Reservoir Quality Evaluation of Sand Bodies of K-Field, Onshore Niger Delta, Using Wireline Logs

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Abstract-Seven reservoirs were identified across three wells A1, A2 and A3; three reservoirs contain hydrocarbon in well A1, six reservoirs contain hydrocarbon in well A2, and four reservoirs contain hydrocarbon in well A3. The reservoirs were correlated using gamma ray log and the reservoirs were found to be continuous across the wells. The petrophysical parameters of the reservoirs evaluated indicate average porosity, permeability, water-saturation and hydrocarbon-saturation values of 31.89%, 305.17md, 40.00% and 60.00%, respectively. The porosity value indicates excellent porosity and permeability very good. The field has both associated gas and non-associated gas reservoirs. The crossplot of water-saturation and porosity revealed that the grain size variation of the reservoirs ranges from coarse-grained to very fine-grained sands. The BVW crossplot indicated that most of the reservoirs are heterogeneous. The environments prevalent in the studied reservoirs, using standard gamma-ray log motif, range from channel sand of deltaic plain settings to shoreface environment.

Key words-Reservoir quality, sand bodies, wireline logs, crossplot, correlation.

1. INTRODUCTION

This study is on the evaluation of petrophysical parameters, depositional environment and correlation of reservoir sand bodies using well logs of three (3) wells in pseudo-named K-Field, Onshore Niger Delta. The petrophysical analyses with wireline logs provide reservoir characteristics (porosity, permeability and fluid saturation). Integrating with other data would guide and enhance exploration and development of the reservoir sand bodies.

The field under study is pseudo-named K-Field in accordance with the Nigerian Agip Oil company (NAOC) confidentiality agreement. The field is an onshore field, located within the Coastal Swamp-1 depobelt (Figure 1). The co-ordinates of the location of this field were concealed due to proprietary reasons. It covers an area extent of 19.89km².

2. Objectives of the Study

- To identify the various sand bodies and correlate them across the field.

Figure 1. Concession map of Niger Delta showing Exploration Blocks, and the K-Field
To identify and quantify hydrocarbons in the reservoir sand bodies and to evaluate the fluid and rock properties.

- To discriminate the gas and oil bearing zones and their contacts.

- To determine the depositional environment using standard wireline log motifs.

### 3. Scope of Work

This research work covers the petrophysical analysis of reservoir sand bodies of three (3) wells: A1, A2 and A3 of total depths 3,580m, 3,170m and 3490m, respectively, wireline log correlation of the wells and depositional environment determination of the reservoir sand bodies from wireline logs.

#### 4.1. Niger Delta Province Geology

The Niger Delta is a prograding depositional complex within the Cenozoic formation of Southern Nigeria. It is located in southern Nigeria. It extends from the Calabar flank and Abakaliki Trough in Eastern Nigeria to the Benin Flank in the west; it opens to the Atlantic Ocean in the south and protrudes into the Gulf of Guinea as an extension from the Benue Trough and Anambra Basin province (Burke and Whiteman, 1970; Tuttle et al, 1999). The delta complex merges westwards across the Okitipupa high into the Dahomey embayment. Onshore portion of the Niger Delta Province is delineated by the geology of southern Nigeria and southwestern Cameroon and the offshore boundary of the province is defined by the Cameroon volcanic line to the east, the eastern boundary of the Dahomey basin to the west (Figure 2).

#### 4.2. Evolution of the Niger Delta

The evolution of the Niger delta is related to the development of the Ridge-Ridge-Ridge (RRR) triple junction and the subsequent separation of the South American and African continents (Short and Stauble, 1967) (Figure 3). The Niger delta has built out over the collapsed continental margin at the site of the triple junction formed during the Middle Cretaceous. The main sediment supply has been provided by an extensive drainage system, the Niger-Benue system through the Anambra basin north of Onitsha and the less important Cross River system through the Afikpo basin (Etu-Efeotor, 1997), which in its lower reaches follows two failed rift arms, the Benue and Bida basins (Burke et al., 1971). In Eocene-Oligocene times, the two river systems appear to have been separated from each other by the late Cretaceous Abakaliki anticlinorium (Figure 2).
4.3. The Stratigraphy of the Niger Delta

The composite Tertiary Sequence of the Niger Delta consists, in ascending order, of the Akata, Agbada and Benin Formation (Evamy et al., 1978). They compose of estimated 28,000ft (8,535m) of section at the approximate depocenter in the central part of the delta (Avbovbo, 1978). There is decrease in age basin ward, reflecting the overall regression of depositional environments within the Niger Delta clastic wedge. Stratigraphic equivalent units to these three formations are exposed in southern Nigeria. The formations reflect a gross coarsening-upward progradational clastic wedge (Short and Stauble, 1967), the Akata Formation deposited in marine, the Agbada Formation deposited in deltaic, and the Benin Formation deposited in fluvial environments (Weber and Daukoru, 1975; Weber, 1986). The Akata Formation is made up of undercompacted, overpressured sequence of shales and siltstone, the formation is estimated to be 18,000 ft (about 6000m) thick in the central part of the clastic wedge (Doust and Omatsola, 1989). The Agbada Formation is the alternation sequence of paralic sandstone and shale and it occurs throughout Niger Delta clastic wedge and has a maximum thickness of about 12,000 ft (4000m). It outcrops in southern Nigeria between Ogwashi and Asaba; it is called the Ogwashi-Asaba Formation (Doust and Omatsola, 1990). The Benin Formation overlying the Agbada Formation consists mainly of sands and gravels with thickness ranging from 0 to 6000ft (0-2000m).

5. Methodology

Figure 4 shows the various methods adopted in the evaluation of the reservoir sand bodies of the studied field using wireline logs.
6. Results and Interpretation

6.1. Correlation of the reservoir sands

The correlation was carried out based on the positions of the reservoir in the succession of sands and shales on the well logs across the wells (Figure 5). The gamma ray (GR) logs were the main log used because it exhibits patterns that are easier to recognized and correlate from well to well. The resistivity logs were then used for the correlation because individual shale beds exhibit distinctive resistivity characteristic across the wells, the shale resistivity markers (SRM) were identified on the three (3) wells logs before the cross-checking.

The Shale resistivity markers (SRM) were used to cross-check the correlation of the GR log and the reservoir sand bodies were found to be continuous. The correlation was done from the top to the bottom of the well logs (Figure 5). From the correlation, it was observed that reservoir R1 to R7 is correlatable in all the wells in the field. This implies that the correlatable reservoirs are genetically equivalent laterally (in the same depositional environment). Some of the correlatable reservoir does not contain hydrocarbon in some wells. The displacement of some correlatable reservoirs in depth is probably as a result of synthetic fault (Figure 5).
Figure 5. Log correlation profile through well A1, A2 and A3 (S-N): Insert the base map of K-Field showing the positions of the wells
6.2. Petrophysical results and interpretation

Total of seven (7) reservoirs (R_{n}) were identified and evaluated/analyzed: well A_1 does not have hydrocarbon in R_4, R_5, R_6 and R_7; well A_2 does not have hydrocarbon in R_3; and well A_3 does not have hydrocarbon in R_1, R_2, and R_5. The correlations were done from top to the bottom of the well and across the field (Figure 5). Only correlatable reservoirs that contain hydrocarbons were evaluated (Table 1). The following petrophysical parameters were computed for the reservoirs:

Table 1. Summary of average petrophysical values for the three wells of K-Field

<table>
<thead>
<tr>
<th>Sand</th>
<th>Reservoir</th>
<th>Top - Bottom Sand (m)</th>
<th>Gross Thickness of Sand (m)</th>
<th>Net thickness of Sand (m)</th>
<th>N/G Ratio</th>
<th>( \Phi ) (%)</th>
<th>( S_w ) (%)</th>
<th>( S_h ) (%)</th>
<th>K (md)</th>
</tr>
</thead>
</table>
| Well A1
| F_3 | R_1 | 2107.50 - 2127.50 | 20.00 | 17.50 | 0.88 | 30.00 | 39.33 | 60.67 | 271.36 |
| F_2 | R_2 | 2150.00 - 2162.50 | 12.50 | 10.00 | 0.80 | 33.50 | 44.33 | 55.67 | 330.80 |
| F_1 | R_3 | 2372.50 - 2392.50 | 20.00 | 17.50 | 0.88 | 31.11 | 48.89 | 51.11 | 228.32 |
| Well A2
| F_3 | R_1 | 2110.00 - 2130.00 | 20.00 | 18.50 | 0.93 | 32.33 | 47.56 | 52.44 | 314.39 |
| F_1 | R_3 | 2367.50 - 2390.00 | 22.50 | 17.50 | 0.78 | 32.50 | 44.20 | 55.80 | 314.55 |
| E   | R_4 | 2607.50 - 2647.50 | 40.00 | 35.00 | 0.88 | 32.06 | 35.24 | 64.76 | 307.90 |
| D   | R_5 | 2700.00 - 2756.00 | 60.00 | 55.00 | 0.92 | 31.48 | 40.60 | 59.40 | 297.76 |
| C   | R_6 | 2797.50 - 2837.50 | 40.00 | 35.00 | 0.88 | 27.41 | 40.82 | 59.18 | 262.49 |
| A   | R_7 | 3072.50 - 3037.50 | 37.50 | 35.00 | 0.93 | 28.63 | 18.63 | 81.37 | 249.76 |
| Well A3
| F_1 | R_3 | 2362.50 - 2382.50 | 20.00 | 14.50 | 0.73 | 30.22 | 25.33 | 74.67 | 273.37 |
| E   | R_4 | 2617.50 - 2652.50 | 35.00 | 33.00 | 0.94 | 30.33 | 53.53 | 46.47 | 275.01 |
| C   | R_6 | 2802.50 - 2877.50 | 75.00 | 67.50 | 0.90 | 30.58 | 57.74 | 42.26 | 281.22 |
| A   | R_7 | 3090.00 - 3110.00 | 20.00 | 12.50 | 0.63 | 30.78 | 26.00 | 74.00 | 302.18 |

6.3. Characteristics of reservoir sand body, R_1 well A_1
It occurs at interval of 2107.5 – 2127.5m and has a gross (G) and net (N) thickness of sand, 20.0 and 17.5m respectively, with N/G ratio of 0.88; average water saturation (Sw) of 39.33% and hydrocarbon saturation (Sh) of 60.67%, the gas water contact (GWC) and oil water contact (OWC) at 2117.5 and 2122.5m respectively; average porosity (φ) and permeability (K) of 30.00% and 271.36 m²d respectively (Table 1). The reservoir therefore, has excellent porosity and very good permeability. The environment of deposition inferred to be fluvial channel. The crossplot of water saturation (Sw) versus porosity (φ) shows grain size variation is medium to very fine-grained sand (Figure 6a). The bulk volume water plot (Figure 6b) shows that the reservoir is heterogeneous and the formation has more water than it can hold by capillary pressure, thus the reservoir is not at irreducible water saturation (Swirr) and cannot produce water-free hydrocarbon during production.

Figure 6. Crossplots of reservoir R₁ in well A1 (A) Grain size determination (B) Bulk volume plot

6.4. Characteristics of reservoir sand body, R₂ well A1

It occurs at interval of 2150.0 – 2162.5m and has a gross (G) and net (N) thickness of sand, 12.5 and 10m respectively, with N/G ratio of 0.80; average water saturation (Sw) of 44.33% and hydrocarbon saturation (Sh) of 55.67%, the GWC is at 2157.5m; average porosity (φ) and permeability (K) of 33.50% and 330.80 m²d respectively (Table 1). The reservoir therefore, has excellent porosity and very good permeability. The environment of deposition inferred to be fluvial channel. The crossplot of water saturation (Sw) versus porosity (φ) shows grain size variation is predominantly very fine-grained sand (Figure 7a). The bulk volume water plot (Figure 7b) shows that the reservoir is heterogeneous and the formation has more water than it can hold by capillary pressure, thus the reservoir is not at irreducible water saturation (Swirr) and cannot produce water-free hydrocarbon during production.
6.5. Characteristics of reservoir sand body, R₃ well A1

It occurs at interval of 2372.5 – 2392.5m and has a gross (G) and net (N) thickness of sand, 20.0 and 17.5m respectively, with N/G ratio of 0.88; average water saturation (Sₜ) of 48.89% and hydrocarbon saturation (Sₜ) of 51.11%; the GWC is at 2382.5m; average porosity (φ) and permeability (K) of 31.11% and 292.12 mD respectively (Table 3.1). The reservoir therefore, has excellent porosity and very good permeability. The environment of deposition inferred to be fluvial channel. The crossplot of water saturation (Sₜ) versus porosity (φ) shows grain size variation is predominantly fine to medium-grained sand (Figure 8a). The bulk volume water plot (Figure 8b) shows that the reservoir is heterogeneous and the formation has more water than it can hold by capillary pressure, thus the reservoir is not at irreducible water saturation (Sₜirr) and cannot produce water-free hydrocarbon during production.
6.6. Characteristics of reservoir sand body, R₁ well A2

It occurs at interval of 2110.0 – 2130.0m and has a gross (G) and net (N) thickness of sand, 20.0 and 18.5m respectively, with N/G ratio of 0.93; average water saturation (Sₚ) of 47.56% and hydrocarbon saturation (Sₘ) of 52.44%; the GWC is at 2120m; average porosity (φ) and permeability (K) of 32.33% and 314.39 m²d respectively (Table 1). The reservoir therefore, has excellent porosity and very good permeability. The environment of deposition inferred to be fluvial channel. The crossplot of water saturation (Sₚ) versus porosity (φ) shows grain size variation is predominantly very fine-grained sand (Figure 9a). The bulk volume water plot (Figure 9b) shows that the reservoir is heterogeneous and the formation has more water than it can hold by capillary pressure, thus the reservoir is not at irreducible water saturation (Sₘirr) and cannot produce water-free hydrocarbon during production.

Figure 9. Crossplots of reservoir R₁ in well A2 (A) Grain size determination (B) Bulk volume plot

6.7. Characteristics of reservoir sand body, R₃ well A2

It occurs at interval of 2367.5 – 2390.0m and has a gross (G) and net (N) thickness of sand, 22.5 and 17.5m respectively, with N/G ratio of 0.78; average water saturation (Sₚ) of 44.20% and hydrocarbon saturation (Sₘ) of 55.80%; the GWC is at 2377.5m; average porosity (φ) and permeability (K) of 32.50% and 314.55 m²d respectively (Table 1). The reservoir therefore, has excellent porosity and very good permeability. The environment of deposition inferred to be fluvial channel. The crossplot of water saturation (Sₚ) versus porosity (φ) shows grain size variation from medium to very fine-grained sand (Figure 10a). The bulk volume water plot (Figure 10b) shows that the reservoir is heterogeneous and the formation has more water than it can hold by capillary pressure, thus the reservoir is not at irreducible water saturation (Sₘirr) and cannot produce water-free hydrocarbon during production.
6.8. Characteristics of reservoir sand body, R₄ well A2

It occurs at interval of 2607.5 – 2647.5m and has a gross (G) and net (N) thickness of sand, 40.0 and 35m respectively, with N/G ratio of 0.88; average water saturation (Sₜₐₜ) of 35.24% and hydrocarbon saturation (Sₕ) of 64.76%; the gas down to (GDT) is at 2382.5m; average porosity (φ) and permeability (K) of 32.06% and 307.96 md respectively (Table 1). The reservoir therefore, has excellent porosity and very good permeability. The environment of deposition inferred to be tidal channel. The crossplot of water saturation (Sₜₐₜ) versus porosity (φ) shows grain size variation from medium to very fine-grained sand (Fig. 11a). The bulk volume water plot (Fig.11b) shows that the reservoir is heterogeneous and the formation has more water than it can hold by capillary pressure, thus the reservoir is not at irreducible water saturation (Sₐₚₑₜ) and cannot produce water-free hydrocarbon during production.
6.9. Characteristics of reservoir sand body, $R_5$ well A2

It occurs at interval of 2700.0 – 2760.0m and has a gross (G) and net (N) thickness of sand, 60.0 and 55.0m respectively, with N/G ratio of 0.92; average water saturation ($S_w$) of 40.60% and hydrocarbon saturation ($S_h$) of 59.40%, the GOC and OWC is at 2727.5 and 2737.50m respectively; average porosity ($\phi$) and permeability (K) of 31.48% and 297.76md respectively (Table 1). The reservoir therefore, has excellent porosity and very good permeability. The environment of deposition inferred to be shoreface. The crossplot of water saturation ($S_w$) versus porosity ($\phi$) shows grain size variation from medium to very fine-grained sand (Figure 12a). The bulk volume water plot (Figure 12b) shows that the reservoir is heterogeneous and the formation has more water than it can hold by capillary pressure, thus the reservoir is not at irreducible water saturation ($S_{wirr}$) and cannot produce water-free hydrocarbon during production.

6.10. Characteristics of reservoir sand body, $R_6$ well A2

It occurs at interval of 2797.5 – 2837.5m and has a gross (G) and net (N) thickness of sand, 62.5 and 52.5m respectively, with N/G ratio of 0.88; average water saturation ($S_w$) of 40.81% and hydrocarbon saturation ($S_h$) of 59.19%, the GOC and OWC is at 2817.5 and 2825.0m respectively; average porosity ($\phi$) and permeability (K) of 29.35% and 262.49md respectively (Table 1). The reservoir therefore, has excellent porosity and very good permeability. The environment of deposition inferred to be channel sands stacked on top of shoreface sand (Hybrid sand). The crossplot of water saturation ($S_w$) versus porosity ($\phi$) shows grain size variation predominantly very fine-grained sand (Figure 13a). The bulk volume water plot (Figure 13b) shows that the reservoir is heterogeneous and the formation has more water than it can hold by capillary pressure, thus the reservoir is not at irreducible water saturation ($S_{wirr}$) and cannot produce water-free hydrocarbon during production.
6.11. Characteristics of reservoir sand body, R7 well A2

It occurs at interval of 3037.5 – 3075.0m and has a gross (G) and net (N) thickness of sand, 37.5 and 35.0m respectively, with N/G ratio of 0.93; average water saturation ($S_w$) of 18.63% and hydrocarbon saturation ($S_h$) of 81.37%, the GDT is at 3072.5m; average porosity ($\phi$) and permeability (K) of 28.63% and 249.76 md respectively (Table 1). The reservoir therefore, has excellent porosity and very good permeability. The environment of deposition inferred to be tidal channel. The crossplot of water saturation ($S_w$) versus porosity ($\phi$) shows grain size variation from coarse-grained to fine-grained sand (Figure 14a). The bulk volume water plot (Figure 14b) shows that the reservoir is homogeneous and thus the reservoir is at irreducible water saturation ($S_{wirr}$), this implies that the reservoir will produce water-free hydrocarbon during production.
6.12. Characteristics of reservoir sand body, R₃ well A₃

It occurs at interval of 2362.5 – 2382.5m and has a gross (G) and net (N) thickness of sand, 20 and 14.5m respectively, with N/G ratio of 0.73; average water saturation (Sₜₚ) of 25.33% and hydrocarbon saturation (S₝) of 74.67%; the GWC is at 2380.0m; average porosity (φ) and permeability (K) of 30.22% and 273.37 m²d respectively (Table 1). The reservoir therefore, has excellent porosity and very good permeability. The environment of deposition inferred to be fluvial channel. The crossplot of water saturation (Sₜₚ) versus porosity (φ) shows grain size variation is predominantly fine to medium-grained sand (Figure 15a). The bulk volume water plot (Figure 15b) shows that the reservoir is homogeneous and thus the reservoir is at irreducible water saturation (Sₜₚₚ), this implies that the reservoir will produce water-free hydrocarbon during production.

![Crossplots of reservoir R₃ in well A₃](image)

Figure 15. Crossplots of reservoir R₃ in well A₃ (A) Grain size determination (B) Bulk volume plot

6.13. Characteristics of reservoir sand body, R₄ well A₃

It occurs at interval of 2617.5 – 2652.5m and has a gross (G) and net (N) thickness of sand, 35 and 33m respectively, with N/G ratio of 0.94; average water saturation (Sₜₚ) of 53.53% and hydrocarbon saturation (S₝) of 46.47%; the G0C and OWC is at 2630.0 and 2637.5m respectively; average porosity (φ) and permeability (K) of 30.33% and 275.01 m²d respectively (Table 1). The reservoir therefore, has excellent porosity and very good permeability. The environment of deposition inferred to be tidal channel. The crossplot of water saturation (Sₜₚ) versus porosity (φ) shows grain size variation is very fine-grained sand (Figure 16a). The bulk volume water plot (Figure 16b) shows that the reservoir is heterogeneous and the formation has more water than it can hold by capillary pressure, thus the reservoir is not at irreducible water saturation (Sₜₚₚ), and cannot produce water-free hydrocarbon during production.

![Crossplots of reservoir R₄ in well A₃](image)

It occurs at interval of 2802.5 – 2877.5m and has a gross (G) and net (N) thickness of sand, 75 and 67.5m respectively, with N/G ratio of 0.90; average water saturation (Sₗ) of 57.74% and hydrocarbon saturation (Sₕ) of 42.26%, the GOC and OWC is at 2807.5 and 2832.5m respectively; average porosity (φ) and permeability (K) of 30.00% and 281.22 mD respectively (Table 1). The reservoir therefore, has excellent porosity and very good permeability. The environment of deposition inferred to be channel sands stacked on top of shoreface sand (Hybrid sand). The crossplot of water saturation (Sₗ) versus porosity (ϕ) shows grain size variation is very fine-grained sand (Figure 17a). The bulk volume water plot (Figure 17b) shows that the reservoir is heterogeneous and the formation has more water than it can hold by capillary pressure, thus the reservoir is not at irreducible water saturation (SₗIRR) and cannot produce water-free hydrocarbon during production.
6.15. Characteristics of reservoir sand body, R₇ well A3

It occurs at interval of 3090.0 – 3110.0m and has a gross (G) and net (N) thickness of sand, 20 and 12.5m respectively, with N/G ratio of 0.63; average water saturation (Sₜₜ) of 26.00% and hydrocarbon saturation (Sₜₜ) of 74.00%, the GDT is at 3110.0m; average porosity (φ) and permeability (K) of 30.78% and 302.18 md respectively (Table 1). The reservoir therefore, has excellent porosity and very good permeability. The environment of deposition inferred to be tidal channel. The crossplot of water saturation (Sₜₜ) versus porosity (φ) shows grain size variation from medium to very fine-grained sand (Figure 18a). The bulk volume water plot (Figure 18b) shows that the reservoir is homogeneous and thus the reservoir is at irreducible water saturation (Sₛₜₜᵣᵣᵣ), this implies that the reservoir will produce water-free hydrocarbon during production.

Figure 18. Crossplots of reservoir R₇ in well A3 (A) Grain size determination (B) Bulk volume plot

7. Depositional environments

The depositional environments of the reservoir sand bodies were inferred by comparing the gamma ray signature with standard log motifs indicative of gamma ray response to variations in grain size (Figure 19).

Sand G: The gamma ray signature is a funnel shaped which shows blocky serrated log signature (Figure 5 and Table 2). The depositional environment of the reservoir is inferred to be a braided fluvial.

Sand F (R₁₇, R₁₈ and R₁₉): The gamma ray signature is serrated (saw-teeth) shaped which shows bedded sand with interbedded shale (Figure 5 and Table 2). This characteristic is common among fluvial channel sands. It may be interpreted to represent aggrading distributary channel-fill (Figure 19).

Sand E (R₅): The gamma ray signature is a bell shaped which shows fining upward log signature (Figure 5 and Table 2). The depositional environment of the sand body is inferred to be tidal channel.

Sand D (R₆): The gamma ray signature is a funnel shaped which shows coarsening upward log signature (Figure 5 and Table 2). The depositional environment of the reservoir is inferred to be a shoreface.

Sand C (R₇): The gamma ray log has a combination curve shaped signature, which may indicate gradual changes or abrupt changes from one environment to another. The
lower part of the log signature is a funnel shaped curve which represents a coarsening upward sequence (Figure 5 and Table 2). The environment of deposition is inferred to be shoreface environment. The upper part of the log signature is a bell shaped curve, which shows a fining upward sequence (Figure 5 and Table 2); the environment of deposition of this part is inferred to be tidal channel environment. The reservoir is then made up of channel sands stacked on top of shoreface sand. The sand of this type of environment is referred to as hybrid sand.

Sand B: The gamma ray signature is funnel shaped which shows coarsening upward log signature (Figure 5 and Table 2); the depositional environment of the reservoir is inferred to be a shoreface.

Sand A (R7): The gamma ray signature is bell shaped, which shows fining upward log signature (Figure 5 and Table 2). The depositional environment of the sand body is inferred to be tidal channel.

Figure 19. Standard log motifs, gamma ray response to variations in grain size (Modified from Emery and Myers, 1996)
<table>
<thead>
<tr>
<th>Sand</th>
<th>GR log shapes/stacking patterns</th>
<th>Characteristic description</th>
<th>Inferred depositional environment</th>
<th>$\Phi$ (%)</th>
<th>$K$ (md)</th>
<th>$S_h$ (%)</th>
<th>$S_w$ (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>$G$</td>
<td><img src="image1.png" alt="image" /></td>
<td>The gamma ray signature is blocky shaped and serrated pattern</td>
<td>Braided fluvial</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>$F$ ($R_1$, $R_2$ and $R_3$)</td>
<td><img src="image2.png" alt="image" /></td>
<td>The gamma ray signature is cylindrical shaped with blocky thickly bedded sand with few interbedded shale</td>
<td>Fluvial channel sand</td>
<td>31.26</td>
<td>293.42</td>
<td>60.90</td>
<td>39.10</td>
</tr>
<tr>
<td>$E$ ($R_4$)</td>
<td><img src="image3.png" alt="image" /></td>
<td>The gamma ray signature is bell shaped</td>
<td>Tidal channel</td>
<td>32.06</td>
<td>307.90</td>
<td>64.76</td>
<td>35.24</td>
</tr>
<tr>
<td>$D$ ($R_5$)</td>
<td><img src="image4.png" alt="image" /></td>
<td>The gamma ray signature is funnel shaped</td>
<td>Shoreface</td>
<td>31.48</td>
<td>297.76</td>
<td>59.40</td>
<td>40.60</td>
</tr>
<tr>
<td>$C$ ($R_6$)</td>
<td><img src="image5.png" alt="image" /></td>
<td>The gamma ray log has a combination curve shaped signature. Lower part: funnel shaped; and upper part bell shaped signature</td>
<td>Channel sand stacked on top of shoreface sand (Hybrid sand)</td>
<td>27.41</td>
<td>262.49</td>
<td>59.18</td>
<td>40.82</td>
</tr>
<tr>
<td>$B$</td>
<td><img src="image6.png" alt="image" /></td>
<td>The gamma ray signature is funnel shaped</td>
<td>Shoreface</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>$A$ ($R_7$)</td>
<td><img src="image7.png" alt="image" /></td>
<td>The gamma ray signature is bell shaped</td>
<td>Tidal channel</td>
<td>29.71</td>
<td>275.97</td>
<td>77.69</td>
<td>22.31</td>
</tr>
</tbody>
</table>
8. Discussion

The reservoirs in the study area are sandstones within the Agbada Formation. Petrophysical evaluation was carried out on the wireline logs. A total of seven (7) reservoirs were identified and are correlatable across the entire wells. Though, some of the correlatable reservoirs do not contain hydrocarbon in some wells; three (3) reservoirs contain hydrocarbons in well A1, six (6) reservoirs contain hydrocarbons in well A2 and four (4) reservoirs contain hydrocarbons in well A3. The average petrophysical parameters of the reservoirs range from 37.78 – 27.41%, 409.15 – 249.76 md, 57.74 – 18.63%, and 81.37 – 42.26% for porosity (ф), permeability (K), water saturation (S_w) and hydrocarbon saturation (S_h), respectively. From the Schlumberger standard (Schlumberger, 1972) the porosity (ф) ranges from excellent to very good, while the permeability (K) is very good. These values show a gradual decrease from top to bottom of the wells, reflecting increase in compaction with depth. The permeability also followed the same trend, though there are fluctuations from reservoir to reservoir. With these petrophysical values, the reservoirs of the study area can be said to be prolific in terms of hydrocarbon production. The crossplots (Asquith and Gibson, 1982) revealed that grain size ranges from coarse-grained to very fine-grained sands.

Most of the reservoirs bulk volume water (BVW) values calculated and plotted on crossplot, as established by Asquith and Gibson, 1982, exhibit wide variation, this indicates that the reservoir are not homogeneous and not at irreducible water saturation (S_{wirr}) and the reservoirs can hardly produce hydrocarbon water-free, though such reservoirs can produce hydrocarbon water-free when the reservoirs have high content of clay. When a reservoir is at S_{wirr}, water saturation (S_w) will not move because it is held on grains by capillary pressure. Hydrocarbon production from a reservoir at S_{wirr} should be water-free. Only R_7 in well A2, R_3 and R_7 in A3 showed BVW values close to constant and can produce hydrocarbon water-free.

Depositional environments of the reservoir sand bodies were inferred by comparing the standard gamma ray wireline log motif which ranged in signatures from channel sand of deltaic plain settings to shoreface environments.

9. CONCLUSION

The reservoir sand bodies of K-Field have both associated and non-associated reservoirs, but the field is more or less a Gas Field. The porosity values that range from excellent to very good. The permeability is very good and the hydrocarbon saturation ranges from 81.37% to 42.26%. The reservoirs of the reservoir sand bodies are not at the zone of irreducible water saturation, except reservoirs R_1 in well A2, R_3 and R_7 in well A3; this implies that the rest will not produce water free hydrocarbons due to their high water saturation, although some others factors like clay within a reservoir, can makes reservoir with high water saturation to produce water free hydrocarbon. Thus, reservoir R_7 in well A2, R_3 and R_7 in well A3 of K-Field are the best in terms of hydrocarbon production, also the channel sands have the best reservoir quality and potential compared to the shoreface reservoir sand bodies studied.

REFERENCES


Ogbe, Ovie Benjamin, Opatola, Olatunji Abraham, Idjerhe Wilson, and Ocheli Azuka

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