KASDI MERBAH- OUARGLA UNIVERSITY

FACULTY OF HYDROCARBONS, RENEWABLE ENERGIES AND EARTH AND
UNIVERSE SCIENCES

DEPARTMENT OF EARTH AND UNIVERSE SCIENCE

Academic Master Thesis

Field: Hydrocarbons
Sector: Production
Speciality: Professional Production

THEME

Analysis of reservoir petro-physical parameters by PNL Saturation Log

Presented by:

BENRAS Fethi

DEKKICHE Moustapha

DOUADI Med Noureddine

In front of the jury:

President: Dr. CHETTI Djamel eddine	MAA Univ. Ouargla
Supervisor: Prof. ZERROUKI Ali Ahmed	Pr Univ. Ouargla
Examiner: Dr. SIDROUHOU Elhadj Mohamed	MAA Univ. Ouargla

University year: 2021/2022.

Thanks

First of all, we would like to thank Allah, the merciful and the merciful for having given us the strength and the patience to carry out this modest work.

Our gratitude and sincere thanks go to our dear supervisor ***Prof. ZERROUKI Ali Ahmed*** *for guiding us throughout the realization of this work.*

Also we address a big thanks to , ***Dr. Chetti Djamel eddine****,* ***Dr. SIDROUHOU Elhadj Mohammed , Mr. BENSASSI Abdelltif****, who helped us a lot in the realization of this work in good conditions.*

Ultimately, we would like to thank everyone who has participated, directly or indirectly, from near or far, in the success of this work for which we have devoted so much while also putting our hearts into it.

Summary

Figures list

Abreviations list

.

GR : Gamma Ray

HBK : Haoud Berkaoui

K : Permeability

QH : Quartzite d'El Hamra

Rt : Formation resistivity (Ω.m)

Rw : water resistivity (Ω.m)

Sw, So: Fluid saturation

Vp : Pore volume (cm^3)

Vs : Solid Volume (cm^3)

Vsh : Volume shale (%)

Vt : Total volume (cm^3)

Ø: Porosity

Øt: Total porosity (%)

Øu: Useful porosity (%)

Unités :

API : American Petroleum Institute

°C : Celsius degree

D : Darcy **Ft** : feet **gr** : Gramme

Khz : kilo hertz

Km: kilometer **m**: metre

mD : mili darcy

Psi: Pound per Square Inch

Ω : Ohm

الملخص

الغرض من هذا العمل هو التعريف بالأداة المستخدمة وملخص المعلومات التي توفرها لنا في المجال وكيفية تحويلها إلى نتائج تحليلية. حتى نتمكن من التدخل في البئر بطريقة صحيحة.

كان التحليل لتقييم وحساب تشبع الماء ومقارنته مع تشبع الماء الأولي من بيانات البئر المفتوح أثناء الحفر (Open hole) من أجل تقييم ورصد تغير التلامس الهيدروكربونات مع الماء باستخدام أدوات RMT . تظهر النتائج مغلف سيغما الديناميكي المغطى بمنحنى سيجما المستخدم لتعريف الهيدروكربون. يحدد موقع منحنى سيجما (SGFC) بين خط الماء (الأزرق) وخط الهيدروكربون (الأخضر) تشبع الماء.

Abstract

The purpose of this work was to introduce the tool used, and the summary of the information it gives us in the field, and the way to convert it into analytical results. so we can intervene in the well in a good way.

The analysis was to evaluate and calculate the water saturation and compare it with the initial water saturation from open hole data in order to evaluate and monitor the change of the hydrocarbon / water contact using RMT tools. The results show the Dynamic Sigma Envelope overlaid with the Sigma curve used as hydrocarbon identification. The position of the Sigma (SGFC) curve between the water Line (blue) and hydrocarbon Line (green) determines the water saturation.

Résumé

Le but de ce travail était de présenter l'outil utilisé, et la synthèse des informations qu'il nous donne sur le terrain, et la manière de les convertir en résultats analytiques. afin que nous puissions intervenir dans le puits d'une bonne manière.

L'analyse consistait à évaluer et à calculer la saturation en eau et à la comparer à la saturation en eau initiale à partir des données de forage ouvert afin d'évaluer et de surveiller l'évolution du contact hydrocarbure / eau à l'aide des outils RMT. Les résultats montrent l'enveloppe Sigma dynamique superposée à la courbe Sigma utilisée comme identification des hydrocarbures. La position de la courbe Sigma (SGFC) entre la ligne d'eau (bleue) et la ligne d'hydrocarbure (verte) détermine la saturation en eau.

General introduction

General introduction

Engineers typically required an estimation of the rock properties in order to compute oil reserves, production capacity, and recovery efficiency of the reservoir. The rock properties which are called petrophysical properties are very important because the amount of hydrocarbon present in a reservoir is a function of its petrophysical properties, and these properties include porosity, permeability and fluid saturation. These properties and their relationships are used to identify and evaluate: hydrocarbon reservoir, hydrocarbon sources, seals, and aquifers. The reservoir and fluid characteristics to be determined are: thickness (bed boundaries), Lithology (rock type), Porosity, Fluid saturations and pressures, Fluid identification and characterization, Permeability (absolute) and Fractional flow (oil, gas, water). It is easy to define these characteristics and to appreciate their part in the assessment of reserves. The difficult part comes in determining their actual value at a level of certainty needed to make economic decisions leading to development and production. The best source of petrophysical properties data is the well logging technique, which is the primary source of petrophysical evaluation of reservoirs in the oil and gas wells. Well logging define as the technique of making petrophysical properties measurements in the subsurface earth formations through the drilled borehole, in order to determine both the physical and chemical properties of rocks and the fluid its contain.

Well logging is the means by which physical properties of subsurface earth formations are measured in situ. The most important, and the most technically challenging, application of well logging is to the characterization of hydrocarbon reservoirs. Oil and gas are found up to 10 km underground in beds of sedimentary or other porous rock. Only part of a typical sedimentary rock is solid mineral matter. The pore space, which accounts for up to 30% of the volume, can be filled by combinations of oil, water, or natural gas. Well logging is directed toward understanding these fluids and their relationship to the solid mineral matrix. A large variety of electromagnetic, acoustic, and nuclear borehole instruments are used for various purposes. Each technique has drawbacks and limitations, and no one logging device (“tool”) is adequate to give a complete description of an earth formation (2, 3). The borehole environment is unusually harsh. Boreholes drilled to extract oil or gas are typically 20 cm in diameter and 1–10 km deep. The geothermal gradient of the earth can give rise to temperatures of 175°C or more and pressures that range to 140 MPa. Borehole logging tools must not only survive but must make quantitative measurements under these conditions. The requirements on electronic components exceed military specifications by a wide margin.

During well logging operations, the drilling rig is idle. Since day rates range to more than $100,000[20], oil companies wish to minimize logging time. This poses a significant constraint on practical logging operations. Typically, data might be required over a depth interval of hundreds of meters, with a vertical resolution of 50 cm. To be economically viable.

Chapter I:
Bibliographic synthesis

Introduction:

The study of the physical properties of rocks in order to evaluate whether or not they may be used to build a reservoir is known as petro-physics.

- That she has a specific amount of storage space available to her. This attribute is characterized by porosity.
- That fluids are able to pass through it. Permeability is one of this property's characteristics.
- It contains a sufficient number of hydrocarbons in an adequate concentration.

The saturations, as well as the impregnated volume, have a role here.

Carotte measures and diagraphies are the most frequent approaches for determining the features of reservoir roches.

1. Reservoir physico-chemical parameters:

1-1. The Porosity:

➢ Definition:

Porosity or void fraction is a measure of the void spaces in a material, and is a fraction of the volume of voids over the total volume, between 0 and 1, or as a percentage between 0% and 100%. Strictly speaking, some tests measure the "accessible void", the total amount of void space accessible from the surface (cf. closed-cell foam).

There are many ways to test porosity in a substance or part, such as industrial CT scanning.

The term porosity is used in multiple fields including pharmaceutics, ceramics, metallurgy, materials, manufacturing, petrophysics, hydrology, earth sciences, soil mechanics, and engineering.

Used in geology, hydrogeology, soil science, and building science, the porosity of a porous medium (such as rock or sediment) describes the fraction of void space in the material, where the void may contain, for example, air or water. It is defined by the ratio: $\emptyset = \frac{V_V}{V_T}$

where V_V is the volume of void-space (such as fluids) and V_T is the total or bulk volume of material, including the solid and void components. Both the mathematical symbols $\emptyset$ and n are used to denote porosity. [1]

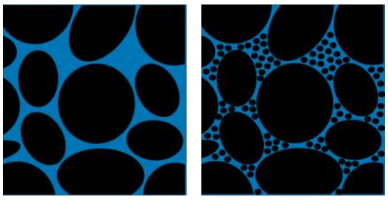


Figure I-01: The Various Volumes in the Rock

➢ The many types of porosity :

• Utility porosity (Φu):

The ratio of the volume of interconnected pores to the overall volume of the échantillon is the useful porosity (also known as connected or effective porosity).

• Residuelle porosity (Φr):

Introduction Because there are only a few unconnected pores. Intra-cristallin vacuums (fluid or gaseous inclusions, for example) or inter-cristallin vacuums connected to the rest of the porous network via too narrow access could be the culprits. The usable porosity is typically between 20% and 25% of the total porosity.

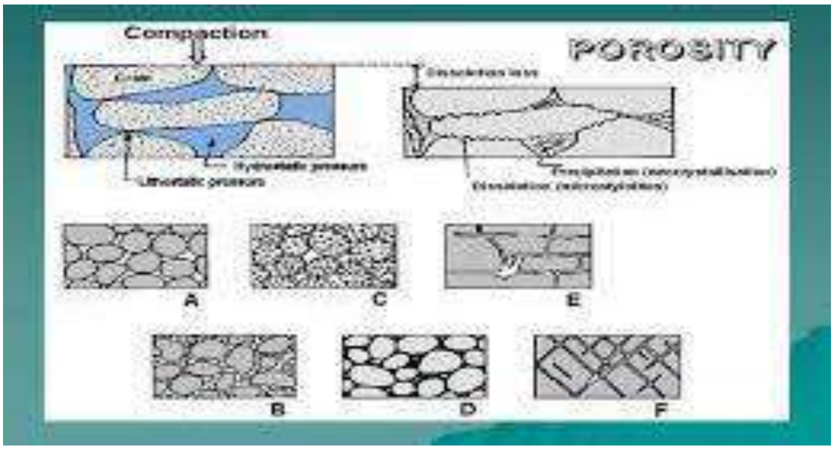


Figure I-02: the various types of porosity

• The total porosity**(Φt)**

Given by Φt = Φu+Φr

1-2. Permeability (k):

➢ I.1.2.1. Definition:

Permeability is a property of porous materials that is an indication of the ability for fluids (gas or liquid) to flow through them. Fluids can more easily flow through a material with high permeability than one with low permeability.[2] The permeability of a medium is related to the porosity, but also to the shapes of the pores in the medium and their level of connectedness. Fluid flows can also be influenced in different lithological settings by brittle deformation of rocks in fault zones; the mechanisms by which this occurs are the subject of fault zone hydrogeology.[3] Permeability is also affected by the pressure inside a material.

Permeability. Q: I have a fluid evaporation debt. (cm^3/s)

Permeability (K) (mD).

μ: the fluid's viscosity (Cp) dP/dx: the pressure drop along the entire length of the échantillon. (pa/cm)

A: Surface of the cylindrical sample.

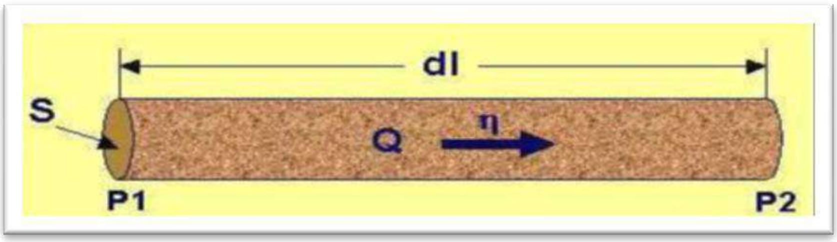


Figure I-03: Darcy's experiment

➢ Types of permeability:

• Absolute permeability:

It is the permeability measured when only one fluid is present, such as gas, water, or oil.

• **Effective permeability**: The outcome of measuring the permeability with a second fluid when a fluid exists in the porosity of the rock (at a saturation other than the minimal irreducible saturation) is known as the effective permeability for that fluid.

• Relative permeability:

It's the proportion of effective to specific permeability. The relative permeability of a fluid fluctuates as a direct function of that fluid's saturation in the rock, and is measured as the percentage displacement of one fluid compared to the other.[4]

The absolute permeability of a rock is determined by the direction in which it is viewed (rocks are not isotropic). The horizontal permeabilities Kh (parallel flow and towards the wells) and vertical permeabilities Kv are defined in particular (problems of segregation of fluids of different densities). In general, the Kv are substantially lower than the Kh as a result of stratification (ratio of 1 to 10 for example).

In practice, at least two fluids (water + hydrocarbons) are always present in hydrocarbon deposits. Darcy's law then allows us to define effective permeability for each of the fluids.

For the first and second fluids:

$$Q_1 = A . \frac{K1}{\mu 1} . \frac{dP1}{dX} \quad \rightarrow \text{I-1}$$

$$Q_2 = A . \frac{K2}{\mu 2} . \frac{dP2}{dX} \quad \rightarrow \text{I-2}$$

The pressures in fluid 1 and 2 being different due to capillary phenomena. We mainly use the notion of relative permeability, for example:

Relative oil permeability = $\frac{\textbf{Effective permeability of oil}}{Rock\ permeability}$

These relative permeabilities depend on the rock element considered and the proportions of the fluids present. [1]

- **Darcy's law:**

The ability of a rock to allow a saturated fluid to move through its pores is referred to as intrinsic or absolute permeability. Darcy's law, an experimental law, can be used to quantify it.

Consider a sample of length dx and section A, saturated with a fluid of dynamic viscosity U, crossed horizontally by a flow rate Q (measured under the conditions of slice dx); in steady state, the upstream pressure is P, the downstream pressure is P-dP.

sealing is done on the side faces. If there is no reaction of the fluid with the rock, which is the general case, we have: the equation of I.1

K, so-called permeability coefficient, is independent of the fluid considered as a first approximation. It is the absolute or intrinsic permeability of the sample in the direction considered. Permeability has the dimension of a surface. In the international SI system; we have K in square meters:

- si : $Q_{(m^3/s)} = k_{m^2} . \frac{A_{m^2}}{\mu_{Pa.s}} \frac{dP_{pa}}{dX_m} \quad \rightarrow \text{I-3}$

Practical system (commonly used in the profession):

- si : $Q_{(cm^3/s)} = k_{mD} \quad . \frac{A_{Cm^2}}{\mu_{CP}} \frac{dP_{pa}}{dX_{Cm}} \quad \rightarrow \text{I-4}$

The usual unit is the milli darcy: $1mD = 0{,}987 \times 10^{-15}\ m^2 \quad \rightarrow \text{I-5}$

In The range of permeabilities encountered is very wide; it varies from 0.1 mD up to more than 10 D. the following terms can be used to specify the value of the permeability:

1mD = 10 $^{-15}m^2$, 1darcy = 1 1mD = 1(μm^2)

k< 1 mD: very low

1 to 10 mD: low

10 to 50 mD: mediocre

50 to 200 mD: average

200 to 500 mD: good

>500 mD: excellent.

Note: In a porous medium, the permeability generally varies with the direction of flow[4]

1-3. Saturation (S):

It is essential to know the nature of the fluids which occupy the pores of the rock. The relative amount of water, oil and gas in the pores of a rock, usually as a percentage of volume. [5]

Water saturation $S_W = \frac{V_w}{V_p}$ (= S_w (water)) → I-6

Oil saturation $S_o = \frac{V_o}{V_p}$ (= S_o (oil)) → I-7

Gas saturation $S_g = \frac{V_g}{V_p}$ (= S_g (gas)) →I-8

We define as follows:

With : $S_w + S_o + S_g = 1$

During the migration of hydrocarbons the displacement of the overlying water has never been complete. Indeed, the permeability to a fluid becomes zero when the saturation in this fluid becomes too low: this threshold is called the irreducible saturation (for the fluid considered). As a result, there will always be water in a deposit, called pore water. This is the consequence of capillary phenomena linked to the exiguity of the pores: water is a "wetting" fluid which spreads over solid surfaces and will remain trapped in the smallest pores.

Common values for pore water saturation are: 10% <Swi< 35%.

Saturation measurements come mainly from logs.[6]

2. Measuring the reservoir's petrophysical properties:

2-1. Porosity measurements:

The porosity is influenced by the size of the grains, their arrangement, their shapes, the cement and the compaction. There are two measurement methods: I.2.1.1. Core measurement: Two of the three quantities Vp, Vs and Vt are therefore determined on a sample, generally of simple geometric shape.

The most classic sample (Plug) is cylindrical; its section is around 4 to 12 cm2 and its length varies between 2 and 5 cm.

The Plugs are first washed and dried. The measuring devices are coupled to microcomputers that allow rapid results to be obtained [4]

2-1-1. Determination of Vt:

- **Measurement by immersion in mercury:**

The apparatus comprises a frame C linked by a rod to a float F which is immersed in a beaker containing mercury. A marker index R is fixed on the stem.

A tray B is hung under the frame.

-First measurement: the sample is placed on plate B with a weight P1 to bring R into contact with mercury.

-Second measurement: the sample is placed under the claws of the float, weights P2 are placed on B to bring R back into contact with mercury pHg specific mass of mercury at the measurement temperature.

For the V_T measurement to be valid, mercury must not enter the sample.[7]

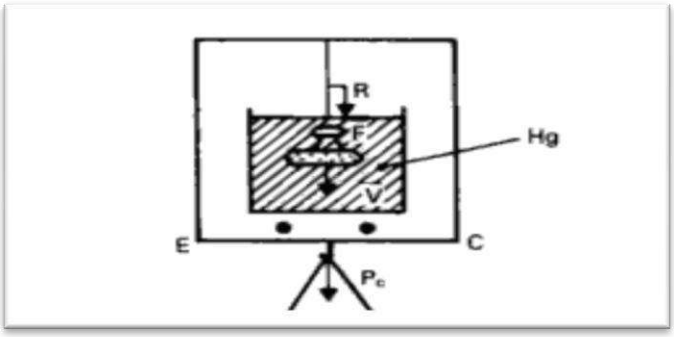


Figure I-04: I.F.P voltmeter

➢ Measurement:

The previous methods are not suitable if the rock has fissures or macropores, as the mercury would penetrate these.[3] We can then take a piece of cylindrical carrot and measure with a caliper its diameter d and its height h: $Vt = \frac{\pi d^2 h}{4}$ → I-9

2-1-2. Determination of Vs:

➢ Measurement of the Archimedean thrust exerted on the sample by a:

Solvent with which it is saturated (Figure I- 05)

This method is the most accurate, but achieving full saturation is tricky and time-consuming. Operations are standardized.

The difference between the weights of the dry sample in the air (Pair) and in the solvent where it is immersed (immersed P) gives Vs: [3]

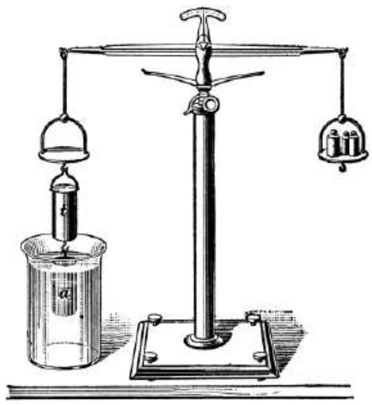


Figure I- 05: determination of Vs submerged weighing

2-1-3. Determination of Vp useful pore volume:

The volume of the pores can be directly determined by measuring the volume of air contained in the pores, weighing a liquid filling the pores, or injecting mercury into the pores.

2-1-4. Fluid summation method:

We study here a sample (fresh) which contains water, oil and gas. The distribution of these fluids is not the same as in the deposit, since there was invasion of the core by the filtrate of the mud and, then, decompression during the ascent of the core. But the sum of the volumes of these three fluids, for a total unit volume of rock, gives the useful porosity of the sample (the total volume is determined using a volumetric mercury pump).[4]

Porosity measurements by direct methods are made in the laboratory on samples extracted from boreholes. These methods consist in measuring the volume of the solid (Vs) which is given by the formula:

$$V_s = V_t - V_v \quad \rightarrow \text{I-10}$$

It will therefore suffice to measure two of these three volumes to calculate the porosity. The most common measurement methods are summarized in Table I-1.

In reality, these methods are not equivalent. If the determination of the total volume does not pose a theoretical problem, it is not the same for the determination of the other volumes (Vv) and (Vs), which are closely related. Methods 3, 4 and 5 (table I-1) only take into account the pores connected to the outside, while methods 6 in part and 7 in total take into account all the voids.[4]

Table I- 01: Main methods for measuring porosity[18]

Volume Measured	Reference in text	Methods of measurement
Total volume (Vt)	1	Archimedean thrust in mercury: non-wetting liquid mercury does not penetrate the pores without pressure. We obtain a very precise measurement of (Vt)
	2	Direct comparator measurement: this method is only suitable for.
Pore volume (Vv)	3	Uptake of wetting fluid by total saturation under vacuum: we obtain directly (Vv) by difference of dry and saturated weight
Volume of solid (Vs)	4	Compressibility of an ideal gas: we draw the pressure volume diagram injected into a chamber first empty then containing the sample. culate the (Vs) of which we neglect the Compressibility
	5	Archimedean thrust in a wetting fluid totally saturating the porous body: by difference between the dry weight and the submerged weight, we measure directly (Vs)
	6	Measurement of the density of the solid: after fine grinding of the porous body Calculation of the density of the solid: by quantitative analysis of the minerals constituting it
	7	Measurement of the density of the solid: after fine grinding of the porous body Calculation of the density of the solid: by quantitative analysis of the minerals constituting it

2-2. Measurement from log:

Porosity measurements by indirect methods are based on geophysics thanks to:

- -Neutron CNL (Compensated Neutron Log)
- -FDC (Formation Density Compensated)
- -Sonic

Measurements by electrical logging are made based on Archie's formula which links the formation factor (F) with the porosity, but also with the shape and size of the pores, which itself depends on the resistivity of Training.

a: empirical coefficient (0.81 for sands; 1 for compact rocks) m: sedimentation coefficient = 2.

Ro: resistivity of the formation saturated with hydrocarbons

Rw: resistivity of the water-saturated formation

These methods are well explained concerning the operation of the tool, its recording and its reading Schlumberger[19] are documents explaining in detail all the settings.

petrophysical their use, their possible combination as well as their interpretation and the corrections to be made.[8]

2-2-1. Neutron Logs (Hydrogen Index):

Using appropriate sources, the formations are subjected to an intense bombardment of fast neutrons, with an initial energy of between 4 and 6 MeV. Thanks to their high initial speed (10,000 km/s), fast neutrons have great penetrating power. They will therefore collide with the nuclei of the atoms of the formations they cross and gradually lose their energy.

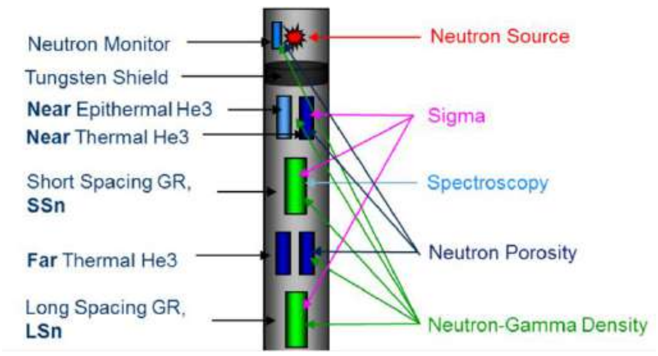


Figure I- 06: Tool and principle for measuring neutron logging.

The measurement of the hydrogen index (IHh) or the porosity (Φn) depends in some way and above all on the number of hydrogen atoms per unit volume in the formation, these being either related to the water or hydrocarbons (therefore to porosity and saturation), or to the molecular composition of the rock, but also to a lesser degree, of the other atoms entering into the composition of the rock either as a result of their power retarder, or by their absorbency.

Application : Combined with other tools, it makes it possible to identify the lithology. Evaluation of the porosity of reservoir rocks. Combine with LDT for gas pockets. Evaluation of the density of hydrocarbons. Good well-to-well correlation criterion.[5]

2-2-2. Density logging:

$\rho b = (1-\varphi).\rho ma + \varphi.\rho f \quad \varphi = \frac{\rho ma - \rho b}{\rho ma - \rho f}$ → I-11

They are all based on the principle of the intersection between incident radioactivity and the components of the formation subjected to the radioactive bombardment. The radioactive source emits gamma radiation which strikes the atoms in the formation.

Three types of interactions occur depending on the energy of the incident protons:

The Compton effect if the energy of the photons is between 0.1 to 1MeV.

The photoelectric effect if the photon energy is less than 0.1 MeV.

The pair production effect if the photon energy is greater than 1.01 MeV.

The recorded density curves are on a sensitivity scale of 1.95 to 2.95 g/cm3.[4]

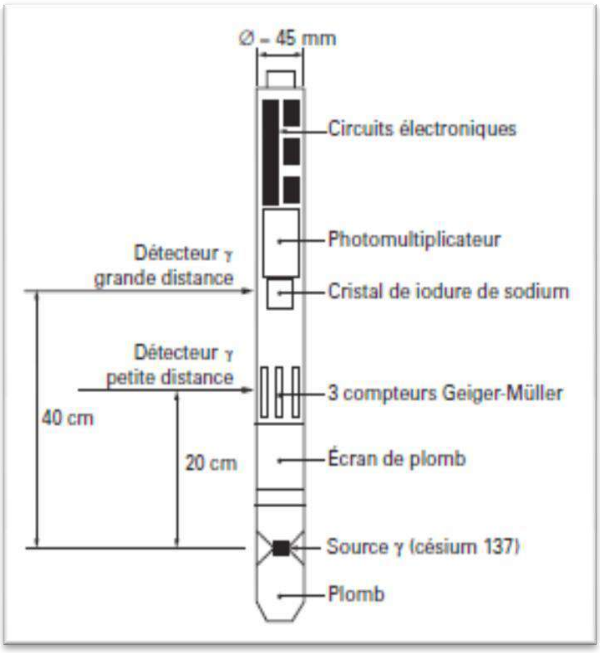


Figure I- 07: tool and principle for measuring density logging.

Application:

The ability to determine a density porosity is crucial for current interpretation. The identification of fluids in reservoirs and the location of gas/oil and oil/water contacts are made possible by comparing neutron, density, and resistivity. Detect the presence of gas in the invaded zone because it causes a significant reduction in density and, as a result, an abnormally high density porosity. Clays are mostly identified by their mineralogical composition..[8]

3. Presentation of the field:

3-1. General geological description of Haoud-Berkaoui field, Algeria:

Introduction:

HAOUD BERKAOUI (HBK) region is one of the principal petroliferous areas of the Triassic province .It was discovered in March, 1965 by a French Petroleum Company. Hydrocarbons were encountered in the Inferior of the Trias Argileux Greseux (TAC) OK 101 wildcat at the top of the structure. The well flowed at 13 to 14 m^3/h with a bottom hole pressure of 480 kg/cm^2 .The development following this significant result showed the existing of another oil accumulation in the Trias (T1) and permitted to get more data for determining oil in place which is estimated to be 136 10^6 stm^3.[9]

3-2. Geographical situation:

Haoud Berkaoui field is located in the Oued Mya basin, northeast of the Algerian Sahara. It is situated more precisely at 700 km southeast of Algiers and 100 km west of Hassi Messaoud field .The field was estimated to encompass approximately 22 kilometers long by 15 km wide.

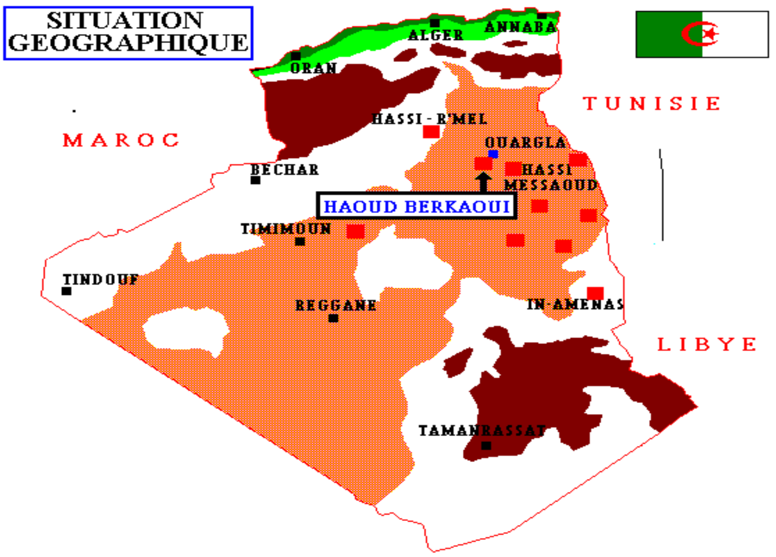


Figure I.08 Geographic Localisation of HBK

3-3. Structural Aspects:

The structural framework in the area is composed of two North-northeast trending structural ridges separated by prominent graben. The graben plunges gradually northeastward to maximum depth of 3600 m. The Haoud Berkaoui field was developed after the Hercynian orogeny; a long a nearly North-South axial trend. Different points of view on the origin and character of the sediments in the area were discussed. The evidence points strongly to a fluvial deposit of either meandering or braided streams.

All the faulting in the region is tensional in nature and appears to be steeply dipping. The principal formation named F1 and F2 have a throw which varies irregularly from NE to SW. the important throw of 200 m of the fault F2 leads to divide the field into two compartments: East flank and West Flank[10].

3-4. Stratigraphic Aspect:

The reservoir interval of interest to this study in the HBK field is the Serie Inferieure, a rock sequence of Triassic age. The sedimentary sequence of the (SI) is composed of alternating beds of shale, sandy shale and sandstones, with an average uneroded thickness of about 50 meters.

The sands are generally fine to medium grained, locally coarse grained, with scattered conglomerates.

In conclusion of what is said, the (SI) is a heterogeneous reservoir where the petrophysical characteristics change not only laterally from well to well but also vertically in the same well[10].

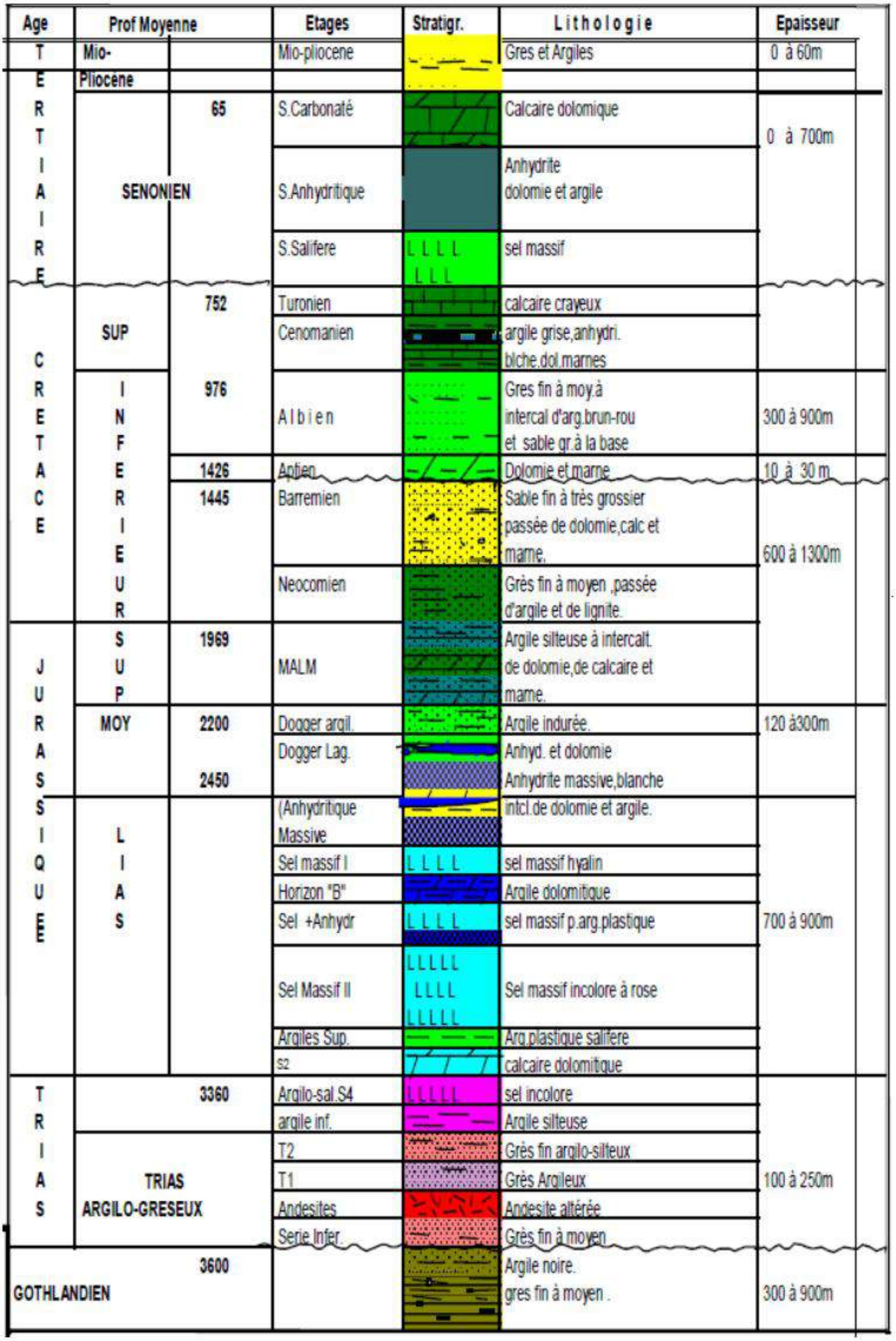


Figure. I. 09. Coupe chronostratigraphique type de Haoud Berkaoui (Unpublished document).

3-5. Reservoir characteristics:

Table(3.1): Characteristics of the “Série Inférieure” (SI) in the HBK reservoir.

Reservoir parameters	Values
Average permeability	56.2 (md)
Average porosity	8.8 %
Average water saturation	32.7 %
Initial reservoir pressure at (-3100)	518 (kgf/cm^2)
WOC depth	3324 (m)
Max depth of the serie inferieure	3325 (m)
Min depth of the serie inferieure	3025 (m)
Average height of serie ibferieure	47 (m)
Bubble point pressure	191 (kgf/cm^2)
Average specific gravity	0.809
Temperature	100° c
Initial GOR	160 (m^3/m^3)
Cut-off porosity	5 %
Cut-off permeability	1 md
Irreducible water saturation	20.5 %

3-6. Reservoir description:

➢ Introduction:

Block I, subject of this study, is situated between two intersecting faults. A major fault named F2 limited the zone from the West and has a throw varying from 0 at its northern to 80 meters near the intersection of the second fault F3. [10]

The wells existing in this block are: OKP 04, OKP 111, OKP 131, OKP 71, OKP 13, OKP 23, OKP 32, OKP11, OKP 35,OKP 36, BKP1.

➢ Vertical heterogeneity:

A geologist team working on this field indicated the existence of four complete mega-sequences which has a general transgressive tendency. These shaly-sand intervals were identified, based on the analysis of cores, nature of shale, sand bodies and their spatial evolution, presence of minerals and the interwell correlations. The geologic layers were named IV, III, II, and I from the shallowest to the deepest. The four geologic layers were also, subdivided into five layers for the characterization simulation model. These subdivisions were based on permeability profile, in order to improve the ability of the model to simulate fluid movement. [10]

➢ Horizontal permeability:

Of all the formation parameters used by petroleum engineers, permeability is one of the most important parameter. It is more variable than porosity and more difficult to measure yet and adequate knowledge of permeability distribution is critical to the prediction of the future reservoir performance. When measured permeability values are available from the core analysis, the value are used directly. In the opposite case, some correlations are also used to determine its value [11].

➢ Porosity:

Porosity logs calibrated against valid core porosities are more reliable than cores alone for well to well correlations of porosity, because core data sets are usually incomplete. When both core and log data were available, the first priority for porosity determination was given to core analysis. Log data are used to complete the missing intervals after being corrected using correlations. [11] [10]

➢ Reservoir fluids:

The oil of HBK has a specific gravity of 0.809 and is highly under saturated at initial reservoir conditions. The laboratory data agreed well with oil densities derived using standing and Katz correlations. The bubble point pressure of the oil is 191(kgf/cm^3) (2716.02 Pisa). The solution gas oil ration is 165(m^3/m^3) and the formation volume factor (FVF) is estimated to be 1.46(res m^3/st m^3) [11]

➢ Reservoir parameters:

Petrophysical data available (K, Φ, S_w , V_{sh}) for each facies group in each layer were obtained from log interpretation (Gamma ray, resistivity , density, sonic, and neutron logs) and core analysis of the wells. Almost all the wells have been partially cored in increment of 0.25 m throughout the drains and the petrophysical data is available for all of them.[11]

Chapitre II :

Pulsed Neutron Logging Tool

Introduction:

1. How PNL logs works?

PNL logs measure the die-away time of a short-lived neutron pulse. They probe the formation with neutrons but detect gamma rays. Chlorine has a particularly large capture cross section for thermal neutrons. If the chlorine in the formation brine dominates the total neutron capture losses, a neutron-lifetime log will track chlorine concentration and, thus, the bulk volume of water in the formation. For constant porosity, the log will track water saturation, S_w. The neutrons are little affected by steel casing, so this is the standard cased-hole saturation tool. Like other nuclear tools, modern PNL tools incorporate two detectors for borehole compensation. These detectors also permit the calculation of a ratio porosity. This ratio porosity is similar, but not identical, to that of a compensated neutron-porosity tool. They differ because the energy of the neutrons from the pulsed accelerator source is higher than the energy from the isotopic source used in compensated neutron logging. Also, the neutron-lifetime tools detect capture gamma rays rather than direct neutron.[12]

2. PNL Definition:

The **PNL** tool you use to run these two logs goes by many names like **RST, RPM**, Raptor, **RAS, PNN, RMT, PNX** and many more, depending on the service providers [13]

RMT-3D Reservoir Monitoring 3-DetectorTM Tool Can Provide the Following Benefits:

1. Sigma - Saturation Monitoring for saline connate waters
   - W/O/G contacts
   - Gas detection
   - Neutron porosity
2. C/O – Saturation Monitoring for fresh connate waters
   - W/O contacts
   - Elemental yields (lithology)
3. SATG - Saturation Monitoring for mixed salinity environment and low porosity
   - Gas detection
   - Many applications besides Formation Evolution
   - Flow detection & velocity (OA Oxygen Activation)
   - GP evaluation (SiA Silicon Activation)
   - Scale evaluation

Tracer monitoring.[14]

3. Pulsed Neutron Theory[15] :

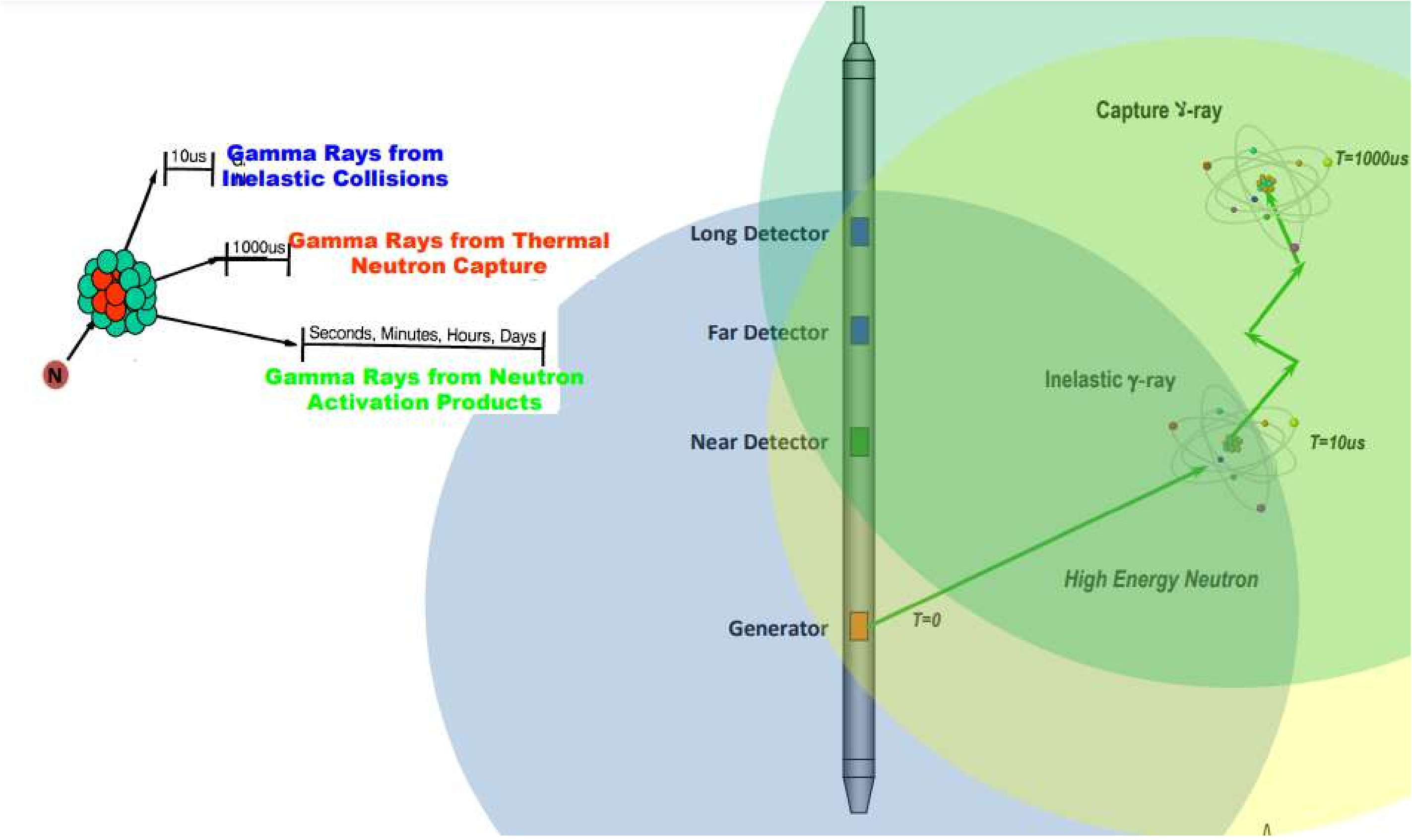


Figure. II. 01 . Technical Pulsed Neutron

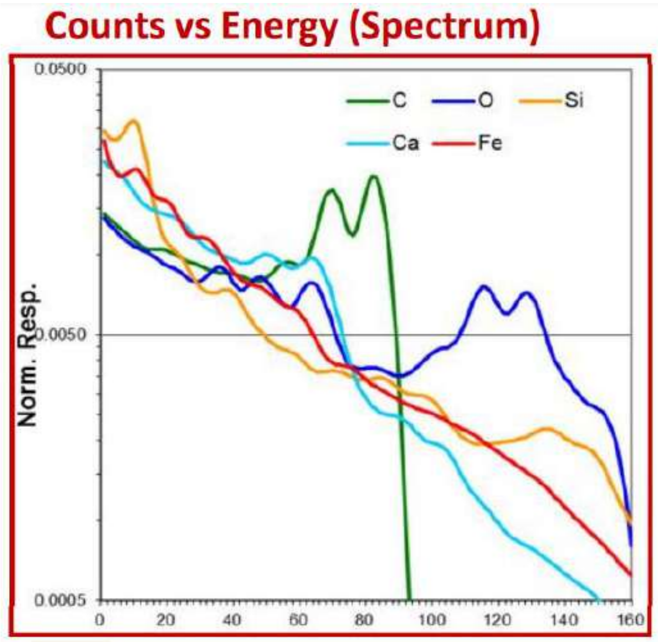


Figure. II. 02 Counts vs Energy (Spectrum)

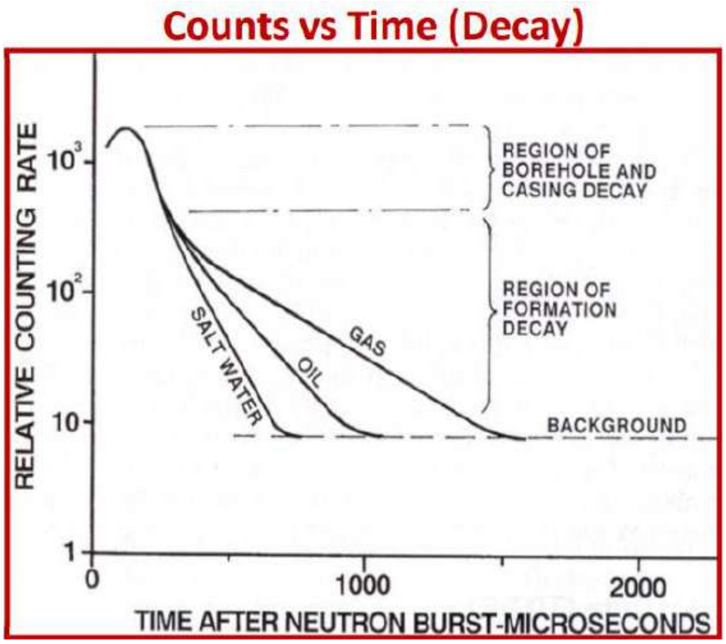
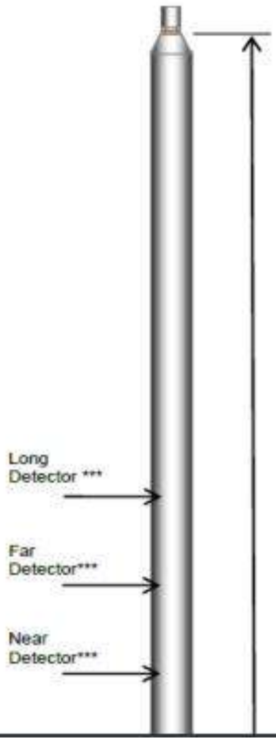


Figure. II. 03 Counts vs Time (Decay)

Part Number 102443922 **TOT : LLT6KO0032** **File Code: 4.07.42.04**



DIMENSIONS AND RATINGS

Max Temp:	*325°F (163°C)*	Max Press:	*15,000 psi (103,400 Kpa)*
Max OD:	*2.125 in. (5.4 cm)*	Min Hole ID:	*2.375 in.* (6.03 cm)
		Max Hole:	*16.0 in. (40.6 cm)*
Tool Length: 15.3 ft (4.66 m) Tool with Telemetry: *24.7 ft. (7.53 m)*		Tool Weight: *86 lb. (39 Kg)* Tool Weigth w/ Telemetry: 146 lb (66 Kg)	

BOREHOLE CONDITIONS

Borehole Type: *Open* ■ *Cased* ■
Borehole Fluids: *Salt* ■ *Fresh* ■ *Oil* ■ *Air* ■
Recommended Max. Logging Speed (C/O): *3 ft./min. (1.0 m/min)* Recommended Max. Logging Speed (Sigma): *15 ft./min (4.75 m/min)*
Tool Positioning: *Centralized* □ * *Eccentralized* ■

HARDWARE CHARACTERISTICS

Source Type:	*14 MeV Neutron Generator*
Sensor Type:	*3 – BGO Scintillometers*
Sensor Spacing:	*Proprietary*
Pulse Scheme:	*10 kHz Inelastic Mode (C/O) / 800 Hz Capture Mode (Sigma)*
Sampling Rate:	*3 in. (7.62 cm) standard / 4 samples per ft. (10 samples/meter)*
Data Records:	*1-128 Decay Channels – 1 each detector* *1-256 Channel Spectra – 3 each detector*
Telemetry System:	*1553 Telemetry System / Ultralink*
Compatibility:	*1553 Compatible / Ultralink*

MEASUREMENT

Principle:	*Neutron Induced Gamma Spectroscopy*
Range:	*> 10% Porosity*
Verticle Resolution:	*24 in. (61 cm)*
Depth of Investigation:	*8 – 12 in. (20 – 31 cm) (C/O)* *10 – 18 in. (25 – 46 cm) (capture)*
Precision (1 SD), COIR2; LIRI2 (C/O):	*2% at 3 ft. (0.91 m)/min.*

Figure II. 04 . Reservoir Monitor tool

4. Sigma Saturation[16] :

1. Oil or Gas Saturation
    - High Salinity Formation
    - Medium to High Porosity
2. Logging Speed – 15 fpm
3. Vertical Resolution – 24” Standard (18” Enhanced Vertical Resolution)
4. Depth of Investigation – 12-18”
5. RMT-I & RMT-3D

4-1. Sigma mode solving for Hydrocarbon Saturation (SHC):

Summation of volumetric responses [16]

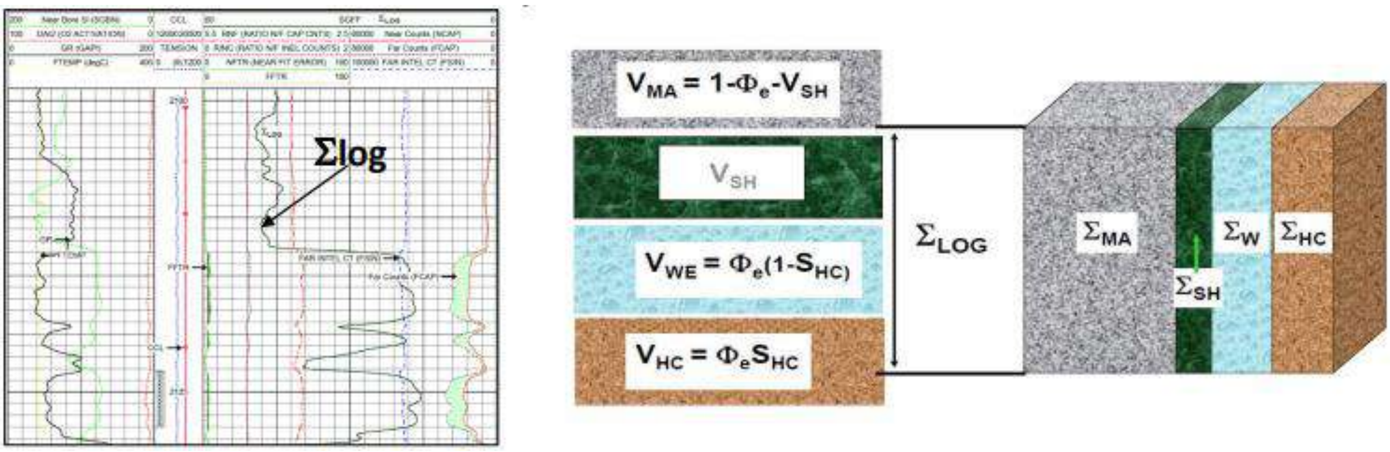


Figure II. 05 Summation of volumetric responses [16]

$$\Sigma_{LOG} = \Sigma_{MA}(1-\Phi_e-V_{SH}) + \Sigma_{SH}V_{SH} + \Sigma_W\Phi_e(1-S_{HC}) + \Sigma_{HC}\Phi_e S_{HC}$$

Rearranging the equation we can solve for SHC [16]

$$S_{HC} = \frac{\Sigma_{LOG} - \Sigma_{MA}(1-\Phi_e-V_{SH}) - \Sigma_{SH}V_{SH} - \Sigma_W\Phi_e}{\Phi_e(\Sigma_{HC}-\Sigma_W)}$$

5. C/O Saturation:

- Oil Saturation Only
- Medium to High Porosity
- Vertical Resolution – 24”
- Depth of Investigation – 8-12”
- Logging Speed – 2 passes each at 2 fpm
- RMT-I & RMT-3D (Preferred)

5-1. C/O mode solving for Oil Saturation (SO):

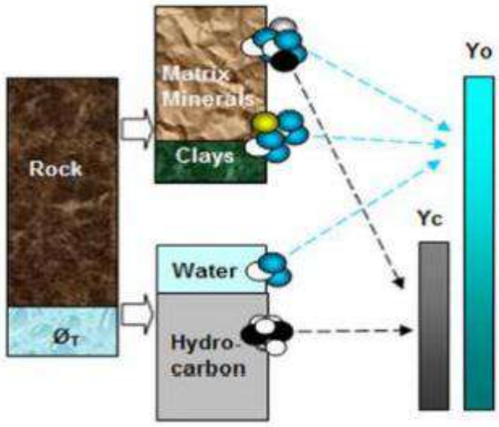
C and O contribution and ΔC/O interpretation method

$$Ca/Si = (0.32\ Vls + 0.30)(1-\phi) + 1.505$$

$$\Delta C/O = C/O_{meas} - 0.15\ Ca/Si_{meas} + 0.07\ \phi_T - 0.263 + offsetco$$

COIR and LIRI overlays in wet zones

Offsetco is a number near zero that sweeps up all the residual environmental effects (borehole size, casing size, cement type, etc.)



$$S_o = 1.53 \frac{1-0.35\phi}{\phi} \frac{\Delta CO}{\Delta CO + 0.19\rho_h}$$

Figure II. 06 C and O contribution and ΔC/O interpretation method [16]

5. SATG Saturation:

- Gas Saturation
  - Low Salinity Formation
  - Unknown Water Formations
  - Low to High Porosity
- Logging Speed – 15 fpm
- Vertical Resolution – 30" Standard
- RMT-3D

6-1. SATG Gas Saturation Mode:

SATG Calculated from the single long detector inelastic and Slow capture Gate [15]

- Low Porosity
- Reduced Salinity Dependency
- Reduced Lithology Dependency
- Depend to fluid density

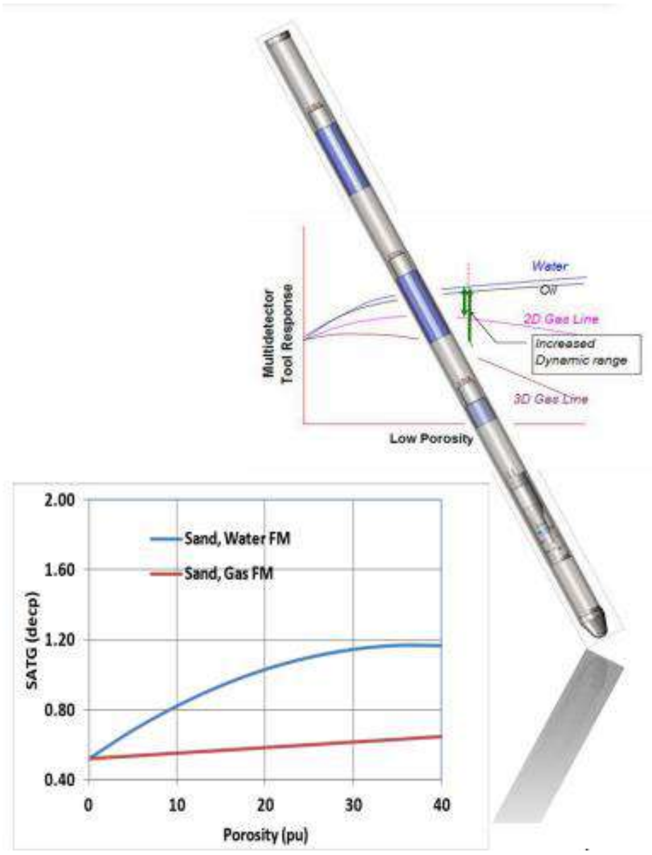


Figure II. 07 RMT-3D SATG mode solving for Gas Saturation (SG) [15]

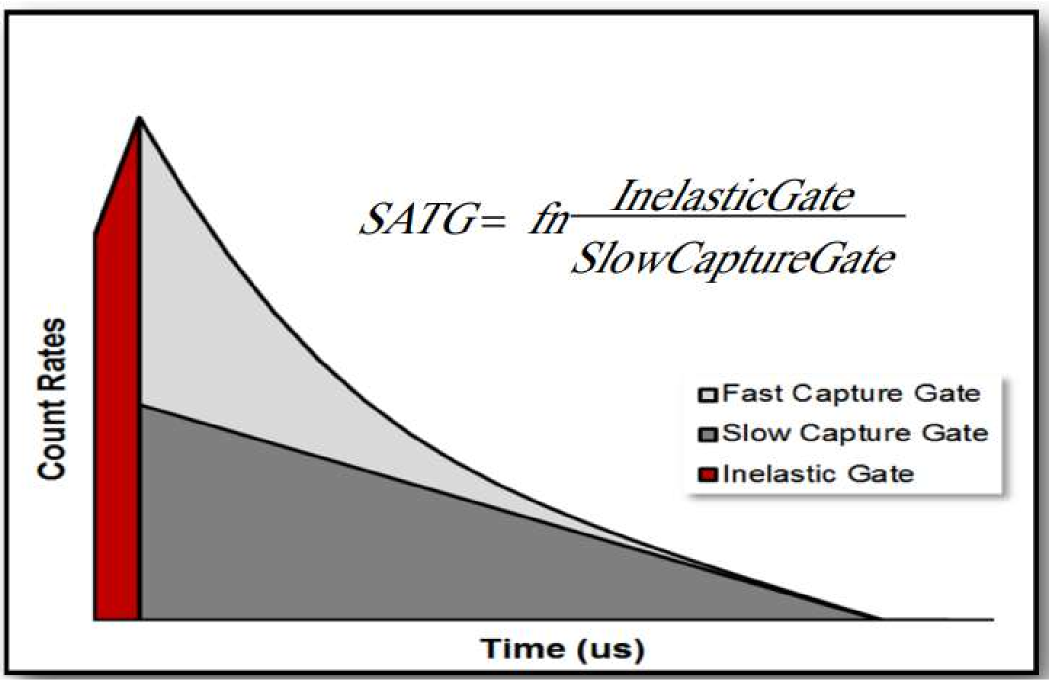


Figure II. 08 SATG long detector

7. PNL Detectors:

Detector	Diameter	Length	DENSITY (gm/cc)	Decay Time (ns)	Gamma Stopping Power per Dia.	Mass (gms)
BGO	1.4"	6"	7.13	300	13.98	1079
GSO	1.1"	4"	6.71	56 - 600	8.12	365
GYSO	1.15"	6"	6.29	60	8.32	643
YSO	1.11"	1"	4.47	42	5.51	62
LaBr3	1.1"	6"	5.51	28	6.67	449
NaI	1.1"	6"	3.67	230	4.44	305

BGO: Bismuth Germanate oxide
GSO: Gadolinium Oxy Orthosilicate
GYSO: Gadolinium Yttrium Orthosilicate
YSO: Yttrium Orthosilicate
LaBr3: Lanthanum Bromide
NaI: Sodium Iodide

Table II. 1 . BGO Crystal detector has the best Gamma Stopping power

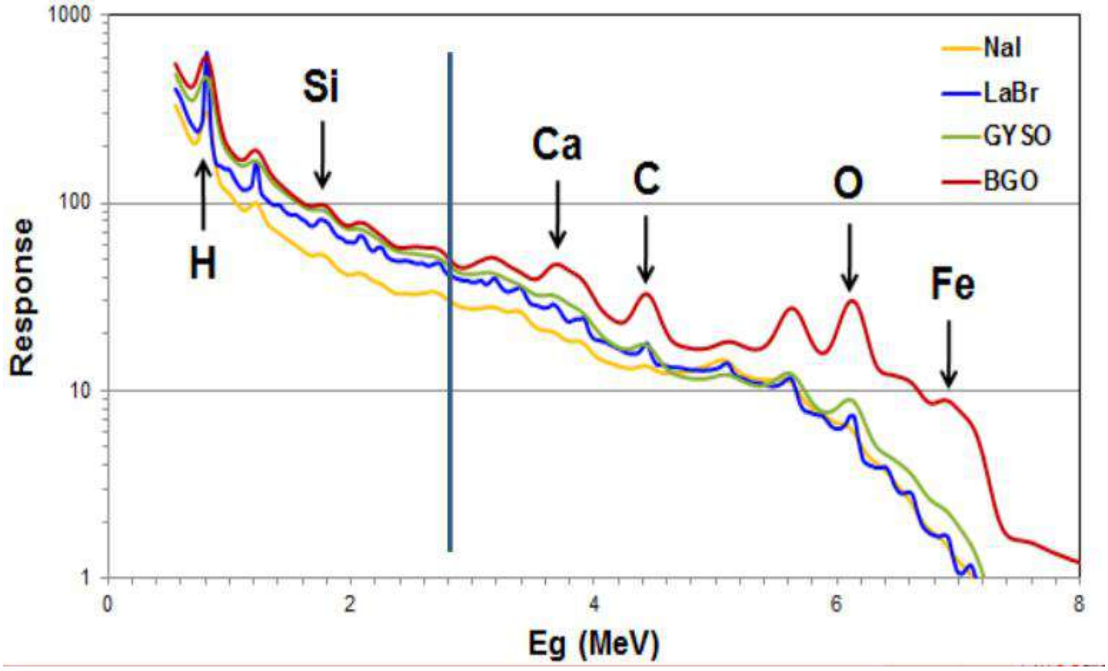


Figure II. 09 PNL Detectors Comparison (Spectral Quality) [16]

After comparing the different detectors readings, we noticed that BGO Crystal detector is the most suitable detector for Gamma stopping.

7-1. Pulsed Neutron Tools: Three Independent Measurements:

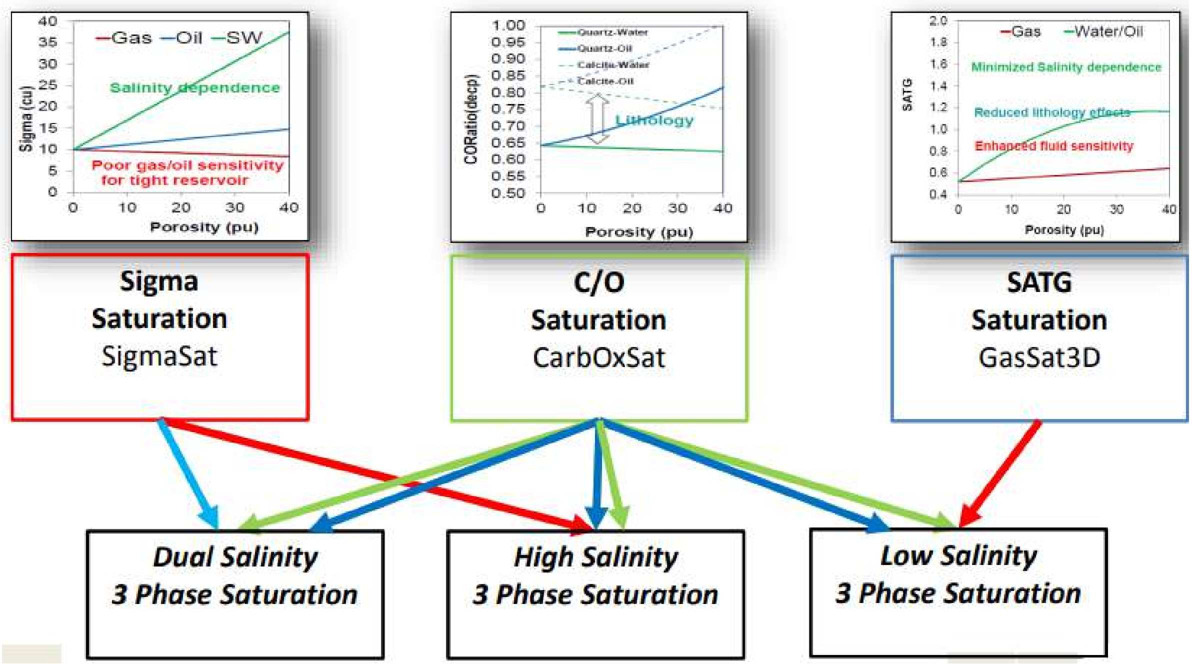


Figure II. 10 Pulsed Neutron Tools: Three Independent Measurements [15]

Solutions:

- Discriminate water/oil contact when the salinity of the formation water is low or unknown
- Evaluate hydrocarbon zone saturations in fresh, mixed, or unknown water salinity environments
- Locate water and oil zones in water floods where mixed salinities exist between formation and flood waters
- Evaluate saturations in formations behind casing when open hole logs are not available
- Monitoring of steam and CO2 flood breakthrough
- Evaluate and monitor open hole completions

Conclusions :

- RMT-3D Reservoir Monitoring 3-DetectorTM Tool Can Provide the Following Benefits:
- Three independent measurements (Sigma, CO, and SATG)
    - Saturation accuracy in finding bypassed pay & reservoir monitoring
    - Eliminates phase-saturation interdependency
    - Uniquely solves simple or complex saturation profiles
- Save time in getting data in one trip in the hole
- Multiple combinability and conveyance methods
- RMT-3D TM tool helps takes the uncertainties out of identifying bypassed pay and monitoring your reservoir.
- Conventional to Unconventional solutions

Chapter III :

RMT-3DAnalysis Workflow Description

1. RMT-3D Analysis Workflow Description:

1. Loading DB file from acquisition system Warrior
2. Converting DB data files to ADI under INSITE platform.
3. RMT-3D-CAL to load RMT-3D calibration into INSITE.
4. Depth shift by correlating with the Open hole data.
5. RMT-Studio to verify capture spectra stabilization.
6. PN-Interp to calculate PN-Vshale, PN Porosity, PN Minerals and Sigma
7. Environment Correction to calculate Sigma Intrinsic.
8. Sigma-Sat to calculate water saturation.
9. CarboxSat to calculate water saturation.
10. SATG to calculate gas saturation.
11. TripleSat solving for three fluids (Saline water oil and gas)

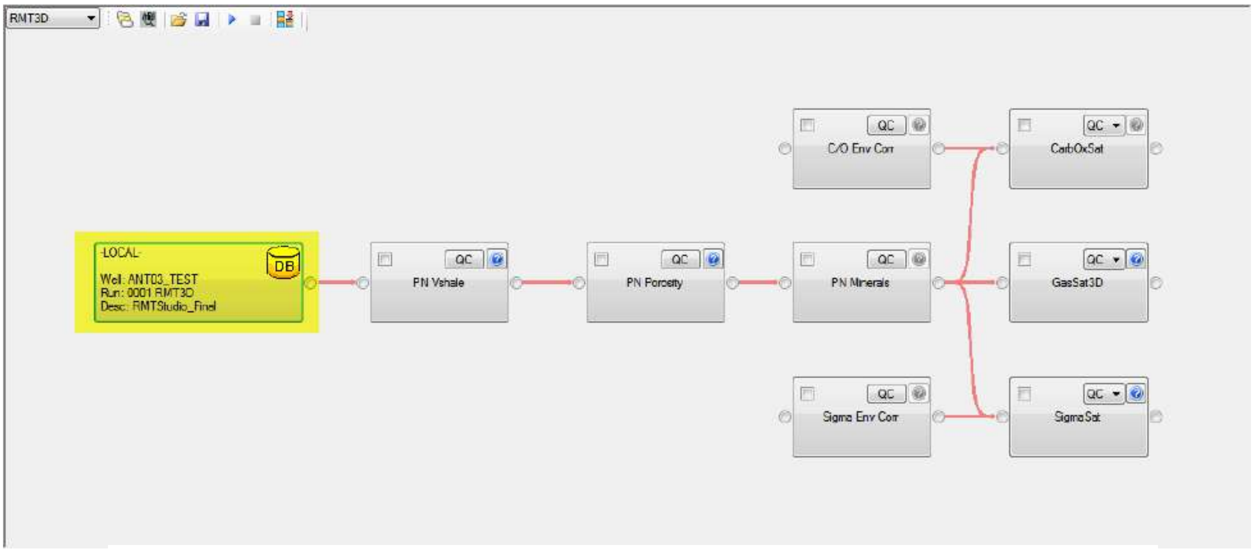


Figure III. 01 The processing of the RPM-C-3D log consists of number of steps[17]

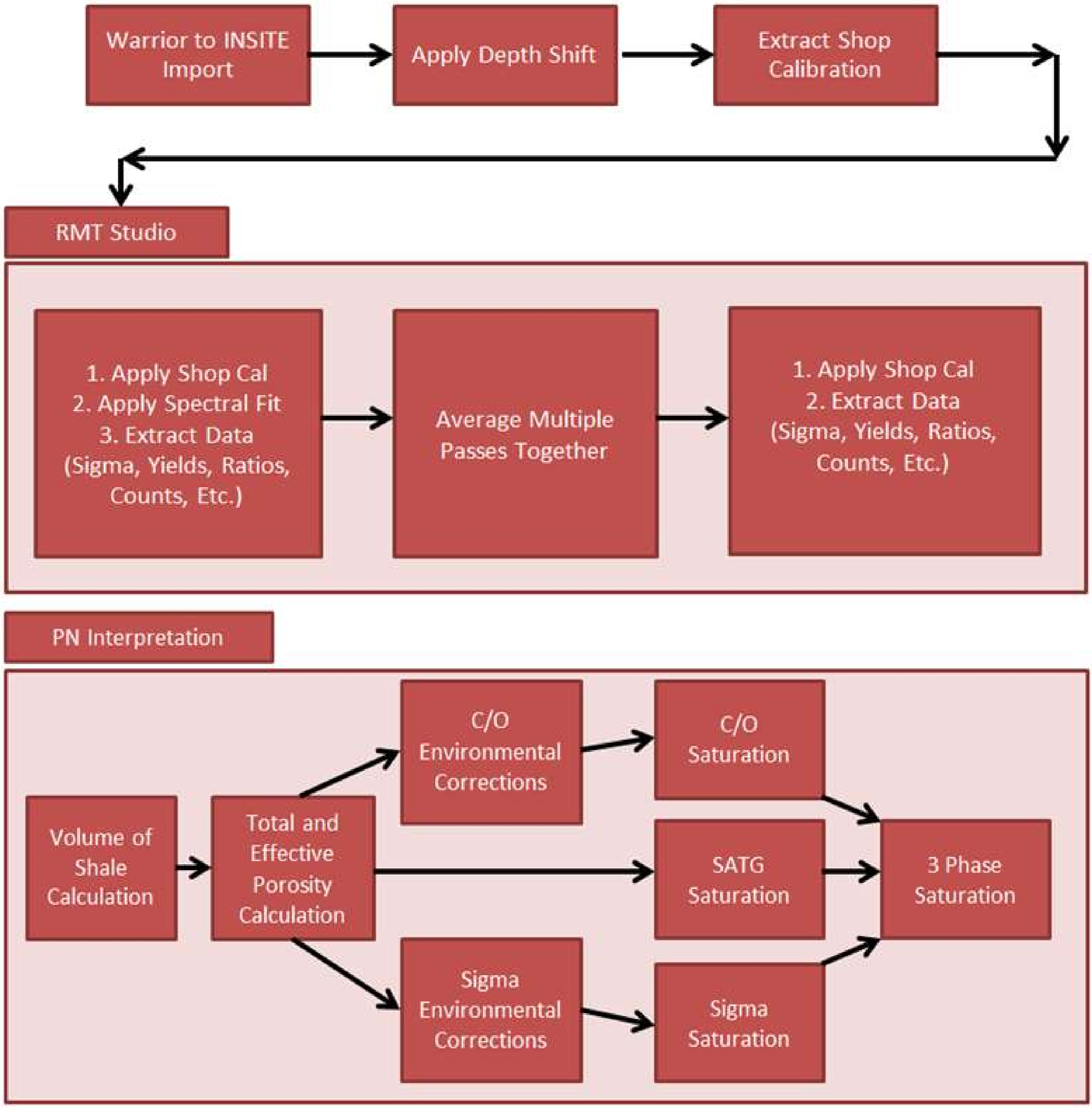


Figure III. 02 Post-Processing Procedures flow chart.

1-1. SigmaSat Analysis Results:

Sigma based saturation is based off the decay of thermal neutron capture counts over time. The decay of these counts occurs in two main time frames, early on after the neutron generator has been turned off, the incoming gamma ray counts are predominantly from the borehole, after that, the formation response is the predominate signal. The slope of the formation decay is sensitive to the fluids contained in the porosity. [17]

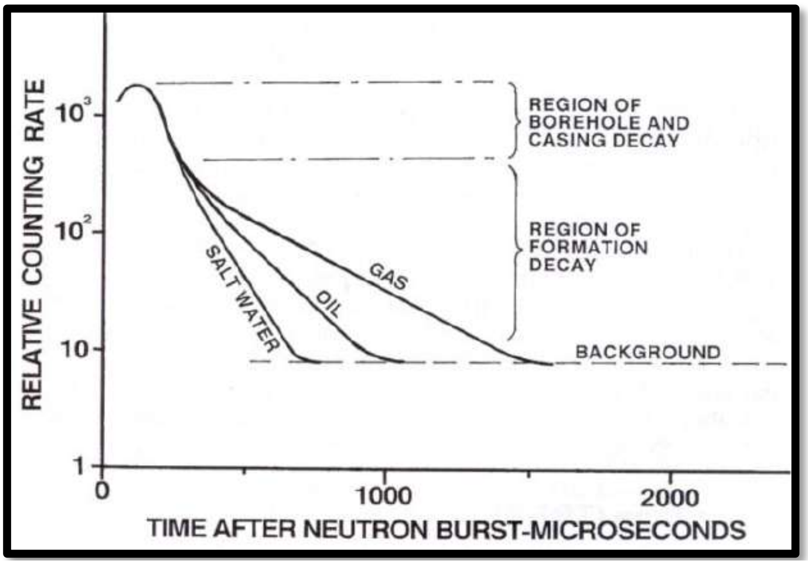


Figure III. 03 SigmaSat Analysis Results

The thermal capture cross section, Sigma, is normally used to determine primarily the oil saturation in reservoirs with high salinity water in the pore space. The basis for this method relies on the large difference in the capture cross section between saline water and oil.

SigmaSat is an INSITE model designed for saturation analysis based on Sigma logs. The total formation capture cross section, Sigma log is the sum of the products of the volume fractions found in the formation and their respective capture cross sections figure below assuming the formation is shaly and contains water and hydrocarbon, thus.

$$\Sigma log=\Sigma ma V ma+\Sigma sh V sh+\Sigma w V w+\Sigma hc V hc \quad \rightarrow \text{III-1}$$ [1]

1 Figure II. 05 Summation of volumetric responses

Rearranging the equation 1, so we can solve for water saturation (Sw):

$$S_w = \frac{(\Sigma_{log} - \Sigma_{ma}) + \varphi_e(\Sigma_{ma} - \Sigma_{hc}) + V_{sh}(\Sigma_{ma} - \Sigma_{sh})}{\varphi_e(\Sigma_w - \Sigma_{hc})} \quad \rightarrow \text{III-2}$$

Where:

Σ_{log} : measured formation Sigma

Σ_{ma} Sigma matrix

Σ_{sh} Sigma shale

Σ_{hc} Sigma hydrocarbon

Σ_{w} Sigma water

Φ_e Effective porosity

V_{sh} Shale volume

S_w Water saturation

According to the equation above, the water saturation can be calculated in any two phase combination such as water-oil, water-gas even oil-gas, only if the Sigma difference within each combination is big enough to get an accurate saturation.

The calculated saturation accuracy depends not only on the sigma difference between liquids or liquid and gas in the reservoir, but also on the porosity. Higher porosity makes it easier to identify each phase in the pore space and produces more accurate saturation than the lower porosity formation. The SigmaSat analysis relies on a total porosity, shale volume and a measured Sigma as its basic inputs.

1-2. CarboxSat Analysis Results:

Carbon/oxygen (C/O) logging is primarily utilized to determine oil water saturations and reservoir performance in areas with low or unknown formation water salinities. The C/O measurement is based on carbon and oxygen reactions with high energy “fast” neutrons producing characteristic gamma rays.

From this measurement, we can distinguish between hydrocarbons (C + H) and water (H + O) in the pore space. [17]

The RMT C/O model mainly measures RC/O and RCa/Si ratios. What we want to know is the oil Saturation So, for a given porosity (Φ). Equations below were derived from tool characterization based on test pit data and used to solve oil saturation:

$$So = 1.53\left(\frac{1-0.35\varphi}{\varphi}\right)\left(\frac{\Delta CO}{\Delta CO + 0.19C_{hc}}\right) \quad \rightarrow \text{III-3}$$

The Chc is the carbon index of the oil defined as value 1.0 for the carbon index of CH2 at 1.0 g/cc. Where:

$$\Delta CO = COIR - 0.15LIRI + 0.07\varphi - 0.236 + A \qquad \rightarrow \text{III-4}$$

Equation 2, essentially represent what is done on the log when C/O and Ca/ Si curves are scaled and offset to overlay in water zones and then allow the curves to separate in higher oil saturation zones.

Figure 6 illustrates ΔC/O as lithology independent measurement of the oil saturation, illustrating these 3 parameters in the fan chart ΔC/O versus porosity for different oil saturations.

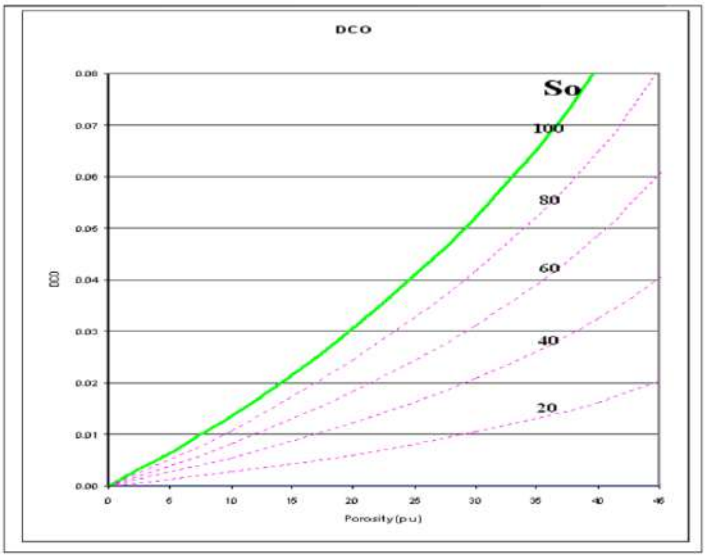


Figure III .04: Lithology independent ΔC/O chart

1-3. SATG Ratio for Gas Saturation:

SATG is the ratio of inelastic counts over slow capture counts and is recorded from the long detector during Sigma mode. SATG first arose with the release of the TMD-3D tool back in 2010 and was added to our current RMT series capability when the RMT-3D was built. We have continually improved the SATG algorithm dealing with lithology and environmental corrections.

SATG (Figure 7) is a ratio of the inelastic counts over the slow capture counts and is recorded from the long detector during the Sigma pass, which is typically run at 15 fpm. The long 3 ft spaced detector improves both the dynamic range of the SATG measurement, and also provides a reduced matrix effect.2

[2] Figure II. 08 SATG long detector

The SATG response has a large sensitivity for gas and low sensitivity between water and oil. The image below shows the SATG response for a 0.15 g/cc natural gas (black), fresh formation water (blue), heavy oil (red), and light oil (maroon). All three fluids, water, heavy oil, and light oil, all have a similar SATG response. [17]

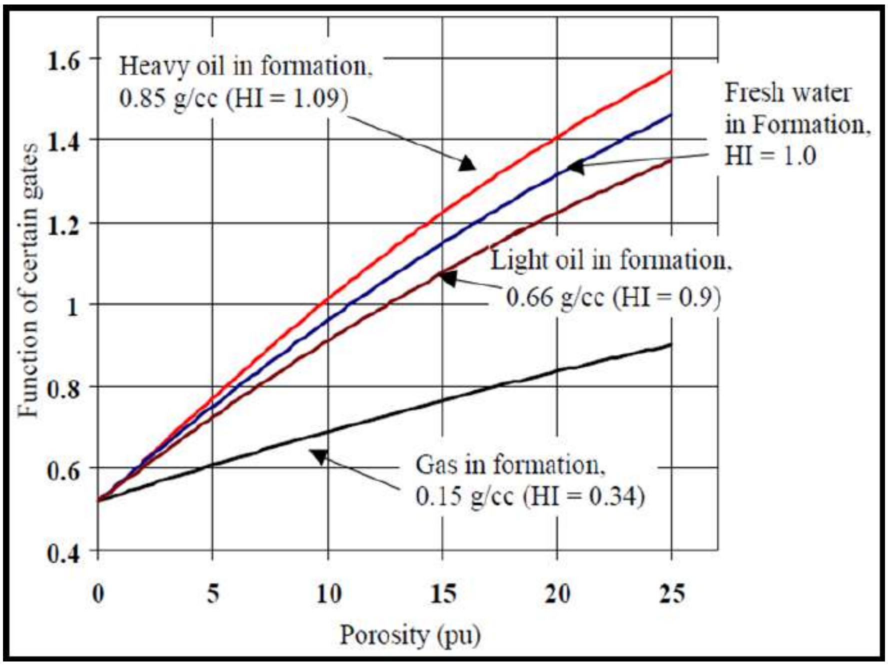


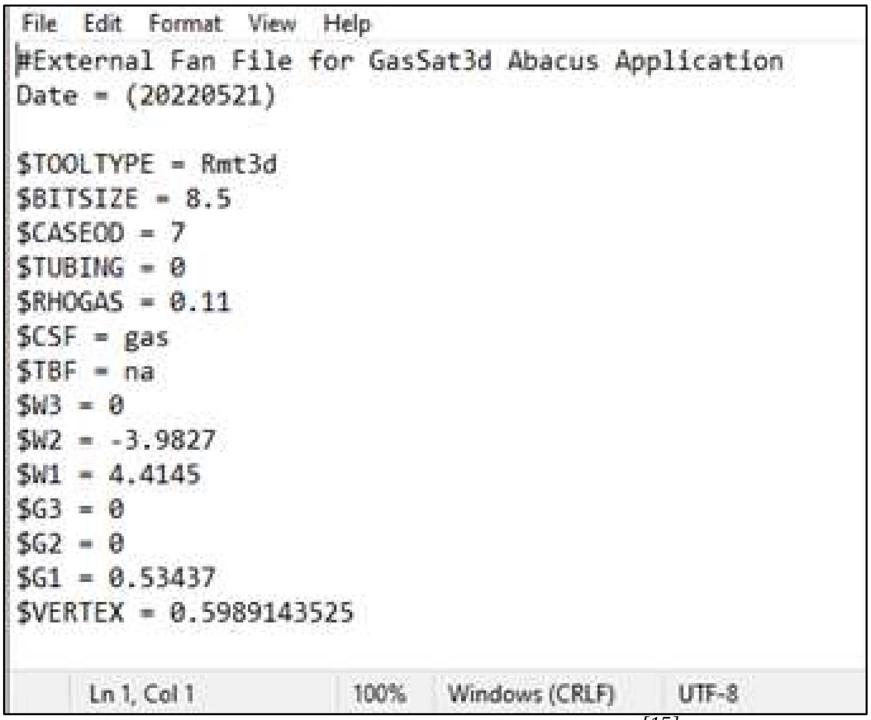
Figure III .05: SATG dynamic range between gas and fluid types.

1-4. SATG Gas Saturation:

The procedures and the normalization of the SATG measurement involve four main steps.

- Step 1 – Sensor physics models the completion and provides a SATG fan file
- Step 2 – Calculate the natural gas density based on depth, temperature, and pressure.
- Step 3 – Determine the shale effect on SATG and correct for it.
- Step 4 – Normalize the fan to a known wet or tight zone.

The SATG fan was modeled based on 8.5” bit size, 7” casing, and no tubing. All fans come with the default 0.11g/cc gas density. The fan is recalculated based on a gas density 0.11 and formation water salinities 234 Kppm as provided from the client, then the model corrected for shale effect on the SATG, and finally Normalize the fan to a known wet or tight zone by moving the fan vertex up or down so the data overlays the wet line in a wet or tight zone.



File Edit Format View Help

```
#External Fan File for GasSat3d Abacus Application
Date = (20220521)

$TOOLTYPE = Rmt3d
$BITSIZE = 8.5
$CASEOD = 7
$TUBING = 0
$RHOGAS = 0.11
$CSF = gas
$TBF = na
$W3 = 0
$W2 = -3.9827
$W1 = 4.4145
$G3 = 0
$G2 = 0
$G1 = 0.53437
$VERTEX = 0.5989143525
```

Ln 1, Col 1 100% Windows (CRLF) UTF-8

Figure III .06: SATG fan completion file [15]

2. Practical part:

➢ Introduction:

This report summarizes the methodologies and the results of data interpretation of RMT instrument which was run for SH-DP Haoud Berkaoui field, Algeria. RMT utilization was proposed and run as a superior technology for the through casing reservoir evaluation and gas quantification. This tool can add more accuracy and face borehole and fluid problems in much higher profitable way, adding also a direct gas evaluation totally independent from mineralogy or salinity effects. The recorded data from RMT were processed and analysed from Baker Hughes Geoscience to characterise the fluids distribution behind casing sections using the SIGMA methodology. The wells described in the present report is BKP-1. The RMT tool was run in two passes in shut-in and flowing regime and the data was recorded in PNC mode. The reservoir formations logged is represented by a Sandstone, Shale lithology[17]

2-1. Objectives:

The main objective of this analysis is the reservoir saturation evaluation.

- Location of Hydrocarbon/Water contact.
- Monitoring of water saturation
- Water saturation evaluation.

2-2. Methodology:

The following summarises the basic methodology used for this RPM Formation Evaluation in order to answer at those questions:

- The raw curves were loaded into Baker Hughes (Workflow Manager 7.1) system for log quality control
- Display/LQC the data: Edit, depth matching and environmental correction of all the data.
- Run Sigma™ and Search analysis nodes to get the fluid saturation using the OH petrophysical parameters (VSH, POR and SW) delivered by the client,
- Discuss the results.

2-3. Available data set :

Baker Hughes ran RPM tool string together with GR-CCL inside a 4.5" casing completion. According to the reservoir properties, well completion and logging objectives, two passes in PNC mode were run in shut-in and in flowing conditions. SIGMA curve recorded in PNC mode used successfully as a SW indicator in reservoir condition as moderate porosity and high formation water salinity. The four RPM passes were recorded as up passes at 6 m/min average logging speed, these were the minimum possible number of passes to minimize the statistical errors that can occur looking at reservoir porosity, well completion, logging speed and formation fluids. The open hole data were delivered by Sonatrach DP Haoud Berkaoui, the Petrophysical interpretation was done by Baker Hughes geoscience. The coverage of the logs data and number of passes are presented in the below table. BKP-1

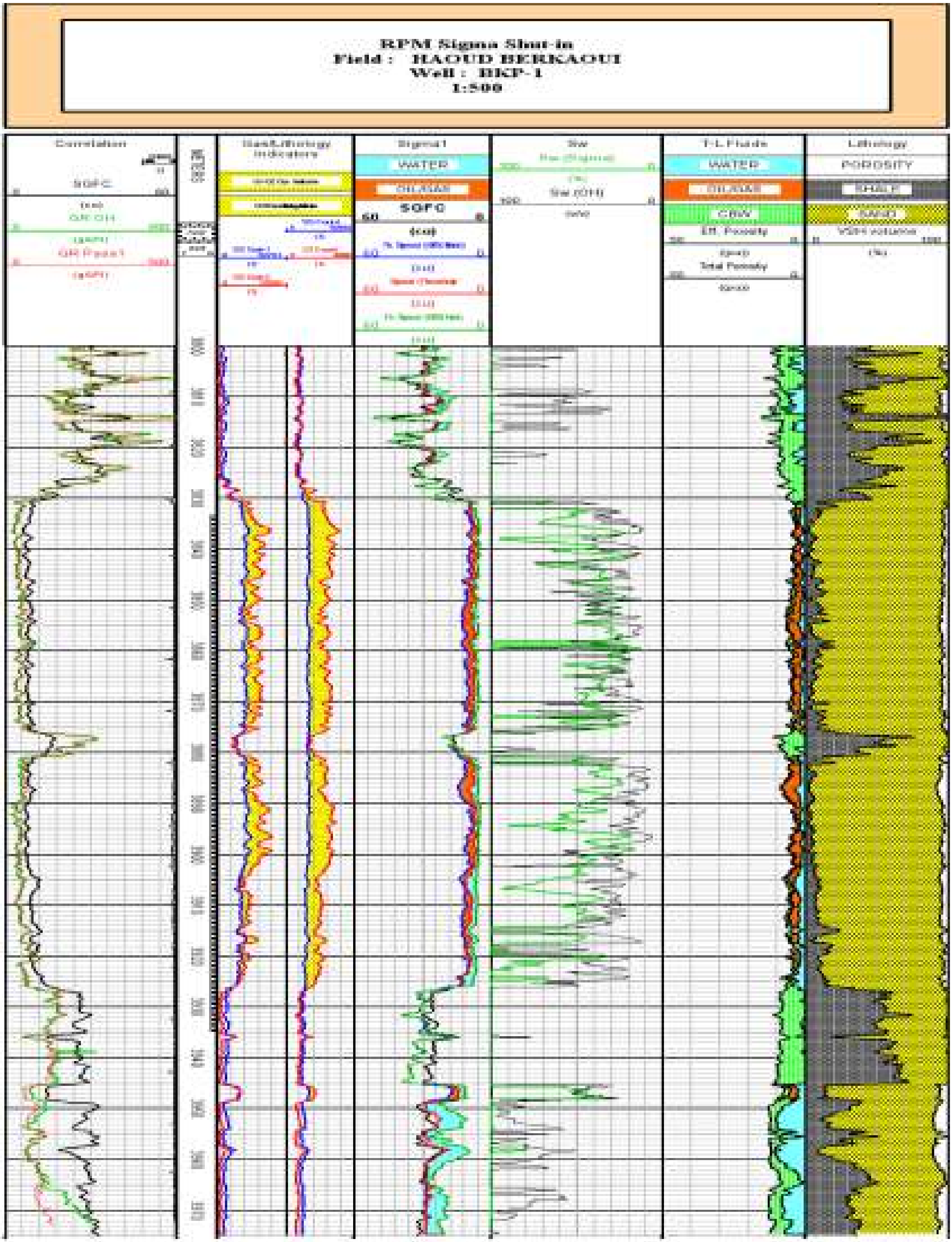
Table III .1. Log data available for study[17]

Interval m MD	Hole/Casing size (inch)	Well Status	Logs acquired	Curves used in RPM Analysis
3790.79 – 3977.48	6 / 4.5"	Shut-In	RPM (PNC)/GR/CCL	EPHIOH, VSH, SGFC
3790.64 – 3977.41	6 / 4.5"	Shut-In	RPM (PNC)/GR/CCL	EPHIOH, VSH, SGFC
3749.19 - 3977.86	6 / 4.5"	Flowing	RPM (PNC)/GR/CCL	EPHIOH, VSH, SGFC
3790.76 - 3977.03	6 / 4.5"		RPM (PNC)/GR/CCL	EPHIOH, VSH, SGFC

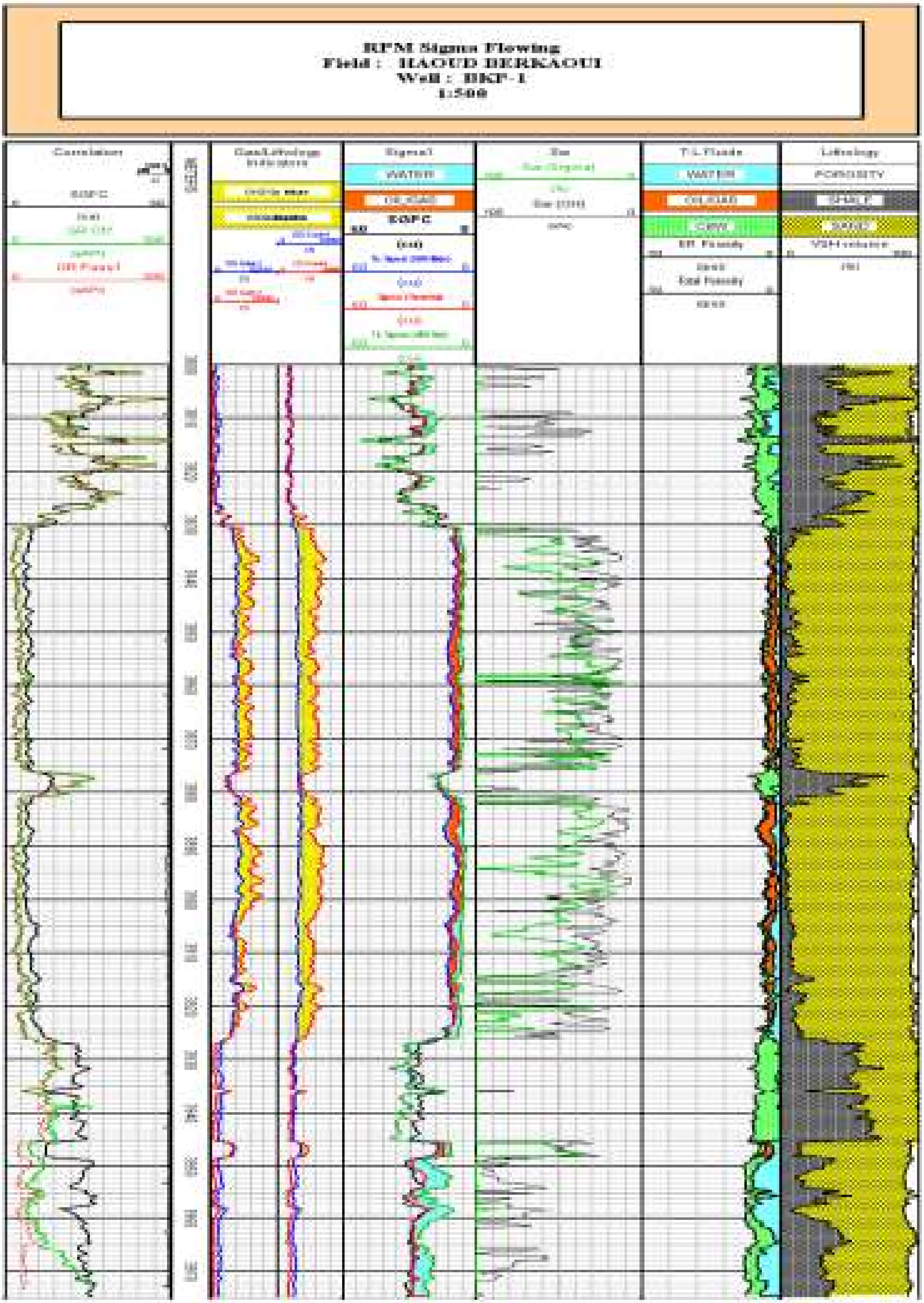
2-4. Depth reference :

All runs were done on Wireline. All measured depths were referenced to the GL above MSL. Depths stated in this report are measured log depths correlated to the SH-DP Haoud Berkaoui supplied correlation open hole logs. [17]

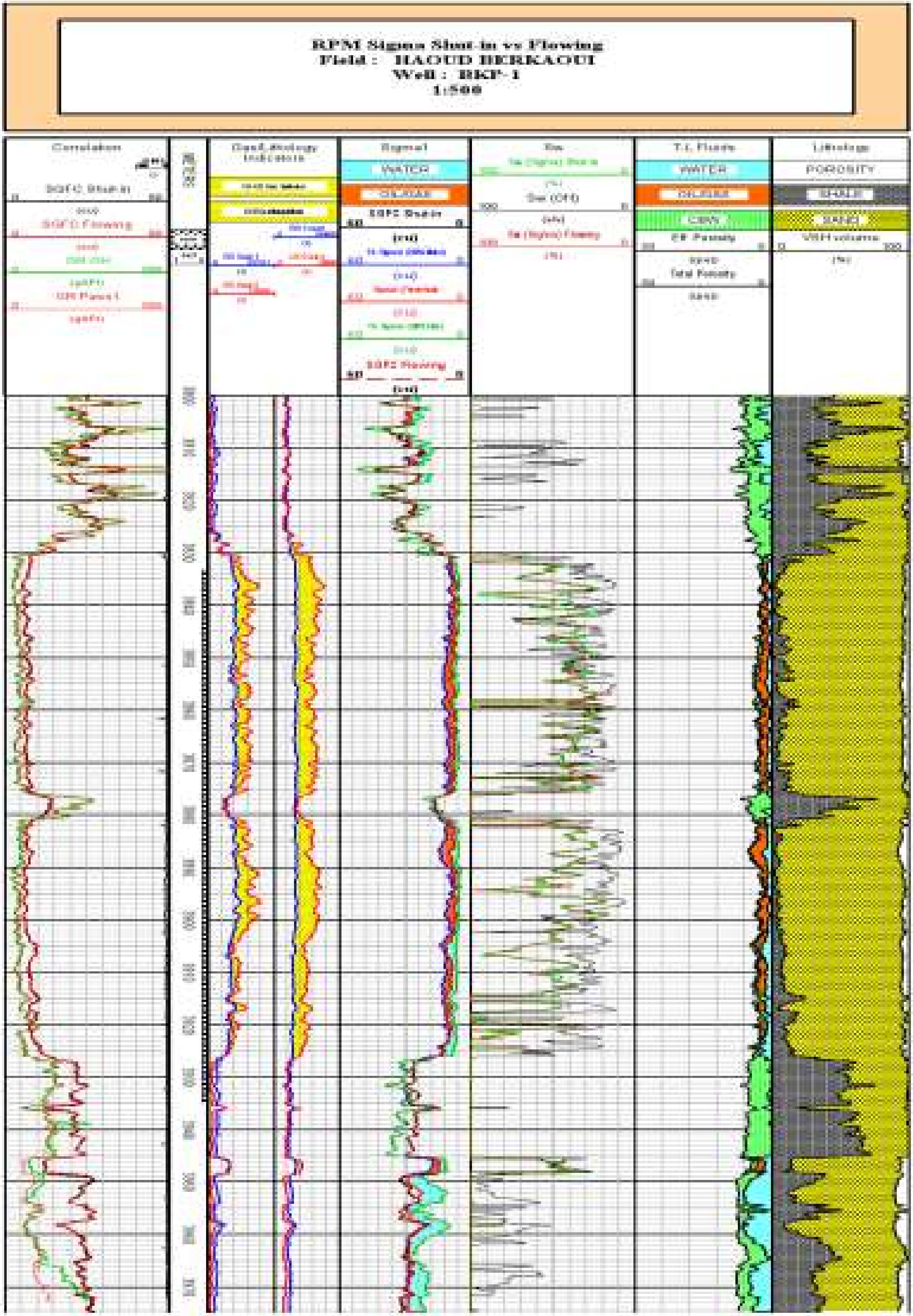
BKP-1 [17]


RPM Sigma Shut-in
Field : HAOUD BERKAOUI
Well : BKP-1
1:500
Correlation
SGFC
Sigma1
WATER
OIL/GAS
SGFC
Sw
T-L Fluids
WATER
OIL/GAS
CBW
Eff. Porosity
Total Porosity
Lithology
POROSITY
SHALE
SAND
VSH volume

BKP-1[17]



BKP-1[17]

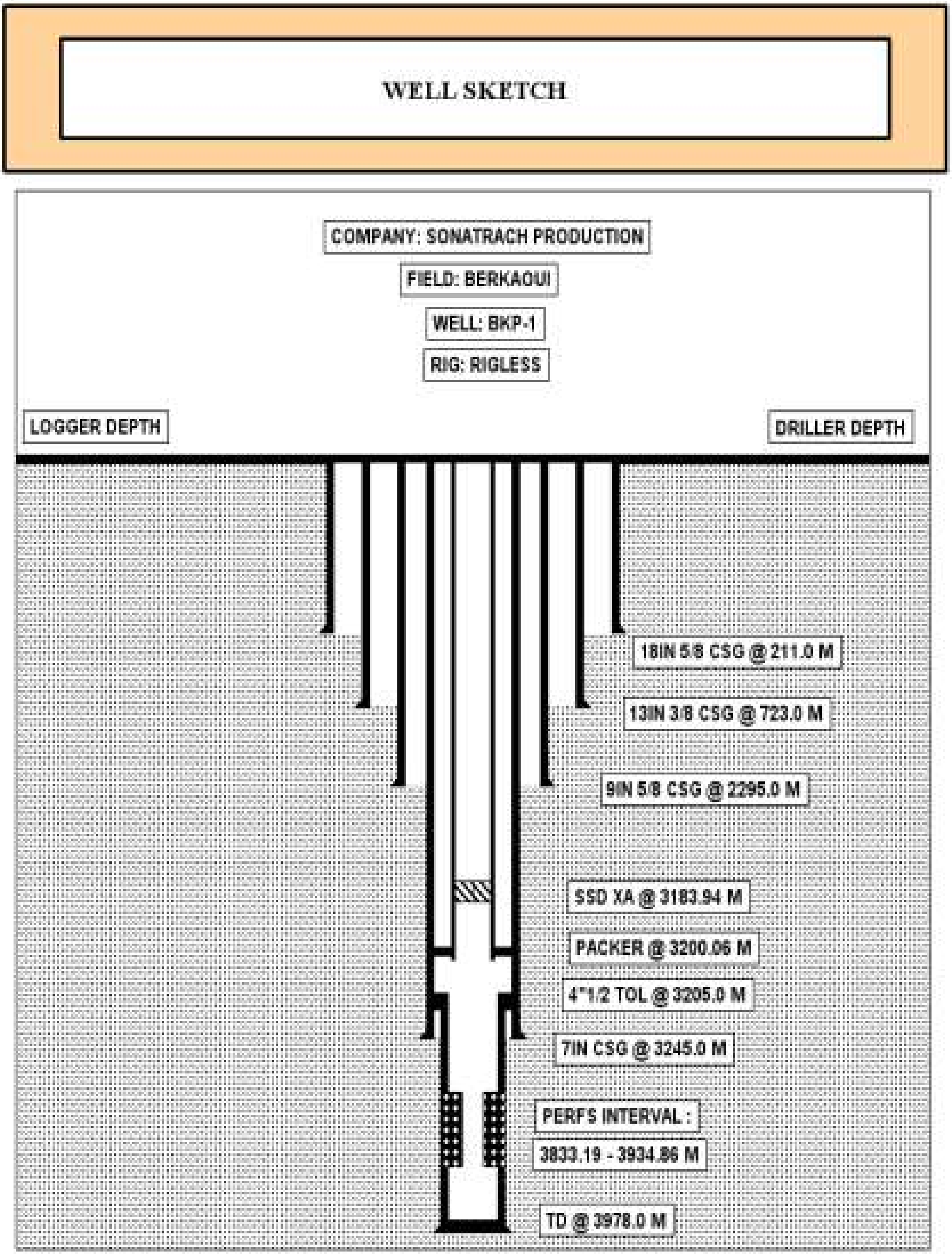


RPM Sigma Shut-in vs Flowing
Field : HAOUD BERKAOUI
Well : BKP-1
1:500
Correlation
Sigma
WATER
OIL/GAS
Sw
T.L Fluids
WATER
OIL/GAS
Lithology
POROSITY
SHALE
SAND

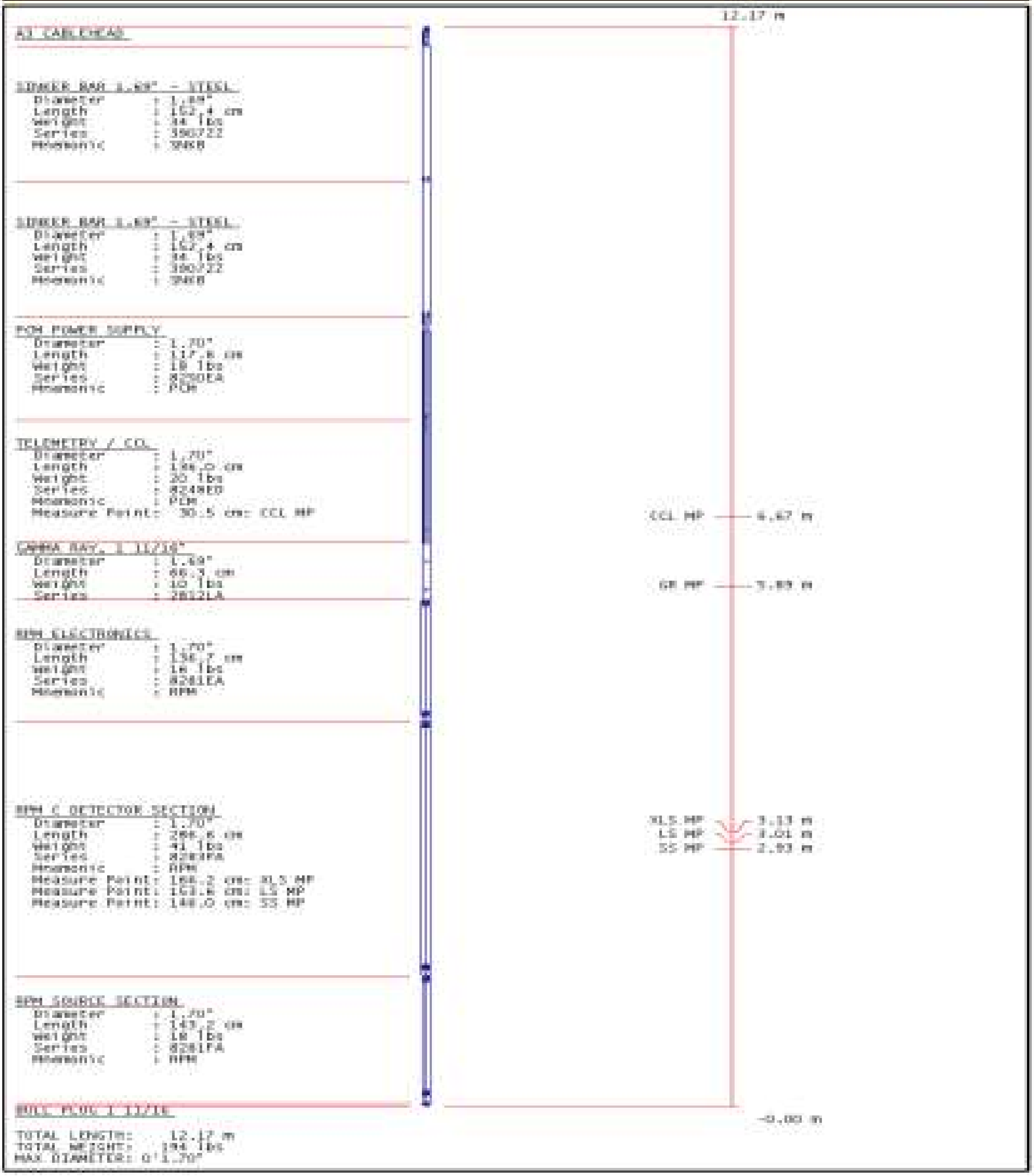
3. Result of practical part:

The purpose of the analysis was to evaluate and calculate the water saturation and compare it with the initial water saturation from open hole data in order to evaluate and monitor the change of the hydrocarbon / water contact. The results show the Dynamic Sigma Envelope overlaid with the Sigma curve used as hydrocarbon identification. The position of the Sigma (SGFC) curve between the water Line (blue) and hydrocarbon Line (green) determines the water saturation. The following conclusion can be drawn from RPM – PNC3D Sigma mode analysis. BKP-1 The zone main zone of interest of this well is Hamra Quarzite with an average porosity of around 3% and average shale volume of 9%, the logged interval was completed with slotted liner. The RPM results for both shut-in and flowing conditions are showing a SW close to original open hole data with OWC be at 3920.75m with SW cut off of 60%. The interval between 3945 and 3948m is showing effective porosity average of 6% with average shale volume of 14%, the water saturation SW average is around 51%.[17]

APPENDIX 1 – Well Completion [17]



INSTRUMENT CONFIGURATION



General Conclusion

Conclusion

The use of modern technology contributes a lot to diagnosing the performance and characteristics of oil and gas reservoirs, which helps in determining the types of interventions at the level of wells to improve productivity or even fix faults caused by special factors according to each well.

In our research, we touched on the PNL device as a kind of advanced device in the field of productivity improvement, as its intervention is during production and does not require killing the well or stopping production.

The use of this device has many advantages that contribute to finding proactive solutions to the problems of production wells. The percentage of water saturation in the reservoir is a major problem. The PNL device works to monitor the development of its flow into the well. We recommend generalizing the use of the PNL device in all petroleum fields as much as possible, as we have seen an improvement in the performance of wells.

Machine computation of desired reservoir parameters from PNL and resistivity-log values may represent a substantial economy in both time and money.

References and Bibliographic

[1]	Website Wikipedia : https://en.wikipedia.org/wiki/Porosity Retrieved : 01-06-2022
[2]	"Reading: Porosity and Permeability | Geology". courses.lumenlearning.com. Retrieved 2022-01-14.
[3]	Bense, V.F.; Gleeson, T.; Loveless, S.E.; Bour, O.; Scibek, J. (2013). "Fault zone hydrogeology". Earth-Science Reviews. 127: 171–192.
[4]	René cossé, techniques d'exploitation pétrolière.
[5]	Website : Schlumberger | oilfield Glossary : https://glossary.oilfield.slb.com/en/terms/s/saturation#:~:text=The%20relative%20amount%20of%20water,as%20a%20percentage%20of%20volume. Retrieved :01-06-2022
[6]	Initiation gisement, © Copyright 2006 ENSPM Formation Industrie — IFP TrainingPRO00842.
[7]	Jean Pascal DEJEAN, Réservoir Engineering Petrophysics – CCA/SCAL, Boumerdès – 26 - 30 Avril 2015, ifptraining.com.
[8]	Diagraphie de pétrole (rapport).
[9]	SH-DP Haoud Berkaoui (Unpublished document)
[10]	SH-DP Haoud Berkaoui geological monitoring service.
[11]	SH-DP Haoud Berkaoui Wells Technical Department.
[12]	Website Petrowiki : https://petrowiki.spe.org/Pulsed_neutron_lifetime_logs#cite_ref-r1_1-0 Retrieved :04-06-2022
[13]	Firdaus Nazlan | Senior Petrophysicist https://www.linkedin.com/pulse/part-12-how-measure-fluid-saturation-behind-casing-enter-nazlan/ Retrieved :04-06-2022
[14]	Website Halliburton : https://www.halliburton.com/en/products/reservoir-monitor-tool-3-detector Retrieved :04-06-2022
[15]	HESP Service company Hassi Messaoud (Unpublished document)
[16]	Website Research Gate : https://www.researchgate.net/publication/312651248_Evaluation_of_Hydrocarbon_Saturation_Using_Carbon_Oxygen_CO_Ratio_and_Sigma_Tool
[17]	Baker Hughes Company (RPM Final Repport)
[18]	Bourbié & al., 1986
[19]	(1989),AAPG,(1986)Selley,(1998,1985)and Benzagouta (1991,2001)
[20]	Website Research Gate : https://www.indeed.com/career-advice/pay-salary/range-salary Retrieved :04-06-2022

Annex

A. RPM Sigma Shut-in Field HAOUD BERKAOUI Well BKP – 1

B. RPM Sigma Flowing Field HAOUD BERKAOUI Well BKP – 1

C. RPM Sigma Shut-in vs Flowing Field HAOUD BERKAOUI Well BKP – 1

D. Well Completion BKP – 1

E. Instrument Configuration