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Evaluation of Shale Volume and Effective Porosity from Wire Line Logs in 'Watty' Field, Niger Delta, Nigeria

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Abstract - Well log data from three wells were evaluated for shale volume and effective porosity. Well log data were obtained from gamma ray, neutron, density, resistivity, sonic and caliper logs. This study aimed at using Larionov and Archie equations to evaluate the shale volume and effective porosity using the well log data obtained from three wells. The results of the analysis depict the presence of sand, sand-shale and shale formations. Hydrocarbon accumulations were found to be high in sand, fair in sand-shale and poor in shale.
The thickness of the reservoir ranged from 1300 to 2500 m. Shale volume and effective porosity values ranged from 0.00 to 0.302 and, 0.047 to 0.302 respectively and porosity values decreasing with increasing depth. Similarly, water saturation, water resistivity and permeability ranged from 0.432 to 0.779, 0.106 to 2.918 Ohm-m and 3.847 to 6.454 Darcy respectively. The values for effective porosity are high in sand, fair in sand-shale and low in shale formations.

Key words - *Shale volume, effective porosity, total porosity, petrophysical parameter, formation factor, water saturation, permeability, saturation exponent.*

1 INTRODUCTION

Shale and porosity are considered the most effective parameters in reservoir characterization (Archie, 1950). Shales are soft finely stratified sedimentary rocks that are formed from consolidated mud or clay and tiny fragments of other minerals such as quartz and calcite. It is more radioactive than sand or carbonate. Shale formation reduces water saturation and other petrophysical parameters. However, existence of shale in formations create uncertainties which influence their evaluation. The presence of shale in porous formations poses problems in the interpretation of wire line logs. These problems affect the accurate interpretation of petrophysical data (Okwoli et al., 2015). Even small amounts of shale can have significant effects in reservoir parameters evaluation. Shale materials can be distributed in the formation as: dispersed, structural and laminar. Shale laminae are tiny layers of clay fragments within sand formations, Structural clays/shales are shale/clay fragments that form sedimentary rock structures. Dispersed clays are clay particles formed between the open fragments of the clastic matrix. Porosity is a void space inside the rock which store and transmit fluids such as oil, gas and water. Porosity is classified as total porosity and effective porosity. Effective porosity is the vast spaces of porous material that can transmit fluid.
Total porosity is the percentage volume occupied by the pore space.

Three lithostratigraphic units are identified in the study area: Benin, Agbada and Akata Formations (Hosper, 1965, Chopra and Mechelena, 2011). Akata Formation (Eocene to Recent) formed at the base of the delta, is of marine origin and composed of thick shale, turbibite sand, clay and slit. Agbada Formation (Lower/Middle Miocene to Pliocene) consists of shale and sandstone beds of equal proportions and, is the major petroleum bearing unit in the delta. Benin Formation (Miocene to Recent) consists of predominantly coastal plain sandstones with local interbeds of shale (Weber and Daukoru, 1985).

Petroleum in the Niger Delta are trapped from sandstones and unconsolidated sand within the Agbada Formation in which the main petrophysical properties are porosity, permeability and shale volume (Akata,1997). These parameters determine the storage and fluid flow capacity for hydrocarbon in the reservoir (Welex, 1978: Whiteman, 1982). This approach identified the relationship between porosity and other reservoir parameters and, led to the evaluation of effective porosity from the total porosity and shale volume.
This paper aimed at evaluating the shale volume and effective porosity from wire line logs using Larionov and Archie

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equations which is considered an accurate method in evaluation of reservoir.

Location and Geology of the study area

The Niger Delta region of Nigeria is a sedimentary basin underlain by, from bottom to top, Akata, Agbada and Benin Formations. The Niger Delta comprises of the weathered top soil and unconsolidated coastal plain sands of the Benin Formation. The Niger Delta is situated in the Gulf of Guinea which extends to south- southern region of Nigeria as shown in figure 1 (Klett et al., 1997, Ameloko, AA and Oweseni, 2015). From Eocene to present, the delta is the largest regressive deltas in the world with a total of 300,000km^2 and sediments volume/thickness of 500,00km^3 and 10km respectively (Kulkie, 1995; Kaplan et al., 1994). The Niger Delta is found in the tropical rainforest which is classified into four zones: coastal inland zone, freshwater zone, lowland rainforest zone and mangrove swamp zone (FME et al., 2006; ANEEJ, 2004). The Niger Delta region comprises of eight states, namely: Abia, Akwa Ibom, Bayelsa, Cross River, Edo, Ondo, Imo and Rivers, in which one petroleum system has been identified called tertiary Niger Delta.

The Tertiary Niger Delta is divided into three formations, namely: Benin, Agbada and Akata Formations (Hosper, 1965). The Akata Formation (Eocene to Recent) formed at the base of the delta, is of marine origin and composed of thick shale, turbibite sand, clay and slit of 7000m thickness (Stacher,1995). The Agbada Formation (Lower/Middle Miocene to Pliocene) consists of shale and sandstone beds of equal proportions which is the major petroleum bearing unit (Okwueze, 2010). Also, it comprises of quartz dominantly and orthoclase feldspar with some amounts of plagioclase, kaolinite and ellite with over 3700m thickness that represents the actual deltaic portion (Evamy et al., 1978). The Benin Formation (Miocene to Recent) consists of predominantly coastal plain sandstones with local interbeds of shale of over 2000 m thickness (Avbovbo, 1978).

Geologically, two provinces have been identified in Niger Delta: Onshore and Offshore. The onshore portion is situated in the southern Nigeria and southwestern Cameroon. It is bounded in the north by Benin flanks, east to north by hinge line and south to west by basement Massif which is identified by outcrops of the Cretaceous on the Abakaliki High in the east and Calabar Flank in the south which is also bordered by hinge line of adjacent Precambrian (Nyantakyi et al., 2013). Offshore boundary of the province is defined by the Cameroon volcanic line of the eastern boundary and west of the Dahomey Basin.

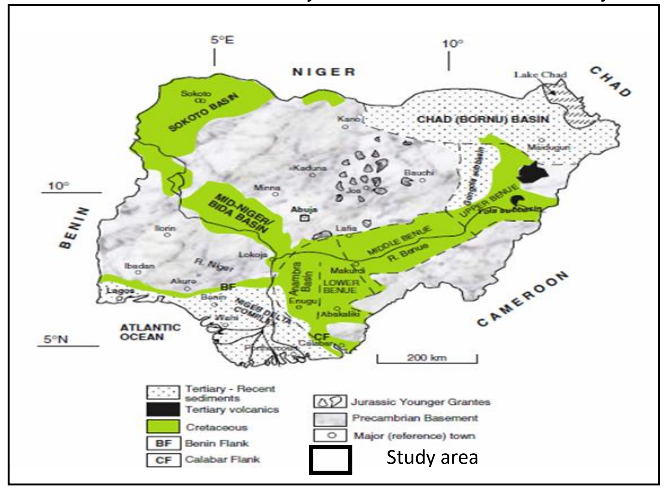

Fig. 1. Map of Nigeria showing the study area

DATA AND METHOD

A total of three wire line logs were analyzed for the evaluation of shale volume and effective porosity. The data set analyzed consists of gamma ray log, density log, neutron log, sonic log and spontaneous log which are used in evaluating of lithology, shale volume and effective porosity respectively. The well logs interpretation identify reservoir and provides the output of log analysis of the reservoir parameters (Asquith and Gibson, 1982). Fundamentally, high porosity formation reading indicates high value of shale, low sand deposition and low hydrocarbon formation while low porosity formation reading indicates low values of shale, high sand deposition and high hydrocarbon (Chapman, 1983, Eghai and Aigbogun, 2012). The first stage in well log analysis is the lithology interpretation (Harry et al, 2017; 2018) which is vital in reservoir characterization. On the other hand, if the lithology interpretation is incorrect, other parameters like shale volume, porosity and effective porosity will be wrong.

Shale volume (V_{sh})

Shale volume interpretation is the second stage in well logs analysis by using gamma ray log. The calculation of shale volume is useful in the determination of the water and hydrocarbon saturations, if the reservoir has high shale formation, that reservoir are highly porous with high clayey deposition and water saturation. This is because shale has a high porous ability to retain water. Also, low shale reservoir has high accumulation of hydrocarbon because formation with low shale volume has high permeability and vice versa. It is expressed as shown in Eqs. 1 to 3.

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Larionov's Equation

In 1969, Larionov proposed two formulas to calculate volume of shale in rocks. These are:

Tertiary rocks: $V_{Sh} = 0.083(2^{3.7 I_{GR}} - 1)$ ………………..(1)

Older rocks:

$V_{Sh} = 0.33(2^{2 I_{GR}} - 1)$ ……………………………..(2)

$$I_{GR} = \frac{GR_{Log} - GR_{Min}}{GR_{Max} - GR_{Min}} \quad \text{……………………….……(3)}$$

Where,

I_{GR} is the gamma ray index,
V_{sh} is the volume of shale,
GR_{log} = gamma ray reading of formation;
GR_{min} = minimum gamma ray for clean sands or carbonates
GR_{max} = maximum gamma ray reading for shale

Porosity (Φ)

Porosity calculation is the third stage in well log analysis. Porosity depends on the lithology interpretation. However, if the lithology interpretation is correct, porosity interpretation will be correct. It could be calculated using density log, sonic log, neutron log, or combination between neutron-density logs. Below shows the calculation of porosity using Archie's equation as expressed in equations 4, 5, 6 and 7.

Archie's Equation

$$\Phi = \frac{Sonic\log value - 55.5}{189 - 55.5} \quad \text{……………………..… (4)}$$

Where 55.5 = Δt_{ma} is the sandstone constant sonic log value, 189 = Δt_{fluid} is the fluid constant sonic log value.

$$\Phi^m = \frac{a}{F} \quad \text{…………………………………………. (5)}$$

Where a is tortuosity sand factor 'a' = 1, m is the compaction sand exponent factor 'm' = 2

$$\Phi = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_{fl}} \quad \text{……………………..……….. (6)}$$

Where ρ_{ma} is the matric density, ρ_b is the bulk density and ρ_{fl} is the fluid density

$$\Phi^m = \frac{R_w}{S_w^n R_t} \quad \text{……………………… (7)}$$

Where S_w^n water saturation, n is the saturation exponent, R_t true formation resistivity and R_w is formation water resistivity

Effective Porosity

Effective porosity is the differences between the total porosity and the product of the volume of shale with shale porosity fractions. It is the ratio of interconnected pore spaces to the total bulk volume of the rock. In a formation that is highly sandy with zero shale content, the effective porosity is equal to total porosity. That is, volume of the shale is equal to zero. However; effective porosity in a formation illustrates a pore space that contains high hydrocarbon and low clayey deposition. The effective and total porosities relationship in a shaly sand reservoir can be expressed as shown in Archie Equations 8, 9 and 10 below:

Archie's Equation

Shale sand reservoir

$$\Phi_e = \Phi_t - V_{sh} \times \Phi_{sh} \quad \text{………………………(8)}$$

Φ_t = fraction of total porosity; Φ_e = fraction of effective porosity; V_{sh} = fraction of volume of shale and Φ_{sh} = fraction of shale porosity.

However, shale porosity can also be determined by substituting shale porosity Φ_{sh} with total porosity Φ_t to get equation 9

Shale reservoir

$$\Phi_e = \Phi_t - V_{sh} \times \Phi_t \quad \text{………………………… (9)}$$

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Shale-bound water

$$\Phi_e = \Phi_t - V_{cbw} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (10)$$

V_{cbw} = fraction of volume of clay or shale-bound water. The volume of the clay bound water replaced the shale volume and its porosity. This can be obtained using Elemental Capture Spectroscopy (ECS).

RESULTS AND DISCUSSION

Well log data from three wells was used for this study. Shale volume and effective porosity were calculated along with other parameters and three formation zones were identified which includes: sand, shale and sand shale. The shale volume and effective porosity were evaluated using Larionov and Archie approaches as shown in equation 1 to equation 10 respectively. The key parameter of Larionov Equation for shale volume calculation is the gamma ray index from gamma ray log. in Archie Equation, the key parameters are: 'm' compaction factor, 'n' saturation exponent and 'a' tortuosity factor. For water saturation and resistivity, the compaction factor and saturation exponent is equal to 2 and tortuosity factor is equal 1 due to its variation in different formation.

Tables 1 and 2 and, figures 2, 3 and 4 show the analysis of shale volume, porosity and other reservoir properties in wells 1, 2 and 3 while tables 4 and 5 show the ranges of evaluated parameters and characterization of the well formation. In each of the wells, three reservoirs where identified. In well 1, mean value of the shale volume is 0.347, mean porosity is 0.211, effective porosity is 0.138, permeability is 4.324D, water saturation and resistivity values are 0.623 and 1.715 Ohm-m respectively. This reservoir indicates a fair hydrocarbon accumulation from sand-shale formation.

In well 2, the volume of shale is 0, mean porosity is 0.302, effective porosity is 0.302, permeability value is 3.847D, water saturation and resistivity are 0.432 and 2.18 Ohm-m respectively. This indicates a high presence of hydrocarbon accumulation from sand formation.

In well 3, the shale volume value 0.740, mean porosity is 0.182, effective porosity is 0.047, permeability value is 6.454D, water saturation and resistivity are 0.799 and 2.985 Ohm-m respectively. This reservoir indicates a low hydrocarbon accumulation from shale formation.

However, it is observed that the value of the effective porosity and shale volume ranged from 0.047 to 0.302 and 0.182 to 0.302. Based on the analysis, high hydrocarbon accumulation is attributed to sand zone with a corresponding high effective porosity and zero shale volume. Fair hydrocarbon zone is attributed to sand-shale zone while low hydrocarbon accumulation is attributed to shale zone with low effective porosity and high shale volume values. The low values of the effective porosity depict grain size effect within the reservoir sand. Subsequently, the reservoir indicates less accumulation of hydrocarbon from shale formation, high hydrocarbon accumulation from sand and fair hydrocarbon accumulation in sand- shale formation.

Table 1: Reservoir Parameters of Well 1

Curves	Units	Top Values	Bottom. Values	Net Values	Minimum Values	Maximum Values	Mean Values
BVW	Dec	1223.05	3040.698	1817.702	0.000	0.411	0.105
CAL	Inch	0	3519.7	3520.551	-999.250	24.299	-340.605
GR_NM	API	0	3519.7	3520.551	-999.250	134.423	36.216
K	Darc	1223.05	3040.698	1817.702	2.053	25.646	4.324
LL9D	gm/cc	0	3519.7	3520.551	-999.250	357.436	-101.946
NPHI	Dec	0	3519.7	3520.551	-999.250	52.006	-478.577
PHI	Dec	1223.05	3040.698	1817.702	0.000	0.600	0.211
RHOB	gm./cc	0	3519.7	3520.551	-999.250	2.589	-346.624
RWapp	Ohmm	1223.05	3040.698	1817.702	0.000	47.022	1.715
SONIC	us/ft	0	3519.7	3520.551	-999.250	170.338	-279.431
SW	Dec	1223.05	3040.698	1817.702	0.046	1.000	0.623
V_{SH}	Dec	1223.05	3040.698	1817.702	0.119	0.876	0.347

Table 2: Reservoir Parameters of Well 2

Curves	Units	Top Values	Bottom Values	Net Values	Minimum Values	Maximum Values	Mean Values
BVW	Dec	1200.023	2499.933	1300.080	0.021	0.348	0.124
CAL	Inch	1200.023	2499.933	1300.080	11.750	17.813	12.333
LL9D	gm/cc	1200.023	2499.933	1300.080	1.745	2.568	2.152
GR_NM	API	1200.023	2499.933	1300.080	26.702	120.198	50.013
K	Darc	1200.023	2499.933	1300.080	2.221	20.688	3.847
NPHI	Dec	1200.023	2499.933	1300.080	0.409	0.409	0.409
PHI	Dec	1200.023	2499.933	1300.080	0.050	0.549	0.302
RHOB	Ohmm	1200.023	2499.933	1300.080	0.750	224.111	28.872
RWapp	Ohmm	1200.023	2499.933	1300.080	0.010	24.366	2.918
SONIC	us/ft	1200.023	2499.933	1300.080	58.200	152.800	114.916
SW	Dec	1200.023	2499.933	1300.080	0.064	1.000	0.432
V_{SH}	Dec	1200.023	2499.933	1300.080	0.000	0.307	0.000

Nomenclature BVW = Bulk volume of water, CAL = Caliper log, GR_NM = gamma ray neutron meter, NPHI = Neutron porosity, PHI = porosity, RHOB = Resistivity density, RW_{app} =

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Apparent water resistivity, SONIC = Sonic log, SW = Water saturation, HS = Hydrogen saturation, V_{SH} = Volume of shale and K= Permeability

Table 3: Reservoir Parameters of Well 3

Curves	Units	Top Values	Bottom Values	Net Values	Minimum Values	Maximum Values	Mean Values
BVW	Dec	2176.633	2499.627	323.141	0.019	0.204	0.140
CAL	Inch	2176.633	2499.627	323.141	12.344	18.031	13.350
LL9D	gm/cc	2176.633	2499.627	323.141	2.034	2.464	2.197
GR_NM	gAPI	2176.633	2499.627	323.141	26.361	106.837	59.466
K	Darc	2176.633	2499.627	323.141	3.996	52.884	6.454
NPHI	Dec	2176.633	2499.627	323.141	0.128	0.481	0.295
PHI	Dec	2176.633	2499.627	323.141	0.019	0.282	0.182
RHOB	Ohm m	2176.633	2499.627	323.141	1.175	12.407	2.985
RWapp	Ohm m	2176.633	2499.627	323.141	0.002	0.842	0.106
SONIC	us/ft	2176.633	2499.627	323.141	57.625	142.750	113.352
SW	Dec	2176.633	2499.627	323.141	0.241	1.000	0.799
V_{SH}	Dec	2176.633	2499.627	323.141	0.717	0.773	0.740

Table 4: Ranges of measured and calculated parameters

K (darc.)	K (darc.)	Φ_e (dec)	Sw (dec)	K (darc.)	R_{Wapp} (Ohmm)
Well 1					
0.347	0.211	0.138	0.623	4.324	1.175
Well 2					
0.000	0.302	0.302	0.432	3.847	2.180
Well 3					
0.740	0.182	0.047	0.799	6.454	2.985

Table 5: Characterization of the well formations

Wells	Characteristics	Formations
1	Fair Fairly effective porosity, moderate shale volume and hydrocarbon accumulation	Sand-Shale
2	Good High effective porosity, zero shale volume and good hydrocarbon accumulation	Sand
3	Weak Low effective porosity, high shale volume and low hydrocarbon accumulation	Shale

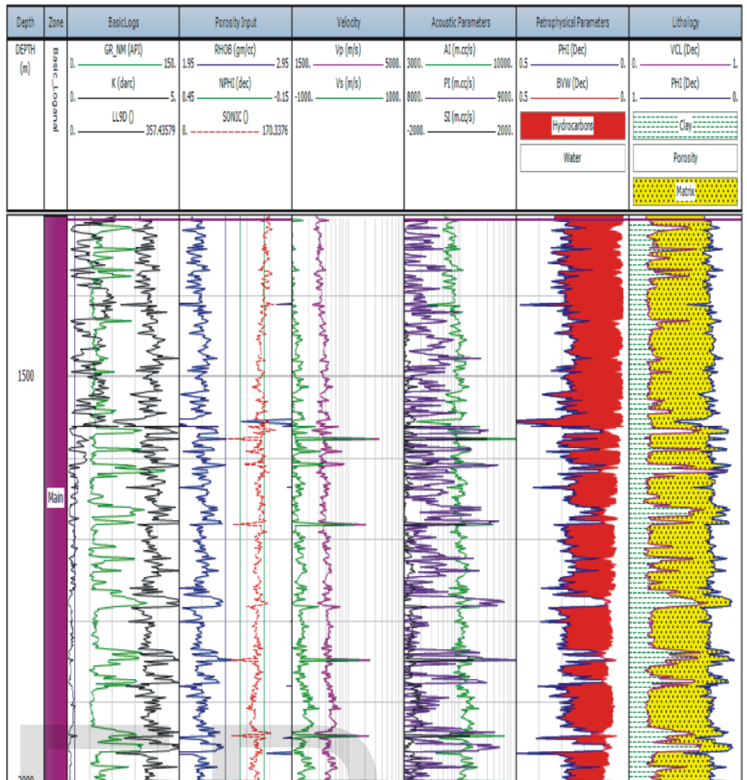

Fig. 2: Well log Interpretation of Well 1

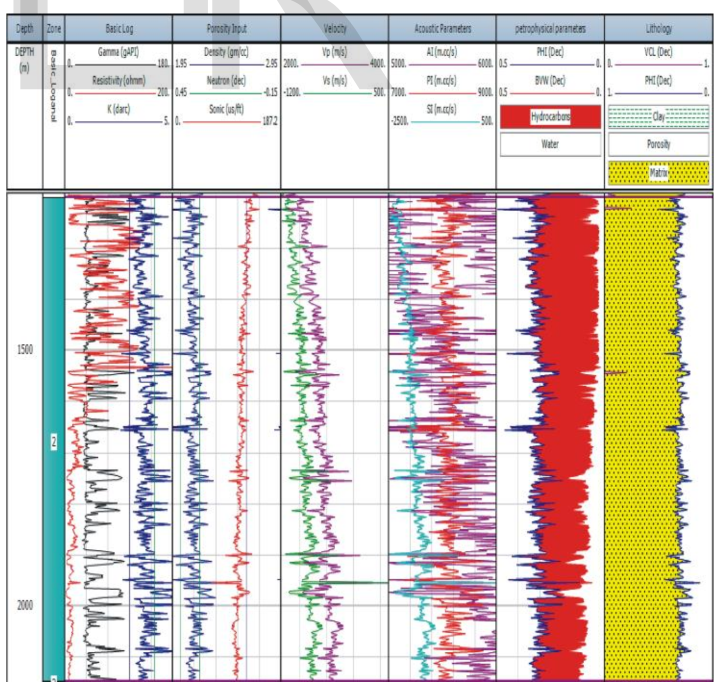

Fig. 3: Well log Interpretation of Well 2

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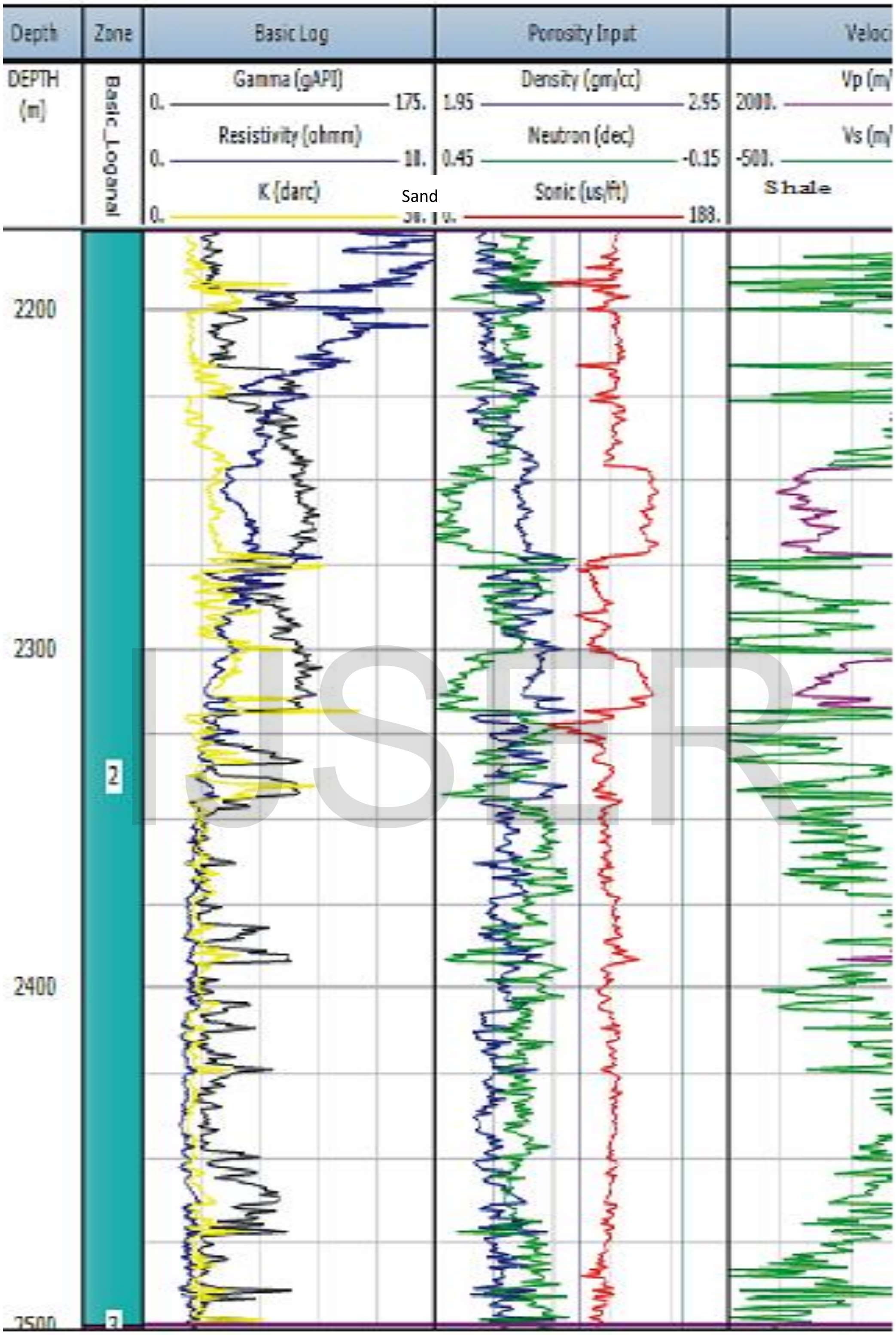

Fig. 4: Well log Interpretation of Well 3

CONCLUSION

The present work evaluates shale volume and effective porosity using petrophysical data from three wells in 'Watty Field' using Larionov and Archie Equations. The result from well log depicts three reservoirs: sand, sand-shale and shale formations. The thickness of the reservoir ranged from 1300 to 2500 m. Shale volumes and effective porosity parameters were evaluated from Larionov and Archie Equations, the values ranged from 0.00 to 0.740 and 0.047 to 0.302 respectively. Similarly, the water saturation, water resistivity and permeability ranged from 0.432 to 0.779, 0.106 to 2.918 Ohm-m and 3.847 to 6.454D in that order. These values of effective porosity are high in sand, fair in sand-shale and low in shale formations.

However, the existence of shale in a formation reduces effective porosity and water saturation and, creates uncertainties in reservoir evaluation and production. The evaluated shale volumes and effective porosity values compared favourably with core analysis data. Thus, this method has proven to be useful approach for the evaluation of shale volumes and effective porosity from wire line log data.

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