Original Research Article

Logging and lithostratigraphic study of the Cenomanian-Santonian reservoirs of four oil wells MSP1, MSP2, MSP3 and MSP4 of the margin of San-Pedro (Côte d'Ivoire)

ABSTRACT

The logging and petrophysical study of four oil wells, MSP1, MSP2, MSP3 and MSP4 from San-Pedro margin of the Ivorian sedimentary basin has made it possible to evaluate the reservoir characteristics of the Cenomanian-Santonian age formations. Lithostratigraphically, this study has shown that this interval consists of clay and sandstone deposits interspersed with frequent past carbonate.

At the logging, ten (10) sandstone reservoirs are highlighted with effective porosities ranging from 16% to 21% and permeabilities from 100 mD to 1100 mD (millidarcy).

These reservoirs have very good petrophysical characteristics however their high water saturation show that they are rather aquifers. The various log gamma ray profiles of the intervals considered highlight a fluvial and marine deposition environment. Sedimentation would have started in a Cenomanian-type fluvial environment and would have continued in a marine environment marked by the accumulation of sandstone and clay under the influence of transgression and regression phases in the Turonian and Lower Senonian.

Keywords *: Logging; Reservoirs; lithostratigraphy; petrophysics; Ivorian basin; Cenomanian; Santonian; depositing environment*

1. INTRODUCTION

Located in the southern part of the country, the Ivorian sedimentary basin grows along the West Atlantic coast from Liberia (Sassandra) to Ghana. It extends between 3 ° 05 W and 7 ° 30 W and develops south of the latitude 5 ° 20 N. It results from the opening of the South Atlantic to the Jurassic and is part of the chain of sedimentary basins bordering the west Atlantic coast from southern Morocco to southern Africa **[1].**

This basin is of Meso-Cenozoic age **[2]** and includes a terrestrial part (onshore) or coastal basin and a submerged part (offshore) object of this study.

The submerged basin or offshore basin represents the largest part of the basin and develops on the continental shelf area, 750 km wide **[3].** This offshore basin is studied only by oil drilling.

It presents a structure in horsts and grabens, in response to the action of transtension phenomena that surround it. These are the transforming faults of Saint-Paul in the North-West and Romanche in the South-East **[4, 5, 6].**

This offshore basin is subdivided into a margin of Abidjan and a margin of San Pedro.

The Abidjan margin is the area of the main hydrocarbon discoveries in Côte d'Ivoire. It contains all the oil fields (Baobab, Lion, Hope, Foxtrot ...) known to date.

The oil exploration campaigns conducted so far at the San Pedro margin have not yet revealed sufficient commercial hydrocarbon accumulations to justify exploitation.

These less favorable oil results from recent wells drilled in this western part of the sedimentary basin of Côte d'Ivoire are prompting new geological studies to better understand the oil system of this margin. It is in this context that this study is initiated.
The main objective sought in this study is to characterize the Cenomanian-Santonian reservoirs of this zone at logging and lithostratigraphic and petrophysical levels. The choice of this interval obeys the fact that most deposits in the Abidjan margin have ages in this range. This study also aims to identify the reservoir zones from their lithological and petrophysical characteristic

2. PRESENTATION OF THE STUDY AREA

The study area is located in the Ivorian offshore sedimentary basin. This basin covers an area of about 22000 km² and a width of 80 km to 150 km from east to west from the coast to depths of water above 3000 m. It constitutes the bulk of the Ivorian sedimentary basin. It presents a structure in horsts and grabens, in response to the action of transtension phenomena that surround it.
These are the transforming faults of Saint-Paul in the North-West and Romanche in the South-East **[4, 5, 6].** This deep basin is subdivided into a margin of San-Pedro in the west and a margin of Abidjan in the east which are two geologically distinct margins **(Fig. 1)**:

- The margin of San-Pedro extends from the Liberian border to the city of Grand-Lahou. This margin is characterized by a deep basement, about 8 km according to the magnetic data of **[7]**. This Socle on which is located a steep continental shelf characteristic of the West margin, is part of the offshore extension of the West African craton. The sediments thicken from north to south where they reach about 700 to 800m at the top of the slope.

- The margin of Abidjan extends from Grand-Lahou to the Ghanaian border. This margin is characterized by a deep basement where sediment thickness increases from west to east (towards the Ghanaian basin) **[8]**.
This thickness was estimated by **[7]** between 6 and 10 Km by magnetic methods, but the seismic overestimated it between 12 and 13 Km. South of Abidjan, the plateau is cut by the bottom hole.

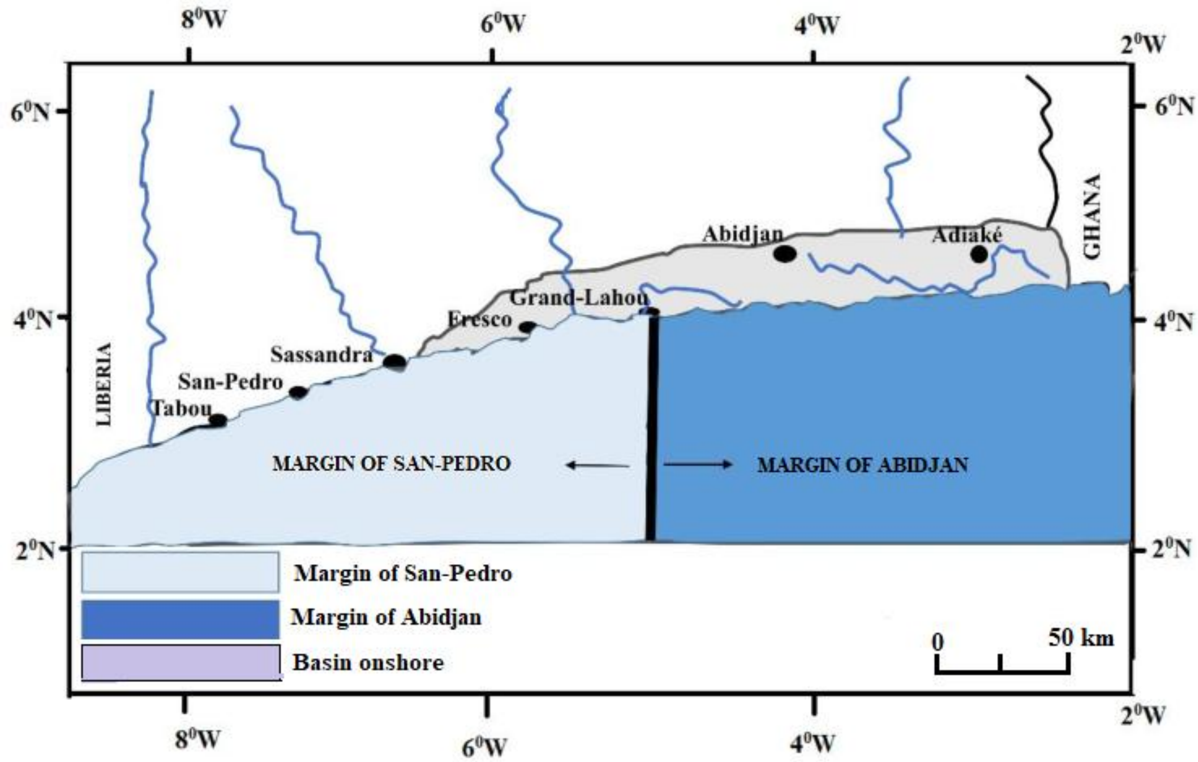

Fig. 1. Margins of the sedimentary basin of Côte d'Ivoire

The whole Ivorian sedimentary basin is divided into forty-eight (48) petroleum blocks today. This study area has fifteen (15) and nine (9) exploratory wells of which four (4) are studied in this work. These wells are located in blocks A, B and C of the San-Pedro Margin **(Fig. 2).** The coordinates of these wells are shown in **Table 1** below.

Table 1. **Wells coordinates**

Block	Wells	Latitude	Longitude	Depth (m)
A	MSP-1	4°23'27,9098''N	6°34'02,2528''W	1838,5
B	MSP-2	4°16'29,841'' N	6°14'43,912" W	2864
C	MSP-3	4°30'58,249" N	5°57'31,953" W	2162
	MSP4	4° 29' 51,756" N	5°56'44,100" W	2303

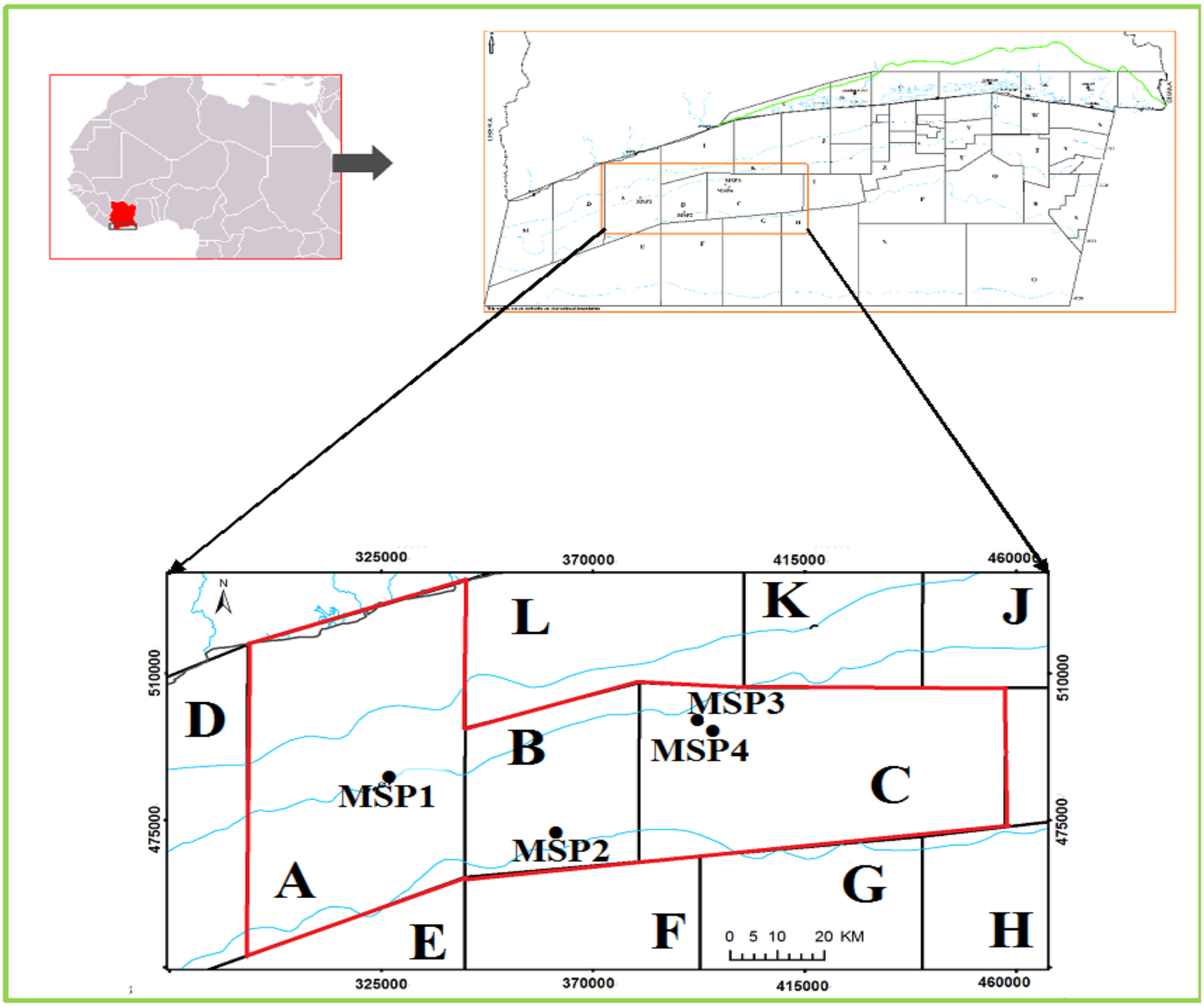

Fig. 2. **Location of the wells**

3. MATERIALS AND METHODS

The material used of this work consists of technical data of drilling reports, digital logging data (L.A.S files), composite logs and computer equipment.

L.A.S (Log Ascii Standard) files are digital files that contain the log data from records made during Wireline or LWD operation.

Drilling reports provide information on the lithology and petrophysical properties of the rock layers traversed by the different wells studied.

Composite logs are a set of logging signatures consisting of Gamma ray, Sonic, Resistivity, Density and Neutron logs derived from digital logging data.

Computer hardware is made up of high-capacity computers and software, the Decision Space Geosciences (DSG) software. It is a multifunction software, which has applications in geology, geophysics and petrophysics. It allows, log analysis, loading, processing and logging data interpretation.

The methodological approach used is based exclusively on log analysis and interpretation.

Logging digital data recorded in L.A.S (Log Ascii Standard) format during acquisition is loaded into a database and processed using Decision Space Geosciences (DSG) software.

Once the files, we proceed to the assignment of the curves, the positioning of the roofs of the floors and the development of the lithological logs.
The assignment consists of matching the curves to each type of log (Gamma Ray, Sonic, Resistivity, Density and Neutron).
Once log logs have been constructed, the different lithological formations the borehole are characterized, on the basis of the signatures of the gamma ray and density-neutron logs and verified by the drill cuttings descriptions and the biostratigraphic analysis.
The potential reservoir zones correspond to the low values of gamma ray and whose thickness is greater than or equal to 10m.
The gamma ray profile analysis also makes it possible to define the depositional environments. This analysis is based on the comparison shape of the gamma ray profile with the standard model **(Fig. 3)** established by **[9]**.
The petrophysical characterization of potential reservoirs, to determine : porosity (Φ), permeability (K), clay volume (Vsh), water saturation (Sw) and Net / Gross (N / G).

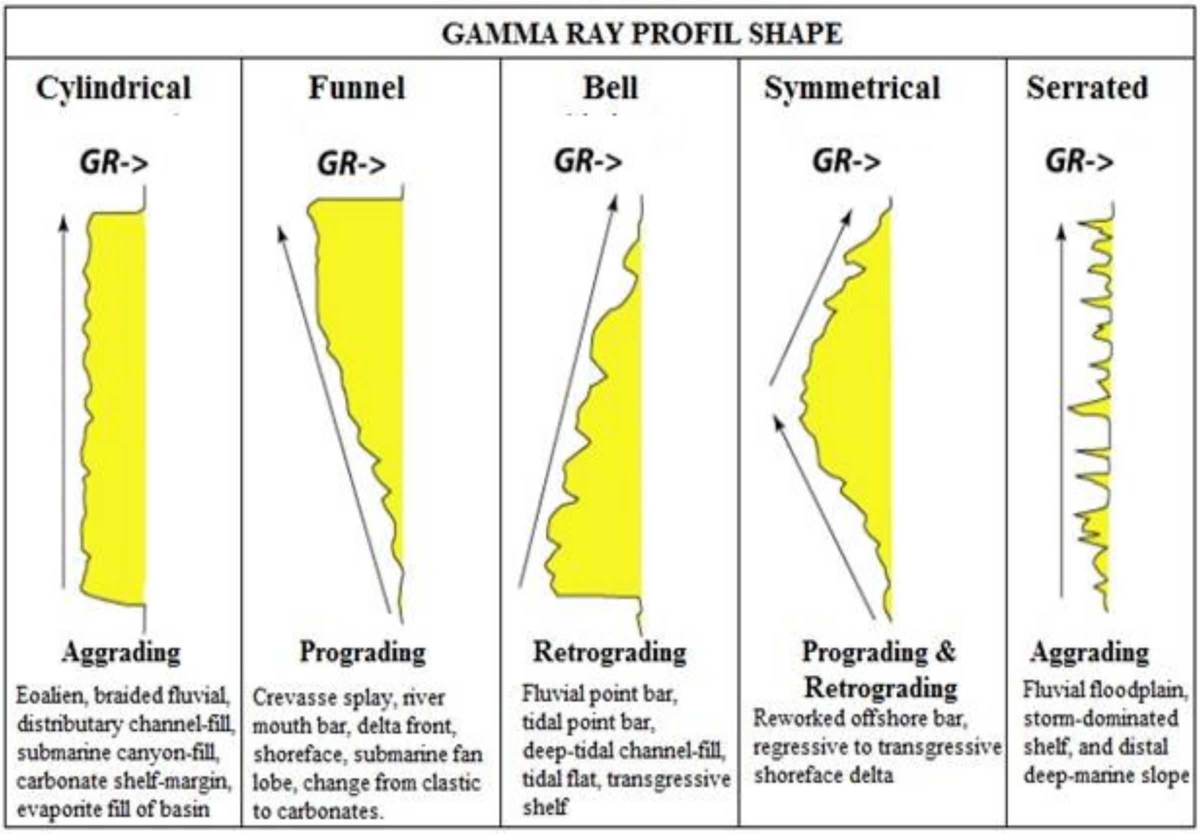

Fig. 3. Standard gamma ray (GR) response model based on variation in grain size and deposit environments [9]

These parameters are calculated from formulas integrating log data. These formulas having been automated, they are directly processed by computer from specialized software such as Techlog.

- **Effective porosity (Φe)**

It excludes unconnected pores and clay-bound water **[10]**. His formula is as follows:

$\Phi e = \Phi t \times (1 - Vsh)$ with Vsh (volume of clay) Eq.1

There are three types of reservoir according to their porosity (**Φe**) :

- low porosity reservoir : (**Φe**) < 5% ;
- medium porosity reservoir : 10% < (**Φe**) < 20% ;
- good porosity reservoir : (**Φe**) > 20%.

- **Permeability (K)**

The empirical formula of **[11]** based on the irreductible saturation method was used to assess the permeability.

$K = (0{,}136 \times \Phi_e^{4{,}4}) / (S_w)_{irr}^{2}$ Eq.2

With :

K : permeability millidarcy ;

$(S_w)_{irr}$: irreducible water saturation in percentage ;

Φ_e : effective porosity in percentage

- **Volume of clay (Vsh)**

The volume of clay is calculated from the density-neutron logs and checked with gamma ray according to the formula:

$Vsh = [GR_{lue} - GR_{min}] / [GR_{max} - GR_{min}]$ Eq.3

- GR_{lue} : GR value of the given bench read directly from the log (API) ;
- GR_{min} : minimum GR value of the same bench (API) ;
- GR_{max} : maximum GR value of the same bench (API).

- **Water saturation (Sw)**

The water saturation is calculated using the equation of **[12]**:

$Sw = ([a \times R_w] / [R_t \times \Phi^m{}_t])^{1/n}$ Eq.4

With:

Sw : water saturation ;

a : Archie tortuosity factor;

R_w : resistivity of formation water ;

Rt : resistivity of deep formation ;

Φ_t : total porosity ;

m = Archie's cementing exponent;

n = saturation exponent of Archie.

- **Net/Gross (N/G)**

This is a parameter that provides information on the quality of the reservoir. This is the Net ratio (ie the net thickness of sand) on the Gross (which corresponds to the total thickness of the reservoir).

So depending on the percentage obtained, the reservoir will be classified as:

- poor quality N / G <0.1 ;
- medium quality 0.1 <N / G <0.5;
- very good quality N / G = 1.

These parameters are interpreted in general by the cut-off below proposed by **[13]**. According to him, a good rock reservoir is one that meets the characteristics below.

- Porosity (Φ)> 10%
- Volume of clay (Vsh) <40%
- Water saturation (Sw) <60%
- Net / Gross > 20%

4. RESULTS

4.1 Identification of top and potential reservoirs

The log signatures analysis coupled with the biostratigraphy data allowed to identify the top of the different formation of the studied wells. The results are shown in Table 2 below.

It is noted that the layers are thicker in wells further south such as MSP-2 and MSP-4 than those located in the north (MSP-1 and MSP-3). Sediment thickness increases from north to south.

Table 2. Top of the formation of studied wells

Wells **Top of stage (m)**	**MSP-1**	**MSP-2**	**MSP-3**	**MSP-4**
Top of Santonian	2960	5068	3821	3976
Top of Coniacian	Eroded	Eroded	3878	4098
Top of Turonian	3080	5162.5	3980	4219
Top of Cénomanian	3260	5370	4090	4315
Cenomanian base	3430	Not reached	4228	4529

These stages are confirmed by recent biostratigraphy data. Recent palynological data distinguish a Lower Cenomanian characterized by the presence of pollen species *Triporopollenites* sp. ; *Classopolis echinatus, Classopolis spinosus, Afropollis gardenus* and *Steveesipollenites binodosus.*

As for the Upper Cenomanian, it is characterized by the association composed of spores and pollen *Classopolis echinatus, Afropollis jardinus, Steveesipollenites binodosus, Triorites africaensis, Classopollis* sp., *Pemphixipollenites inequiexinus, Galeocornea causea, Ephedripites* sp., *Gnetaceapollenites diversus, Classopollis classoides* (**Plate 1**).

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The microfauna is dominated by the planktonic foraminifera *Herdbergella planispira, Herdbergella delrioensis, Herdbergella* sp. and *Globigerinoides bentonensis* **[14].**

- **Turonian**

The highlight of Turonian is mainly planktonic foraminifera: *Whiteinella baltica, Whiteinella paradubia Herdbergella delrioensis, Herdbergella simplex, Heterohelix moremani, Whiteinella archaeocretacea* **[15, 16].**

Palynologically, no species has been clearly described as a good stratigraphic marker. However, Turonian is characterized from pollen grains *Florentinia radiculata, Florentinia* sp., *Tricolpites giganteus, Odontochitina operculata, Tricolpites* sp., *Tricolpites microstriatus, Tricolpites* sp., and *Parasyncolpites* sp. **[15] (Plate 2)**.

- **Lower Senonian (Santonian-Coniacian)**

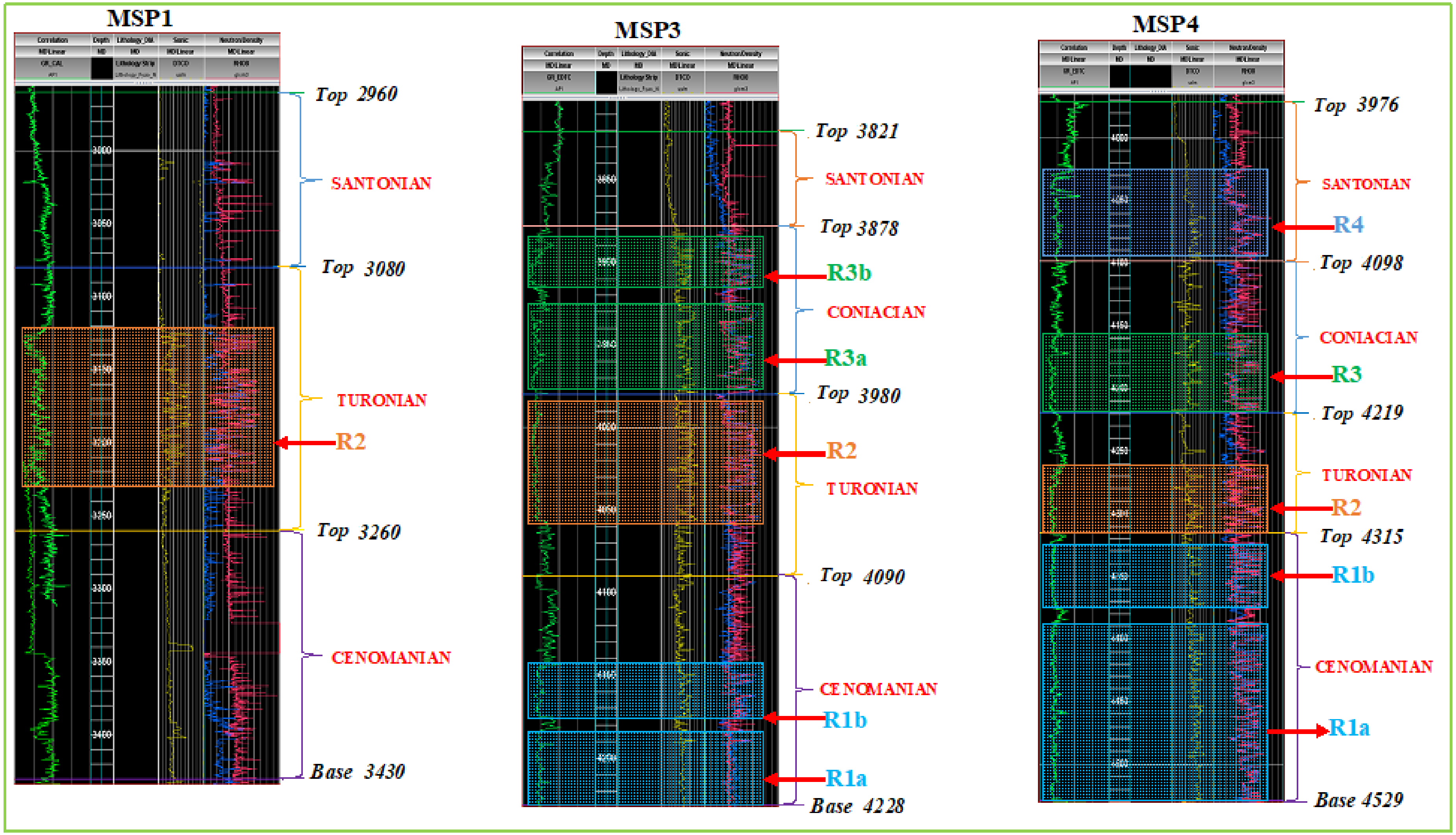
The lower Senonian is characterized by the planktonic foraminifera *Dicarinella concavata, Marginotruncana renzi, Hastigerinoides alexanderi, Herdbergella* sp. and *Heterohelix globulosa* **[17]**.
Palynologically, this stage is characterized by marker dinocysts such as *Canningia* sp., *Oligosphaeridium complex, Dinogymnium acuminatum, Dinogymnium* sp., *Xenascus* sp., *Oligosphaeridium pulcherrinum, Circulodinium distinctum, Droseridites senonicus,* and *Ariadnaesporites spinosus* **[18] (Plate 3)**.

4.2 Reservoirs oil potentials

Analysis of Gamma Ray (GR) data from the wells revealed potential reservoirs. Classically, gamma-ray is used for the determination of clay and sand formations. The highest values of gamma ray correspond to the clay formations and the lowest values to the sandy formations.
In principle, gamma ray measures the clayiness of the formation **[19].** This study revealed ten (10) reservoir levels of variable thickness in the four wells studied. **Table 3** below gives details of these reservoirs and their lithostratigraphic characteristics. Some reservoirs have small discontinuity intervals which are in fact clay beds of high gamma Ray value interspersed in a zone of low values **(Fig. 4 and 5).** These intercalations are encountered in the tanks R3 and R1 compartmentalized in tanks R3a, R3b and in tanks R1a and R1b at the wells MSP-3 and MSP-4.
The reservoir levels encountered in this study mainly consist of calcareous, clay and sandstone. These reservoirs are clay and silts. They are covered by thick layers of clay or silts **(Fig. 6)**.

Table 3. Potential reservoirs and their lithostratigraphic characteristics

<table>
<tr><th rowspan="2">Reservoirs of stage</th><th colspan="4">Wells</th></tr>
<tr><th>MSP-1</th><th>MSP-2</th><th>MSP-3</th><th>MSP-4</th></tr>
<tr><td>Santonian (R4)</td><td>No reservoir R4</td><td>R4 (95m)
Sandstone white to gray with fine to very coarse grains</td><td>No reservoir</td><td>R4 (70m)
Fine to coarse sandstone poorly cemented with a clay-limestone cement</td></tr>
<tr><td rowspan="2">Coniacian (R3)</td><td rowspan="2">No reservoir R3</td><td rowspan="2">No reservoir R3</td><td>R3b (50m)
Fine to coarse sandstone, compacted or not, with limestone cement</td><td rowspan="2">R3 (50,5m)
Very fine to medium sandstone with limestone cement,</td></tr>
<tr><td>R3a (60m)
Fine to coarse sandstone, compacted or not, with limestone cement</td></tr>
<tr><td>Turonian (R2)</td><td>R2 (110m)
Coarse sandstone, with limestone cement</td><td>R2 (90m)
Gray sandstone, fine to medium, with limestone cement and clay interlayers</td><td>R2 (70m)
Fine to coarse sandstone with limestone cement</td><td>R2 (55m)
Gray sandstone, very fine to medium, with limestone cement</td></tr>
<tr><td rowspan="2">Cenomanian (R1)</td><td rowspan="2">No reservoir R1</td><td rowspan="2">No reservoir R1</td><td>R1b (23m)
Fine to coarse sandstone, compacted or not, white to gray, calcareous cement</td><td>R1b (54m)
Very thin to medium gray to light gray to calcareous cement</td></tr>
<tr><td>R1a (38m)
Fine to coarse sandstone, compacted or not, white to gray, calcareous cement</td><td>R1a (146m)
Very thin to medium gray to light gray to calcareous cement</td></tr>
</table>



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265 AA

266 **Fig. 4. Potential reservoir levels of MSP1, MSP3 and MSP4 wells**

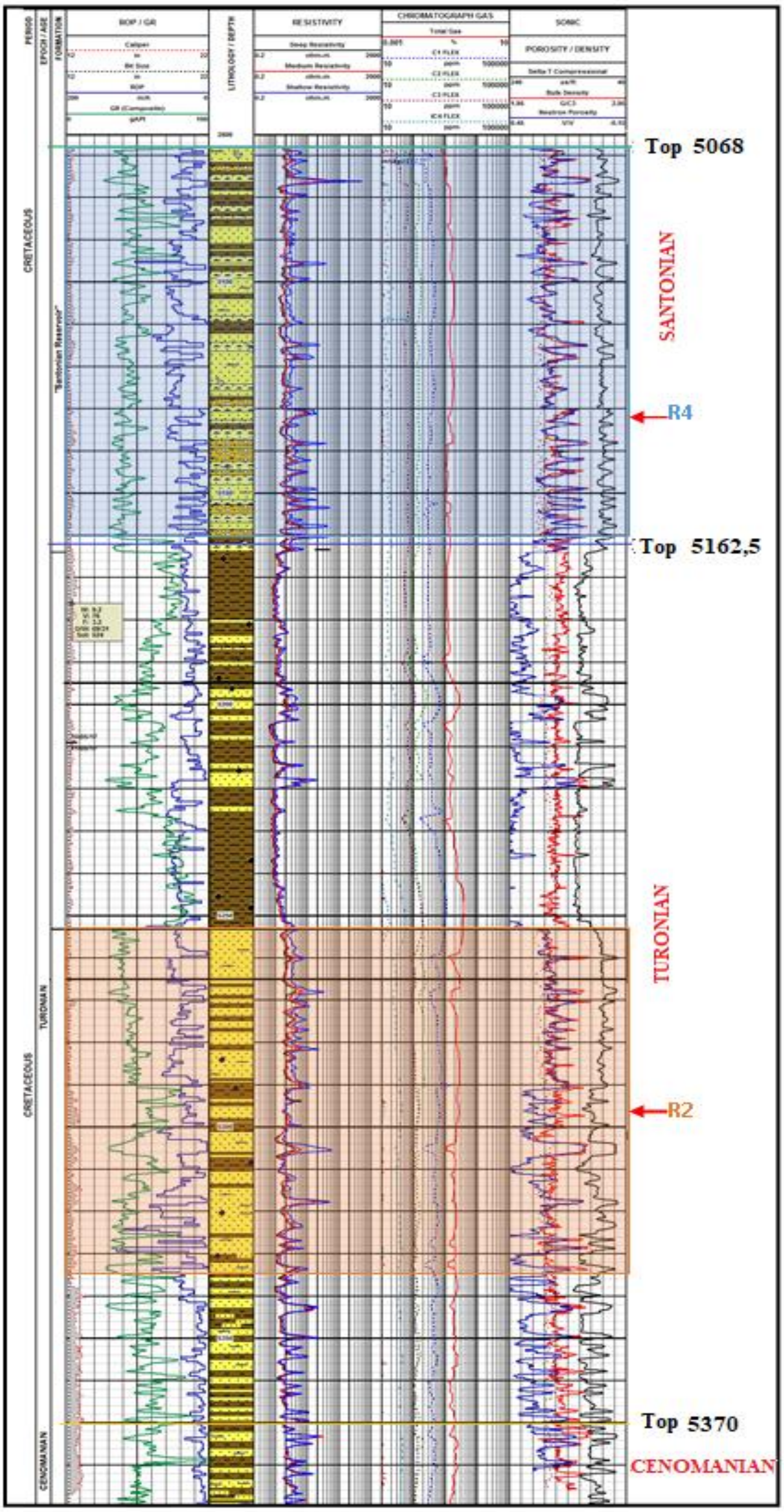
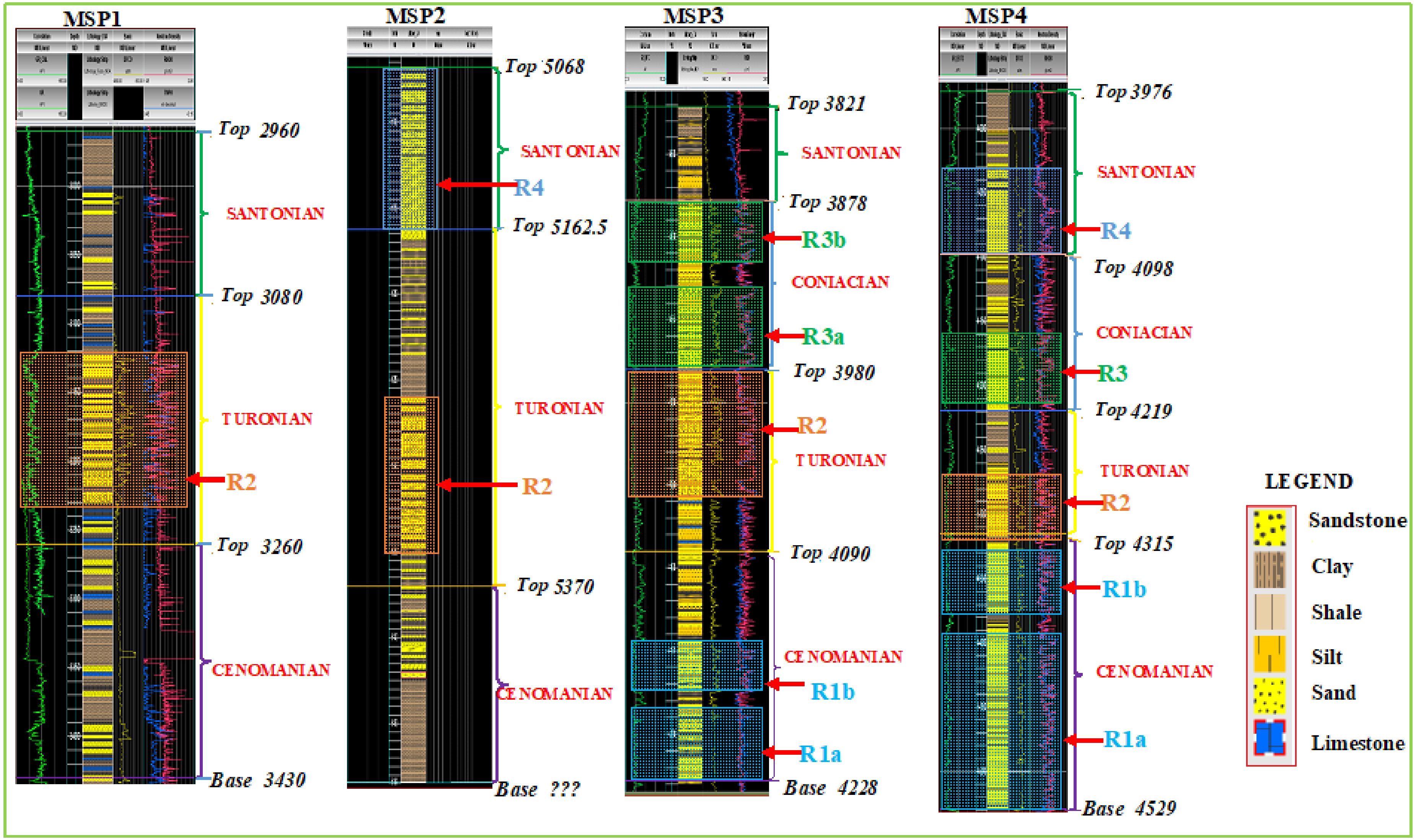


Fig. 5. Potential reservoir levels of the MSP2 well



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271 **Fig. 6. Lithostratigraphic log of the different wells studied**

4.3 Correlation of reservoir levels of studied wells

The West-East correlation profile between the different reservoirs **(Fig. 7)** shows that only the turonian reservoir (R2) is continuous over the entire profile and that its thickness decreases progressively from west to east. As for the other tanks, they are discontinuous. The Cenomanian (R1) and Coniacian (R3) reservoirs are present only in the East. We also note that the Santonian reservoir (R4) is absent in the center of the profile that is to say in the block B and that its thickness decreases from West to East. This can be explained by erosion caused by eustatic variations in the Ivorian sedimentary basin. The absence of R1 and R3 in the rest of the zone may be due to a no deposit phase or erosion. If the thickness of the tank R3 decreases towards the East, the thickness of R4 increases.

4.4 Petrophysical characteristics of reservoirs

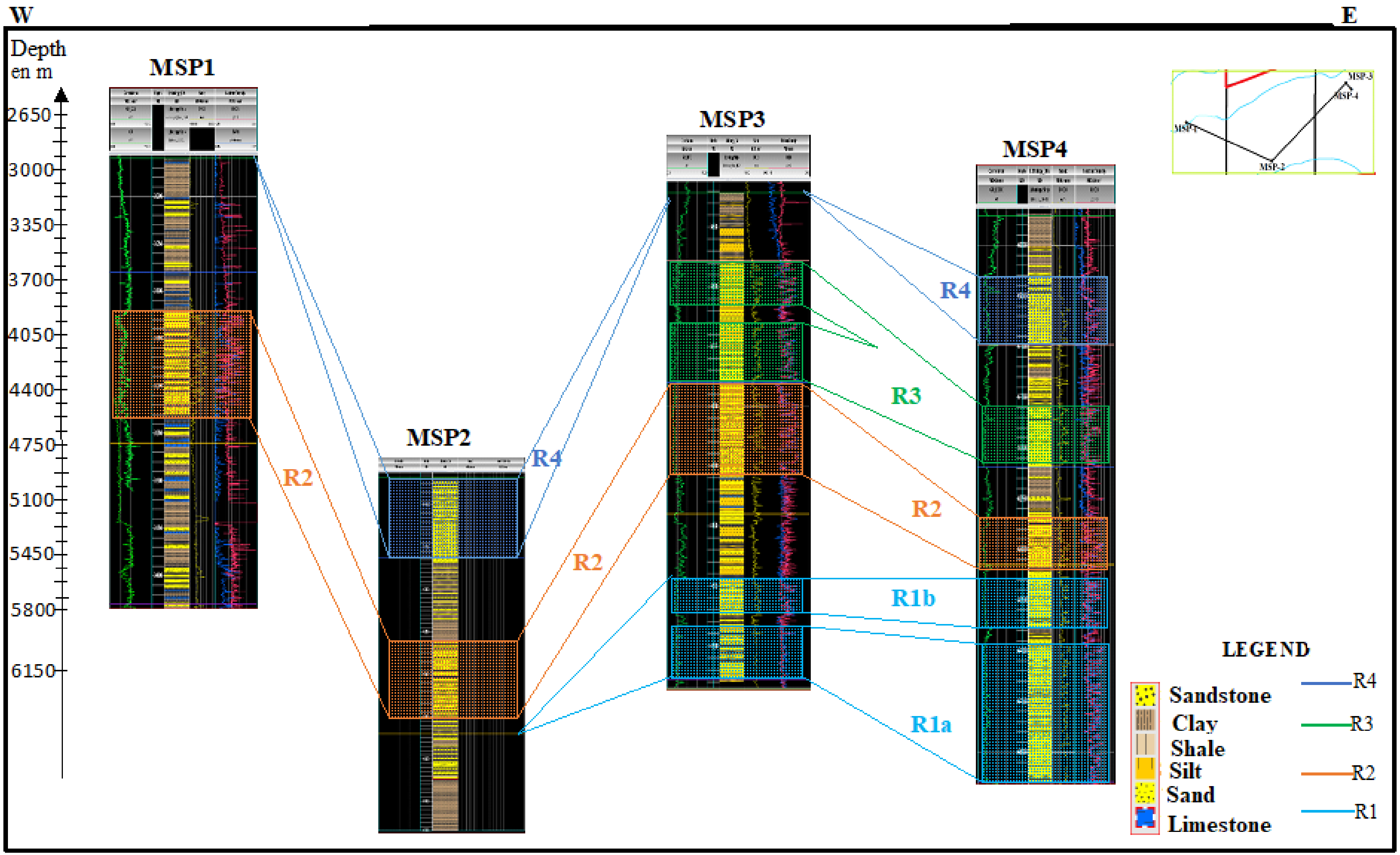
The results of the petrophysical evaluation are recorded in the table 4 below.

Table 4. Results of the petrophysical study

BLOCK	WELLS	FORMATIONS	INTERVAL		RESERVOIRS							
			EXTENSION (m)	Gross (m)	GR (API)	Net (m)	N/G (%)	VSH (%)	PHIE (%)	PERM (mD)	SWE (%)	FLUID
A	MSP1	TURONIAN	3120-3230	110	37	30	29	21	21	155	98	water
B	MSP2	SANTONIAN	5068 - 5162.5	95	45-60	80	83	19	20.1	NA	100	water
		TURONIAN	5260 - 5350	90	45-60	60	67	25	19.6	NA	99	water
C	MSP3	CONIACIAN	3878-3980	102	15-30	53	52	11	18	NA	94	water
		TURONIAN	3980-4060	80	25-37	31	39	12	19	NA	86	water
		CENOMANIAN	4153-4228	75	30-37	40	53	15	16	NA	95	water
	MSP4	SANTONIAN	4028-4098	70	30-45	46	66	13	18	100-1100	81	water
		CONIACIAN	4155-4219	64	25-30	56	88	14	18	100-300	94	water
		TURONIAN	4260-4315	55	25-30	47	86	17	18	NA	95	water
		CENOMANIAN	4315-4529	214	30-45	193	90	8	20	400-700	91	water

The analysis of the petrophysical parameters reveals generally for the different wells studied that**:**

- Porosity (Φ) varies from 16% to 21% in all tanks. This result indicates that the reservoirs have medium to good porosities.



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293 **Fig. 7. West-East Correlation Profile of Well Wells Studied**

- **Volume of clay (Vsh):** With the exception of the reservoir R2 of the MSP2 well, which can be qualified as a medium quality reservoir with a Vsh of 25%, the other reservoirs are good qualities because the volume of clay is less than 20%.

- **Water saturation (SW):** This study shows that the water saturation of the different tanks is greater than 80%. This result indicates that the identified reservoirs are aquifers.

- **Net to Gross (N / G):** The Net to Cross values are above 20% and indicate that the tanks are good qualities.

In general, **[13]** estimates that an oil reservoir is of good quality if the cut-off values of the following parameters are respected:
- Porosity (Φ)> 10%
- Volume of clay (Vsh) <40%
- Water saturation (Sw) <60%
- Net / Gross > 20%

With the exception of water saturation, our results indicate that the potential reservoirs highlighted are of good quality. They have all the necessary characteristics to store hydrocarbons except that they are all aquifers.

4.5 Deposit environments of reservoir levels

From the different form of the Gamma Ray profile of the identified reservoir levels, the associated depositing environments are determined. **Fig. 8, 9, 10 and 11** below indicate the deposition environments of the identified reservoirs.
At the Cenomanian, reservoir sediments deposited either in a fluvial environment because of the serrated form of the Gama Ray or marine with strong fluvial influence because of cylindrical shape that tends towards the serrated form of Gama Ray **(Fig. 8).** This is confirmed by the palynological data which indicates a predominance of spores and pollen grains characteristic of a continetal environment **(Plate 1)**. Also the marine influence is indicated by the presence of foraminifers.
In Turonian, reservoir sediments were deposited in environments ranging from marine to fluviatile through deltaic environments due to the combination of cylindrical, serrated, funnel and bell-shaped Gama Ray **(Fig. 9).** This is confirmed by the presence of dinocyst which characterizes this marine environment **(Plate 2)**.
At the Conancian and Santonian tanks were set up in a marine environment (**Fig. 10 and 11**). This is confirmed by the presence of dinocyst which characterizes this marine environment **(Plate 3)**.

From this study, two dominant deposition environments emerge. Sedimentation would have started in a fluvial environment and would have continued in a marine environment marked by the accumulation of sandstone, clay, limestone. However, frequent variations of the deposition conditions in connection with the phenomena of transgressions and regressions are observed.

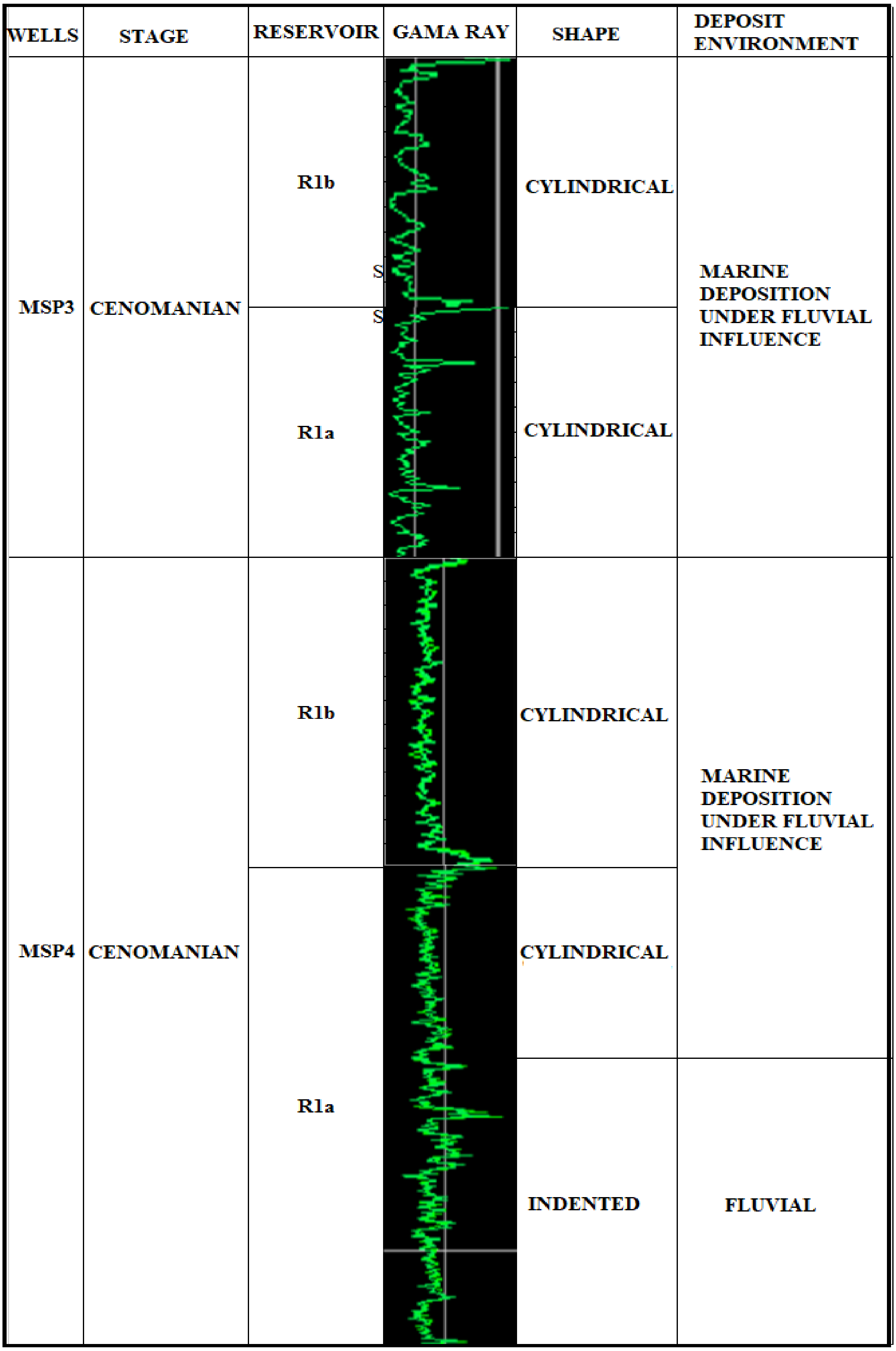


Fig. 8. Cenomanian reservoir deposit environments

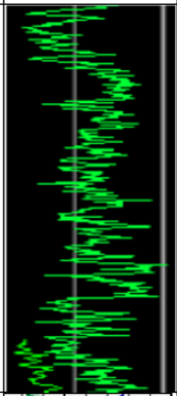
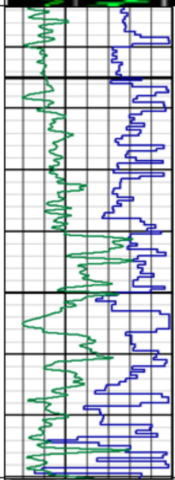
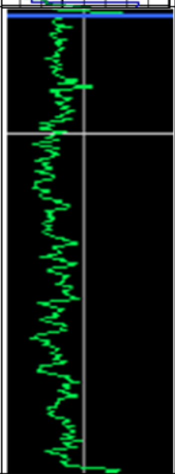
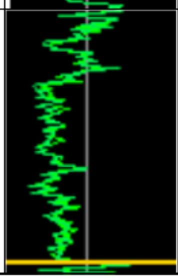
WELLS	STAGE	RESERVOIR	GAMA RAY	SHAPE	DEPOSIT ENVIRONMENT
MSP1	TURONIAN	R2		CYLINDRICAL	MARINE
				BELL	FLUVIAL
				INDENTED	
				FUNNEL	
MSP2	TURONIAN	R2		CYLINDRICAL	MARINE
				SYMMETRICAL	
				BELL	DELTAIC
MSP3	TURONIAN	R2		INDENTED	DELTAIC
MSP4	TURONIAN	R2		CYLINDRICAL	MARINE

Fig. 9. Turonian reservoir deposit environments

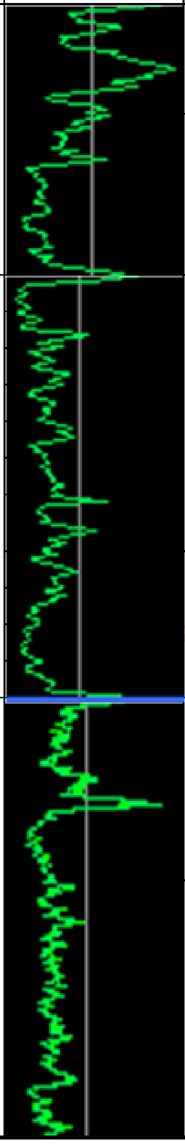
<table>
<tr><th>WELLS</th><th>STAGE</th><th>RESERVOIR</th><th>GAMA RAY</th><th>SHAPE</th><th>DEPOSIT ENVIRONMENT</th></tr>
<tr><td rowspan="5">MSP3</td><td rowspan="5">CONIACIAN</td><td rowspan="2">R3b</td><td rowspan="7"></td><td></td><td rowspan="2">MARINE</td></tr>
<tr><td>CYLINDRICAL</td></tr>
<tr><td rowspan="3">R3a</td><td>CYLINDRICAL</td><td>MARINE</td></tr>
<tr><td>SYMMETRICAL</td><td>DELTA</td></tr>
<tr></tr>
<tr><td rowspan="2">MSP4</td><td rowspan="2">CONIACIAN</td><td rowspan="2">R3</td><td>CYLINDRICAL</td><td rowspan="2">SUBMARINE CHANNEL DEPOSIT</td></tr>
<tr><td>CYLINDRICAL</td></tr>
</table>

Fig. 10. Conancian reservoir deposit environments

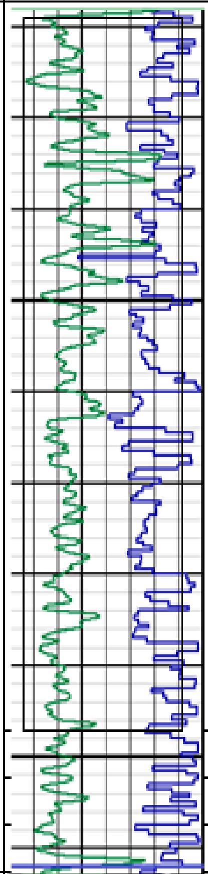
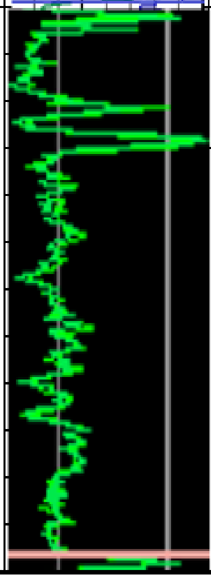
WELLS	STAGE	RESERVOIR	GAMA RAY	SHAPE	DEPOSIT ENVIRONMENT
MSP2	SANTONIAN	R4		CYLINDRICAL WITH INTERSPERSED CLAY LEVEL AT THE TOP	MARINE
MSP4	SANTONIAN	R4		CYLINDRICAL CYLINDRICAL	MARINE

Fig. 11. Santonian reservoir deposit environments

5. DISCUSSION

The identification of reservoir levels based on low gamma ray profiles was used by **[20]** in Benin to highlight Albian reservoirs in the deep offshore part of the Beninese coastal basin. These potential reservoirs are sandy with a variable percentage of clay that serves as cement.
Thus, with this method, 10 silty reservoir levels presenting clay levels by location are highlighted and are consistent with those obtained by **[21]** which indicate that the reservoirs of Côte d'Ivoire basin are sandstone.

➢ Lithostratigraphy

This study reveals that sedimentation is mainly silico-clastic dominated by clays and sandstones (dominant facies) and incidentally silts, sands and limestones. **[17]** has shown that deposits in the Upper Albian-Lower Senonian interval of the Ivorian sedimentary basin are characterized by clay-sandstone deposits locally enriched with limestone. The results of Chierici were confirmed by those of **[2]** and recalled by **[22].**
The gritty nature of the reservoirs described in this work is confirmed by the work of **[21].**
[7] demonstrated that the lithology of reservoir levels of the Abidjan margin in the Cenomanian-Santonian interval is identical to that described in this study on the margin of San-Pedro.

➢ Correlation

The correlation established between the reservoir levels shows that the thickness of the Turonian reservoirs is gradually decreasing from west to east of our study area as described by the results of **[23]** recalled by **[22],** which showed that the Turonian is not visible throughout the basin because it is strongly eroded during the Turonian **[17]** or Senonian regression **[2].**
The effect of this erosion has been accentuated more in the East where the Turonian is no longer continuous and appears in tatters. However in the margin of San Pedro, the Turonian is not in flap but is continuous on the scale of the margin. The other identified reservoirs are not continuous either because they are eroded or have not been deposited.

➢ Petrophysical evaluation

The petrophysical evaluation shows that the different reservoirs identified are of good quality because their petrophysical characteristics are in line with those of a quality reservoir according to **[13].** However, the strong cementation of sandstone at some levels has contributed to the reduction of porosity and has influenced overall petrophysical properties that could have been better. **[24]** have shown that the porosity of rocks is related to the diagenesis and the dissolution of certain minerals, the low porosity of the reservoirs of the MSP2 well.
This study also shows that the study area was affected by transgressions and regressions that caused lateral and vertical facies variations. These phenomena could sensibly modify the petrophysical characteristics of the reservoirs.

➢ Deposit environment

Comparison of the Gamma Ray signatures of the reservoirs identified with the standard model established by **[9]** shows that sedimentation of the study area started in a fluvial environment and continued in a marine environment. The variations recorded in the different phases are mainly due to the numerous transgressions and regressions movements experienced by the

Ivorian sedimentary basin. Indeed, **[25]** and **[26]** showed that the deep oceanic domain of the Ivorian basin recorded three transgressive episodes.

It begins with the transgression of the Upper Albian, which is not a generalized phenomenon at the scale of the whole basin **[2].** At the end of the Upper Albian, there is a generalized regression on the scale of the whole basin which marks the passage from the Albian to the Cenomanian.

This regression, which marks the passage from the Albian to the Cenomanian, results in an important discordance of the Cenomanian on the Albian.

The Cenomanian reservoirs (R1) would have deposited during this regression, or the littoral conditions favorable to the deposition of fluvial types prevailed in the basin.

At the Cenomanian, there is a re-watering of the basin. This second transgressive episode generalized throughout the basin will continue until the end of the Lower Senonian.

This marine transgression is highlighted in the MSP4 well where all the tanks have been highlighted and deposited in a marine environment.

This marine transgression is interrupted at times by periods of regression, thus generating fluviatile and deltaic deposits observed in the Turonian reservoirs of the MSP1 and MSP3 wells.

According to **[2],** in the Lower Senonian, there is another regressive phase which causes a strong erosion of the deposits of the Lower Senonian and in places those of the Turonian.

This regression is highlighted in this study by the deposition of deltaic or fluvial sediments that cover the marine deposits in the MSP3 well.

This period is characterized by clay-sandstone deposits enriched locally in limestone.

The third transgressive episode occurs in the Upper Senonian.

6. CONCLUSION

This study made it possible to characterize the Cenomanian, Turonian and Lower Senonian reservoirs of four oil wells located on the margin of San Pedro.

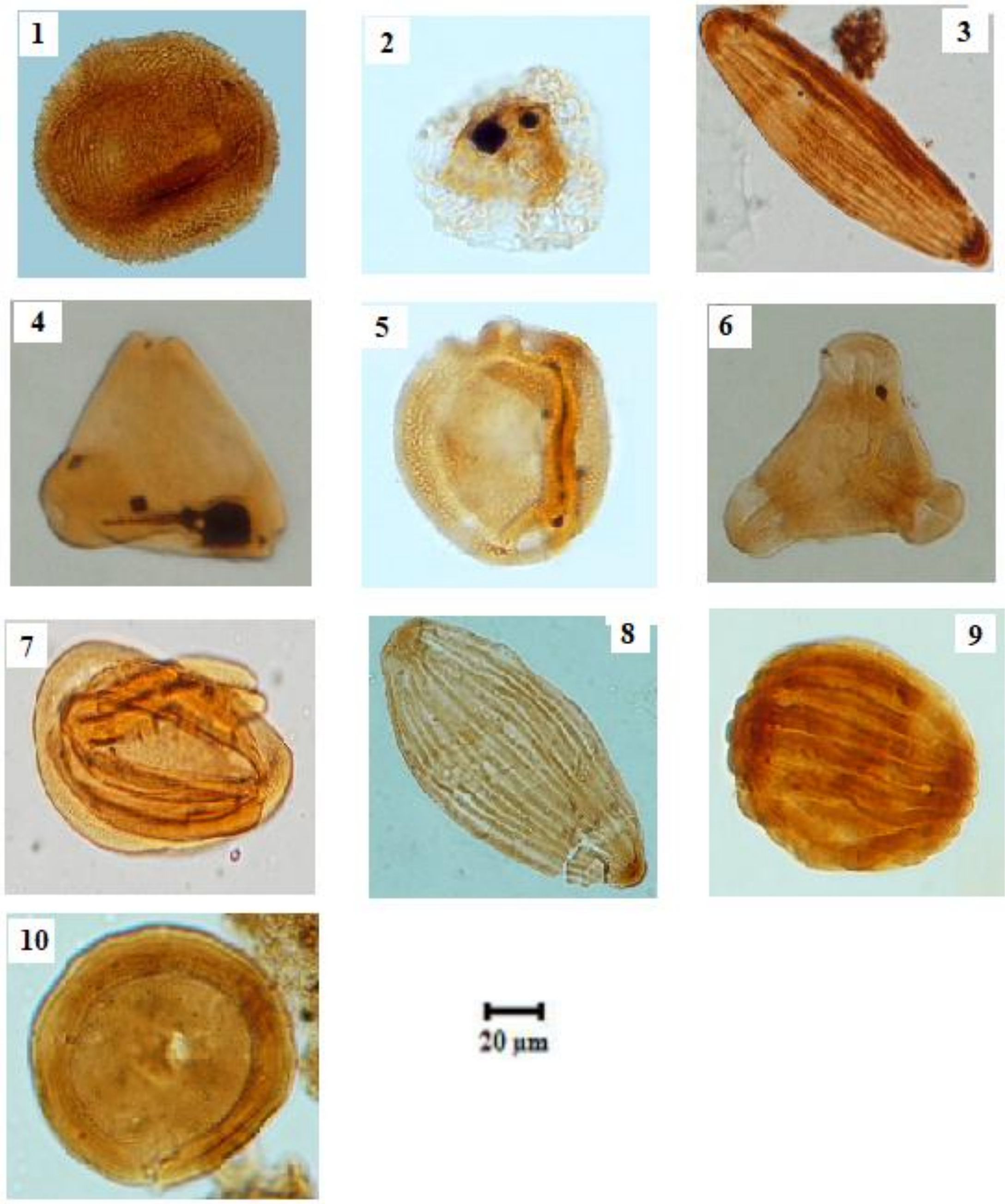
On the lithostratigraphic level, the analysis of log log data and log gamma ray revealed a total of ten (10) reservoir levels in all four wells studied in the Cenomanian-Santonian interval.

These reservoir levels identified, are mainly sandstone with fine grains and with limestone or clay cement. These reservoir are surmounted by clay or silts that serve as rock cover.

Lithological synthesis has shown that these sandstones come from the mainland and are deposited in a marine or deltaic environment with low to high energy.

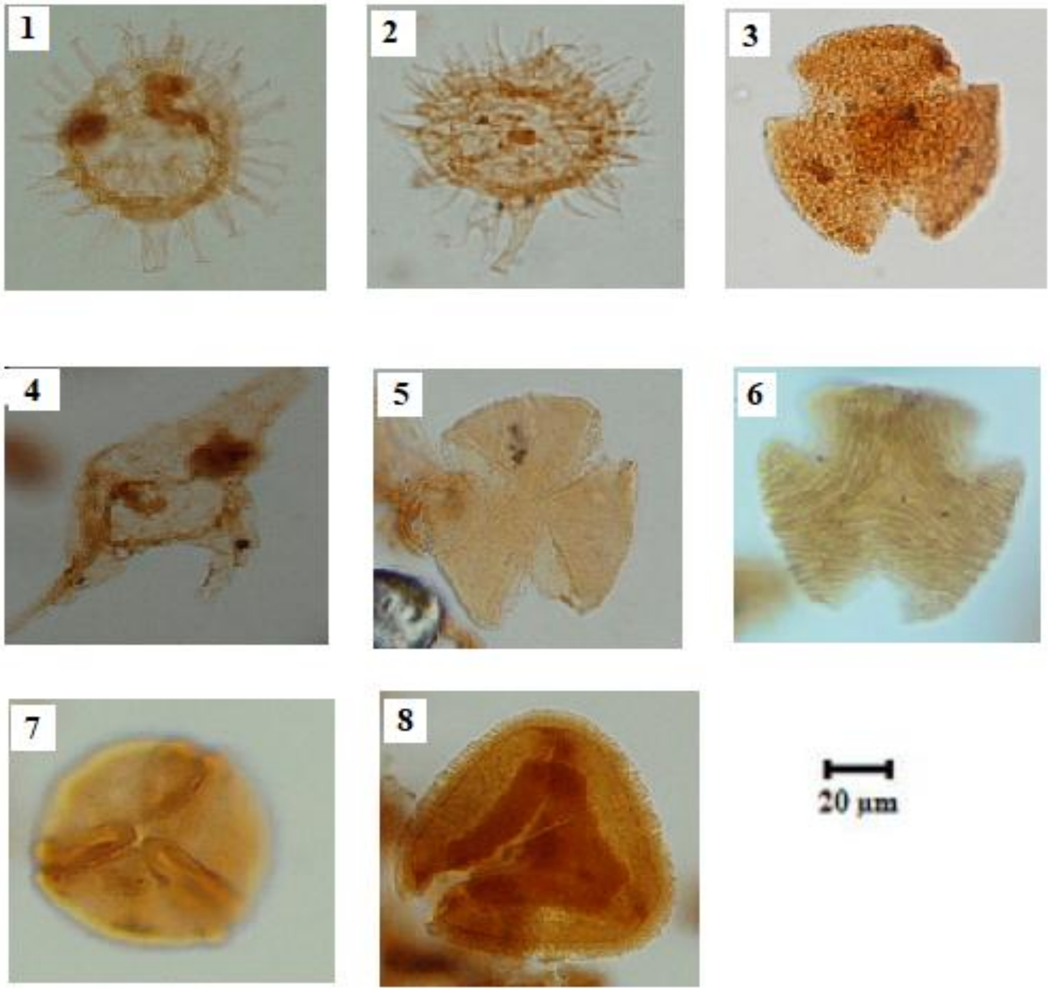
Petrophysically, petrophysical parameters have shown that reservoirs are of good quality; they have all the conditions necessary to store hydrocarbons. However, their high water saturation makes them aquifers.

Plate 1: Cenomanian palynomorphs



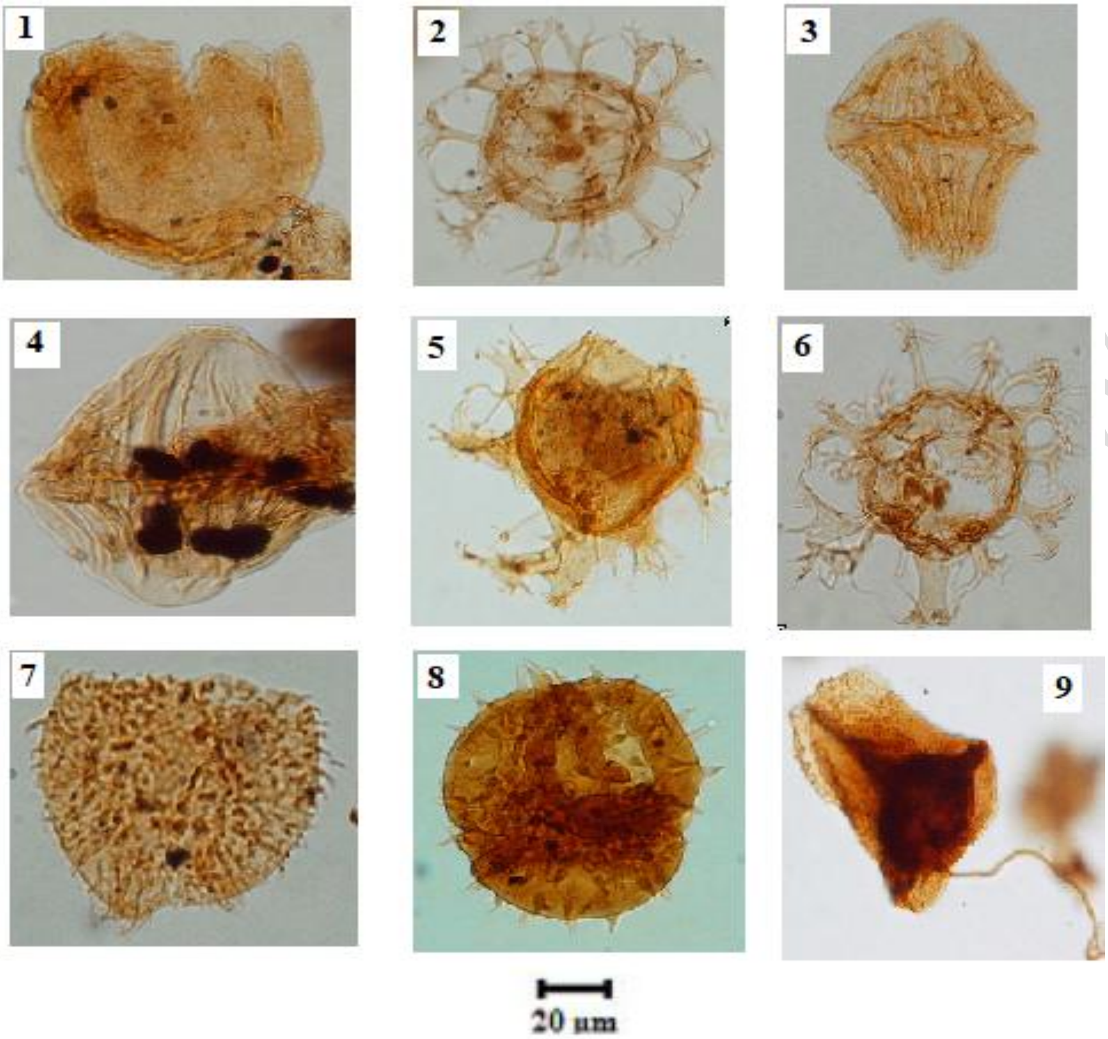
1-Classopolis echinatus, 2-Afropollis jardinus, 3- Steveesipollenites binodosus, 4- Triorites africaensis, 5- Classopollis sp.*; 6- Pemphixipollenites inequiexinus, 7- Galeocornea causea, 8- Ephedripites* sp.*, 9- Gnetaceapollenites diversus, 10- Classopollis classoides.*

Plate 2 : Turonian palynomorph



1-Florentinia radiculata, 2- Florentinia sp., *3- Tricolpites giganteus, 4- Odontochitina operculata, 5- Tricolpites* sp., *6- Tricolpites microstriatus, 7- Tricolpites* sp. SCI 348-155, *8- Parasyncolpites* sp.

Plate 3 : Early Senonian Palynomorphs (Coniacian-Santonian)



1- *Canningia* sp., 2- *Oligosphaeridium complex*, 3- *Dinogymnium acuminatum*, 4- *Dinogymnium* sp., 5- *Xenascus* sp., 6- *Oligosphaeridium pulcherrinum*, 7- *Circulodinium distinctum*, 8- *Droseridites senonicus*, 9- *Ariadnaesporites spinosus.*

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