



RESERVOIR HYDROCARBON VOLUMETRIC ANALYSIS OF SAPELE DEEP FIELD, NIGER DELTA, SOUTHERN NIGERIA

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ABSTRACT

The calculation of hydrocarbon volume in place of Sapele Deep field in the Niger Delta, Nigeria was done by the integration of seismic and well logs data using the petrel software. On average, the entire field has a hydrocarbon pore volume of 90,341.68, STOIP value of 1,156,970,604.11 BCF/BBSTB and an ultimate recovery value of 951,966,117.95 MMCF/MMSTB with a primary recovery factor of 0.81 (81%). Petrophysical evaluation reveals that the field on average, has a gross thickness of 268.60m (886.38 ft), net sand thickness of 6.67 m (22.01 ft), porosity value of 0.21 (21%), permeability of 1493.14 mD, shale volume of 0.16, net-to-gross value of 0.51 and water saturation (S_w) of 0.43 (43%). The combination of well log neutron and density log reveals that the study area is made up of both single and double-phase reservoirs

1.0 Introduction

Virtually all the petroleum in the Niger Delta is found in paralic sands. The hydrocarbons are trapped in rollover anticlines or against growth faults, especially along footwall (Figure 1). Minor stratigraphic traps also occur in some fields due to lateral facies changes or in association with clay-filled channels (Orife and Avbovbo, 1981). The Niger Delta is comprised of five off-lapping siliciclastic sedimentation cycles. These cycles or depobelts as they are more typically called, grade 250 kilometers southwestward over the oceanic crust that underlies the Gulf of Guinea (Stacher, 1995). The depobelts are defined by syndimentary fault trends that formed in response to different rates of subsidence and sediment supply (Doust and Omatsola, 1990). As the delta prograded, when local subsidence diminished greatly, the focus of sediment deposition was forced to shift seaward, forming a new depobelt. Each depobelt is a separate unit that corresponds to a break in regional dip of the delta and is bounded landward by growth faults and seaward by large counter-regional faults or the growth fault of the next depobelt seaward (Evamy et al., 1978). Five major depobelts are generally recognized, each with its sedimentation, deformation, and petroleum history (Nyantakyi et al., 2013).

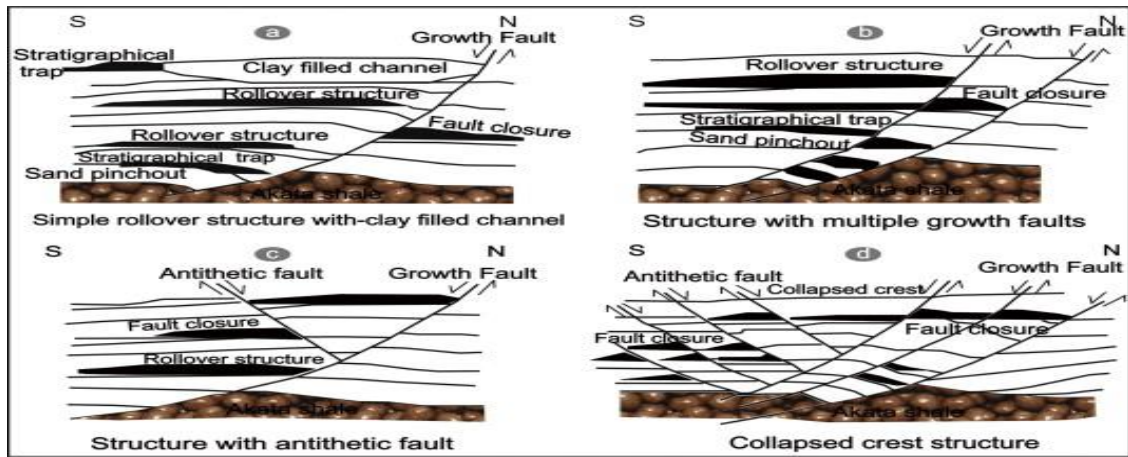


Figure 1: Examples of Niger Delta oil filed structures and associated trapping styles (Stacher, 1995)

Reservoir hydrocarbon volumetric analysis is a technique that employs geological observations and information to estimate original fluids-in-place. It is often referred to as a "static method" as it primarily sources its data from core samples, wireline logs, and geological maps. Volumetric calculations are typically used prior to production to estimate reserves, and after considerable production to determine the efficiency of recovery, the area extent of the reservoir, and as a basis for advanced studies such as reservoir simulations (Airen and Mujakperuo, 2023a).

The Niger Delta Basin to date is the most prolific and economic sedimentary basin in Nigeria by the virtue of the impact size petroleum accumulations, discovered and produced as well as the spatial distribution of the petroleum resources to the Onshore, Continental Shelf through Deepwater terrains (Airen and Mujakperuo, 2023b). Classic integrated geological studies have shown that several different depobelts are abound in the Niger Delta basin.

Reservoir characterization is the concatenation of all relevant information that is required to describe a reservoir in terms of its ability to store and produce hydrocarbons. This entails knowing the complete reservoir architecture, including the internal and external geometry, its model with the distribution of reservoir properties, and understanding the fluid flow within the reservoir. Such information helps improve production rates, rejuvenate oil fields, predict future reservoir performance, minimize cost expenditure, and help managements of oil companies to draw up accurate financial models. According to Halderson and Damsleth (1993), the principal goal of reservoir characterization is to outsmart nature to obtain higher recoveries with fewer wells in better positions at minimum cost through optimization. The oil and gas industry is a technology-driven industry, our ability to locate and extract hydrocarbons from beneath the ground surface is tied directly to the evolution of technologies, concepts, and interpretative sciences. These technologies are seismic-based methods for imaging features beneath the ground's surface, advances in well logging techniques, improvements in the ability to drill in deep water beyond the continental shelf, the advent of horizontal drilling, micropaleontology, biostratigraphy, to name a few.

Reservoir's characterization has evolved over the past 20 years, from a simple engineering evaluation to multidisciplinary teams of geologists, geophysicists, petrophysicists, and petroleum engineers working together. The integration of these various disciplines has changed our perception of the characteristics of oil and gas reservoirs. Whereas it used to be commonly perceived that oil and gas reservoirs were relatively simple geologic features, the reality is that they are quite complex, and they can be subdivided into architectural elements or compartments on the basis of several structural and stratigraphic features. Part of the misconception comes from the fact that one cannot see a reservoir, because it is beneath ground level in the subsurface. Slatt (1998), has claimed that in Rocky Mountain basins,

compartmentalized reservoirs are the rule, rather than the exception. With the increased flow of information into the public domain concerning reservoirs worldwide, this claim appears to be valid beyond the Rockies. Thus, in the initial through final stages of characterization, investigators should assume that the field will be compartmentalized and segmented, even at scales too small to recognize by normal subsurface technologies. By integrating the various disciplines mentioned above, it is possible to accurately quantify the characterization process. Often, the most limiting factor to a proper reservoir characterization is time. For a variety of reasons, the integrated team may not have sufficient time to complete the required work before drilling or other production steps are initiated (i.e., the cart is placed before the horse).

Sapele field is a large, mature field that is further subdivided into two fields (Sapele Shallow and Sapele Deep) due to its structural complexity. Sapele Shallow as the name implies, is made up of shallow reservoirs with heavy oil as its hydrocarbon content, while Sapele Deep is made up of heavily compartmentalized reservoirs with gas and light oil as its hydrocarbon content. The field is in the Northwestern part of the Niger Delta, which has been actively producing for over 3 decades and for the past few years, has been experiencing production decline and sometimes failed wells. Thus, there is a need to approach the study area with an improved reservoir characterization for a better understanding of the geologic complexities of the field, to improve hydrocarbon recovery from existing oil and gas reservoirs of the study area.

2. Materials and Methods

The study area was formerly owned and operated by Shell Petroleum Development Company PLC for over 3 decades and over time, reservoir hydrocarbon production declined as the field turned to a matured field. At this point, SHELL lost investment interest in the field and so decided to sell it off to SEPLAT in 2010 to increase her (SHELL) focus in Nigeria offshore and deep-water fields.

This investigation is borne out of the fact that the study area has been synonymous with poor reservoir performance. Hence, wells are constantly serviced to burst production. This led to carrying out the evaluation of the subsurface geology of the study area using 3D Seismic, well logs, biostratigraphy, and Pressure Volume Temperature (PVT) data, to acquire a better understanding of the subsurface structural geometry, stratigraphy, petrophysical parameters, depositional environment, age and type of hydrocarbon contained in the reservoirs. This information will help in maximizing hydrocarbon recovery from the reservoirs by ensuring a consistent reservoir description which helps in optimal well placement and other exploration decisions.

The Sapele Deep field is the distal portion of Sapele field of OML 41 (Figure 2), located in the Northwestern (Greater Ughelli Depobelt) part of the Niger Delta (Figure 3).

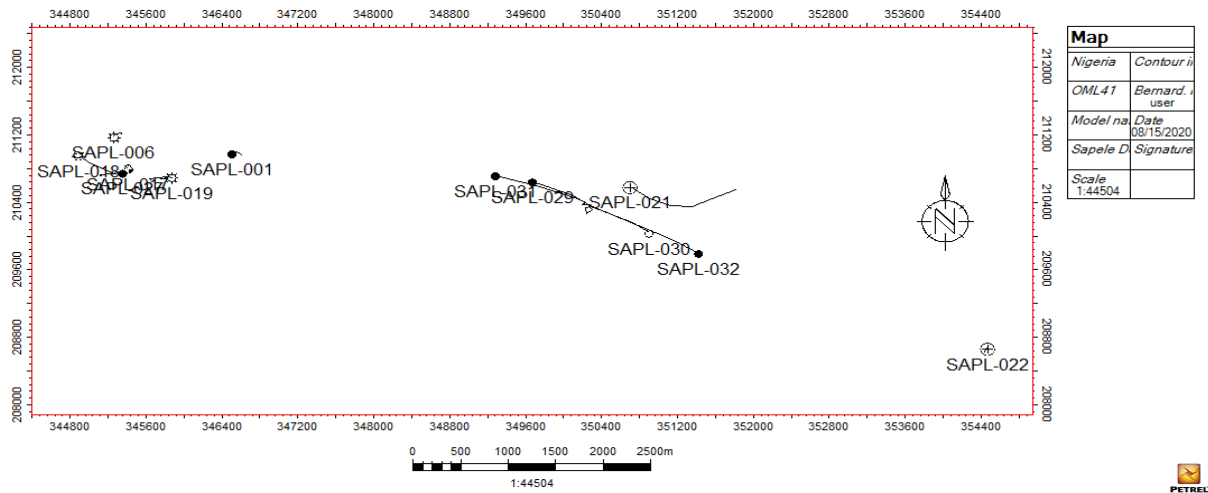


Figure 2: Base map of oil wells in the study area (Using Petrel)

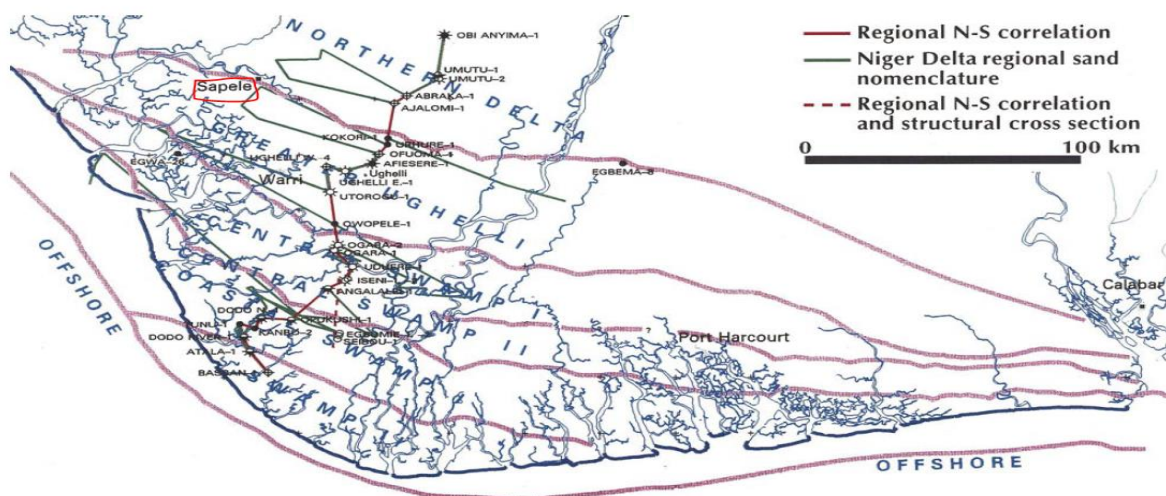


Figure 3: Location map of Niger Delta Depobelts, Showing the Study Area (Reijers et al., 2011)

The materials used while carrying out this research work are a suit of subsurface data which includes, 3D seismic cube, and well logs data provided across the fields. Petrel®2016 (Schlumberger software) was used in the interpretation of the data. These subsurface data belong to Seplat Petroleum Development Company PLC and were released under the approval of the Department of Petroleum Resources (DPR),

2.1 Petrophysical parameters

Composite well log data (Gamma Ray, Resistivity, Density and Neutron Logs) were used for the petrophysical evaluation of the reservoirs.

2.2 Hydrocarbon Pore Volume (HCPV)

Before hydrocarbon migration and accumulation took place, the reservoir rock was saturated with water. The displacement of water by hydrocarbon is never complete and therefore hydrocarbon-bearing formations always contain water. Equation 1 was used to deduce the HCPV of the reservoirs.

$$HCPV = A \times H \times \Phi \times NTG \times (1 - S_w) \quad (\text{Ilavagan, 2018}) \quad (1)$$

Where:

A = Hydrocarbon-bearing area of the reservoir NTG = Net to gross thickness ratio
 H = Gross thickness $(1 - S_w)$ = 1-water saturation (hydrocarbon saturation)
 Φ = Porosity

2.3 Stock Tank Oil Initially in Place (STOIP)

STOIP is the total amount of crude oil present in a hydrocarbon reservoir before the commencement of any production in equivalent volume that the oil will occupy when it is stocked in a storage tank. In mathematical terms, STOIP can be expressed using Equation 2.

$$STOIP = \frac{7758 \times A \times h \times \Phi \times (1-S_w)}{B_{oi}} \quad (\text{Amigun and Bakare, 2013}) \quad (2)$$

Where:

7758 = Acre-feet conversion for oil

A = Area in acres

h = Net Pay thickness in feet

Φ = Porosity

S_w = Water saturation

B_{oi} = Oil Formation volume factor.

2.4 Stock Tank Gas Initially in Place (STGIIP)

The STGIIP can be delineated by using static geologic data to determine the volume of the pore space of the reservoir. Once the volume of the pore space is estimated, then the gas formation volume factor (B_{gi}) can be used to estimate the STGIIP, as seen in equation 3.

$$STGIIP = \frac{43560 \times A \times h \times \Phi \times (1-S_w)}{B_{gi}} \quad (\text{Chidozie, 2017}) \quad (3)$$

Where:

43560 = Acre-feet conversion for gas

A = Area in acres

h = Net Pay thickness in feet

Φ = Porosity

S_w = Water saturation

B_{gi} = Gas Formation volume factor.

2.5 Recovery Factor

Oil recovery factor (RF) is the most significant parameter for all exploration and development (E&P) companies mainly during the early reservoir life, because several investment decisions are based on the amount of hydrocarbon, which could be obtained from the target asset with the available techniques and operational practices.

The empirical relation used to calculate the hydrocarbon recovery factor of the study area water-drive reservoirs using five factors that affect the oil recovery in sandstone reservoirs as shown in Equation 4 is obtained from Wiener et al, 2010.

$$RF = 0.114 + 0.272 \log k + 0.256 S_w - 0.136 \log m_o - 1.538 \Phi - 0.0003h \quad (\text{Anthony and Aurelius, 2012}). \quad (4)$$

Where:

RF = Recovery Factor

k = Permeability (mD)

S_w = Water Saturation

m_o = Oil viscosity (cp)

Φ = Porosity

However, ultimate recovery factor can be obtained by multiplying stock tank oil initially in place (STOIP) by recovery factor (RF).

$$\text{Ultimate Recovery (UR)} = \text{STOIP} \times \text{RF} \quad (\text{Glover, 2016}) \quad (5)$$

3. Results and Discussion

3.1 Well 01 Analysis

Figure 4 shows well 01 penetrated three reservoirs (B, C and D) out of the thirteen reservoirs present in the field.

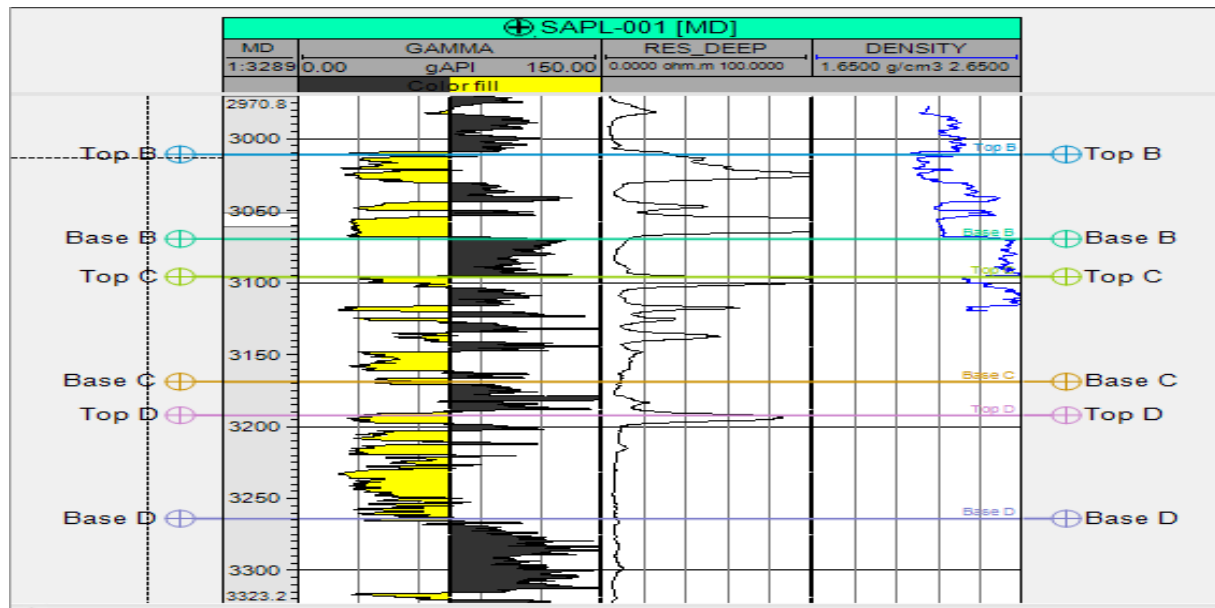


Figure 4: Well Log Signature of Well 01 from 2970.8 m to 3323.2 m (Using Petrel®2016).

3.1.1 Petrophysical Summary of Well 01 Reservoirs

Table I revealed that well 01 reservoirs has an average gross thickness of 66.42 m (219.19 ft), shale volume of 0.14, net sand thickness of 7.90 m (26.07 ft), porosity of 0.21, permeability of 1458.6 mD and a water saturation of 0.38 (38%). From the above-mentioned petrophysical values, well 01 reservoirs possess very good to excellent petrophysical properties which agrees with Rider (1986).

Table I: Petrophysical Summary of Well 01

Reservoirs	Gross Thickness (m)	V_{sh}	Net Sand (m)	Φ	Eff_{ϕ}	K (mD)	F	NTG	S_{wirr}	S_w	S_h
B	56.55	0.10	13.34	0.24	0.22	1703.45	25.98	0.71	0.11	0.12	0.88
C	70.91	0.20	5.92	0.18	0.10	1168.22	43.80	0.33	0.15	0.30	0.70
D	71.80	0.10	4.45	0.20	0.20	1504.20	42.50	0.31	0.15	0.73	0.27
Average	66.42	0.14	7.90	0.21	0.18	1458.60	37.43	0.50	0.14	0.14	0.62

V_{sh} = Volume of Shale

S_{wirr} = Irreducible Water Saturation

NTG = Net-to-Gross ratio

3.1.2 Reservoir Volumetric Analysis of well 01

The net sand thickness, porosity values and water saturation values as revealed in the various reservoir petrophysical table, field area extent of 16515.73, 7758 acre-feet conversion constant for oil reservoirs and 1.20 oil formation volume factor were used in delineating well 01 reservoir volumetrics. As shown in Table 2, well 01 has an average STOIP of 448,153,428.39 Million Stock Tank Barrels (MMSTB) of oil and an ultimate recovery of 287,469,260.17 MMSTB with a recovery factor of 0.71 (71%). The following volumetric analysis have proven that well 01 is economically viable with ultimate recoverable hydrocarbon given by;

$$\begin{aligned}
 \text{Average Primary Recovery Reserve} &= UR \times \text{Barrel estimate} \\
 &= 287,469,260.17 \times 50 \\
 &= \$14,373,463,008.50 \text{ at } \$50 \text{ per barrel.}
 \end{aligned}$$

Table 2: Hydrocarbon Volumetric Summary of Well 01

Reservoirs	HCPV	STOIIP	RF	UR
B	460,777.50	992,727,349.80	0.61	605,286,712
C	162,547.60	262,828,523.50	0.71	185,861,293
D	68,727.34	88,904,411.88	0.80	71,259,776
	Average			
	134,032.73	448,153,428.39	0.71	287,469,260.17

Average Primary Recovery Reserve @USD50.00/B = 287,469,260.17 × 50 = \$14,373,463,008.50

3.2 Well 06 Analysis

Well 06 penetrated seven reservoirs (B, C, D, E, F, G and H) out of the thirteen reservoir sands present in the field (Figures 5a and b). Reservoir “B” was delineated with well tops at a depth of 2999.53 m (9898.45 ft) as the top of the reservoir and 3036.85 m (10021.61 ft) as the base. Reservoir “C” was delineated at a top depth of 3073.37 m (10142.12 ft) and a base of 3144.04 m (10375.33 ft). Reservoir “D” was delineated at 3163.90 m (10440.87 ft) as top and base at 3239.33 m (10689.79 ft) as revealed by the well tops marker. Reservoir “E” was deciphered with well tops at a depth of 3444.99 m (11368.47 ft) as the top of the reservoir and 3460.87 m (11420.87 ft) as the base. Reservoir “F” was delineated at a top depth of 3554.56 m (11730.05 ft) and a base of 3602.21 m (11887.29 ft).

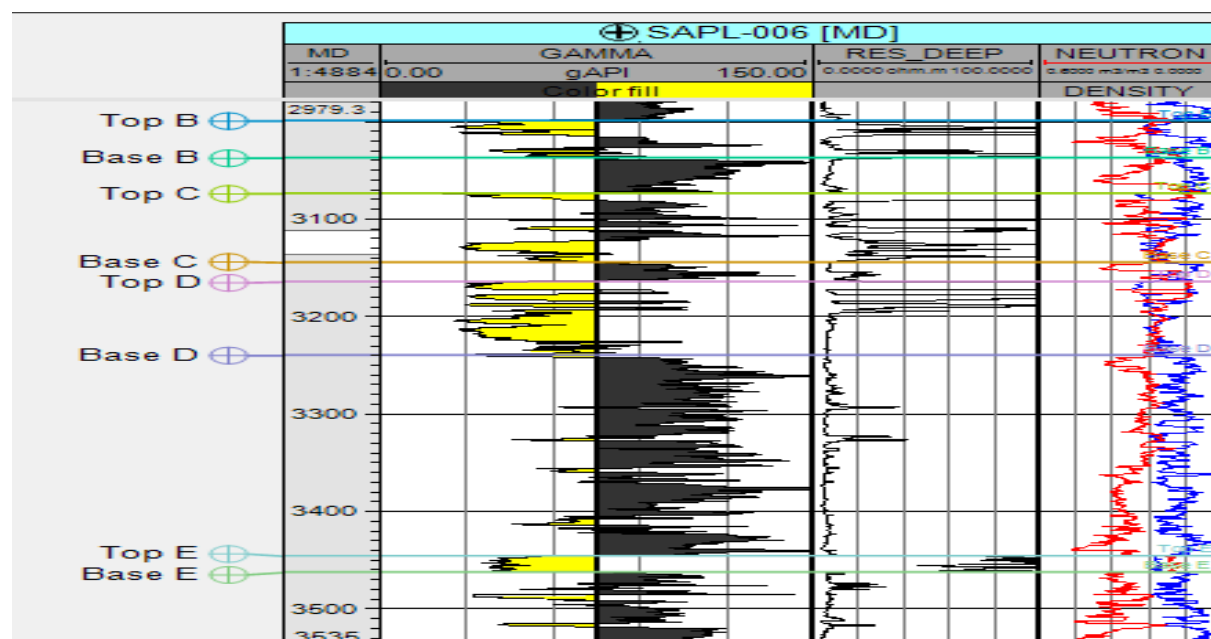


Figure 5a: Well log signature of well 06 from 2979.3 m to 3535 m (Using Petrel®2016).

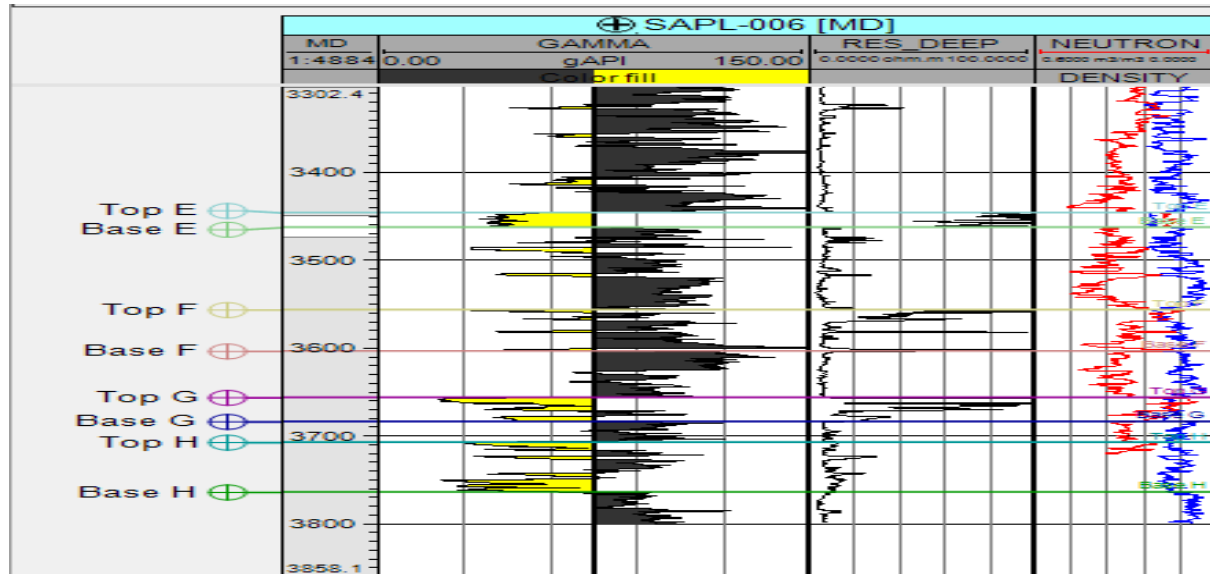


Figure 5b: Well log signature of well 06 from 3302.4 m to 3800 m (Using Petrel®2016).

3.2.1 Petrophysical Summary of Well 06 Reservoirs

The data presented in Table 3, indicates that well 06 reservoirs on average, have a gross thickness of 47.47 m (156.65 ft), shale volume of 0.15, net sand thickness of 6.94 m (22.90 ft), porosity of 0.20, permeability of 1416.23 mD and a water saturation of 0.47 (47%). Based on this, we can infer that well 06 reservoirs retain a very good to excellent petrophysical properties.

Table 3: Petrophysical Summary of Well 06

Reservoirs	Gross Thickness (m)	V_{sh}	Net Sand (m)	Φ	Eff_{ϕ}	K (mD)	F	NTG	S_{wirr}	S_w	S_h
B	37.32	0.110	9.250	0.22	0.20	1605.600	18.47	0.50	0.10	0.40	0.60
C	70.67	0.080	5.346	0.24	0.22	1836.270	14.76	0.38	0.09	0.40	0.60
D	75.43	0.270	5.520	0.23	0.18	1720.130	21.98	0.44	0.10	0.50	0.50
E	18.00	0.060	16.060	0.22	0.20	1552.000	17.26	0.89	0.09	0.30	0.70
F	47.65	0.200	1.630	0.19	0.16	1305.260	21.79	0.17	0.10	0.40	0.60
G	28.00	0.065	8.790	0.17	0.16	1038.150	30.16	0.63	0.12	0.40	0.60
H	55.24	0.250	2.000	0.15	0.12	856.220	46.82	0.07	0.15	0.90	0.10
Average	47.47	0.150	6.940	0.20	0.18	1416.233	24.46	0.44	0.11	0.47	0.53

3.2.2 Hydrocarbon Volumetric Summary of Well 06 Reservoirs

As revealed in Table 4, well 06 has an average STOIP of 311,672,938.26 MMCF/MMSTB and an ultimate recovery of 215,892,954.64 MMCF/MMSTB with a recovery factor of 0.73 (73%). Hence, the volumetric evaluation has shown that well 06 is economically viable with an average ultimate hydrocarbon recuperation of \$10,794,647,732 at \$50 per barrel (Table 5).

Table 4: Hydrocarbon Volumetric Summary of Well 06

Reservoirs	HCPV	STOIP	RF	UR
B	130,875.400	423,054,840.70	0.70	297,542,719
C	223,770.000	289,334,627.90	0.67	195,221,567
D	139,025.500	205,780,865.20	0.73	150,360,992
E	134,796.300	871,458,088.60	0.67	581,555,355
F	53,039.130	68,748,305.52	0.72	49,320,481
G	96,101.800	310,649,065.60	0.73	226,370,129
H	3,924.137	12,684,774.30	0.86	10,879,439
Average	111,647.500	311,672,938.26	0.73	215,892,954.640

Average Primary Recovery Reserve @USD50.00/B = 215,892,954.64 x 50 = \$10,794,647,732

3.3 Well 17 Analysis

This well intercepted eight reservoirs (B, C, D, E, F, G, H, and I) out of the thirteen reservoir sands present in the field (Figures 6a and b) and ranges in depth from 2967.2 m (9791.76 ft) to 3630 m (11979 ft). Well 17 is made up of three single-phase gas reservoirs, three single-phase oil reservoir and two double-phase reservoirs (Gas/Oil).

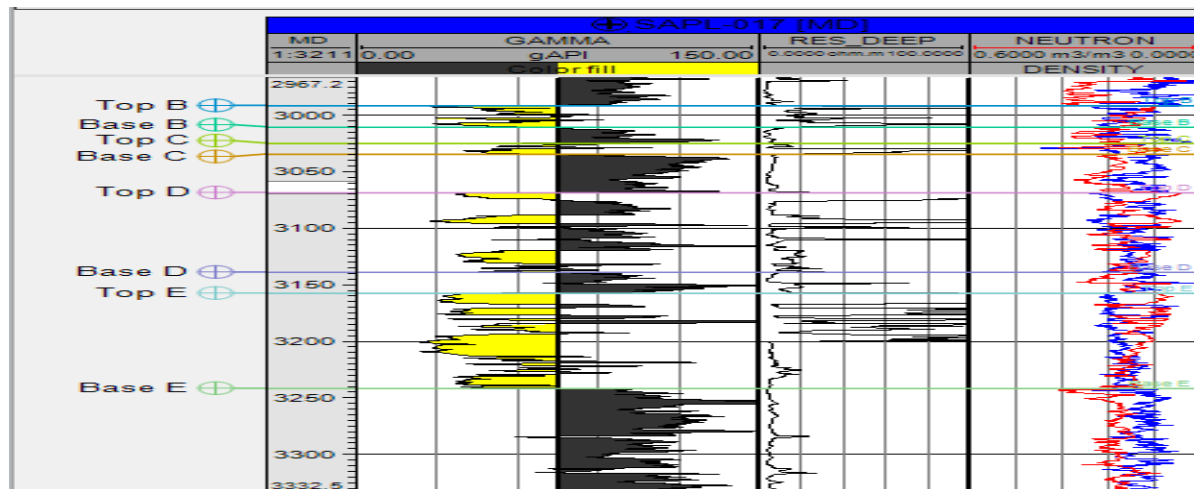


Figure 6a: Well log signature of well 17 from 2967.2 m to 3332.5 m (Using Petrel®2016).

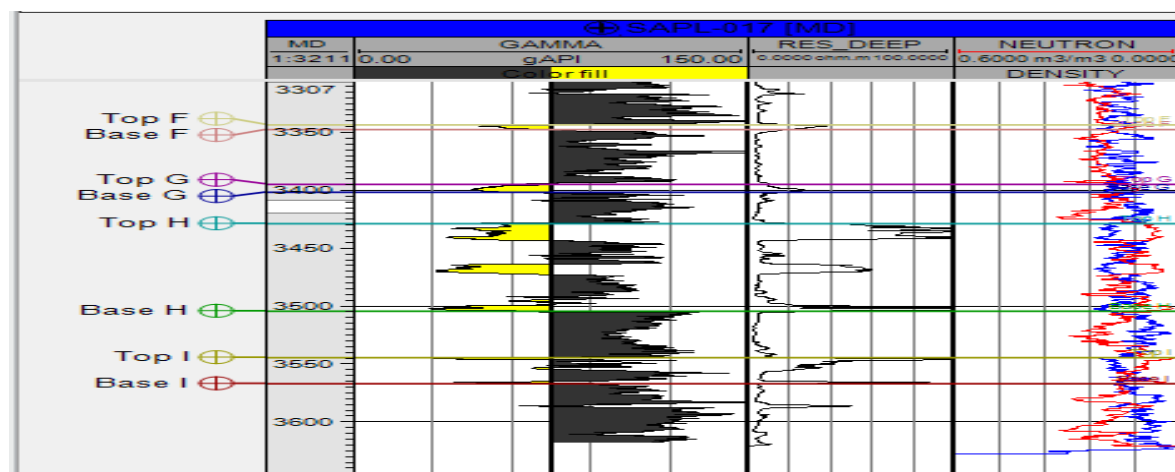


Figure 6b: Well log signature of well 17 from 3307 m to 3630 m (Using Petrel®2016).

3.3.1 Petrophysical Summary of Well 17 Reservoirs

The cumulative petrophysical summary as shown in Table 5, indicates that well 17 reservoirs on average, have a gross thickness of 36.30 m (119.79 ft), shale volume of 0.13, net sand thickness of 6.36 m (20.99 ft), porosity of 0.21, permeability of 1479.46 mD and a water saturation of 0.47 (47%). However, using Seplat shale volume cut-off of 0.35 and water saturation cut-off of 0.60 for Sapele deep, it means the reservoirs in well 17 are very good with sound petrophysical properties except for reservoir “D” which has a water saturation of 0.73 that is far above the cut-off.

Table 5: Petrophysical Summary of Well 17

Reservoirs	Gross Thickness (m)	V_{sh}	Net Sand (m)	Φ	Eff_{ϕ}	K (mD)	F	NTG	S_{wirr}	S_w	S_h
B	18.99	0.15	13.39	0.20	0.18	1393.54	31.86	0.71	0.13	0.53	0.47
C	9.50	0.20	6.32	0.24	0.19	1866.85	15.52	0.67	0.09	0.59	0.41
D	70.67	0.12	4.96	0.23	0.21	1740.15	16.29	0.35	0.09	0.42	0.58
E	83.68	0.08	7.44	0.24	0.22	1796.77	14.92	0.36	0.09	0.31	0.69
F	3.86	0.14	2.99	0.19	0.17	1313.13	21.94	0.77	0.10	0.51	0.49
G	5.99	0.11	5.58	0.19	0.17	1219.23	24.15	0.93	0.11	0.68	0.32
H	75.46	0.11	8.90	0.19	0.18	1309.58	22.69	0.35	0.11	0.43	0.57
I	22.23	0.13	1.32	0.18	0.16	1196.42	26.90	0.12	0.11	0.31	0.69
Average	36.30	0.13	6.36	0.21	0.19	1479.46	21.78	0.53	0.10	0.47	0.53

3.3.2 Hydrocarbon Volumetric Summary of Well 17 Reservoirs

From Table 6, we can deduce that well 17 reservoirs on average, have STOIP of 1,416,052,696.66 BBCF/BBSTB and ultimate recovery of 1,207,418,779.00 BBCF/BBSTB with a recovery factor of 0.84 (84%). Therefore, the volumetric appraisal has revealed that well 17 is economically feasible with an average ultimate hydrocarbon recovery of \$60,370,938,950.00 at \$50 per barrel (as shown in Figure 7).

Table 6: Hydrocarbon Volumetric Summary of Well 17

Reservoirs	HCPV	STOIP	RF	UR
B	69,470.17	449,124,617.97	0.84	376,943,761.59
C	34,308.96	1,245,415,192.60	0.88	1,092,270,920.04
D	180,928.30	1,169,701,335.12	0.78	916,858,367.00
E	265,007.90	1,713,275,786.40	0.75	1,280,708,943.82
F	15,712.70	101,582,585.32	0.83	84,386,561.35
G	9,772.50	117,906,349.62	0.9	106,633,125.45
H	161,911.10	5,877,372,394.42	0.89	5,224,743,203.92
I	18,017.72	654,043,311.84	0.88	576,805,348.85
Average	94,391.17	1,416,052,696.66	0.84	1,207,418,779.00

Average Ultimate Recovery @ USD50.00/B = 1,207,418,779.00 × 50 = \$60,370,938,950.00

3.4 Well 18 Analysis

As indicated in Figures 7a and b, well 18 penetrated the thirteen reservoirs (B, C, D, E, F, G, H, I, J, K, L, M, and N) present in the field and ranges in depth from 3001 (9,903.30) m to 3720 m (12,276 ft). Reservoirs in this well are all single-phase reservoirs, the first reservoir is a single-phase oil reservoir, while the remaining twelve reservoirs are single phase gas reservoirs.

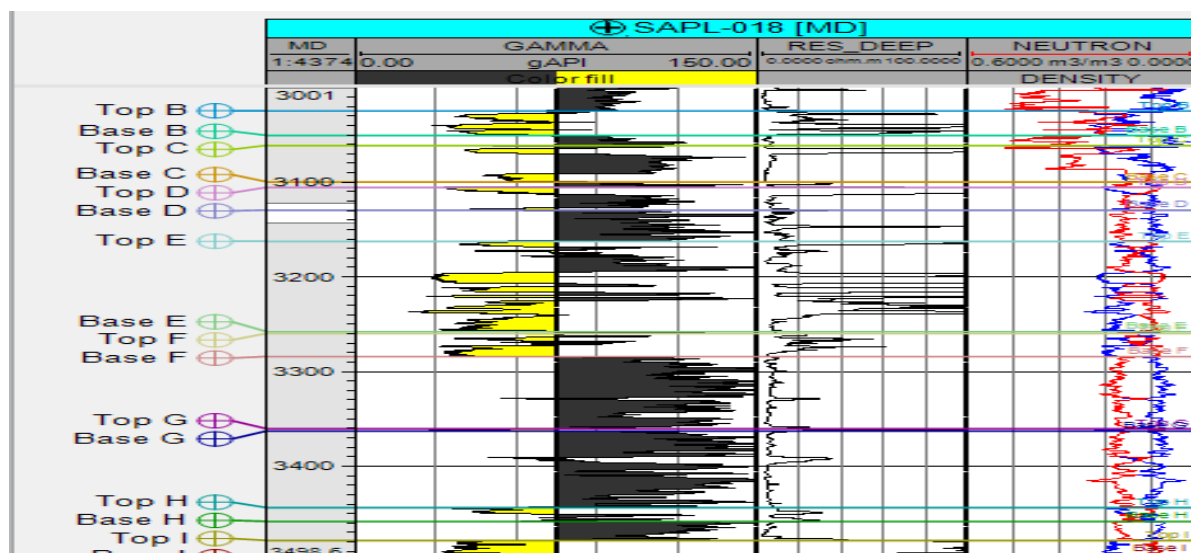


Figure 7a: Well log signature of well 18 from 3001 m to 3498.6 m (Using Petrel®2016)

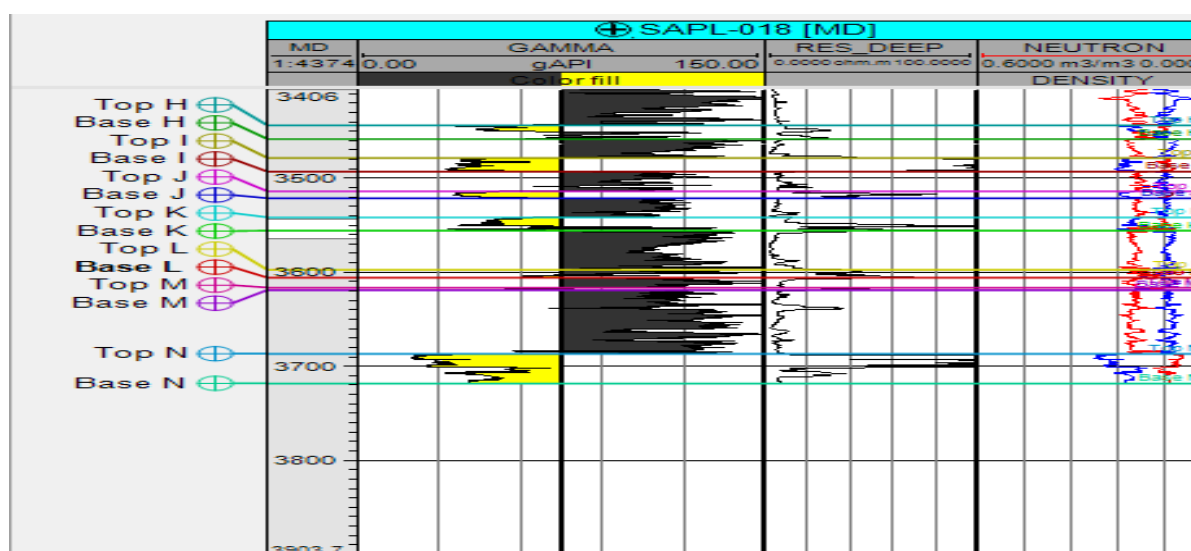


Figure 7b: Well log signature of well 18 from 3406 m to 3720m (Using Petrel®2016)

3.4.1 Petrophysical Summary of Well 18 Reservoirs

The amassed petrophysical data of all well 18 reservoirs (Table 7), stipulates that the reservoirs on average, have a gross thickness of 23.43 m (77.32 ft), net sand thickness of 6.67 m (22.01 ft), shale volume of 0.15, porosity of 0.21, permeability of 1466.46 mD, a water saturation of 0.49 (49%) and a net to gross ratio of 0.44.

Table 7: Petrophysical Summary of Well 18 reservoirs

Reservoirs	Gross Thickness (m)	V_{sh}	Net Sand (m)	Φ	Eff_{ϕ}	K (mD)	F	NTG	S_{wirr}	S_w	S_h
B	25.52	0.12	19.29	0.22	0.19	1537.19	21.88	0.76	0.10	0.51	0.49
C	38.48	0.27	5.59	0.23	0.19	1766.02	24.47	0.15	0.11	0.61	0.39
D	23.94	0.09	3.91	0.21	0.19	1508.27	18.55	0.33	0.10	0.40	0.60
E	95.41	0.19	5.71	0.22	0.19	1587.88	21.35	0.36	0.10	0.34	0.66
F	24.73	0.16	14.84	0.21	0.18	1437.18	21.63	0.56	0.10	0.68	0.32
G	2.99	0.23	1.13	0.17	0.13	1108.54	27.28	0.37	0.12	0.50	0.50
H	14.55	0.09	6.24	0.21	0.19	1496.69	18.27	0.43	0.10	0.73	0.27
I	14.95	0.06	12.77	0.23	0.22	1678.61	15.89	0.85	0.09	0.25	0.75
J	7.38	0.06	6.26	0.23	0.21	1660.53	16.35	0.85	0.09	0.49	0.51
K	14.15	0.24	1.94	0.19	0.16	1308.81	24.91	0.14	0.11	0.59	0.41
L	8.37	0.20	0.75	0.18	0.14	1146.87	25.64	0.09	0.11	0.33	0.67
M	2.60	0.22	0.45	0.18	0.14	1131.80	26.49	0.05	0.12	0.44	0.56
N	31.50	0.08	7.80	0.23	0.21	1695.56	17.01	0.74	0.09	0.52	0.48
Average	23.43	0.15	6.67	0.21	0.18	1466.46	21.52	0.44	0.10	0.49	0.51

3.4.2 Hydrocarbon Volumetric Summary of Well 18 Reservoirs

Well 18 reservoirs on average, have STOIP of 2,179,663,023.41 BBCF/BBSTB and ultimate recovery of 1,900,314,137.78 BBCF/BBSTB with a recovery factor of 0.88 (88%) as seen in Table 8. Based on this evaluation, we can infer that well 18 is a profitable well with ultimate hydrocarbon recovery of \$95,015,706,889.00@ \$50 per barrel (as shown in Figure 9).

Table 8: Hydrocarbon Volumetric Summary of Well 18

Reservoirs	HCPV	STOIP	RF	UR
B	109,982.09	711,034,225.00	0.82	581,252,233.80
C	28,211.01	1,024,059,713.58	0.89	909,473,063.96
D	54,477.67	1,977,539,249.65	0.85	1,681,505,242.87
E	180,028.47	6,535,033,417.00	0.83	5,449,505,257.14
F	161,209.55	5,851,906,540.98	0.93	5,435,426,001.34
G	5,333.91	193,620,737.08	0.91	176,785,534.04
H	19,462.90	706,503,356.47	0.94	666,894,234.90
I	118,729.48	4,309,880,002.15	0.81	3,507,480,421.16
J	39,395.09	1,430,041,931.79	0.88	1,253,979,402.07
K	8,480.22	307,832,149.52	0.92	284,706,530.18
L	4,856.37	176,286,210.60	0.88	155,580,742.91
M	2,408.62	87,432,733.87	0.92	80,103,809.11
N	138,414.57	5,024,449,036.69	0.90	4,521,391,317.72
Average	66,999.23	2,179,663,023.41	0.88	1,900,314,137.78

Average Ultimate Recovery @USD50.00/B = 1,900,314,137.78 x 50 = \$95,015,706,889.00

3.5 Well 19 Analysis

This well intercept twelve reservoirs (B, C, D, E, F, G, H, I, J, K, L, and M) out of thirteen reservoirs present in the field and ranges in depth from 30021.72 (9,971.68 ft) m to 3761.55 m (12,413.12 ft). This well contains both single and double-phase reservoirs, it has four single-phase gas reservoirs, four double-phase (Gas/Oil) reservoirs and four single-phase oil reservoirs (Figures 8a, b and c).

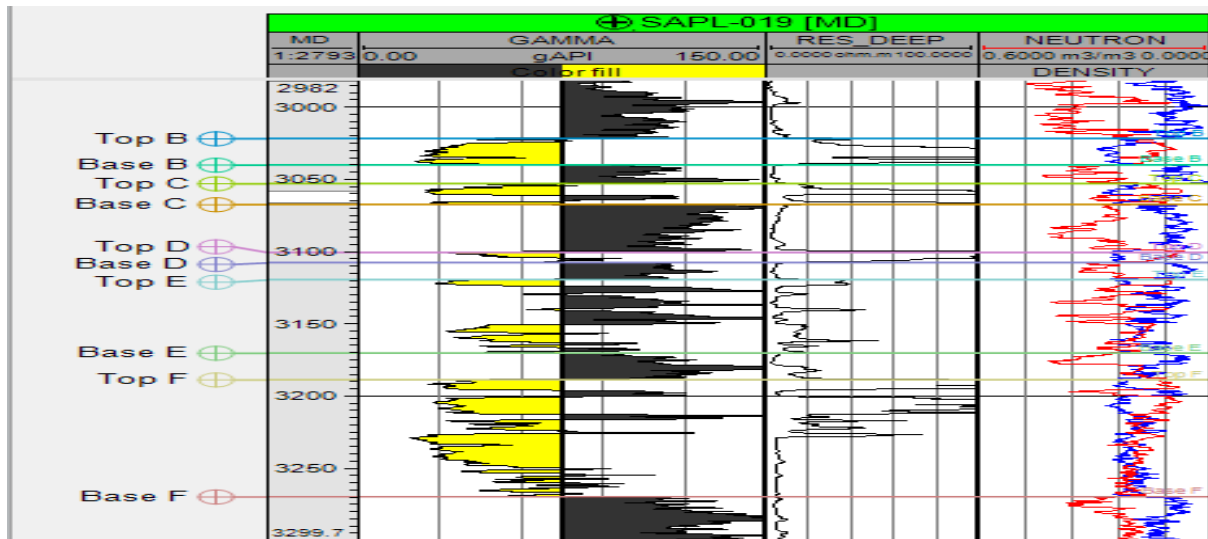


Figure 8a: Well log signature of well 19 from 2982 m to 3299.74 m (Using Petrel®2016).

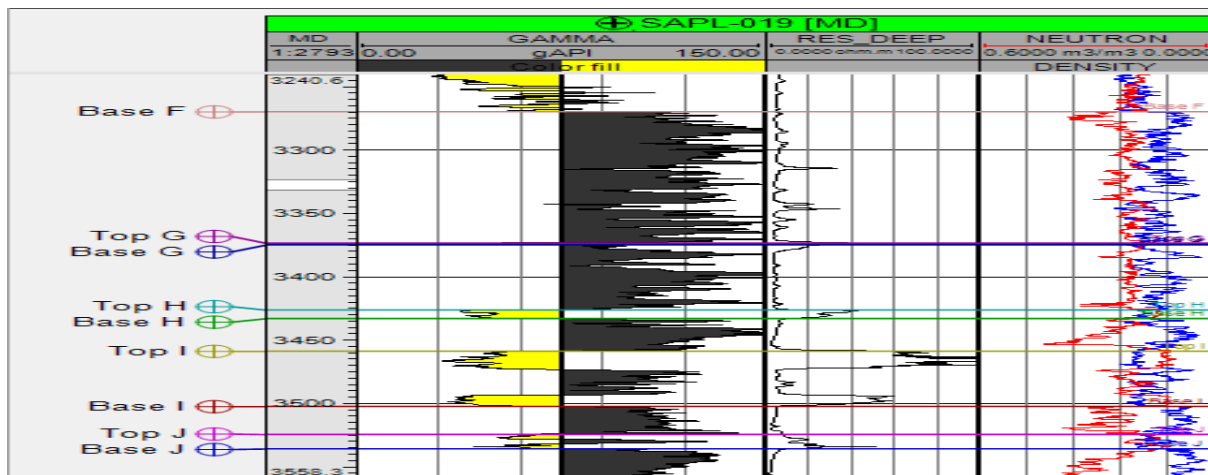


Figure 8b: Well log signature of well 19 from 3240.63 m to 3558.3m (Using Petrel®2016).

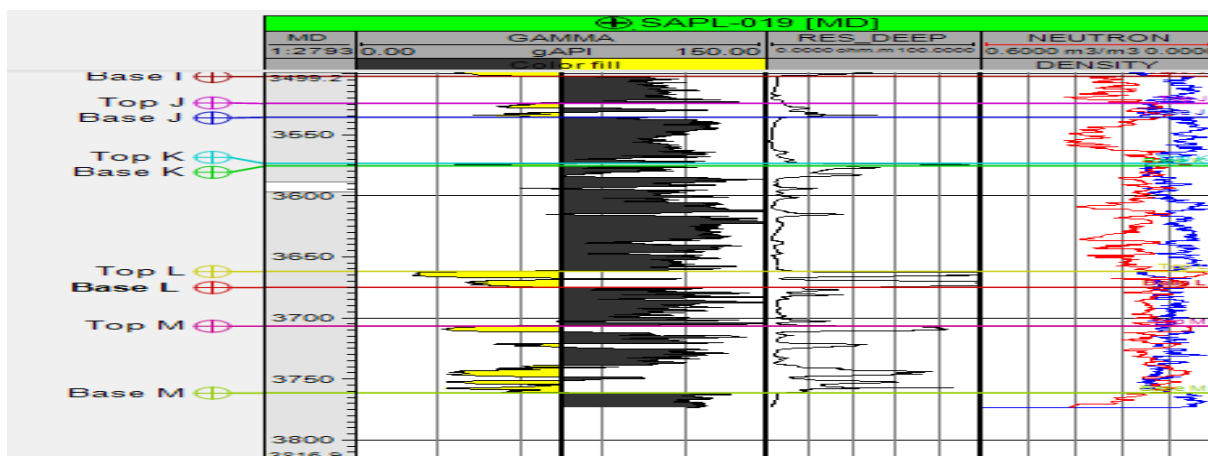


Figure 8c: Well log signature of well 19 from 3499.20 m to 3761.55m (Using Petrel®2016).

3.5.1 Petrophysical Summary of Well 19 Reservoirs

The collective petrophysical data of well 19 reservoirs (Table 9), specifies that the reservoirs on average, have a gross thickness of 25.37 m (83.72 ft), net sand thickness of 6.50 m (21.45 ft), shale volume of 0.16, porosity of 0.20, permeability of 1368.95 mD, water saturation of 0.45 (49%) and a net to gross ratio of 0.58.

Table 9: Petrophysical Summary of Well 19 reservoirs

Reservoirs	Gross Thickness (m)	V_{sh}	Net Sand (m)	Φ	Eff_{ϕ}	K (mD)	F	NTG	S_{wirr}	S_w	S_h
B	18.25	0.05	15.64	0.25	0.24	1908.34	14.37	0.86	0.09	0.34	0.66
C	14.47	0.30	7.80	0.21	0.17	1435.37	33.67	0.54	0.13	0.56	0.44
D	7.34	0.06	3.23	0.25	0.24	2003.82	12.74	0.44	0.08	0.24	0.76
E	50.92	0.15	4.34	0.21	0.18	1439.96	20.61	0.34	0.10	0.56	0.44
F	80.57	0.30	5.08	0.21	0.15	1503.9	20.08	0.38	0.10	0.53	0.47
G	1.56	0.09	0.95	0.21	0.19	1424.71	19.26	0.61	0.10	0.43	0.57
H	6.45	0.07	6.06	0.18	0.17	1210.39	24.25	0.94	0.11	0.51	0.49
I	43.84	0.06	9.85	0.2	0.19	1364.01	20.93	0.45	0.10	0.37	0.63
J	11.35	0.44	5.18	0.17	0.11	1047.68	33.18	0.46	0.13	0.70	0.30
K	2.00	0.09	1.37	0.18	0.17	1183.17	24.6	0.69	0.11	0.32	0.68
L	12.66	0.14	11.71	0.16	0.14	981.73	36.68	0.92	0.14	0.42	0.58
M	54.97	0.13	6.81	0.15	0.13	924.36	35.91	0.37	0.13	0.42	0.58
Average	25.37	0.16	6.50	0.20	0.17	1368.95	24.69	0.58	0.11	0.45	0.55

3.5.2 Hydrocarbon Volumetric Summary of Well 19 Reservoirs

From Table 10, well 19 reservoirs on average, have STOIIP of 975,022,010.30 MMCF/MMSTB and ultimate recovery of 805,469,155.46 MMCF/MMSTB with a recovery factor of 0.84 (84%). Based on these findings, we can imply that well 19 is a lucrative well with ultimate hydrocarbon retrieval of \$40,273,457,773.00@ \$50 per barrel (Table 10).

Table 10: Hydrocarbon Volumetric Summary of Well 19

Reservoirs	HCPV	STOIIP	RF	UR
B	137,931.09	5,006,898,440.22	0.81	4,046,189,387.65
C	38,476.50	1,396,696,795.20	0.90	1,250,055,140.49
D	33,976.06	1,233,330,863.21	0.78	967,107,639.73
E	85,203.44	550,840,228.01	0.85	468,546,846.22
F	163,449.46	1,056,700,762.75	0.84	883,350,186.12
G	6,029.53	218,871,939.30	0.88	191,956,210.72
H	29,824.68	192,816,581.54	0.85	163,804,758.53
I	135,412.31	875,440,554.05	0.80	699,238,970.40
J	14,290.50	92,388,110.04	0.91	83,763,861.04
K	9,203.70	59,501,893.85	0.80	47,783,682.51
L	58,703.66	379,519,169.26	0.85	322,112,636.71
M	98,570.58	637,258,786.15	0.85	541,720,545.34
Average	67,589.29	975,022,010.30	0.84	805,469,155.46

Average Ultimate Recovery @USD50.00/B = 805,469,155.46 x 50 = \$40,273,457,773.00

3.6 Well 27 Analysis

Well 27 comprises of both single and double-phase reservoirs, it has six single phase gas reservoirs, two double-phase (Gas/Oil) reservoirs and three single-phase oil reservoirs (Figures 9a and b). This well intercepted eleven reservoirs (B, C, D, E, F, G, H, I, J, K, and L) out of thirteen existing reservoirs in the field and ranges in depth from 3008.31 (9,927.42 ft) m to 3468.55 m (11,446.22 ft).

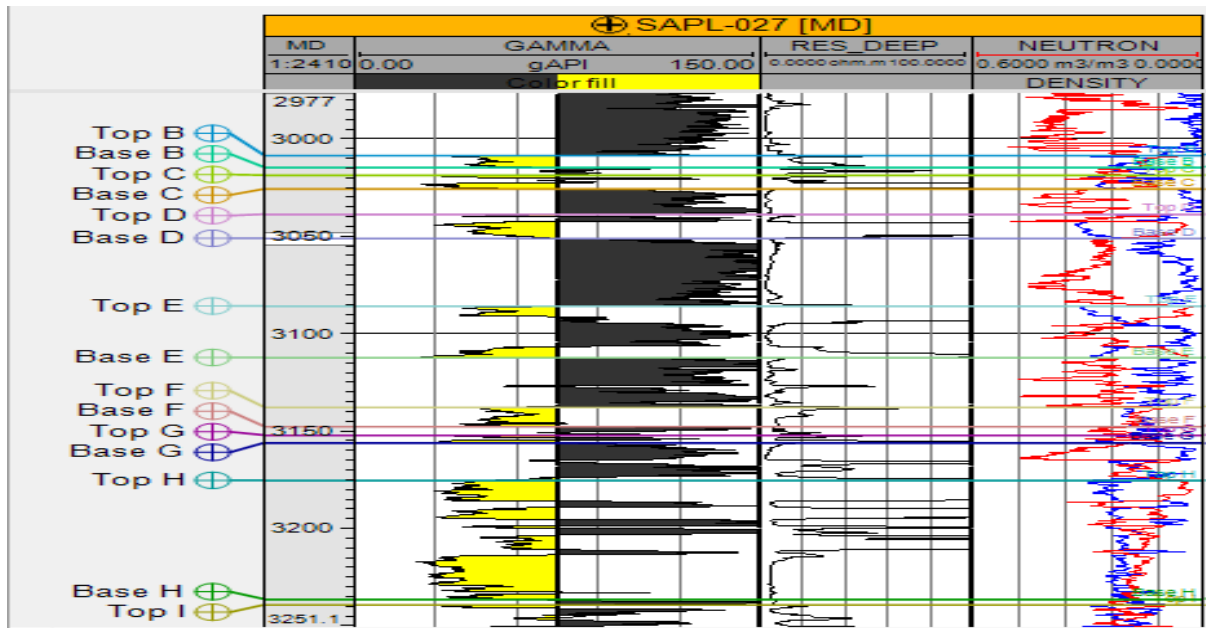


Figure 9a: Well log signature of well 27 from 2977.60 m to 3251.10 m (Using Petrel®2016).

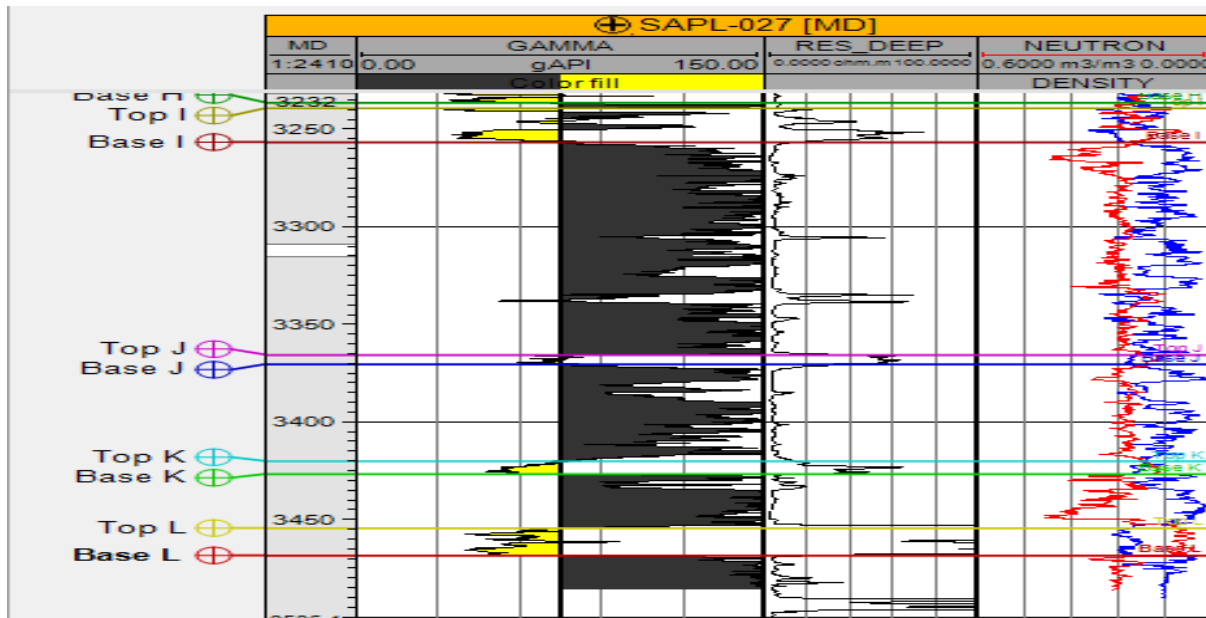


Figure 9b: Well log signature of well 27 from 3232 m to 3506.10 m (Using Petrel®2016).

3.6.1 Petrophysical Summary of Well 27 Reservoirs

The combined petrophysical result of well 27 reservoirs as reveal in Table 11, states that the reservoirs on average, have a gross thickness of 16.44 m (54.25 ft), net sand thickness of 5.65 m (18.64 ft), shale volume of 0.23, porosity value of 0.23, permeability value of 1769.15 mD, water saturation of 0.42 (42%) and a net to gross ratio of 0.58.

Table 11: Petrophysical Summary of Well 27 reservoirs

Reservoirs	Gross Thickness (m)	V_{sh}	Net Sand (m)	Φ	Eff_{ϕ}	K (mD)	F	NTG	S_{wirr}	S_w	S_h
B	6.27	0.25	5.11	0.20	0.16	1393.83	27.77	0.81	0.12	0.59	0.41
C	6.86	0.46	5.5	0.27	0.20	2232.58	23.12	0.80	0.11	0.47	0.53
D	12.24	0.09	3.97	0.31	0.28	2782.08	8.73	0.32	0.07	0.13	0.87
E	26.58	0.06	5.11	0.26	0.24	2056.56	12.66	0.19	0.08	0.39	0.61
F	9.71	0.45	6.34	0.18	0.12	1146.23	37.38	0.65	0.14	0.78	0.22
G	4.03	0.05	4.01	0.26	0.24	2037.52	12.82	0.99	0.08	0.14	0.86
H	71.8	0.25	8.51	0.23	0.18	1703.77	18.2	0.47	0.09	0.47	0.53
I	17.61	0.35	5.97	0.23	0.17	1768.04	16.32	0.34	0.09	0.55	0.45
J	4.93	0.26	2.13	0.21	0.16	1511.37	17.88	0.43	0.09	0.36	0.64
K	6.57	0.14	4.29	0.19	0.16	1244.96	24.41	0.65	0.11	0.47	0.53
L	14.19	0.15	11.19	0.22	0.19	1583.68	17.25	0.75	0.09	0.22	0.78
Average	16.44	0.23	5.65	0.23	0.19	1769.15	19.69	0.58	0.10	0.42	0.58

3.6.2 Hydrocarbon Volumetric Summary of Well 27 Reservoirs

Well 27 reservoirs on average as seen in Table 12, have STOIP of 1,611,259,527.64 BBCF/BBSTB and ultimate recovery of 1,295,232,420.62 BBCF/BBSTB with a recovery factor of 0.83 (83%). Based on these findings, we can infer that well 27 is a sound well with an ultimate hydrocarbon recovery of \$64,761,621,031.23@ \$50 per barrel (as shown in Table 13)

Table 12: Hydrocarbon Volumetric Summary of Well 27

Reservoirs	HCPV	STOIP	RF	UR
B	23,394.13	151,243,036.72	0.87	131,777,322.86
C	64,854.89	2,354,232,365.68	0.83	1,962,510,700.66
D	57,347.69	2,081,721,111.59	0.72	1,492,876,526.56
E	43,617.20	1,583,304,362.06	0.82	1,303,896,962.98
F	20,772.27	134,292,726.40	0.92	123,217,879.21
G	129,374.55	4,696,295,986.84	0.78	3,648,951,631.26
H	224,579.39	1,451,905,742.82	0.82	1,184,750,933.69
I	33,992.73	1,233,935,971.89	0.88	1,082,937,524.18
J	15,734.23	101,721,807.63	0.79	80,486,930.68
K	23,381.23	151,159,626.98	0.83	125,641,375.72
L	104,243.58	3,784,042,065.47	0.82	3,110,508,839.07
Average	67,390.17	1,611,259,527.64	0.83	1,295,232,420.62

Average Ultimate Recovery @USD50.00/B = 805,469,155.46 x 50 = \$64,761,621,031.23

Table 13: Cumulative Average Volumetric of Sapele Deep

Reservoirs	HCPV	STOIP	RF	UR
Well 01	134,032.73	448,153,428.39	0.71	287,469,260.17
Well 06	111,647.50	311,672,938.26	0.73	215,892,954.64
Well 17	94,391.17	1,416,052,696.66	0.84	1,207,418,779.00
Well 18	66,999.23	2,179,663,023.41	0.88	1,900,314,137.78
Well 19	67,589.29	975,022,010.30	0.84	805,469,155.46
Well 27	67,390.17	1,611,259,527.64	0.83	1,295,232,420.62
Average	90,341.68	1,156,970,604.11	0.81	951,966,117.95

Average Ultimate Recovery Reserve @USD50.00/B = 951,966,117.95 x 50 = \$47,598,305,897.50

4. Conclusion

The entire Sapele deep field has an average hydrocarbon pore volume of 90,341.68, STOIP value of 1,156,970,604.11 BBCF/BBSTB and an ultimate recovery value of 951,966,117.95 MMCF/MMSTB with primary recovery factor of 0.81 (81%). The high recovery factor in this

field is due to the presence of gas and appreciable water drives which has contributed to the high Primary recovery factor. Considering fluctuation in oil price, an average oil price of USD50.00 per barrel will generate on average, \$47,598,305,897.50 billion from a primary production of 951,966,117.95 MMCF/MMSTB in the field. Thus, Sapele Deep field is an economically viable field.

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