

Petrophysical Evaluation of Two Wells in Offshore Niger Delta, Nigeria

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ABSTRACT

This study provides accurate behavior of petrophysical properties with depth for this formation by using Interactive Petrophysics software. The results of the analysis revealed the presence of different sand and shale units, from the analysis of the geological logs comprising gamma-ray and electrical resistivity, the Sonic, Density, Gamma, Neutron, Resistivity and Net Pay Zone value for the reservoirs. The total porosity in the reservoirs was found to range from 0.006 to 0.514, Bulk volume of water in the reservoirs is between 0.042-0.144, Volume of shale for the reservoirs is between 0.034-0.198, the water saturation ranges from 0.147 to 0.519 and the hydrocarbon saturation 0.481 to 0.853. Good well-to-well lithology correlation was established across the fields studied. It was found from this research that the bulk of the hydrocarbon encountered in the Niger Delta basin was found to be within a depth range of 2853.77-3413.76 m (9359.5-11200.5 ft), with net pay zone ranging from 16.91-32.00 m (55.5-105 ft). The hydrocarbon reservoirs in this study were found to be in the Agbada formation, which is in conformity with the geology of the Niger Delta, Nigeria.

1. Introduction

The most common technique to determine petrophysical parameters of a reservoir is well logging. Log-derived parameters such as porosity, permeability, and water and hydrocarbon saturation are the key parameters for characterizing a reservoir to estimate the hydrocarbon volume. Hydrocarbon reservoirs are the major importance of exploration and production companies. Most of the reservoirs at least consist of two different phases of fluids. These phases are gas- water or oil-water some of the reservoirs have all of the three phases of gas, oil and water. Sandstone as the most eminent reservoirs rock has many spaces to reserve hydrocarbon. Carbonates rocks are also important hips to reserve considerable quantities of hydrocarbon.

Reservoirs characterization is a process of describing various reservoir properties using all the available data to provide reliable reservoir models for accurate reservoir performance prediction (Jong, 2005). In order to calculate the hydrocarbon reserve in a geological formation, one needs to know the water saturation amount. Improper calculation of

water saturation leads to great errors in reserve estimation. (Andisheh et al., 1997).

The geological formations in the Niger Delta-Nigeria consist of sands and shales with the former ranging from fluvial (channel) to fluviomarine (Barrier Bar), while the later are generally fluviomarine or lagoon. These Formations are mostly unconsolidated and it is often not feasible to take core samples or make drill stem tests (Aigbedion, 2007). Formation evaluation is consequently based mostly on logs, with the help of mud logger and geological information as in this study. Petrophysical parameters like the lithology, fluid content, porosity, water saturation, hydrocarbon saturation and permeability were derived; from the well log data. Three major lithostratigraphic units have been recognized in the Niger Delta (Short and Stauble, 1967). These are the Akata, Agbada and Benin formations (Fig. 1). Details of the geology of the Niger Delta has been discussed by several authors (Short and Stauble, 1967).

The Benin formation, which is a loose fresh water bearing sand with occasional lignite and clay and going up to 2,286

m deep with no over pressures. The Agbada formation is made up of alternation sands and shales. The sands are mostly encountered at the upper parts while Shales are found mostly at the lower parts. The Agbada formation is thickest at the centre of the Delta and goes up to 457.2 m. This is the seat of most oil reservoirs and centre of over pressures.

Formation evaluation in the area of study within Niger Delta basin will allow an estimate to be made of porosity, fluid content and type and lithology. The physical and chemical properties of the rock determined in this way are an invaluable aid to describing sub-surface geology (Aigbedion, 2007).

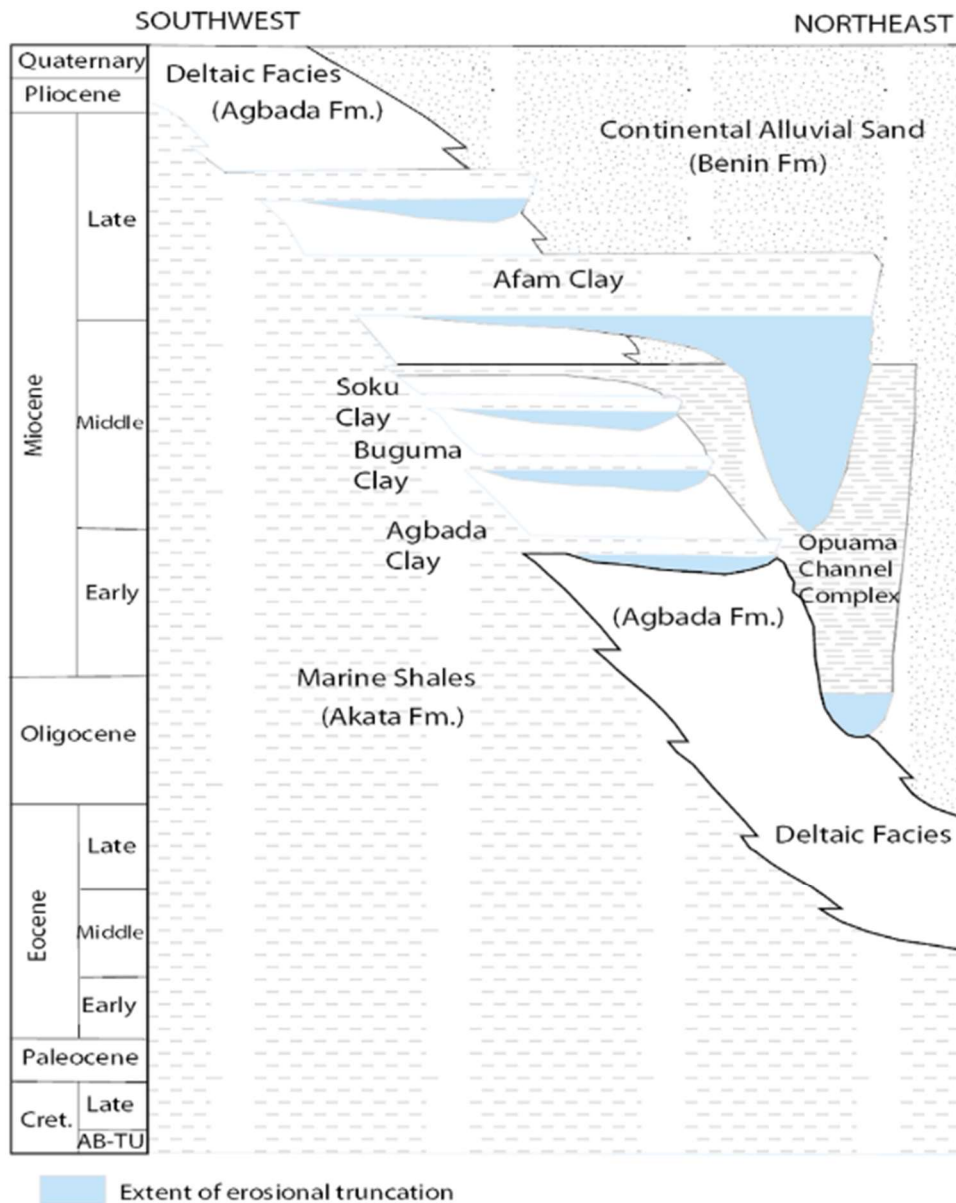


Fig. 1. Stratigraphic column showing the three formations of the Niger Delta (Short and Stauble, 1967)

In the evaluation of a clastic reservoir, the presence of clay particles or shale within the sand is a parameter which must be considered. Shaliness is known to affect both formation characteristic and logging tool response. Carbonates, non-clastic reservoirs, are characteristically limestone and dolomite. Their importance as reservoirs rocks should not be under estimated. Approximately, 50% of hydrocarbon reservoirs are carbonate rocks (Schlumberger, 1985). Well

logging tools respond primarily to the chemical nature of matrix and pore fluids.

If a reservoir rock, which is electrochemically clean, in other words, conduction take place only through the free ions within the formation water, and then reservoir rock is called an Archie reservoir rock or Archie porous media. However, all reservoirs are not clean sand. They contain shale. This

condition is called non-Archie porous medium. The Archie equation can be applied for the sw for shale section of the reservoir. There are water saturation models addressing the clay effect.

This paper aim to evaluate petrophysical parameters (bulk volume of water, porosity, apparent water resistivity, volume of shale and hydrocarbon and water saturation) using basic logs (calliper, density, gamma ray, resistivity and sonic) in the study area, which can be used to evaluate other well log data across the Niger Delta, Nigeria.

2. Study Area

The Niger Delta forms one of the world’s major hydrocarbon provinces and it is situated on the Gulf of Guinea on the west coast of central Africa (Southern Nigeria). It covers an area within longitudes 4°E – 9°E and latitudes 4°N – 9°N (Fig. 2). It is composed of an overall regressive clastic sequence,

which reaches a maximum thickness of about 12 km (Evamy et al., 1978).

The Niger Delta consists of three broad Formations (Short and Stauble, 1967): the continental top facies (Benin Formation), the Agbada Formation and the Akata Formation. The Benin Formation is the shallowest of the sequence and consists predominantly of fresh water-bearing continental sands and gravels. The Agbada Formation underlies the Benin Formation and consists primarily of sand and shale and is of fluviomarine origin.

It is the main hydrocarbon-bearing window. The Akata Formation is composed of shales, clays and silts at the base of the known delta sequence. They contain a few streaks of sand, possibly of turbiditic origin. The thickness of this sequence is not known for certain, but may reach 7000m in the central part of the delta (Short and Stauble, 1967).

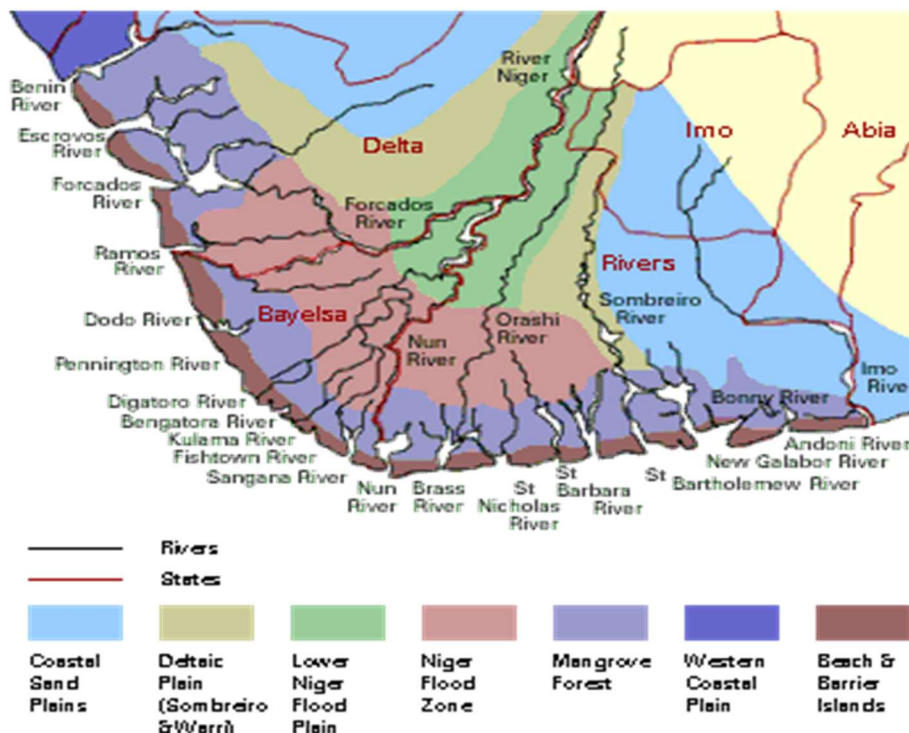


Fig. 2. Map of the Niger Delta Region of Nigeria (Short and Stauble, 1967)

Petroleum in the Niger Delta is produced from sandstone and unconsolidated sands predominantly in the Agbada Formation. The characteristics of the reservoirs in the Agbada Formation are controlled by depositional environment and the depth of burial. Known reservoir rocks are Eocene to Pliocene in age and are often stacked, ranging in thickness from less than 15 meters with about 10% having greater than 45 meters thickness (Evamy et al., 1978). The thicker reservoirs represent composite bodies of stacked channels (Doust and Omatsola, 1990). Based on reservoir geometry and quality, Kulke (1995) described the most

important reservoir types as point bars of distributary channels and coastal barrier bars intermittently cut by sand-filled channels. Doust and Omatsola (1990) described the primary Niger Delta reservoirs as Miocene paralic sandstones with 40% porosity, 2 Darcy’s permeability, and a thickness of 100 meters. The lateral variation in reservoir thickness is strongly controlled by growth faults; the reservoir thickening towards the fault within the down-thrown block (Weber and Daukoru, 1975). The grain size of the reservoir sandstone is highly variable with fluvial sandstones tending to be coarser than their delta front counterparts. Point bars

fine upward, and barrier bars tend to have the best grain sorting. Much of this sandstone is nearly unconsolidated, some with a minor component of argillic-silicic cement (Kulke, 1995). Porosity slowly decreases with depth because of the age of the sediments. Most known traps in Niger Delta fields are structural although stratigraphic traps are not uncommon.

The structural traps developed during synsedimentary deformation of the Agbada paralic sequence (Evamy et al., 1978). Structural complexity increases from the north (earlier formed depobelts) to the south in response to increasing instability of the under-compacted, over-pressured shale. Doust and Omatsola (1990) described a variety of structural trapping elements, including those associated with simple rollover structures clay-filled channels, structures with multiple growth faults, structures with antithetic faults and collapsed crest structures. On the flanks of the delta, stratigraphic traps are likely as important as structural traps. In this region, pockets of sandstone occur between diapiric structures. Towards the delta toe (base of distal slope) this alternating sandstone-shale sequence gradually grades to essentially sandstone.

The primary seal rock in the Niger Delta is the interbedded shale within the Agbada Formation. The shale provides three types of seals - clay smears along faults, interbedded sealing units against which reservoir sands are juxtaposed due to faulting and vertical seals (Doust and Omatsola, 1990). On the flanks of the delta, major erosional events of early to middle Miocene formed canyons that are now clay-filled. These clays form the top seal for some important offshore field locations.

3. Methodology

In his pioneering work Archie (Archie, 1952) sets out the fundamentals of rock-type classification. Any porous network is related to its host rock fabric; therefore, Petrophysical parameter, such as porosity (ϕ), permeability (K) and saturation (S), for any given (type of rock) are controlled by pore sizes and their distribution and interconnection. The goal of reservoir characterization is to predict the spatial distribution of such Petrophysical parameter on a field scale. Archie (1952) stated that a broad relationship exists between porosity and permeability of a formation. Petrophysics also refer to the careful and purposeful use of rock physics data and theory in the interpretation of reservoir geophysics observation.

The Archie equation is well known for determine water saturation of a reservoir rock and therefore initial hydrocarbon reserve estimation of the reservoir. Archie introduced an equation which relates resistivity index (RI) and formation resistivity factor (F) in order to calculate water saturation. Using this equation water saturation is computed (Archie, 1942). The formation resistivity factor F is related to porosity, and the resistivity index, RI is related to the water saturation. Archie's equation requires the values of cementation exponent m, saturation exponent, n and the rock consolidation exponent or tortuosity a. The equation was not a precise one, as he pointed out, and was only an approximate relationship. However, Archie equation is

valued for Archie reservoir rock or clean sands (Worthington, 1985).

3.1. Delineation of shale beds and volume of shale determination

Gamma ray logging is a method of measuring naturally occurring gamma radiation to characterize the rock or sediment in a borehole or drill hole. It is a wireline logging method used in mining, mineral exploration, water-well drilling, for formation evaluation in oil and gas well drilling and for other related purposes.

The Gamma Ray (GR) log is particularly useful for defining shale beds when the spontaneous potential log is distorted or absent. The GR log reflects the proportion of Shale and in many regions can be used qualitatively as a Shale indicator. The bed boundary is picked at a point midway between the maximum and minimum deflection of the anomaly.

There are many different ways of determining the volume of Shale (V_{sh}) in a Shaly formation (Schlumberger, 1987). In a Shaly porous and permeable zone, V_{sh} can be estimated from the deflections of the GR curve using Equation 2 when I_{GR} is estimated from Equation 1 (Agbasi et al., 2013; Agbasi et al., 2017).

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

$$V_{sh} = 0.08(2^{(3.71I_{GR})} - 1) \quad (2)$$

Where I_{GR} is the gamma ray index, GR_{log} log reading of gamma ray, GR_{max} maximum log reading of gamma ray, GR_{min} minimum reading of gamma ray log and V_{sh} is volume of shale estimated from the gamma ray log data.

3.2. Porosity determination

A sonic log is an acoustic log that emits sound waves which start at the source, travel through the formation, and return back to the receiver (Agbasi et al., 2013). The travel time from the source to the receiver is called slowness and as a result sonic logs are sometimes referred to as sonic slowness logs. Total porosity can be calculated from sonic logs using Equation 3 (Agbasi et al., 2013; Agbasi et al., 2017).

$$\phi_w = \frac{\Delta t_{log} - \Delta t_{max}}{\Delta t_{ft} - \Delta t_{max}} \quad (3)$$

Equation 3 is the Wyllie Time Average Porosity equation. Where Δt_{log} is the reading on the sonic log in $\mu s/ft$, Δt_{max} is the transit time of the matrix material (about 55.5 $\mu s/ft$) and Δt_{ft} is the transit time of the saturating fluid (about 189 $\mu s/ft$ for fresh water).

3.3. Formation water resistivity

Using the Archie's equation that related the formation factor (F) to the resistivity of a formation at 100% water saturation

(R_o) and the resistivity of formation water (R_w), was estimated (Agbasi et al., 2013) as;

$$F = \frac{a}{\phi^m} \quad (4)$$

Where m (porosity exponent) = 1.3 and a (tortuosity) = 0.62

$$R_w = \phi^2 R_t \quad (5)$$

3.4. Water saturation

Determination of the water saturation for the uninvaded zone was achieved using the Archie (1942) equation given below for clean formation and the dual water model for shaly formations;

$$S_m^n = \frac{(F \times R_w)}{R_t} \quad (6)$$

But;

$$F = \frac{R_o}{R_w} \quad (7)$$

Thus;

$$S_m^n = \frac{R_o}{R_t} \quad (8)$$

$$\text{Or } S_m^2 = \frac{R_o}{R_t} \quad (9)$$

Where; n : 2 (water saturation exponent), m : porosity exponent, F : formation factor, S_m^n = Water saturation of the uninvaded zone, R_o : resistivity of formation at 100% water saturation, R_t : true formation resistivity, R_w : apparent water resistivity, a : tortuosity and ϕ : porosity. Therefore,

$$S_w = \left[\frac{a \times R_w}{\phi^m \times R_t} \right]^{1/n} \quad (10)$$

3.5. Bulk volume of water and hydrocarbon saturation

The Bulk volume of water is given by

$$BVW = \phi \times S_w \quad (11)$$

Where; ϕ : porosity and S_w : water saturation

From water saturation S_w , hydrocarbon saturation can be estimated using Equation 12

$$S_w + S_H = 1 \quad (12)$$

Where; S_w : water saturation and S_H : hydrocarbon saturation

4. Results and Analysis

The results of the well log data are presented in well log panel and table, the analysis was done using computer aided petrophysical software, Interactive Petrophysics (IP v. 4.5). Gamma ray logs was used to infer lithology (sand and shale), resistivity log was used to discriminate between fluid (oil and water) and the density and sonic log was used to calculate porosity.

4.1. Well X01

Fig. 2 shows the log plot of well X01, having a stratum of sandstone within its formation intervals. Two reservoirs were identified in well X01, the depths of the reservoirs are between 3335.73-3367.58 m (10944-11048.5 ft) and 3413.91-3438.60 m (11200.5 – 11281.5 ft), while the net pay zone is 32.00 m (105 ft) and 24.84 m (81.5 ft) for well X01 R1 and well X01 R2 respectively. The net pay zone of the reservoirs shows good accumulation of hydrocarbon saturation. Figs. 3 and 4 are the basic log plot for the identified reservoirs in well X01. The mean values of the petrophysical parameters of well X01 R1 are: Bulk volume of water, 0.051, Calliper, 8.327 in, Density, 2.135 g/cm³, Gamma Ray, 34.796 gAPI, Porosity, 0.312, Resistivity, 95.023 ohmm, Apparent water resistivity, 7.859 ohmm, Sonic, 89.255 us/ft, Volume of shale, 0.162 and Water saturation, 0.179. The mean values of the petrophysical parameters of well X01 R2 are Bulk volume of water, 0.042, Calliper, 8.189 in, Density, 2.139 g/cm³, Gamma Ray, 40.943 gAPI, Porosity, 0.31, Resistivity, 166.82 ohmm, Apparent water saturation, 17.376 ohmm, Sonic, 90.909 us/ft, Volume of shale, 0.198, and Water saturation, 0.147.

Table 1 also presents the minimum, maximum and mean values of the petrophysical parameters in the two reservoirs in well X01.

4.2. Well X02

Fig. 5 shows the log plot of well X02, having a sequence of sandstone within its formation intervals. Two reservoirs were identified in well X02, the depths of the reservoirs are between 2852.77-2881.27 m (9359.5-9453 ft) and 3056.23-3072.99 m (10027-10082 ft), while the net pay zone is 28.65 m (94 ft) and 16.92 m (55.5 ft) for well X02 R1 and well X02 R2 respectively. The net pay zone of the reservoirs shows good accumulation of hydrocarbon saturation. Figs. 6 and 7 are the basic log plot for the identified reservoirs in well X02. The mean values of the petrophysical parameters of well X02 R1 are: Bulk volume of water, 0.144, Calliper, 11.891 in, Density, 2.193 g/cm³, Gamma Ray, 47.662 gAPI, Neutron, 0.264, Porosity, 0.28, Resistivity, 3.021 ohmm, Apparent Resistivity, 0.236 ohmm, Sonic, 92.922 us/ft, Volume of shale, 0.062, and Water saturation, 0.519. The mean values of the petrophysical parameters of well X02 R2 are Bulk volume of water, 0.114, Calliper, 12.172 in, Density, 2.256 g/cm³, Gamma Ray, 43.533 gAPI, Neutron, 0.223, Porosity, 0.24, Resistivity, 3.427 ohmm, Apparent Resistivity, 0.194 ohmm, Sonic, 87.539 us/ft, Volume of shale, 0.034, Water saturation, 0.483.

Table 2 also presents the minimum, maximum and mean values of the petrophysical parameters in the two reservoirs in well X02.

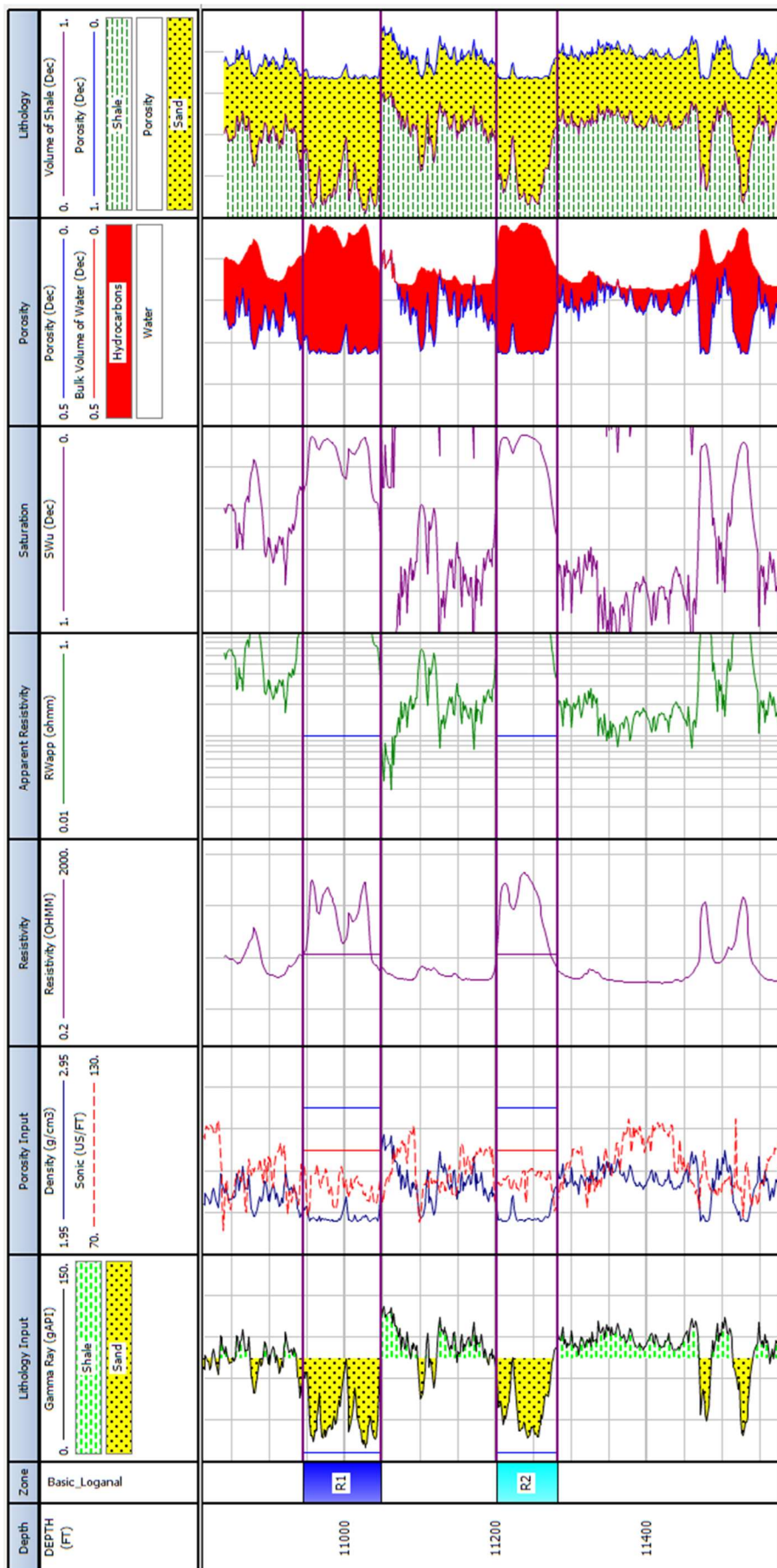


Fig. 3. Basic log plot for Well X01

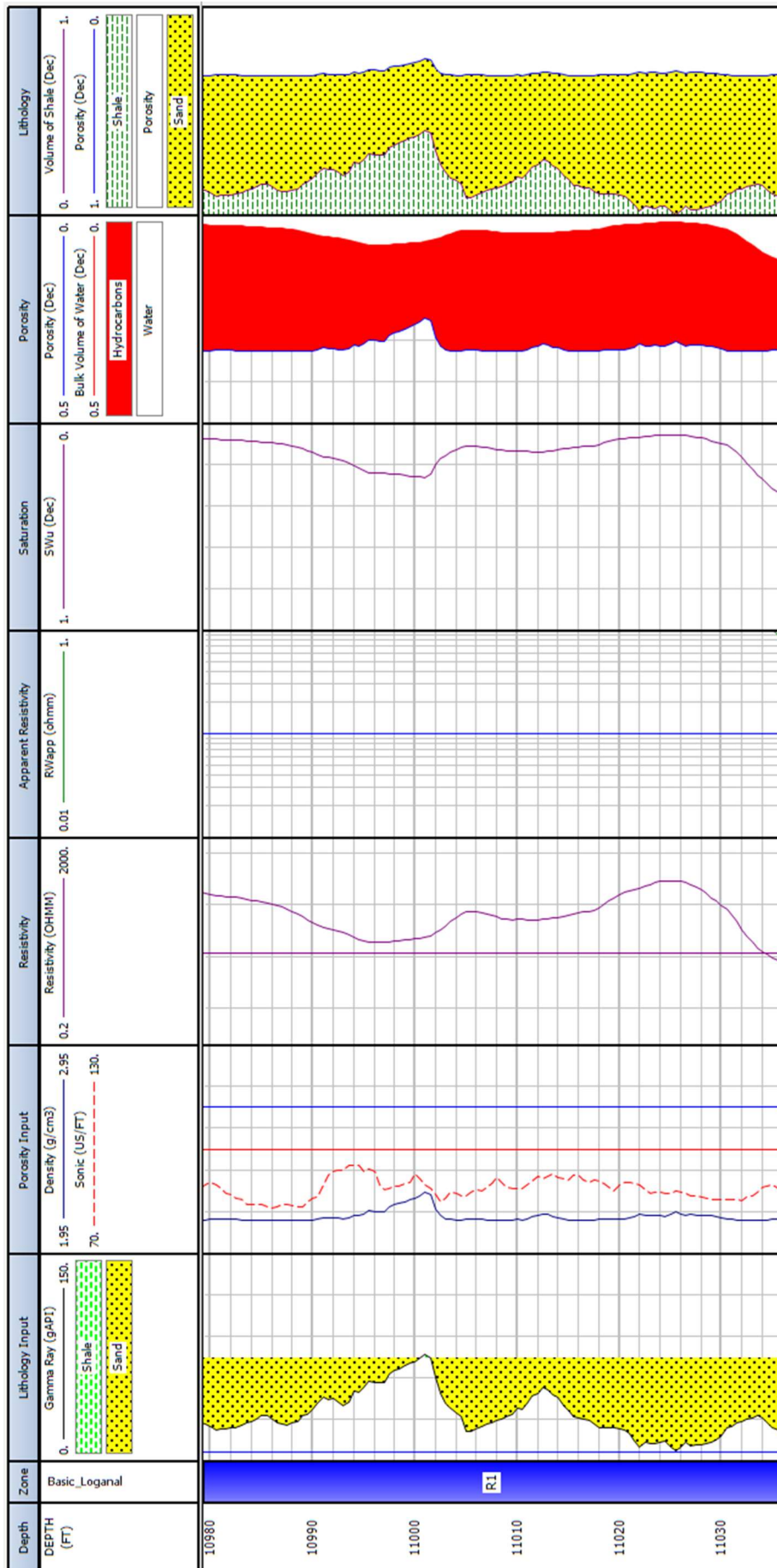


Fig. 4. Basic log plot for Well X01, reservoir 1

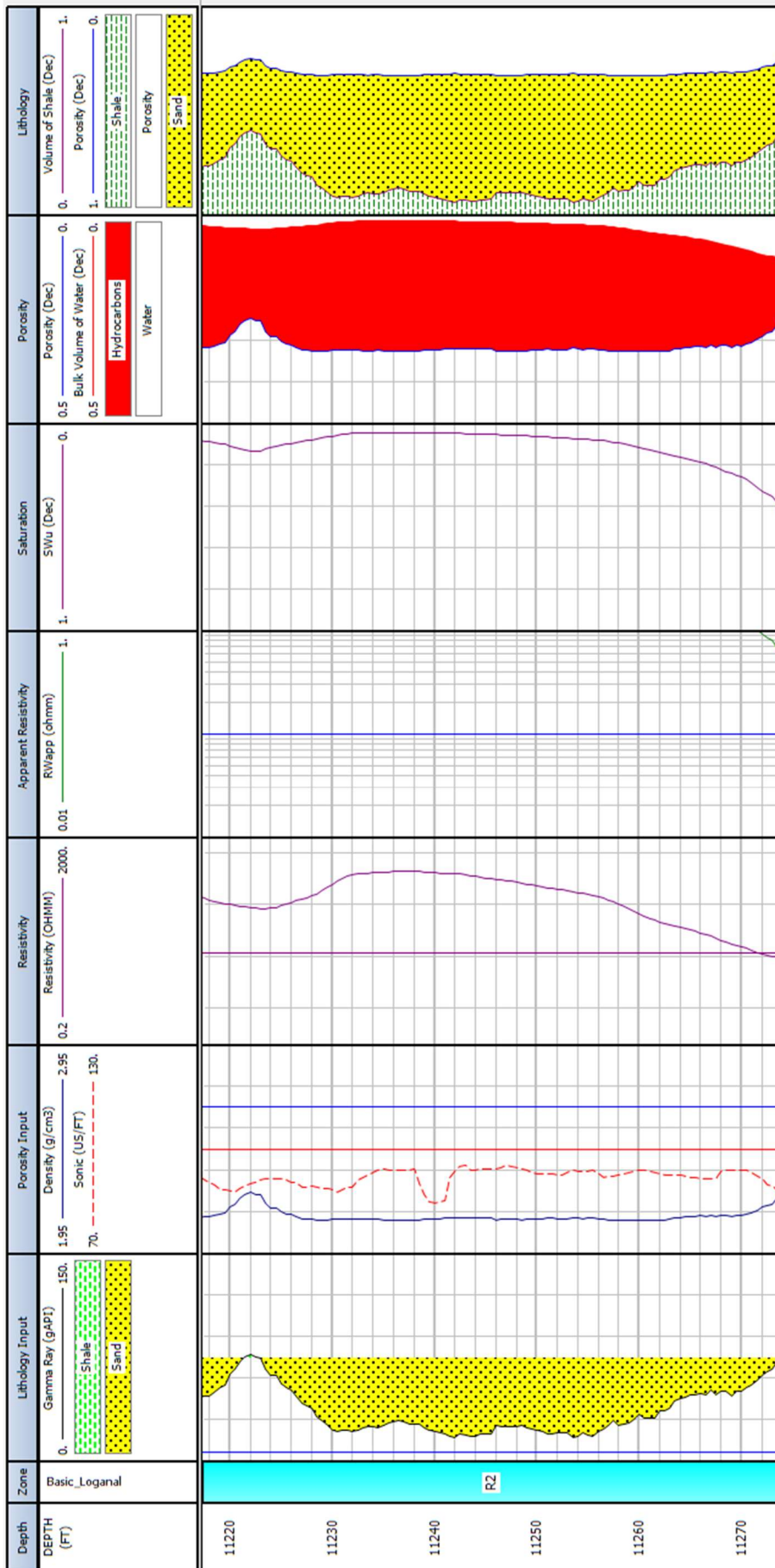


Fig. 5. Basic log plot for Well X01, reservoir 2

Table 1. Mean values of basic log data and estimated petrophysical parameters for well X01

Well X01		Top: 10944 ft Bottom: 11048.5 ft Net: 105 ft			Top: 11200.5 ft Bottom: 11281.5 ft Net: 81.5 ft		
Curve	Units	Min	Max	Mean	Min	Max	Mean
Bulk volume of water	Dec	0.018	0.137	0.051	0.015	0.131	0.042
Calliper	in	7.878	9.547	8.327	8.022	9.254	8.189
Density	g/cm ³	2.109	2.485	2.135	2.109	2.309	2.139
Gamma Ray	gAPI	6.69	108.132	34.796	16.518	87.254	40.943
Porosity	Dec	0.1	0.328	0.312	0.207	0.328	0.310
Resistivity	OHMM	5.345	320.137	95.023	5.808	438.999	166.82
RWapp	ohmm	0	28.517	7.859	0.264	47.237	17.376
Sonic	US/FT	78.436	96.15	89.255	80.951	95.327	90.909
Volume of shale	Dec	0.001	0.585	0.162	0.057	0.464	0.198
Water saturation	Dec	0.055	0.999	0.179	0.046	0.615	0.147

Table 2. Mean values of basic log data and estimated petrophysical parameters for well X02

Well X02		Top: 9359.5 ft Bottom: 9453 ft Net: 94 ft			Top: 10027 ft Bottom: 10082 ft Net: 55.5 ft		
Curve	Units	Min	Max	Mean	Min	Max	Mean
Bulk volume of water	Dec	0.107	0.166	0.144	0.089	0.138	0.114
Calliper	in	11.813	12.028	11.891	12.101	12.33	12.172
Density	g/cm ³	2.12	2.365	2.193	2.14	2.43	2.256
Gamma Ray	gAPI	30.363	93.076	47.662	31.758	76.176	43.533
Neutron	dec	0.215	0.303	0.264	0.171	0.284	0.223
Porosity	Dec	0.18	0.322	0.28	0.147	0.309	0.24
Resistivity	OHMM	2.251	5.452	3.021	2.294	5.512	3.427
RWapp	ohmm	0.135	0.338	0.236	0.108	0.292	0.194
Sonic	US/FT	86.225	99.588	92.922	82.4	104.75	87.539
Volume of Shale	Dec	0.000	0.444	0.062	0	0.291	0.034
Water Saturation	Dec	0.429	0.678	0.519	0.387	0.635	0.483

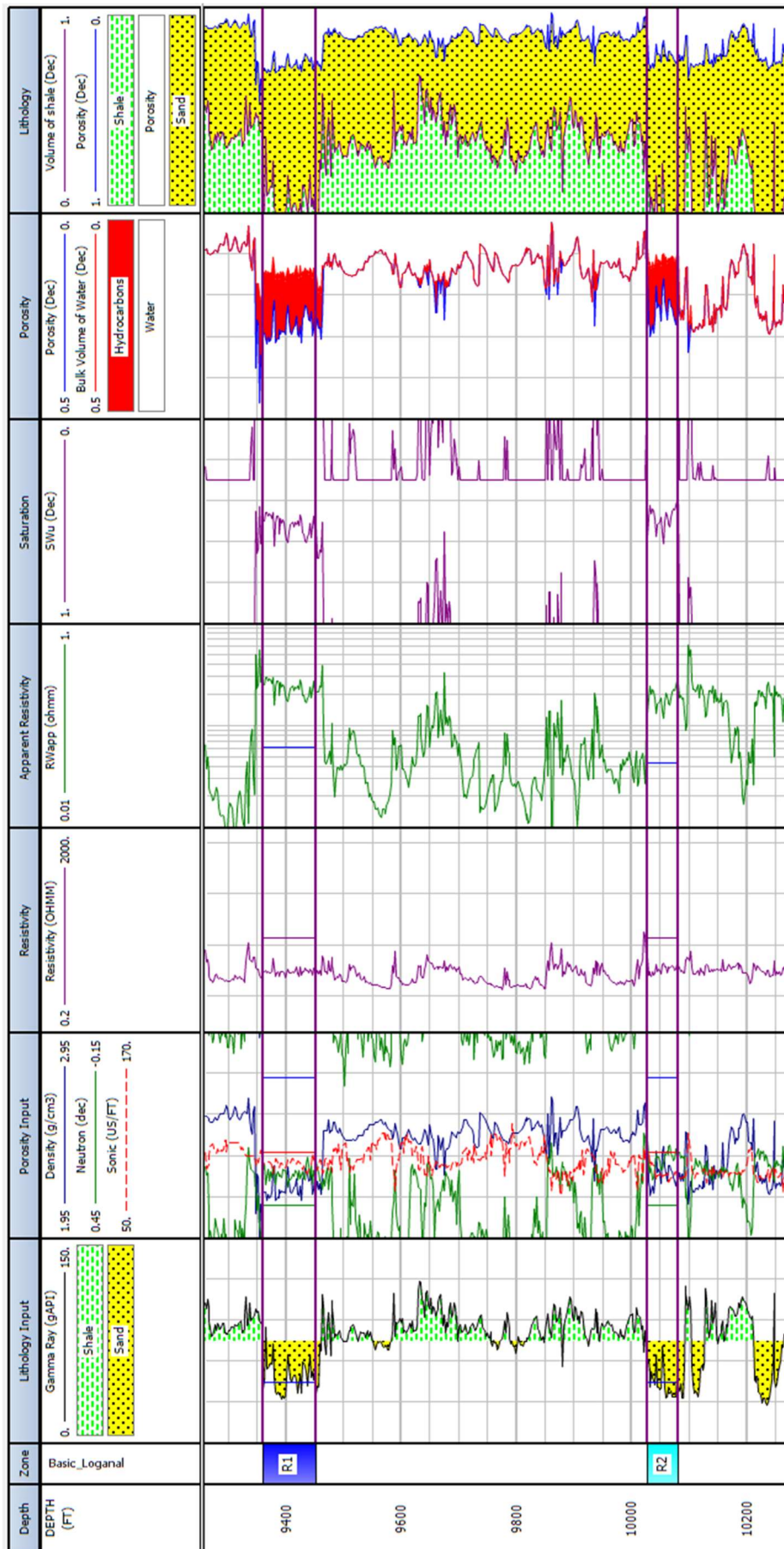


Fig. 6. Basic log plot for Well X02

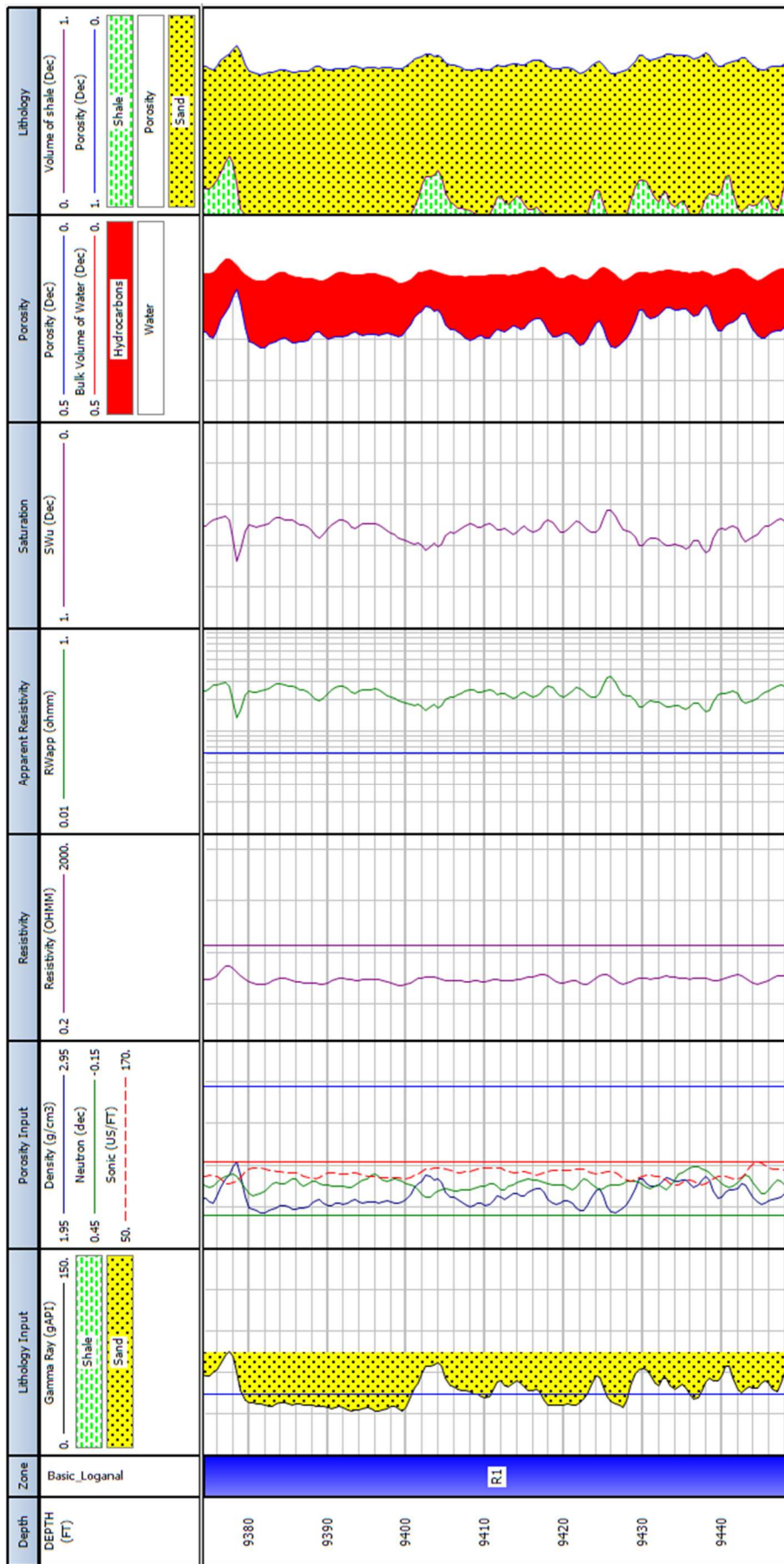


Fig. 7. Basic log plot for Well X02, reservoir 1

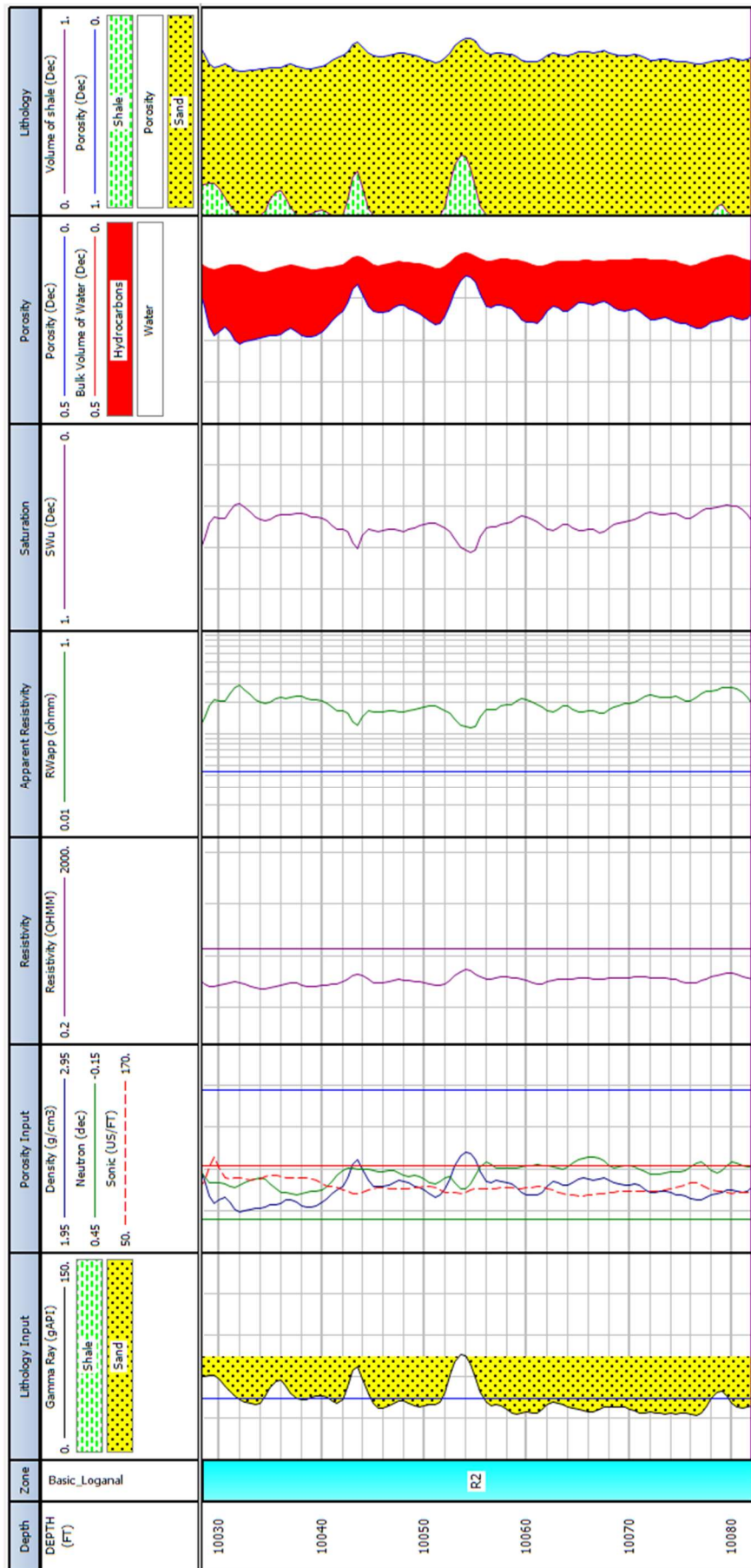


Fig. 8. Basic log plot for Well X02, reservoir 2

5. Conclusion

The well log analysis methods used are effective and less costly in hydrocarbon prospecting, and can be used for more exploratory research and basin growth when combined with other geophysical methods such as seismic and core analysis. A reservoir simulation based on this new definition of the reservoir would have greater predictive power because in this analysis, the reservoir flow capacity is described better.

The evaluated petrophysical parameters in the two wells has shown that the wells are viable for hydrocarbon exploration and also have large hydrocarbon accumulations. The petrophysical parameters show that the porosities in the wells are classified as good porosity, low water saturation and high hydrocarbon saturation, with low volume of shale and low bulk volume of water.

Petrophysical analysis was performed for all of the identified hydrocarbon intervals, using suites of geophysical well logs from two wells studied in the Niger Delta Fields. One of the most significant tasks in reservoir engineering is the characterization of various reservoir parameters that have been done in this research. Water saturation is a parameter that helps in the assessment of hydrocarbon content in reservoirs.

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