

Petrophysical Analysis of Abura Field, Onshore Niger Delta, Nigeria.

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Abstract

This research investigates the hydrocarbon potential and reservoir quality of Abura field located in onshore Niger Delta, using wireline log data. Suites of well logs consisting of gamma ray, resistivity, neutron, density, and sonic logs from nine wells were interpreted to determine subsurface lithology, fluid types, and to evaluate petrophysical properties for assessment of hydrocarbon potential of the field. Sequences of sandstone and shale lithology were observed within the interval logged which is an indication of the Agbada formation in the Niger Delta. Three major reservoirs denoted as reservoirs 3AB-6, 6AB-6 and 2AB-4 were observed and correlated throughout the field. The petrophysical parameters were four wells which have complete logs. The estimated petrophysical properties values for the reservoirs ranges between 0.05 - 0.35 for volume of shale, 0.12 - 0.30 for porosity, 0.15 - 0.4 for water saturation, 0.12 - 0.30 for net-to-gross, and 700 - 2000 mD for permeability. The computed values of the porosity, water saturation, Net to Gross ratio and permeability show that the reservoirs have good to excellent quality and high hydrocarbon accumulations. This outcome of this research has shown that formation evaluation is crucial for reservoirs characterization.

Keywords: Computer Processed Interpretation; Geophysical logs; Porosity; Water saturation; Niger Delta.

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I. Introduction

The Niger Delta region of Nigeria has a huge accumulation of hydrocarbons. Production and sales of crude oil from the region have been a major source of revenue for the federal government. The Niger Delta is a prolific oil province, made up of a complex stratigraphy of sand and shale formations. The Niger Delta has only one petroleum system known as the Akata-Agbada petroleum system and is the most important region of the West African Continental Margin (Aizebeokhai and Olayinka 2011; Tuttle et al. 1999). Hydrocarbon production in the Niger Delta is mainly from the sandstones and unconsolidated sands of the Agbada Formation. Formation evaluation of reservoir rocks is crucial for all kinds of studies planned for an oil field.

Formation evaluation is an important technique utilized to assess the producibility potential hydrocarbon-bearing reservoirs. The techniques adopted involves geophysical wireline log interpretation to determine the reservoir properties. The goals of reservoir formation evaluation are to determine parameters such as porosity, lithology, fluid saturations, permeability, and assess the presence of hydrocarbon presence (Mahmoud et al., 2023; Amer et al., 2025).

Formation evaluation is the determination of rock properties such as porosity, permeability, shale volume, lithology, and fluid saturation within the reservoir. This information is used for volumetric estimation, determination of hydrocarbon flow behaviour, and hydrocarbon recovery estimation (Maura 2015). Accurate estimation of petrophysical properties is crucial in well log interpretation. Some geologists and geophysicists have worked on the determination of reservoir properties of different oil fields using geophysical well logs in the Niger Delta (Adeoye, and Enikanselu, 2009; Aigbedion, and Iyayi, 2007; Imaseum and Osaghae, 2013; William, et al., 2011). The objectives of the study are to identify reservoir and evaluate petrophysical parameters of the reservoirs in the study area.

II. Summary of Geology of the Niger Delta

The location of the Abura field in Niger Delta is shown in Figure 1. It is located within Latitude 5° 25' N to 5° 35' N and Longitude 5° 50' E to 6° 05' E. The Abura field is about 30 km southwest of Warri, Delta State Nigeria. The Niger Delta is in the Gulf of Guinea and is within the Benue Trough system. The Tertiary Niger Delta development commenced in the Eocene, and about 12km thickness of deltaic and marine sediments have been deposited in the basin. The basin has prograde south-westward since it started, forming depobelts.

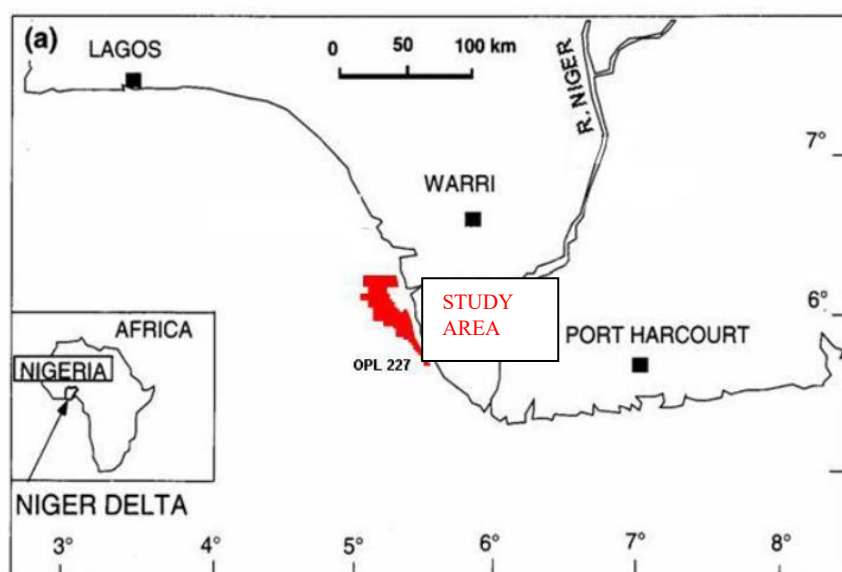


Fig. 1: Map of Niger Delta showing the Location of the studied Area

Three geological formations namely Akata, Agbada and Benin formations are observed in the Niger Delta (Figure 2). The Akata Formation is made up of marine shales and is the main source rock in the basin (Stacher, 1995).

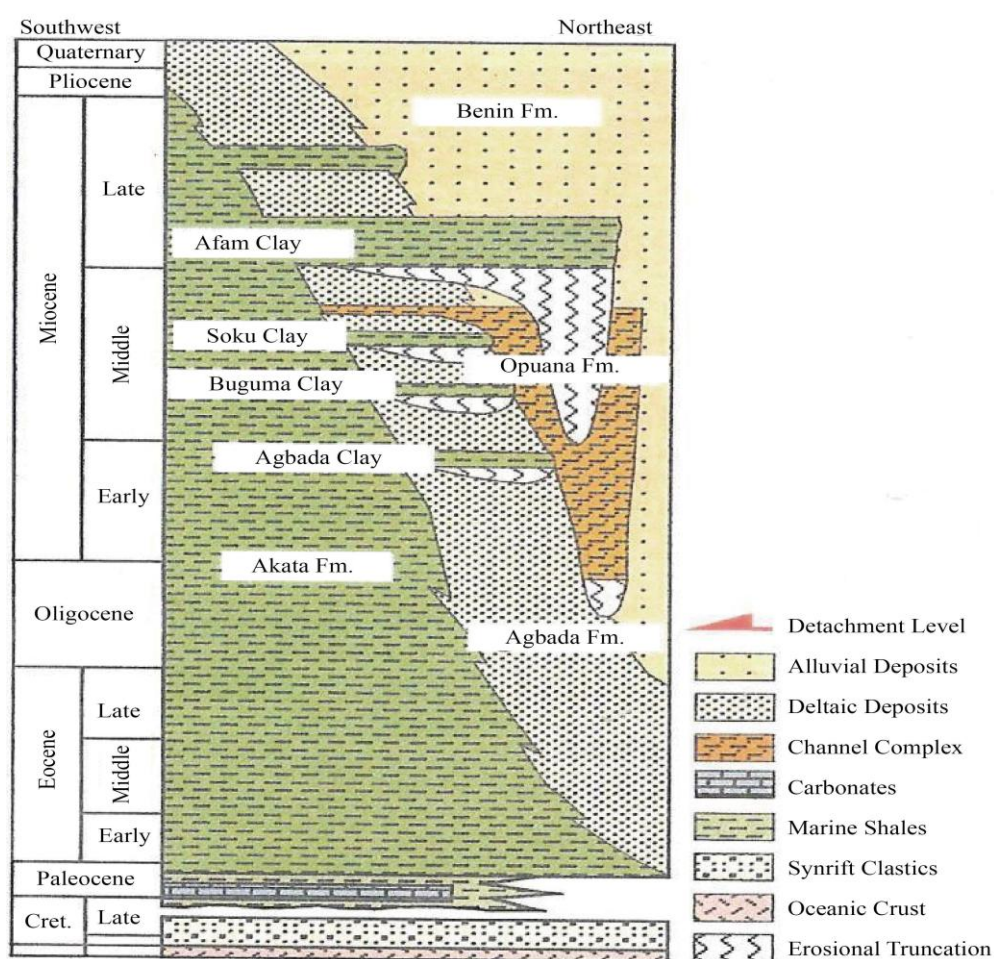


Figure 2: Stratigraphy of the Niger Delta

The Akata Formation underlies the entire Niger delta and, in some places, it is overpressure. The average thickness of the Akata Formation is approximately 6 Km. The Akata Formation is overlain by Agbada Formation which is made up of paralic sand/shale sequence. The Agbada Formation is the major reservoir rock in the Niger delta. The Agbada Formation is overlain by Benin Formation, which is a continental deltaic sand. The Niger Delta basin is characterized with shale diapirs, growth faults and rollover anticlines. These geological structures formed structural traps in the basin (Doust and Omatsola, 1990; Ekweozor and Daukoru, 1994; Klett et. al., 1997)

III. Materials and Methods

Suite of geophysical well logs from nine bore holes in the Abura field were used for this study. The suites of geophysical logs are made of gamma ray, calliper, resistivity, density, and neutron and sonic logs. Technology software was used for the formation evaluation. The procedure adopted include lithology and reservoir identifications, shale volume estimation, porosity and fluid saturation estimation and permeability estimation. The raw well log data were examined for quality control and edited before qualitative and quantitative interpretations were executed. The following petrophysical properties of the observed reservoirs in the field were determined.

Determination of shale volume

Hydrocarbon reservoirs are usually associated with shale content in some cases and there is need to correct for the shale volume during volumetric analysis. The gamma-ray log was used for estimating the shale volume in the observed reservoirs. The gamma ray index (IGR) was calculated from the available gamma ray log with the aid of the equation (Kulke, 1995):

$$I_{GR} = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}} \quad 1$$

Where,

I_{GR} = gamma ray index

GR_{log} = gamma ray reading of formation from log

GR_{min} = minimum gamma ray (clean sand)

GR_{max} = maximum gamma ray (shale)

The estimated gamma ray index was used for calculating the volume of shale by using the equation for tertiary rocks (Schlumberger, 1988; Larionov, 1969)

$$V_{sh} = 0.083 \left(2^{3.7 \times I_{GR}} - 1.0 \right) \quad 2$$

Where,

V_{sh} = volume of shale

I_{GR} = gamma ray index.

Determination of Porosity from Density Log

Porosity is the pore space in a rock. It can be determined from the density, neutron and sonic logs. The total porosity in hydrocarbon-bearing formation in this study was determined using density log by applying the equation (Darling, 2005; Schlumberger, 1988; Ijasa et al, 2013,).

$$\phi_D = \frac{\ell_{max} - \ell_b}{\ell_{max} - \ell_{fl}} \quad 3$$

Where

ℓ_{max} = density of rock matrix = 2.65 g/cm³

ℓ_b = bulk density from log

ϕ_D = total Porosity from the Density log

ℓ_{fluid} = density of fluid occupying pore spaces (0.4g/ cm³ for gas, 0.9g/cm³for oil and 1.0 g/ cm³ for water)

Effective porosity of the reservoirs was obtained from the total porosity. The effective porosity represents all the connected pores in the reservoir. Most of the reservoirs in the Niger Delta are made up of shaly-sand sequences or are associated with shale contents. Therefore, there is need to account for this shale contents in calculating the porosity of reservoirs. This is the reason for the determination of the effective porosity. The effective porosity (ϕ_e) was calculated using shale volume and total porosity (Al-Ruwaili, 2007). The effective porosity is determined as

$$\phi_e = \phi_D * (1 - V_{sh}) \quad 4$$

where

ϕ_D = Total porosity

ϕ_E = Effective Porosity

V_{sh} = Volume of shale

Determination of Water saturation (S_w)

Water saturation is the proportion of the pore space occupied by water and it is computed in fraction or percentage. In clean formations, water saturation is by direct application of Archie's (1942) equation. Archie observed that the resistivity of water saturated, clean formation (R_o) bears a constant relationship with the resistivity of the water saturating it (R_w). The relation is:

$$R_o = F \cdot R_w \quad 5$$

where

F = formation resistivity factor (F).

The formation factor varies predictably as the rock porosity changes according to the expression:

$$F = a/\phi^m \quad 6$$

Where

a = tortuosity factor,

m = cementation factor.

Reservoir rocks having less than 100% water saturation and resistivity R_t are found to obey the rule:

$$S_w = \sqrt[n]{\frac{a \times R_w}{\phi^m \times R_t}} \quad 7$$

Where

n = saturation exponent.

S_w = water saturation level,

R_w = water resistivity,

R_t = formation resistivity (virgin zone) containing the hydrocarbon,

ϕ = total porosity of the reservoir.

The values of a, m and n were obtained from available literatures for the study area. In this work, the fluid saturation of a reservoir is usually expressed as a function of the total pore space. The higher the value of water saturation in a reservoir sand, the lower the hydrocarbon content. Hydrocarbon saturation (S_h) is the fraction of pore volume occupied by oil or gas. It was computed by subtracting the computed water saturation in the reservoir from one (AbdElhady, et al., 2015):

$$S_h = 1 - S_w \quad 8$$

Determination of Net-To-Gross

Net-to-gross (NTG) is the ratio of total thickness of reservoir productive pay zone to that of the total thickness of the subsurface reservoir interval. It has a direct relationship with the shale volume in the reservoir (Abbaszadeh et al. 2003). The NTG was calculated using equation (Al-Baldawi, 2015):

$$NTG = \frac{\Sigma(\text{Net Int})}{\Sigma(\text{Gross Int})} \quad 9$$

Where

Net Int. = interval of the net pay section of the reservoir;

Gross Int = interval of the entire reservoir.

Determination of Permeability

Permeability is a measure of the ease with which fluid can flow through a formation. The unit of permeability is the millidarcy (mD). Permeability is the measure of the ability of a porous medium to transmit fluid without change in the structure of the medium or displacement of its parts. The permeability values for the observed reservoirs were calculated using the model equation by Owolabi et al. (1994).

For oil;

$$K(\text{mD}) = 26552 \times \phi^2 - 34540 \times \phi^2 \times S_{wr}^2 + 307 \quad 10$$

For gas;

$$K = 30.7 + 2655 (\Phi - E^2) - 3454 (\Phi - E * Swirr)^2$$

11

Where;

$Swirr$ = irreducible water saturation

K = permeability in millidarcies

Φ = porosity

Sw = water saturation

The model was used because it takes into consideration the unconsolidated reservoir sand within the Niger Delta.

IV. Results and Discussion

Identified Lithology and Reservoirs

The lithology and reservoir identifications were based on the gamma ray and resistivity signatures. The gamma ray log was utilized to delineate shale and sandstone intervals and identify lithologic changes. The identified lithologies are colour coded for easy recognition in the logs. Low gamma ray reading representing deflection to the left indicate sand body and they are colour coded with yellow while high gamma ray values representing deflection to the right indicate shale body and they are coded with dark colour as shown in the correlation panel in Figure 3. Sandy shale lithology was also observed beside the two major lithologies. The gamma ray logs from the nine boreholes show alternation of sand and shale which is typical of Agbada formation in the Niger Delta (Beka & Oti, 1995). It was observed from the correlation panel that the depth of the wells logged varied from one well to another.

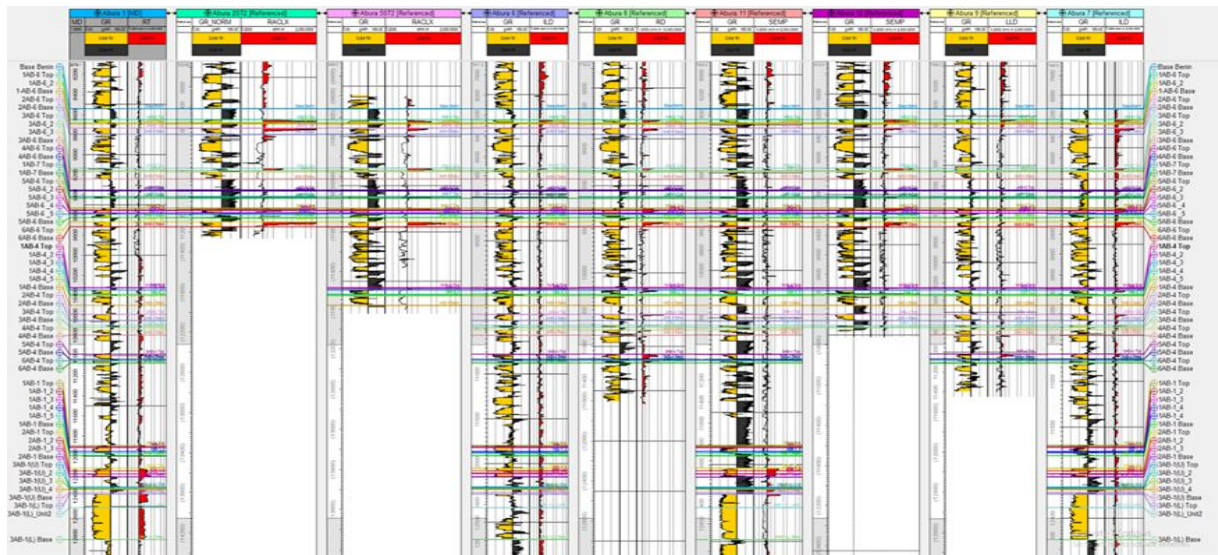


Fig. 3: Well correlation panel showing delineated lithologies and reservoirs.

Combination of resistivity and gamma ray logs were used for the delineation of the reservoirs. High resistivity values corresponding to a low gamma ray log indicate a reservoir zone while a high gamma ray log value corresponding to low resistivity log is indicative of shale, water-bearing zones or conductive formations. In the resistivity log, zones with bright colours such as red, orange, or yellow signify high resistivity and it suggest potential hydrocarbon-bearing zones or non-conductive, clean formations. Dark or subdued colours such as blue, green, or purple represent low resistivity and they correspond to water-saturated zones or shales. Multiple reservoir zones were delineated in some wells, with certain wells. Three major reservoirs (reservoir 3AB-6, reservoir, 6AB-6 and reservoir 2AB-4) were delineated and correlated across the nine wells. The consistent gamma ray and resistivity patterns across the wells indicates continuous lithological units while sharp changes in gamma-ray and resistivity logs are interpreted as a lithological contact Zones. The reservoirs are present across multiple wells at almost the same depths, indicating lateral continuity and widespread depositional environment with relatively uniform stratigraphy.

Computed Petrophysical Properties

The computed petrophysical properties for the identified the three reservoirs in the study area are shale volume, total and effective porosities, water saturation, net-to-gross, and permeability. Tables 1 to 4 show the values of the petrophysical properties obtained in the reservoirs for four wells Abura 1, Abura SST2, Abura 8 and Abura 9.

Table 1: Computed petrophysical properties in the delineated reservoirs for Abura 1

Reservoir	Top Depth (TVDSS, ft)	Base Depth (TVDSS, ft)	VShale (fraction)	Effective Porosity, ϕ_e (fraction)	Total Porosity, ϕ_t (fraction)	Water Saturation, S_w (fraction)	Permeability, k (mD)
6AB-6	9667.93	9717.00	0.05–0.25 (clean sands dominant in W/SW; shale pockets NW)	0.15–0.25 (best corridors S–SE and crest flanks)	0.14–0.28	0.15–0.45 (pay zones typically <0.20 W/SW; higher in NE)	700–2,000 (locally >1,200– 2,000 in sand fairways; <350– 500 in shale-rich blocks)
2AB-4	10588.64	10650.19	0.15–0.45 (clean SW corridors; higher Vsh central–SE)	0.14–0.22 (local highs 0.20–0.28 in SE)	0.12–0.30	0.20–0.55 (oil-prone SW/central; water-prone NE)	350–2,400 (best >1,500 in SE/central; <500 in NW/NE)
3AB-6	9132.77	9241.22	0.05–0.25 (clean sands prevalent; local shale pockets)	0.12–0.25 (best N/NE and central)	0.20–0.28	0.20–0.45 (higher S_w near faults/structural lows)	700–2,000 (SE block highest; <350–500 in shale-rich/deeper zones)

Table 2: Computed petrophysical properties in the delineated reservoirs for Abura SST2

Reservoir	Top Depth (TVDSS, ft)	Base Depth (TVDSS, ft)	VShale (fraction)	Effective Porosity, ϕ_e (fraction)	Total Porosity, ϕ_t (fraction)	Water Saturation, S_w (fraction)	Permeability, k (mD)
6AB-6	10313.95	10425.77	0.15	0.18	0.22	0.25	1,200
3AB-6	10899.26	10951.60	0.30	0.15	0.20	0.35	800

Table 3: Computed petrophysical properties in the delineated reservoirs for Abura 8

Reservoir	Top Depth (TVDSS, ft)	Base Depth (TVDSS, ft)	VShale (fraction)	Effective Porosity, ϕ_e (fraction)	Total Porosity, ϕ_t (fraction)	Water Saturation, S_w (fraction)	Permeability, k (mD)
6AB-6	9412.19	9476.43	0.175	0.18	0.22	0.325	1052
2AB-4	10504.29	10599.46	0.35	0.16	0.19	0.39	755
3AB-6	8798.32	8922.05	0.165	0.21	0.23	0.29	1067

Table 4: Computed petrophysical properties in the delineated reservoirs for Abura 9

Reservoir	Top Depth (TVDSS, ft)	Base Depth (TVDSS, ft)	VShale (fraction)	Effective Porosity, ϕ_e (fraction)	Total Porosity, ϕ_t (fraction)	Water Saturation, S_w (fraction)	Permeability, k (mD)
6AB-6	9590.63	9647.74	0.19	0.20	0.23	0.33	1050
2AB-4	10523.32	10601.84	0.325	0.14	0.18	0.425	750
3AB-6	9026.74	9126.67	0.175	0.18	0.22	0.30	1000

IV. Discussion

Two major lithologies (sandstone and mudstone) were delineated from the gamma ray log. The gamma ray logs from all the boreholes show alternation of sandstone and shale, which is an indication that the log zones are part of the Agbada Formation in the Niger Delta (Beka and Oti, 1995). The sharp changes observed in the gamma-ray and resistivity logs represent lithological contacts. The irregular log correlation may be due to faults, pinch-outs, or unconformities. The consistent shale and sandstone units across the wells are the result of a widespread depositional environment with almost uniform stratigraphy. Three major hydrocarbon-bearing reservoirs were delineated through qualitative analysis of the integration of resistivity log with the GR log. The three reservoirs are 6AB-6, 2AB-4, and 3AB-6, respectively.

The well correlation panel shows consistent gamma ray and resistivity patterns across the nine wells, which is an indication of continuous lithological units. Sharp changes in gamma-ray and resistivity logs are interpreted as a lithological contact. The differences in logs across the wells may be interpreted as lateral facies changes or structural features, or an indication of a different depositional environment.

Petrophysical properties were calculated for four of the wells (Abura 1, Abura SST2, Abura 8, and Abura 9) in the field. The petrophysical properties are Volume of shale, total porosity, effective porosity, water saturation, and permeability. The volume of shale ranges from 0.05 to 0.35 in the three reservoirs delineated in the wells. This is an indication that the reservoirs are dominated by sandstone with some pockets of shale. The computed effective and total porosity ranges between 0.12 and 0.30 for the reservoirs. The results show that the quality of the porosity in the reservoirs is very good. Most of the water saturation obtained for the reservoirs in the wells are less than 0.40, which implies that the reservoirs have good hydrocarbon saturation. The values of permeability computed for the wells in the reservoirs range between 700 to 2000 mD. The computed values of the petrophysical properties show that the three reservoirs have good quality.

V. Conclusion

The formation evaluation of geophysical logs from Abura field, onshore Niger delta was carried out to evaluate the reservoir properties. The petrophysical property model of the study area exhibits lateral variations in the porosity distributions which are directly related to the facies changes. Two major lithologies and three reservoirs were delineated. The lithologies are sand and shale, while the reservoirs are 6AB-6, 6AB-3, and 2AB-4. The values of computed petrophysical properties such as porosity, volume of shale, net-to-gross, water saturation, and permeability show that the reservoirs qualities are good. The computed porosity and water saturation range from 19.0 to 22.7 percent and 0.19 to 0.286, respectively. The computed permeability ranges from 516 to 1662 mD, while the Net-to-Gross ratio for the four reservoirs ranges from 0.844 to 0.947. Generally, the reservoirs have good petrophysical properties. The computer processed log interpretation gives a quick view of the vertical variation of the petrophysical properties with depth.

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