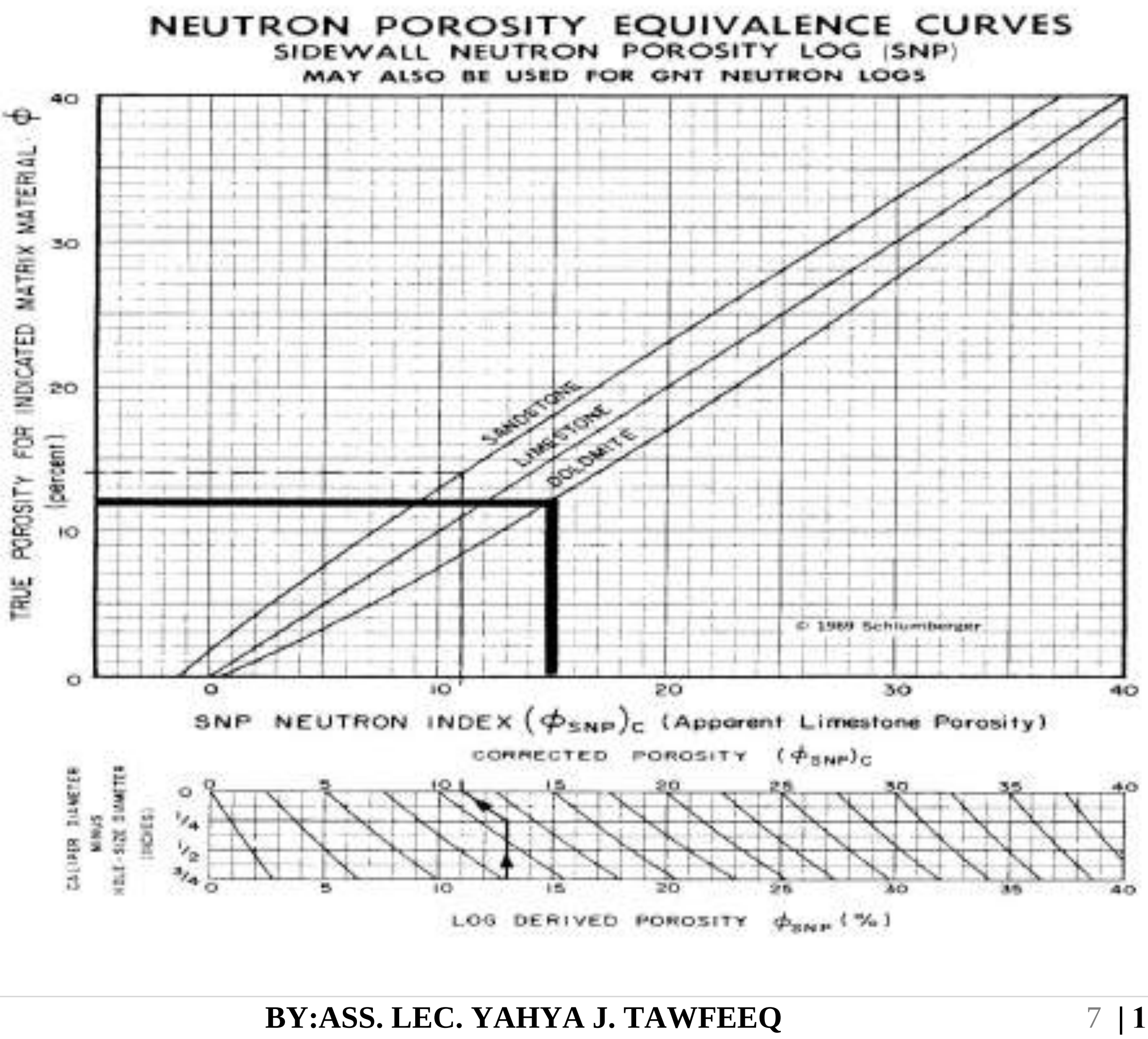
❖ CNL & SNP Log

- The first modern neutron log was the **Sidewall Neutron Log SNP**.
- The Sidewall Neutron Log has both the source and detector in a pad which is pushed against the side of the borehole.
- The most modern of the neutron logs is a **Compensated Neutron Log CNL** which has a neutron source and two detectors.
- The advantage of Compensated Neutron logs over Sidewall Neutron logs is that they are <u>less affected by borehole irregularities</u>.
- Both the Sidewall and Compensated Neutron logs can be recorded in apparent limestone, sandstone or dolomite porosity units.
- If a formation is limestone and the neutron log is recorded in apparent limestone porosity units, apparent porosity is equal to true porosity. However. when the lithology of a formation is sandstone or dolomite, apparent limestone porosity *must* be corrected to true porosity by using the appropriate chart (**Neutron Porosity Equivalence Curves**).

Example..4// Correcting of Sidewall Neutron Porosity (SNP) for lithology by using charts. **Given**: The lithology is dolomite. Also. the apparent limestone porosity is 15%. The value for apparent limestone porosity is read directly from a Sidewall Neutron Porosity Log (SNP).

Procedure:

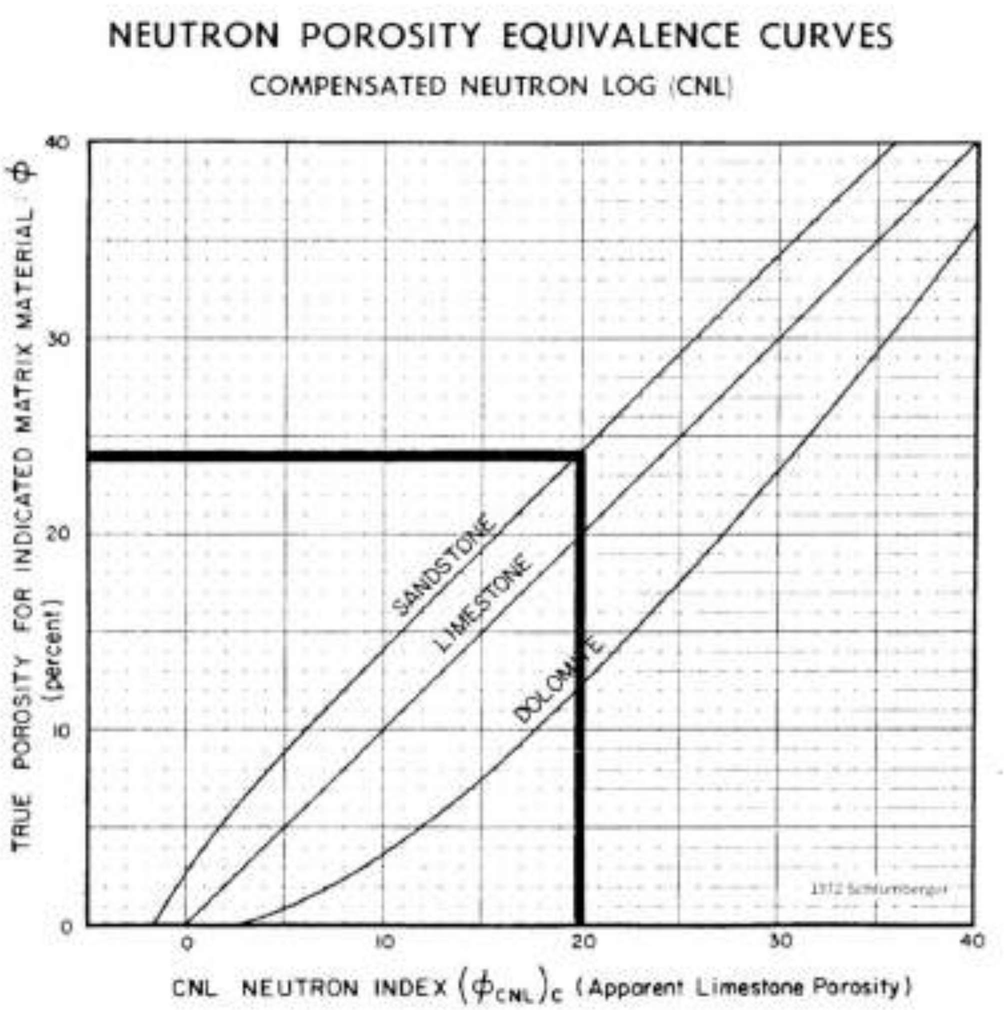
1. Find the value for apparent limestone porosity (read from an SNP log) along the scale at the bottom of the correction chart. In this example the value is 15 %.
2. Follow the value vertically until it intersects the diagonal curve representing dolomite.
3. From that point, follow the value horizontal1y to the left and read the true porosity *Φ* on the left-hand scale: 12%.



Example..5// Correcting of Compensated Neutron Porosity (CNL) for lithology by using charts. **Given**: The lithology is sandstone. Also. the apparent limestone porosity is 20%. The value for apparent limestone porosity is read directly from a Compensated Neutron Porosity (CNL).

Procedure:

1. Find the value for apparent limestone porosity (read from an CNL log) along the scale at the bottom of the correction chart. In this example the value is 20 %.
2. Follow the value vertically until it intersects the diagonal curve representing sandstone.
3. From that point, follow the value horizontal1y to the left and read the true porosity Φ on the left-hand scale: 24%.



- **In shaly formation,** the value of neutron porosity must be corrected in clay formation by the following equation;

$$\varphi_{Ncorr} = \varphi_{Nlog} - V_{clay} * \varphi_{Nclay} \dots\dots(3)$$

Where;

φ_{Ncorr} = Corrected neutron porosity.

$\varphi_{N\log}$ = Neutron log reading of the interval.

V_{clay}= Volume of clay.

φ_{Nclay} = neutron log of the adjacent clay formation.

☒ Combination Neutron-Density Log

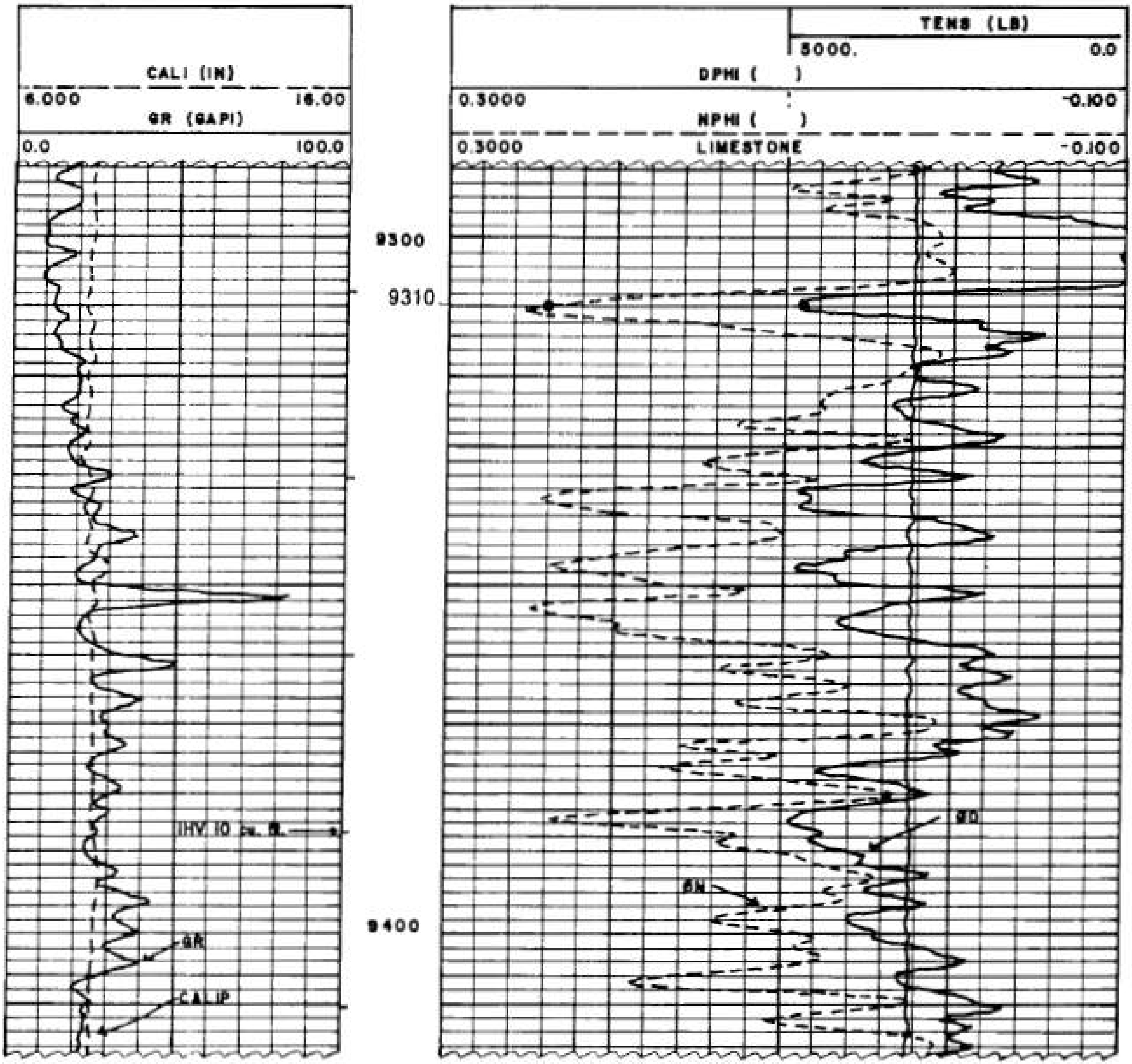
- The Combination Neutron-Density Log is a combination porosity log. Besides its use as a porosity device, it is also used to determine lithology and to detect gas-bearing zones.
- The Neutron-density Log consists of neutron and density curves recorded in tracks #2 and #3 and a caliper and gamma ray log in track # 1.
- Both the neutron and density curves are normally recorded in limestone porosity units with each division equal to either two percent or three percent porosity: however, sandstone and dolomite porosity units can also be recorded.

Example..6// Example of a Combination Neutron-Density with gamma ray log and caliper.

Track # 1--This track contains both GR log with scale (0-100) API and caliper log with scale (6 – 16) inches.

Tracks #2 and #3-Both neutron porosity and density porosity curves. The scale for both is the same, ranging from - 10% to + 30% in increments of *2%.* and is measured in limestone porosity units. On this log the density porosity is represented by a solid line and the neutron porosity is represented by a dashed line.

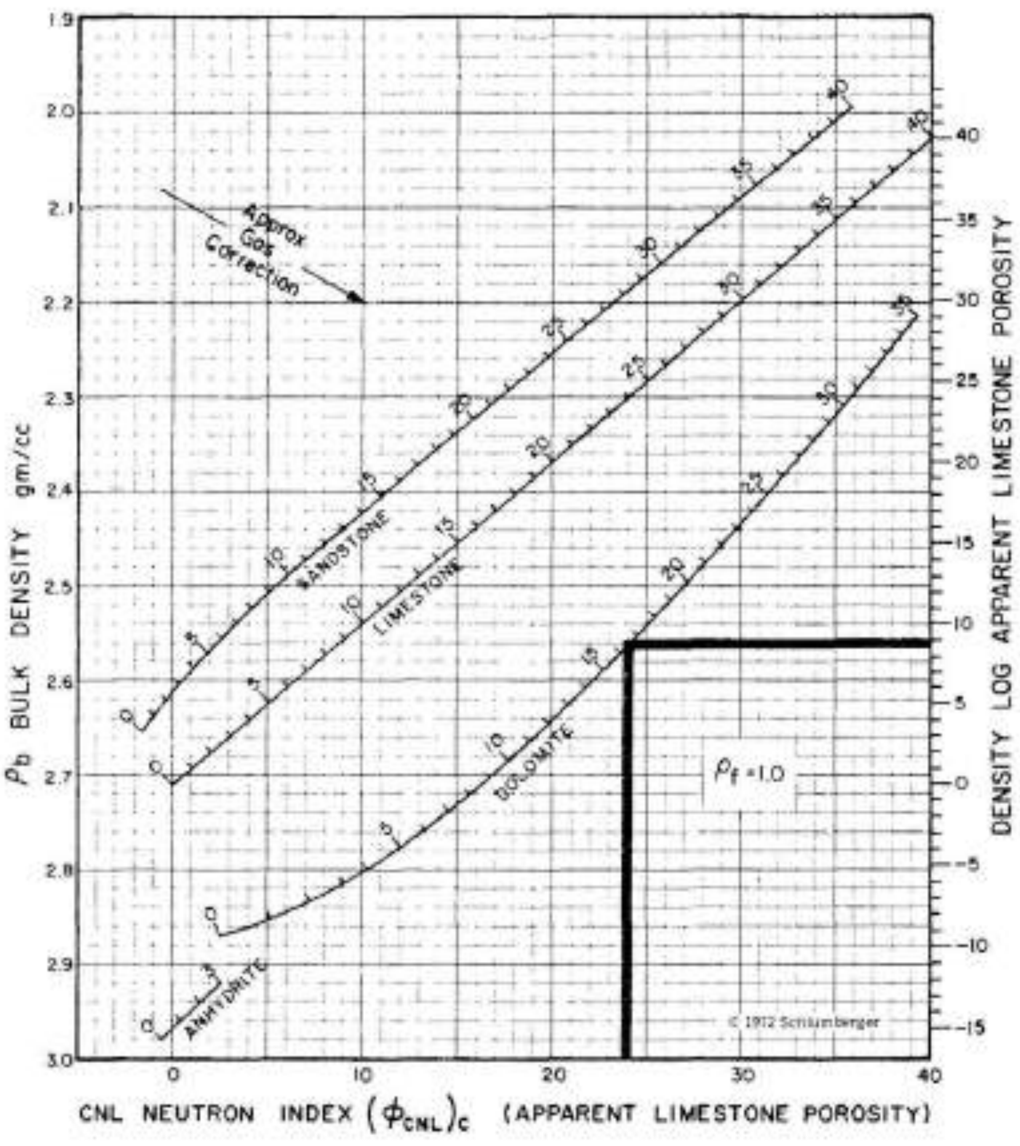
- The porosity can he obtained by first reading apparent limestone porosities from the neutron and density curves (for example: at depth 9324 ft. PHID = 3.5% and PHIN=8%), then these values are cross-plotted on a neutron-density porosity **chart** (**CP-1c , and CP-1d**) to find true porosity and lithology.


CALI (IN)
6.000
16.00
GR (GAPI)
0.0
100.0
9300
9310
9400
IHV 10
GR
CALIP
TENS (LB)
5000.
0.0
DPHI ( )
0.3000
-0.100
NPHI ( )
0.3000
LIMESTONE
-0.100
ØD
ØN

Example…7// Using Chart (CP-1c) for correcting Neutron-Density Log porosities for lithology. **Given**; ρ_f= 1 gm/cc (fresh muds) PHID =9%, PHIN=24% at depth 9310 ft.(From Example 4)

Procedure:

1. Locate the neutron porosity value on the bottom scale (24%) and find the density porosity value on the right-hand scale (9%).
2. Follow the values until they intersect on the chart. In this example, the values meet on the lithology curve for dolomite, and the intersection shows a true porosity value of 16.5%.



- Examination of the neutron-density porosity charts (CP-1d and CP-1d) reveals that the porosity values are only slightly affected by changes in lithology. Therefore, porosity from a Neutron-Density Log can be calculated *mathematically*.
- The alternate method of determining neutron-density porosity is to use the root mean square formula,

$$\varphi_{N-D} = \sqrt{\frac{\varphi_N^2 + \varphi_D^2}{2}} \ldots\ldots\ldots\ldots(4)$$

Where:

φ_{N-D}= neutron-density porosity
φ_N = neutron porosity (limestone units)
φ_D= density porosity (limestone units)

Example…8// From Example…4, at depth 9324 ft. PHID = 3.5% and PHIN=8%, if ρ_f= 1.1 gm/cc, calculate the porosity.

From cross-plot (CP-1d), indicates that the lithology is a limey dolomite and the porosity is ***6%.***

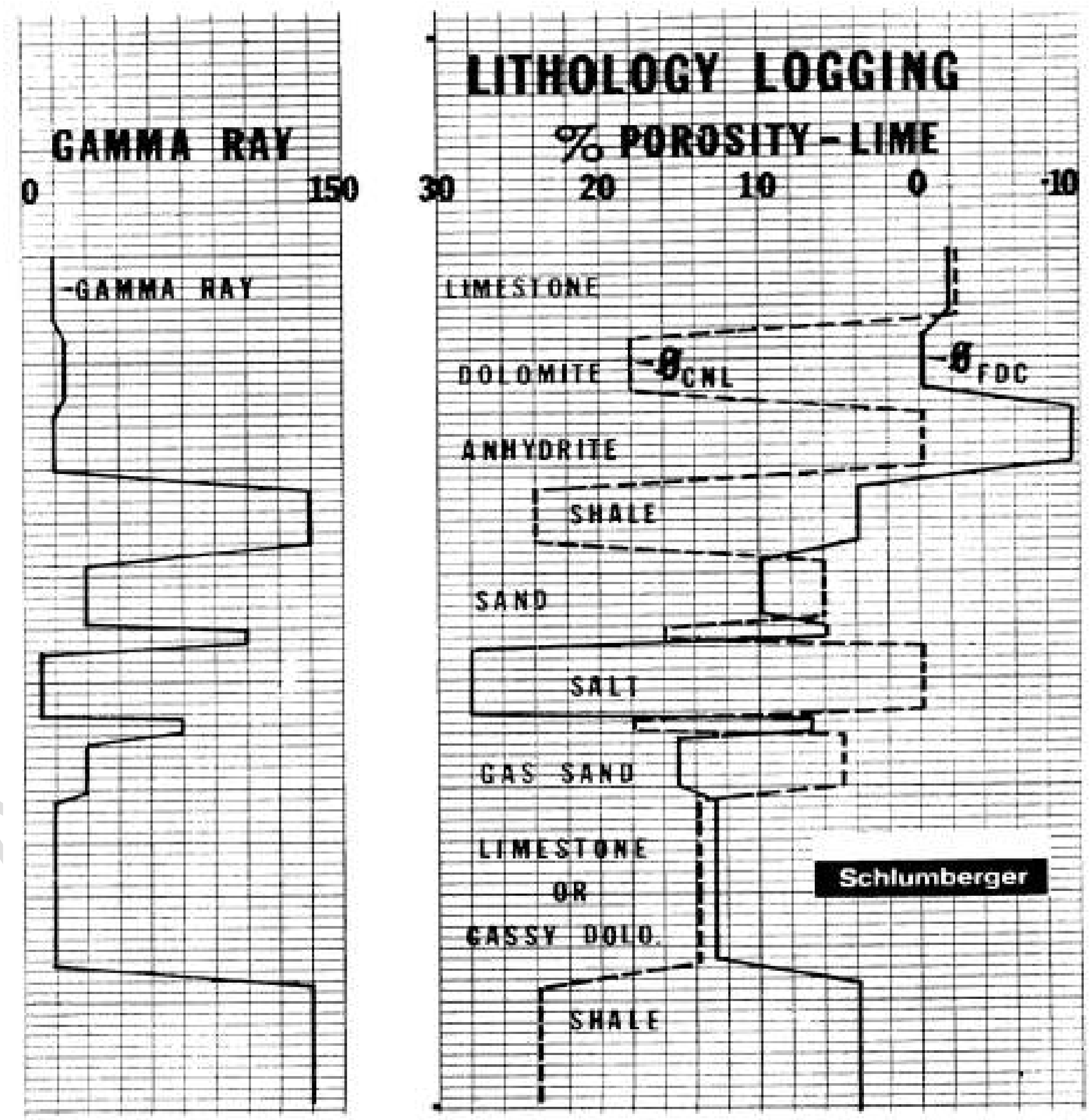
From Equation: we calculate a porosity of ***6.2%.*** This calculated porosity value compares favorably with the value obtained from the crossplot method.

- When a Neutron-Density Log records a density porosity of less than (0%) the following formula should be used to determine neutron-density porosity;

$$\varphi_{N-D} = \frac{\varphi_D + \varphi_N}{2} \ldots\ldots\ldots\ldots(5)$$

Note: Eq.5 used in Gas Bearing formations and when a Neutron-Density Log records a density porosity of less than (0%), while Eq.4 used in Oil or Water Bearing formations.

Example…9// A. Using Combination Gamma Ray Neutron-Density Log as a tool for determining lithology**.**
B. Using Combination Gamma Ray Neutron-Density Log as a tool for detection water/oil/gas bearing zone**.**

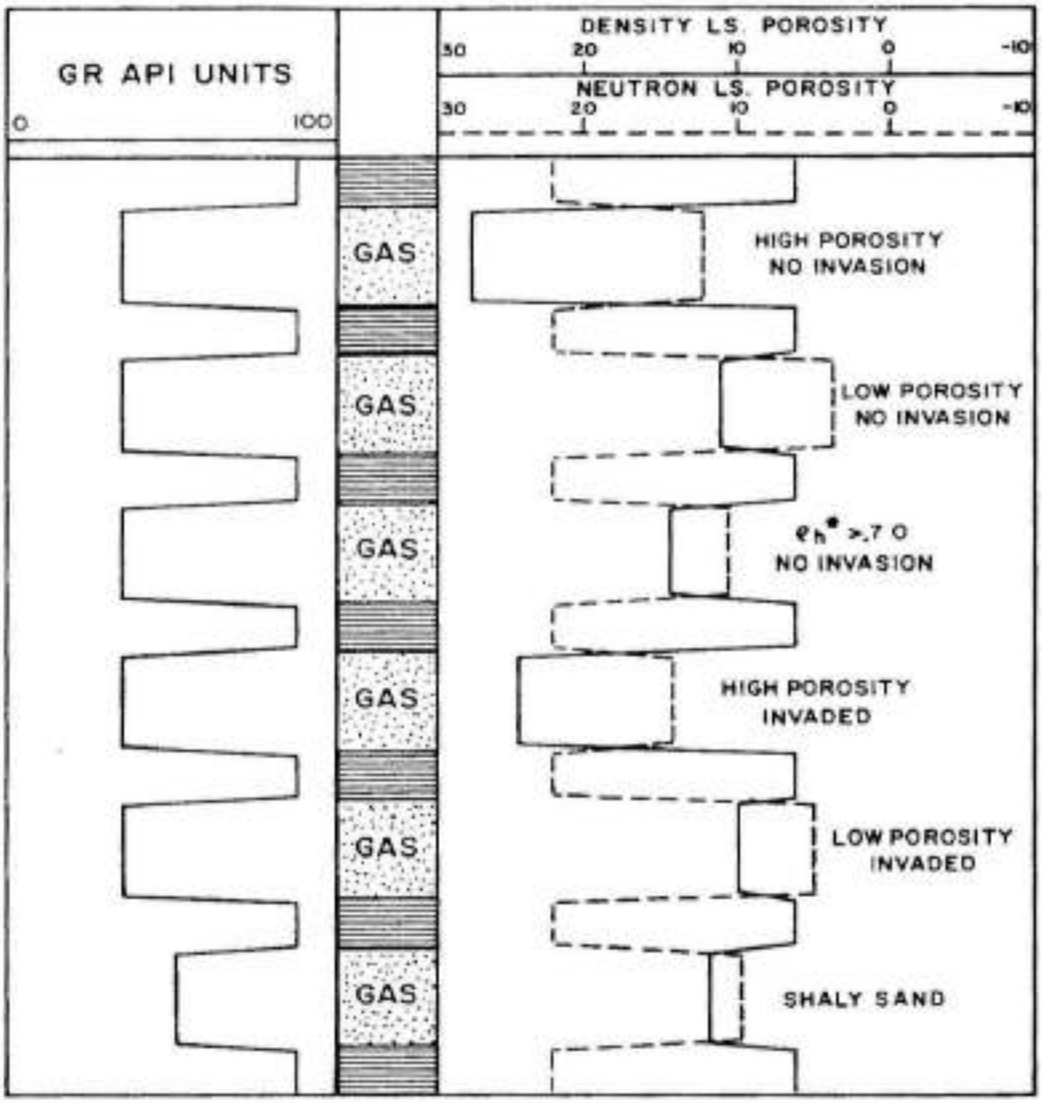


A. The relationship between log responses on the Gamma Ray Neutron-Density Log and rock type provides a powerful tool for the subsurface geology. By identifying rock type from logs, facies maps can be construct for the field.

Lithology	ϕ_N and ϕ_D
Sandstone	Neutron-Density crossover ($\phi_N > \phi_D$) of 6 to 8 porosity units
Limestone	Neutron and density curves overlay ($\phi_N \approx \phi_D$)
Dolomite	Neutron-density separation ($\phi_N < \phi_D$) of 12 to 14 porosity units
Anhydrite	Neutron porosity is greater than density porosity ($\phi_N > \phi_D$) by 14 porosity units; $\phi_N \approx 0$
Salt	Neutron porosity is slightly less than zero. Density porosity is 40 porosity units (0.40) or more. Watch for washed out hole (high Caliper) and bad density data

B. The *oil or water-bearing sand* has a density log reading of four porosity units more than the neutron log. In contrast, the gas-bearing sand has a density reading of up to 10 porosity units more than the neutron log. Where an *increase* in density porosity occurs along with a *decrease* in neutron porosity in a gas-bearing zone, it is called *gas effect.* Gas effect is created by gas in the pores. Gas in the pores causes the density log to record too high a porosity (i.e. gas is lighter than oil or water) and causes the neutron log to record too Iowa porosity (i.e. gas has a lower concentration of hydrogen atoms than oil or water). The effect of gas on the Neutron-Density Log is a very important log response because it helps the engineers to detect gas-bearing zones.

Example…10// Neutron-Density responses log responses in gas-bearing sandstones, show how gas effect varies with depth of invasion, porosity, hydrocarbon density and shale content.



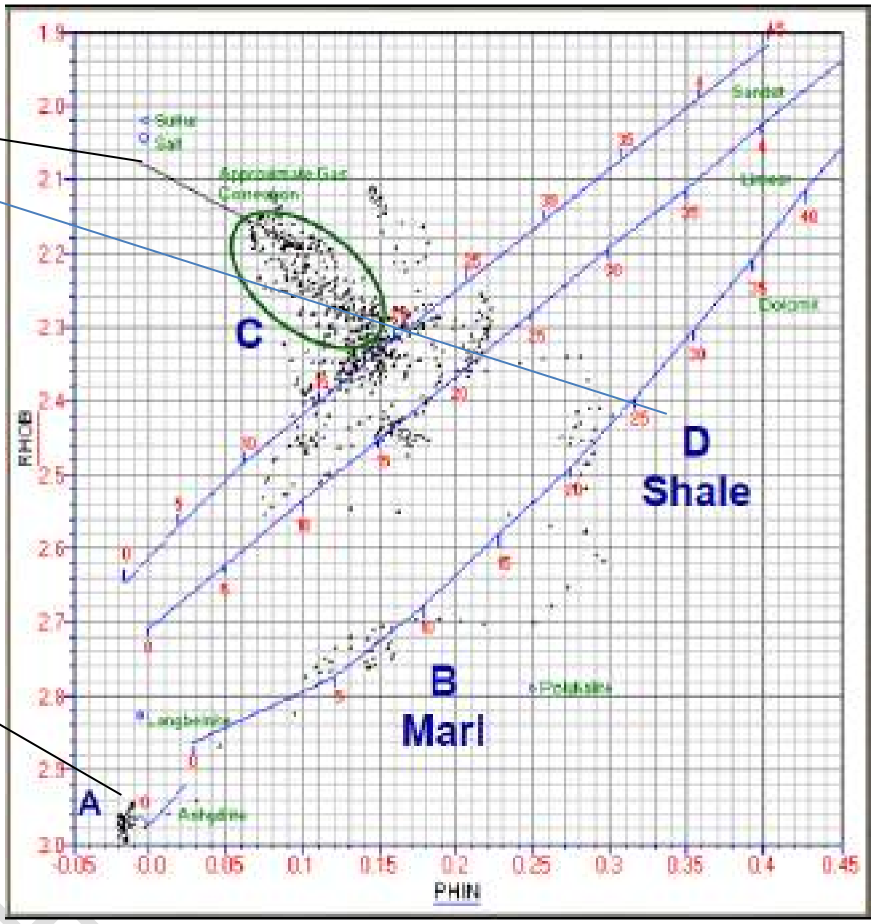
* ρh HYDROCARBON DENSITY

Gas Effect

Shale Effect

Note : sometimes shale plots like dolomite, so use GR log to differentiate

Anhydrate



- **Estimation of Hydrocarbon Density** From neutron and density logs
- ✓ **Used Chart: CHART (CP-10).**
- ✓ This chart estimate the density of the saturating hydrocarbon from a comparison of neutron and density measurements, and the hydrocarbon saturation in the portion of the rock investigated by the neutron and density logs (invaded or flushed zone).
- ✓ The neutron log (either CNL or SNP log) and the density log must be corrected for environmental effect and lithology before entry into the charts.

✓ To use, enter the appropriate chart with the ratio of neutron porosity to density porosity, and the hydrocarbon saturation. The intersection defines the hydrocarbon density in g/cm^3.

Example…9: ΦCNL_{cor} = 15 p.u. ΦD_{cor} = 25 p.u. and Sh_r = 30%

Therefore, ρh = 0.28 g/cm^3

- Schlumberger (1974) proposed an equation to compute the **total porosity** from neutron and density logs that may be expressed as:

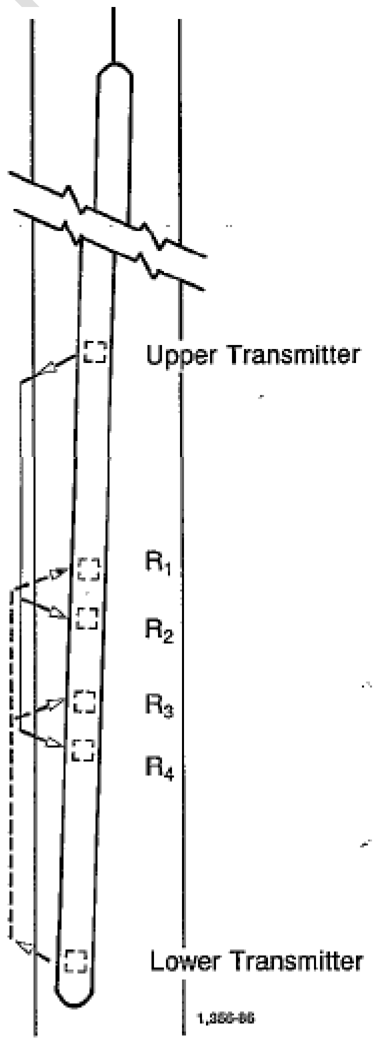
$$\varphi_{ND} = \varphi_t = \frac{\varphi_{Ncorr} + \varphi_{Dcorr}}{2} \ldots\ldots..(6)$$

- **Effective porosity** is the total porosity less the fraction of the pore space occupied by clay. In very clean sands, total porosity is equal to effective porosity**.**

$$\varphi_e = \varphi_t * (1 - V_{clay}) \ldots\ldots..(7)$$

Sonic Log

- The sonic log is a porosity log that measures interval transit time (Δt) of a compressional sound wave traveling through one foot of formation.
- The sonic log device consists of one or more sound transmitters, and two or more receivers.
- Modern sonic logs are **borehole compensated** devices (**BHC**). These devices greatly reduce the effects of borehole size variations, as well as errors due to tilt of the sonic tool.
- Interval transit time (Δt) in microseconds per foot is the reciprocal of the velocity of a compressional sound wave in feet per second.
- Interval transit time (Δt) is recorded in tracks #2 and #3. A sonic derived porosity curve is sometimes recorded in tracks #2 and #3, along with the Δt curve. Track # 1 contains a caliper log and a gamma ray log or an SP log.
- The interval transit time (Δt) is dependent upon both lithology and porosity. Therefore a formation's matrix velocity must be known to derive sonic porosity either by chart (**CHART Por-3**) or by the following formula (*Wyllie et.al.* 1958, equitation):



$$\varphi s = \frac{\Delta t_{log} - \Delta t_{ma}}{\Delta t_{fl} - \Delta t_{ma}} \ldots\ldots\ldots(8)$$

Where;

φs = Sonic (acoustic) porosity = primary porosity

Δt_{log} = Sonic travel time from the log.

Δt_{ma} = Matrix travel time.

Lithology	Δt_{ma} (µsec/ft)	Lithology	Δt_{ma} (µsec/ft)
limestone	47.6	Salt	67
Dolomite	43.5	Anhydrite	50
Sandstone	55.5		

Δt_{fl} =is the interval transit time in the fluid within the formation. [For fresh water mud = 189 (µsec/ft) and for salt-water mud = 185 (µsec/ft)].

- The Wyllie et al (1958) formula for calculating sonic porosity can be used to determine porosity in consolidated sandstones and carbonates formations.
- When sonic log is used to determine porosity in unconsolidated sands, an empirical compaction factor or C_p should be added to the Wyllie et al (1958) equation:

$$\varphi s = \frac{\Delta t_{log} - \Delta t_{ma}}{\Delta t_{fl} - \Delta t_{ma}} \cdot \frac{1}{C_P} \ldots \ldots \ldots (9)$$

C_P = The compaction factor is obtained from the following formula:

$$C_P = \frac{\Delta t_{sh}}{100} \ldots \ldots \ldots \ldots (10)$$

Where:

Cp = compaction factor

Δt_{sh} = interval transit time for adjacent shale.

Note: Eq.9 used only when $\Delta t_{sh} > 100$ (µsec/ft).

- When vuggy or fracture porosity are calculated by the Wyllie formula, porosity values *will be too low*. This will happen because the sonic log only records matrix porosity rather than vuggy or fracture secondary porosity.
- The percentage of vuggy or fracture secondary porosity can be calculated by subtracting *sonic porosity* from *total porosity.* Total porosity values are obtained from density or neutron log.
- The percentage of secondary porosity, called-SPI or secondary porosity index, can be a useful mapping parameter in carbonate exploration.

$$SPI = \varphi_s - \varphi_t \dots\dots\dots\dots (11)$$

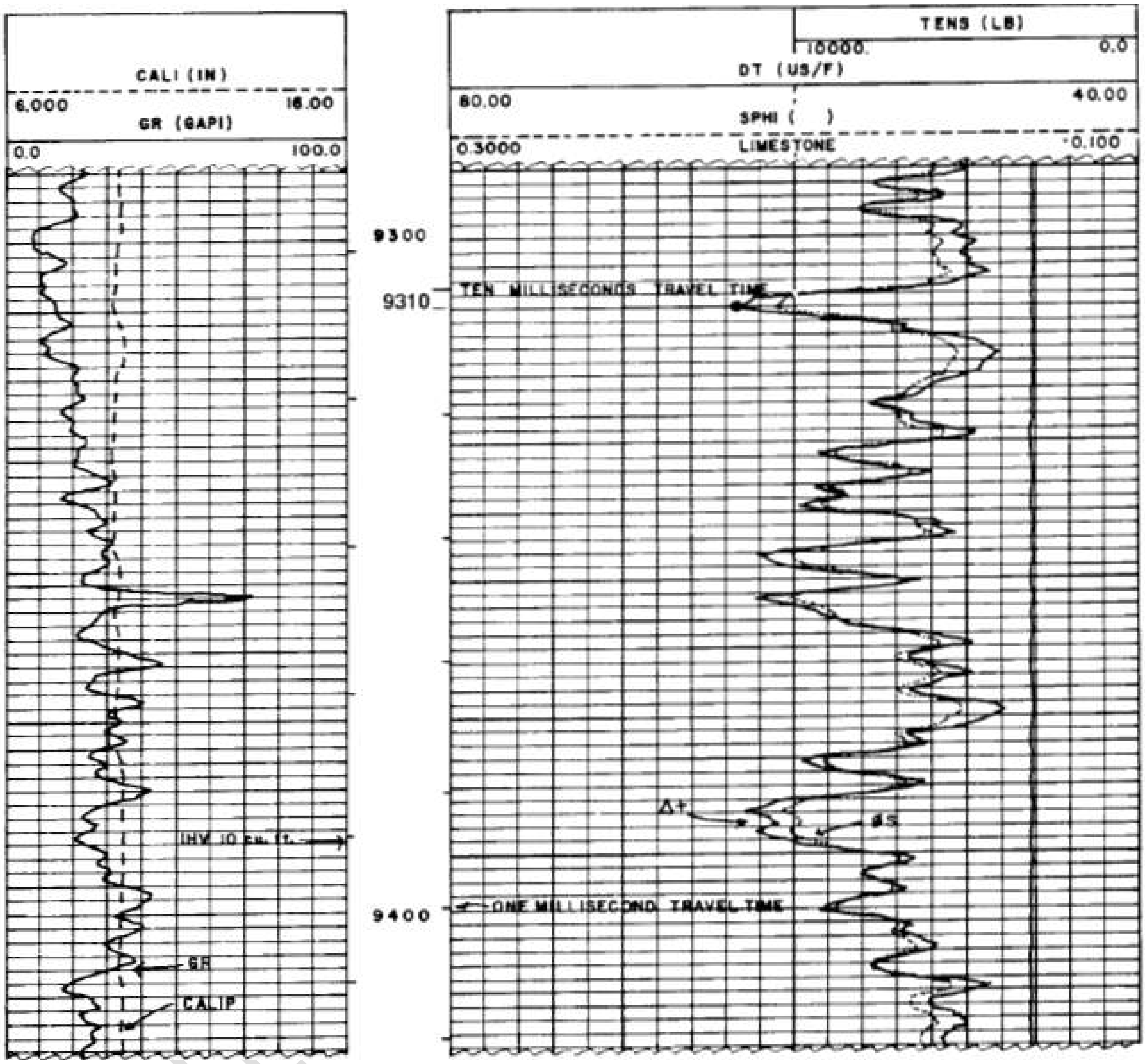
- The interval transit time (Δt) of a formation is increased due to the presence of hydrocarbons (i.e. *hydrocarbon effect).* If the effect of hydrocarbons is not corrected, the sonic derived porosity *will be too high*. The following empirical corrections suggested for hydrocarbons effect:

$$\varphi = \varphi_{sonic} * 0.7 \dots\dots\dots (12) \qquad gas$$

$$\varphi = \varphi_{sonic} * 0.9 \dots\dots\dots (13) \qquad oil$$

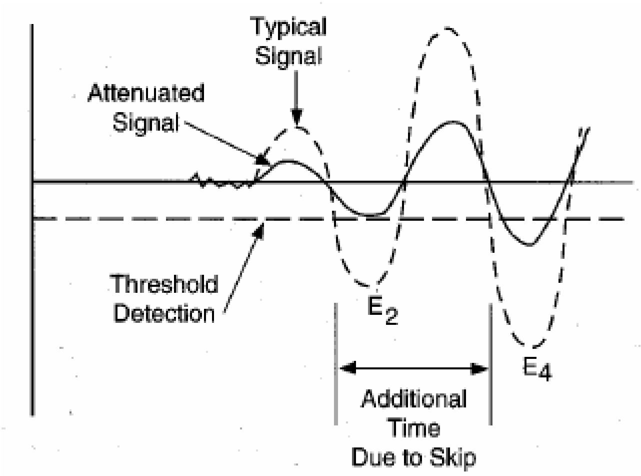
Example…..11// sonic log with gamma ray log and caliper.

- **Track # 1**--This track contains both GR log with scale (0-100) API and caliper log with scale (6 – 16) inches.
- **Tracks #2 and #3**-Both the interval transit time (Δt) scale and the porosity scale are shown in this track. Sonic log interval transit time (Δt) is represented by a solid line, on a scale ranging from 40 to 80 *µsec/ft.* increasing from *right-to-left.*
- The sonic porosity measurement (limestone matrix) is shown by a dashed line, on a scale ranging from --10% to + 30% porosity increasing from *right-to-left.*
- At the sample depth used in Figure below (9310 ft), read a sonic log interval transit time (Δt) value of 63 µsec/ft.

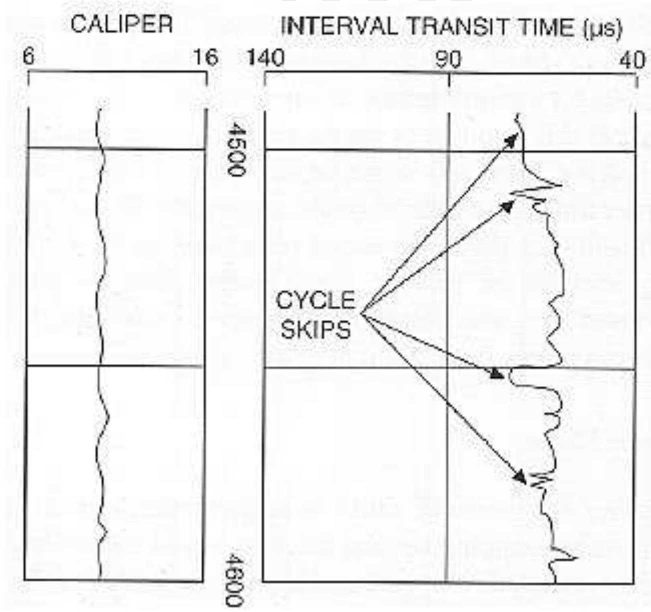

CALI (IN)
6.000 16.00
GR (GAPI)
0.0 100.0
IHV 10 cu. ft.
GR
CALIP
9300
9310
9400
TENS (LB)
10000. 0.0
DT (US/F)
80.00 40.00
SPHI ( )
0.3000 LIMESTONE -0.100
TEN MILLISECONDS TRAVEL TIME
Δt
ØS
ONE MILLISECOND TRAVEL TIME

Cycle Skipping.

Cause: Dampening of first arrival at far receiver



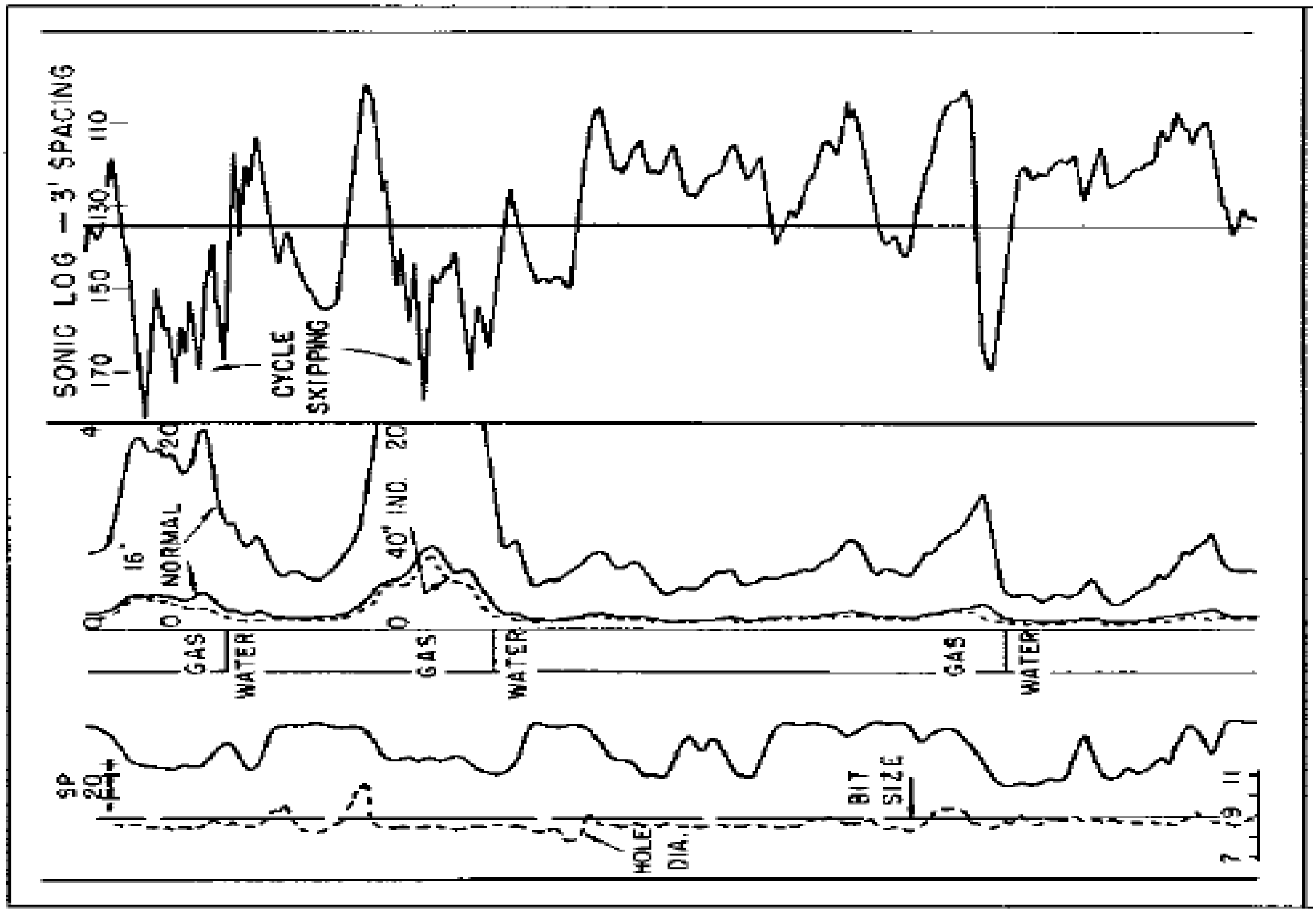
Effect: Sonic curve shows spiking or an abrupt change towards a higher travel time.

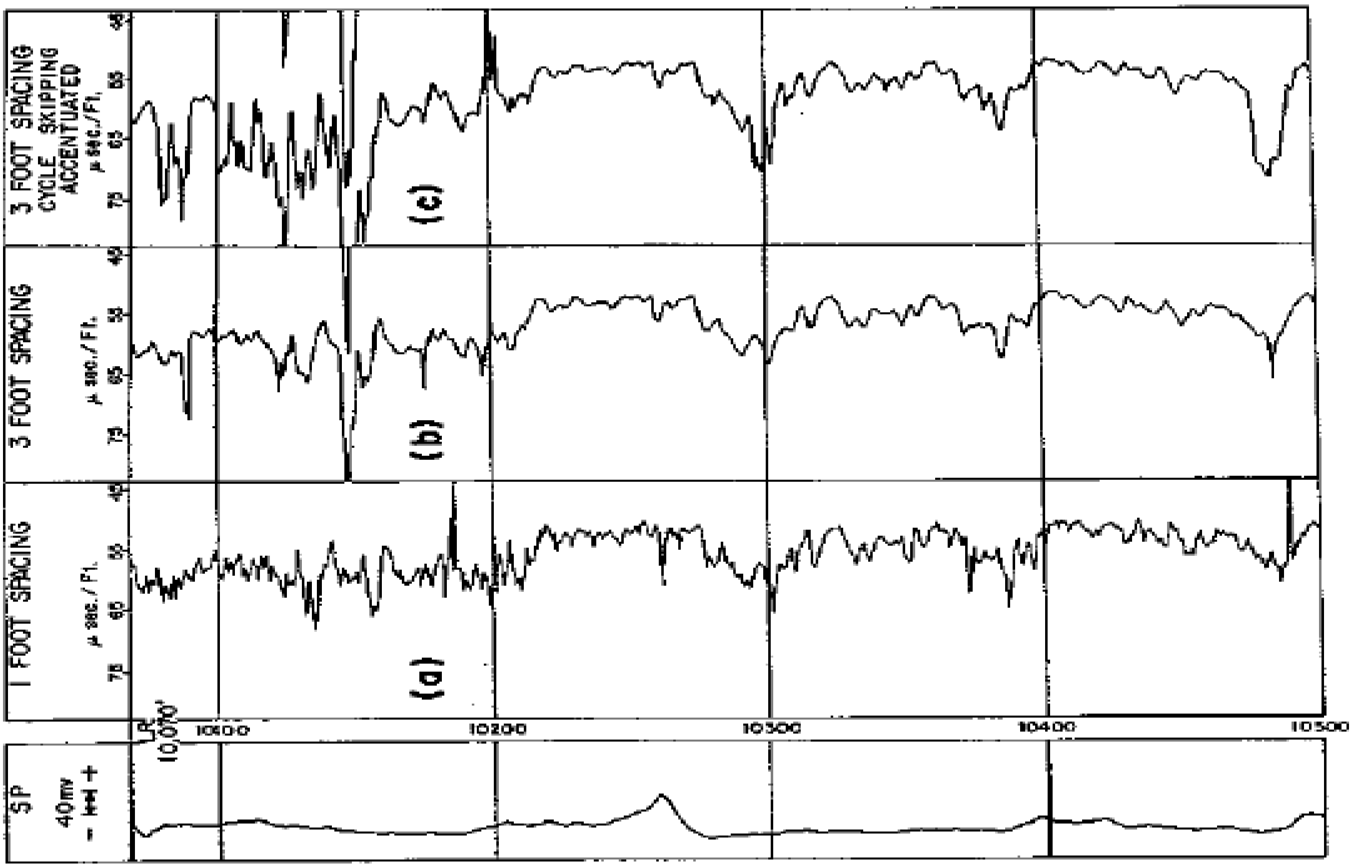


Occurs in: (1) series of thin beds of different velocities; (2) gas bearing zone; (3)Unconsolidated formations; (4)fractured formations.

تحدث هذه الظاهرة نتيجة ضعف الموجة الأنكسارية عند وصولها جهاز الألتقاط الثاني فلا تسجل الموجة وأنما تسجل الموجات الأنكسارية الثانوية وهذا تأخير في وصول الموجة بسبب زيادة مفاجئة في تسجيل الزمن (t) .ضعف الموجة الأنكسارية الأولية يعود الى عوامل عديدة منها وجود طبقات غير متماسكة او وجود طبقات كلسية متشققة

Fig. 1 shows an example of cycle skipping. **Fig.2a** shows an example of cycle skipping associated with fractured formations. **Fig.2b** shows cycle skipping in the interval of 10090 to 10150 ft.


SONIC LOG — 3' SPACING
110
130
150
170
CYCLE
SKIPPING
16" NORMAL
40" IND.
GAS
WATER
GAS
WATER
GAS
WATER
SP
20
BIT SIZE
HOLE DIA.
7
9
11


3 FOOT SPACING CYCLE SKIPPING ACCENTUATED
μ sec./Ft.
(c)
3 FOOT SPACING
μ sec./Ft.
(b)
1 FOOT SPACING
μ sec./Ft.
(a)
10,070'
10100
10200
10300
10400
10500
SP
40mv