Petrophysical Study and Formation Evaluation of Jake Reservoir, Block 6, Muglad Basin, Sudan

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ABSTRACT - The study area (Jake oilfield) is located on the Western Escarpment of the Fula Sub-basin of the Muglad Basin, which is bounded by the latitudes 11°20' and 11°36′ N and longitudes 28° 30′ and 29° 36′ E. This oilfield has been structurally subdivided into three main structures of Jake, Jake Central and Jake South. The goal of this study is to identify and to interpret the reservoir quality and properties (lithology, porosity, shale volume, and water saturation) and then to detremine sand continuity of Bentiu formation, to achieve this goal in successful way the information and data of three wells (Jake South -2, Jake South -3, Jake South -15) were made available, then the evaluation of the given data has been processed using the interactive petrophysic software (IP 3.6) version. The wireline logging and mud logging data had been carefully evaluated during the process of the data application, and data quality was thought to be good. Eventually, the results obtained using the shaly sand evaluation techniques, were in better agreement with core and test data. For the Reservoir and shale identification the most useful indicator was obtained from the behavior of the density and neutron logs. The neutron – density cross plot is the best method for lithology identification. Density – Neutron cross plot values had been used to identify the pure matrix and/related porosity, v-shale, porosity and water saturation models had been done and full interpreted from the initial results cut off parameters also determined and multi targets prospects of all wells had been marked, beside net-reservoir and net-pay had been obtained successfully.In Jake South -2 (the maximum net pay thickness for Bentiu reservoirs is 48.2m and the minimum thickness is 3.66m, the average effective porosity is 17%, and the average water saturation is 48%), in Jake South -3 (the maximum net pay thickness for Bentiu reservoirs is 4.72m), the average porosity is 22%, and average water saturation is 86%). Hence in Jake South -15 (the maximum net pay thickness for Bentiu reservoirs is 28.12m, the minimum thickness is 4.5m, the average porosity is 18% and the average water saturation is 33%).

Key words: *petrophysical evaluation, water saturation, capillary pressure, shaly sand models.*

المستخلص–تقع منطقة الدراسة (حقل جيك النفطي) في حوض الفولا الفرعي لحوض المجلد بين خطي عرض '11°20 و '11°36 شمال وخطي طول '30 °28 و '36 °29 شرق. يقسم هذا الحقل النفطي من حيث التركيب إلي ثلاثة تراكيب هي جيك، جيك وسط و جيك جنوب.تهدف هذه الدراسة لتحديد وتفسير نوعية المكمن والخواص البتروفيزيائية (التكوين الصخري – المسامية –حجم الطين والتشبع بالماء) ومن ذلك يمكن تحديد التتابع الرمل لتكوين بانتيو. ومن أجل الوصول لهذا الهدف بصورة ناجعة تمت الأستعانة بمعلومات وبيانات ثلاثة من الآبار في منطقة الدراسة هي (جيك جنوب–2، جيك جنوب–3 وجيك جنوب–15) تمت المعالجة لبيانات هذه الآبار ببرنامج (interactive petrophysic software (IP 3.6) version). تم تقييم تسجيلات الآباروتسجيلات سائل الحفر ذات الجودة الجيدة لهذه الآبار بعناية أثناء عملية المعالجة. النتائج التي تم الحصول عليها باستخدام تقنية تقييم الطين الرملي في توافق تام من النتائج المتحصل عليها بتسجيلات اللباب الصخري. أهم مؤشر لتحديد خصائص المكمن وحجم الطين تم استخلاصها من معطيات نتائج تسجيلات الكثافة والنيوترون. كما أن رسومات تقاطع علاقة النيوترون– الكثافة من أنسب الطرق لتحديد التكوين الصخري. قراءات رسومات تقاطع علاقة الكثافة– النيوترون أستخدمت لتحديد حجم الحبيبات الصخرية والمسامية. في هذه الدراسة تم أنشاء نماذج لكل من حجم الطين والتشبع بالماء وأيضاً تم تحديد النتائج الأولية لنسب المعاملات البيروفيزيائية لهذه الآبار إلي جانب ذلك تم تحديد حجم الخزان الكلي وحجم الطبقات الحاملة للزيت بصورة ناجحة.في البئر جيك شمال–2 أقصي سمك لتكوين بانتيو بلغ 48.2 متر وأقل سماكة 3.66 متر والمسامية

الفعالة بلغت 17% كما أن متوسط نسبة التشبع بالماء 48%. أما في البئر جيك شمال-3 أقصي سمك لتكوين بانتيو بلغ 4.72 متر ومتوسط المسامية الفعالة بلغت 22% ومتوسط التشبع بالماء 86%. في البئر جيك شمال-15 أقصي سمك لتكوين بانتيو بلغ 28.12متر وأقل سماكة 4.5 متر ومتوسط المسامية الفعالة بلغت 18% ومتوسط التشبع بالماء 33%.

INTRODUCTION:

The Muglad basin is characterized by thick non-marine clastic sequence of Late Jurassic - Early Cretaceous and Neogene age [7] and it contains a number of hydrocarbon accumulations of various sizes, the largest of which are the Heglig and Unity oil fields. A total of 44 wells have been drilled in the Jake oilfield. There are four proven hydrocarbon-bearing formations: Ghazal, Zarqa, Bentiu and Abu Gabra, and two producing formations: Bentiu and Abu Gabra.

Location and accessibility: The Muglad basin idealizes part of Central Africa Rift System. It is oriented NW-SE. The basin is situated within Sudan and South Sudan, and it covers area of approximately 120,000km². The study area (Jake oilfield) is located on the Western Escarpment of the Fula Sub-basin of the Muglad Basin in Sudan.The area is approximately bounded by the latitudes 11°20' and 11°36′ N and longitudes 28° 30′ and 29° 36′ E. This oilfield has been structurally subdivided into three main structures, which are Jake, Jake Central and Jake South, see Figure 1.

The Muglad basin is characterized by low relief flat plain area surrounded by three types of structures and igneous extrusion, in the NW of the basin is bounded by Jebel Marra and Nuba mountains in the NE, with the exception of some isolated sandstone outcrops of Miocene to Pliocene age east of the Muglad Town [6].

The superficial deposits of black cotton soils cover the area by laterite deposits, [2]. Moreover, alluvial and wadi sediments as well as swamp deposits of the White Nile tributaries. The stratigraphy of the study and adjacent areas are ranging from Precambrian to quaternary Figure 2.**Previous Study:**

Muglad Basin is recognized to a major part of Sudanese interior rift basins. It is the major basin of oil revenue in Sudan; consequently, there are many companies of oil exploration and development working in this basin. Most of the exploration works in the Muglad rift basin were conducted by a group of scientists from Cheveron, an overseas company, between1974 and 1988. Browne and [5] following Chevron's successful search for hydrocarbons in southern Sudan rift extended their hydrocarbons search into Melut concession Block along the White Nile.

[7] Suggested that the rifted terrains of Sudan and Kenya have been collectively referred to as the Central African Rift System (CARS), he also gave an excellent account of petroleum geology, oil discoveries in the area, and the exploration history and operation, also discussed the stratigraphy of the basin, and geochemistry as well as the reservoir characteristic. There are three phases of rifting affect the stratigraphic column, each of which represent general coarsening upward cycle that began with lacustrine through shore lake deposit into fluvial deposit. These fluvial lacustrine Sequences in Central Sudan were subdivided by the means of biostratigraphy into five palynological zones, [9] and [17] studied and reported the stratigraphy and regional geology of Muglad Basin and surrounded areas.

[1] Studied the Late Jurassic/Cretaceous strata of the NW Muglad Basin with respect to pale environment, thermal analysis and paleogeography of the area. [10] studied the thick skin and thin skin structural feature of the Muglad rift baisn. [14] Studied the tectonic influence in the fold and fault trap of the Muglad basin. [11] studied the tectonstratigraphy of the Muglad rift basin.

Before the oil exploration activities, the available information about the geology of Sudan is fragmented and the knowledge on the overall geological setting of the Sudan has improved after the beginning of the oil exploration activities in the 1970 [3]

The Muglad basin is considered as part of a trend of Cretaceous sedimentary basins of rift origin, which cut across north central Africa trough to West Africa, through Chad and the Central African Republic, into Sudan [12]. The sedimentary succession of Muglad basin is characterized by thick non marine clastic sequence of Jurassic, Cretaceous and middle Tertiary period, which deposited in deepest trough and extensive basal area [7].

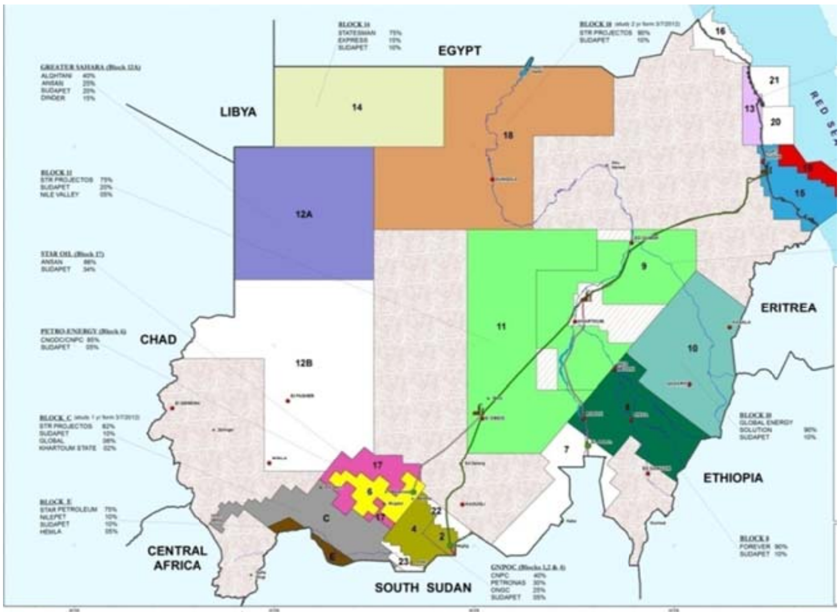


Figure 1: location map of Muglad Basin

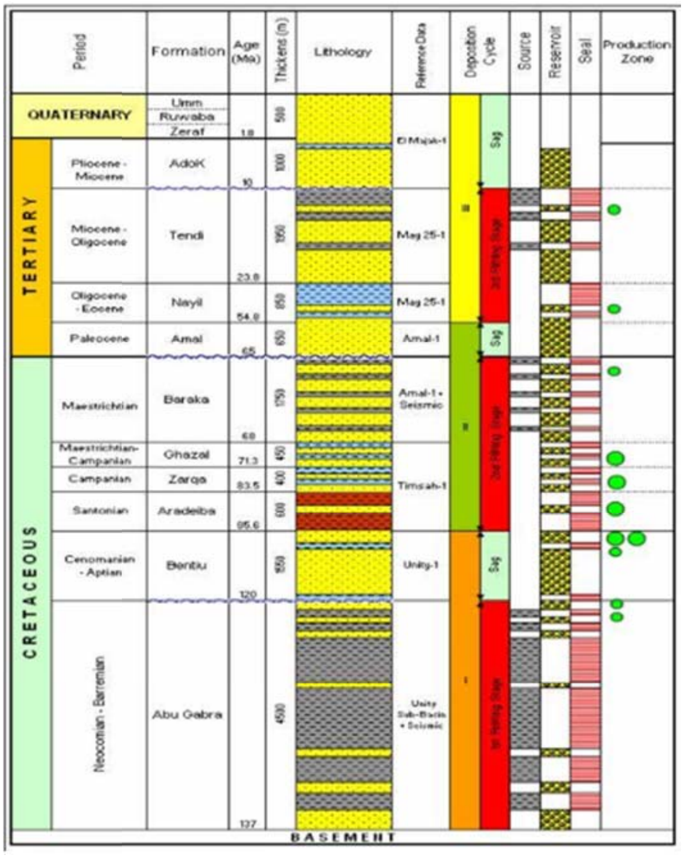


Figure 2: Stratigraphic units of the Muglad rift basin, SW Sudan, their lithology and depositional environment (adapted from Schull 1988).

Schull stated that; there are three rifting episodes and these episodes of rifting resulted in the deposition of sedimentary section of up to 13km thick in the deep troughs.

The first depositional cycle (Early Cretaceous) consists mainly of suboxic organic-rich shales comprising the main lacustrine source beds of the Sharaf and Abu Gabra formations, which are overlain in the sag phase by medium to coarse grained sandstones of the Bentiu formation. The second depositional cycle (Late Cretaceous - Paleocene) is the Darfur group, comprising fluvial and deltaic clay stones at the bottom (Aradeiba formation) and thin sandstone beds

(Zarga and Ghazal formations), thickening toward the top of the section (Baraka formation) and overlain by the coarser Amal formation.

The Kordofan group (Oligocene - Late Eocene), which forms the third depositional cycle, consists of the largely shaly Nayil and Tendi formations and culminates in the coarse sandstones of the Adok formation. The Recent - Miocene Zeraf formation unconformably overlies the Adok and probably represents fluvial reworking of these earlier deposits [12]

Objective of the Study:

The main objective of this study is to identify and to interpret the reservoir quality and properties (lithology, porosity, shale volume, and water saturation) and predict the depositional environment and sand continuity of Bentiu formation in Jake South area.

Methodology:

To conduct this study in successful way, the following materials and information were made available by the Oil Exploration and Production Authority, wells data includes: Wire Line logging data for three wells, three master logs and geological reports. And then using the IP 3.6 version software (interactive petrophysic), which is used for all of the petrophysical analysis. The software is also used to generate the cross plots interpret the data for final formation evaluation and to predict the zones of hydrocarbon potentiality.

Methods of Investigation

The integrated work flow is divided into three steps: lithology, porosity and saturation. The user is guided through the workflow, and at each step customized log displays and cross plots facilitate parameter selection and quality control of analysis results. Interactive graphical zonation and selection of parameter values compliments traditional text-based parameter tables, allowing for rapid optimization of interpretation results.

Log Quality Control (LQC):

The term log quality control (LQC) is very important part of every logging job because log data can be affected by the borehole conditions such as wash out (caving) and or tool problems.

Calculation of Formation Temperature:

To calculate the temperature gradient in order to know the formation temperature, it has been a prerequisite for accurate log calculation. The resistivity of formation fluids and water-based drilling mud’s varies greatly with temperature. The bottom hole temperature (BHT) measurement was used to calculate a mean geothermal gradient Table 1.

TABLE (1): MUD SAMPLE AND (BHT) OF THE WELLS.

Well Name	Mud Sample	Bottom Hole Temperature (BHT)
Jake South -2	27.50	86.2
Jake South -3	28.22	73.0
Jake South -15	27.85	66.0

Reservoir and shale identification:

The most useful indicator of reservoir rock was obtained from the behavior of the density and neutron logs. All the density and neutron reading logs cases was corresponded to a fall in the gamma ray log because the gamma ray log measures the natural radioactivity in formations track 3 as shown in well Jake South -15 Figure 3 and The deep laterolog or deep resistivity (LLD or RD) represented in track 5 in combination with the GR log were used to differentiate between hydrocarbon and non-hydrocarbon bearing zones.

Consequently, the zones of interest for the petrophysical interpretation were defined in terms of clean zones with hydrocarbon saturation (low GR and high resistivity). The formation density and neutron logs were used for the differentiation of the various fluid types. The gas zones are interpreted from crossover of the porosity logs i.e. formation density and neutron logs, oil zones are based on high resistivity values as shown in Figure 3 and water zones corresponds to very low resistivity shown in well Jake South -15,see Figure 4.

The non-reservoir rock (shale) was clearly identified as zones where the density lies to the right of the neutron, associated with increasing in gamma ray. Also presence of washout is dominantly related to the presence of shale.

As presented in Figure 3 the oil zone shows high resistivity in track 5, in track 3 the GR used to correlate the lithology, in track 4 the green flag stands with shale and yellow flag for sand, track 10 for porosity with green flag for oil and track 11 for lithology.

Figure 4 illustrate the water zone with low resistivity as shown in track 5, a high indicator of spontaneous potential (SP) shown in track 3, the GR in track 3 for correlation the lithology, the non-reservoir with bad resistivity and high gamma ray (GR) indicator of shale as shown by green flag in track 4, hence the predominately shale with occasionally sand in lithology track as shown in well Jake South -3, Figure 5.

Lithology reconstruction:

There are two independent sources of lithology data available from oil wells, one set of data coming directly from the drilling (mud logging samples), and another set from wire line logging. For reliable lithological reconstruction, the two set of data are essential. When any two log values are cross plotted, the resulting series of points used to define the relationship between the two variables. The neutron – density cross plot is the best method for lithology identification. Density – Neutron cross plot values had been used to identify the pure matrix and/or the related porosity. This cross plot uses a straight line relationship between two variables to quantify the desired characteristics and to identify lithology, see Figure 6 and Figure 7.

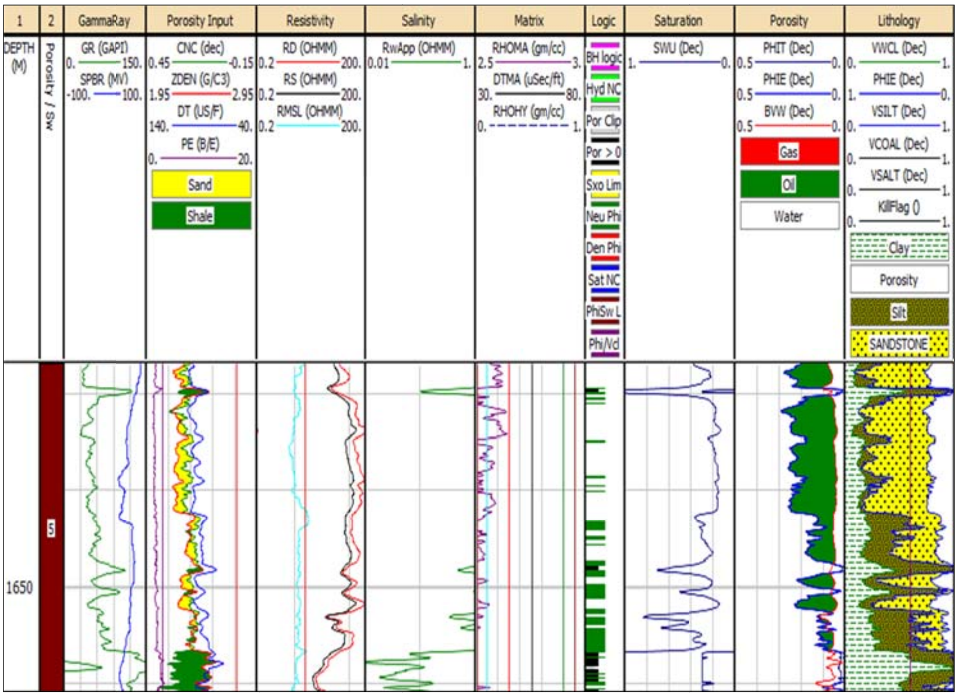


Figure 3: Oil zone – (Jake South -15)

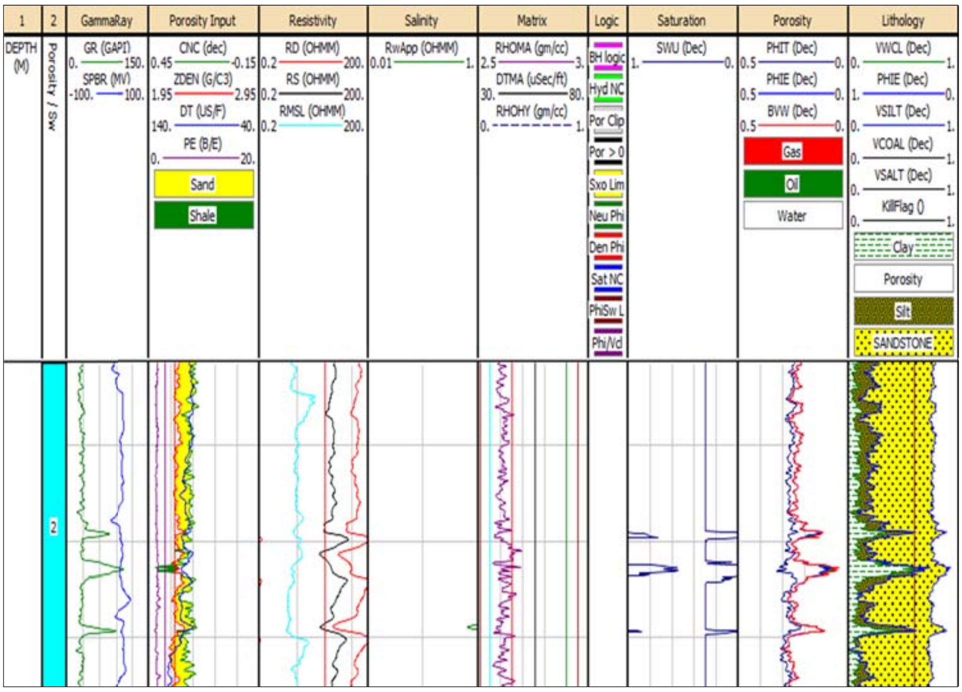


Figure 4: Water zone –(Jake South -15)

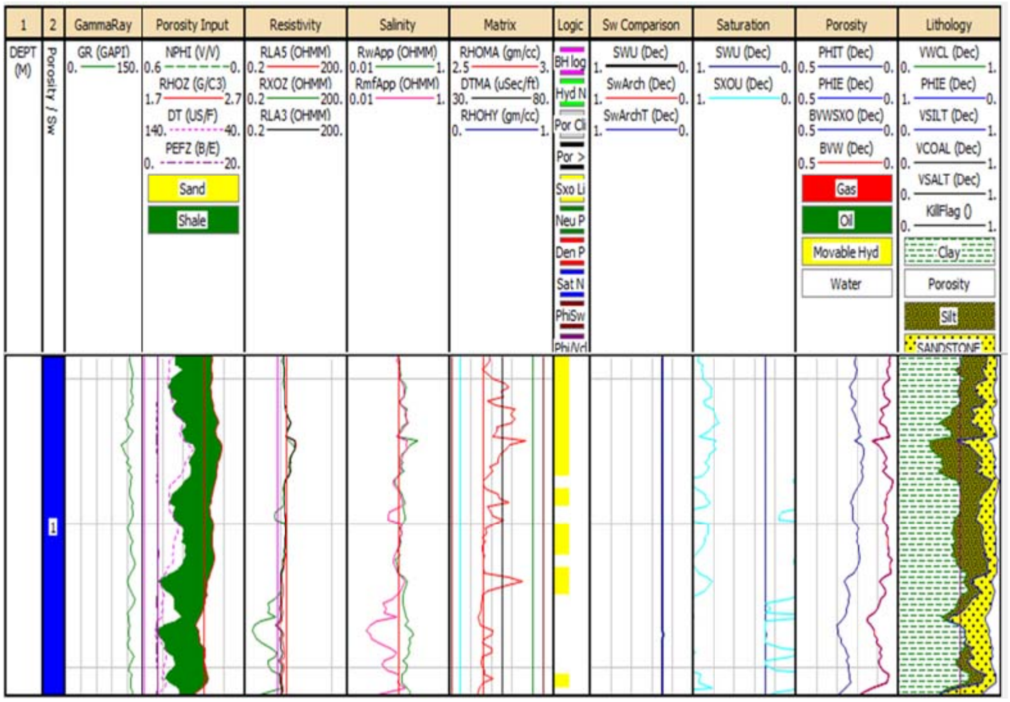


Figure 5: Non-reservoir rock – (Jake South -3)

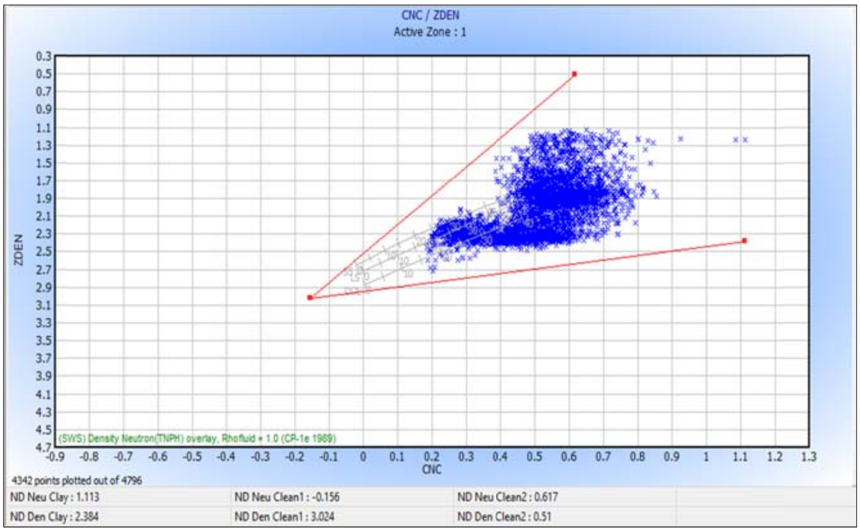


Figure 6: Lithology identification from density – neutron crossplot (Jake South -15).

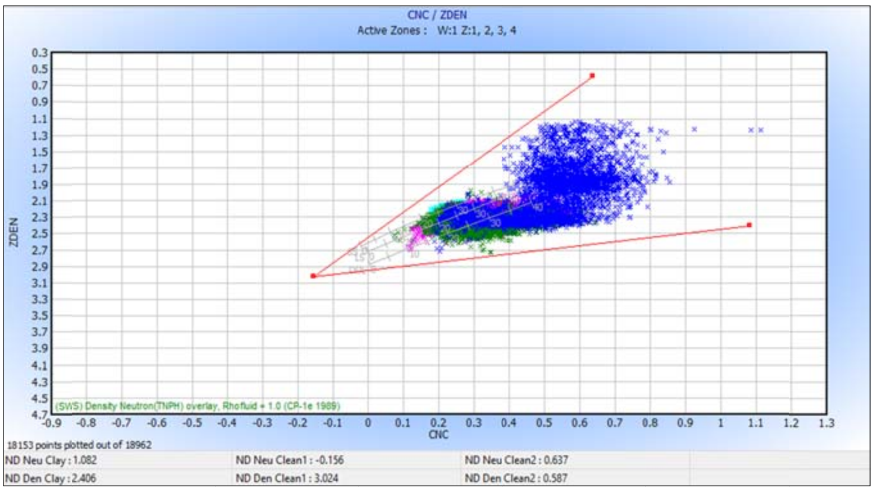


Figure 7: Lithology identification from density – neutron crossplot for all zones (Jake South -15).

Interpretation models:

This study used to make full interpretation models for the petrophysical parameter in order to pick up all zones that are considered to be reservoir rocks for best identify the hydrocarbons places, the v-shale, porosity and water saturation models had been done and full interpreted from the initial results cut off parameters also determined and multi targets prospects of all wells had been marked, beside net-reservoir and net-pay had been obtained successfully.

Shale volume model:

Many log combinations were used to estimate volume of shale, because most log responses are influenced by the presence of shale in the formation such as resistivity, SP, GR, RHOB (density), NPHI (Neutron log) and DT (sonic log).

Types of shale indicators:

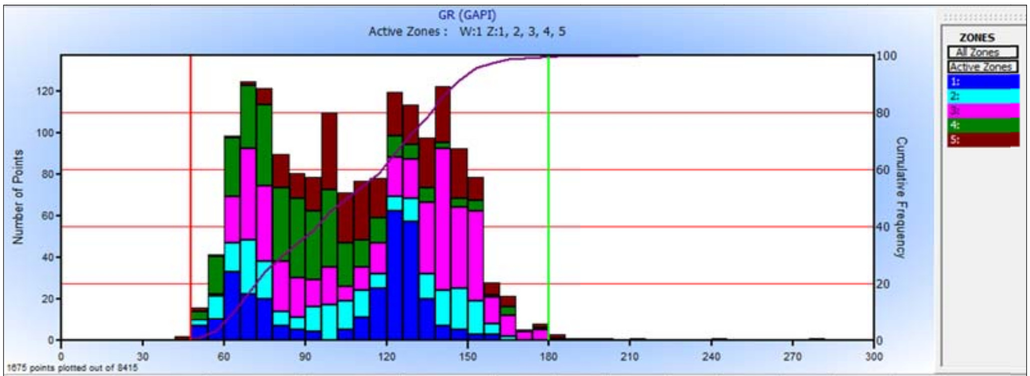
1. Single curve shale indicators.
2. Two curve shale indicators (double).

Single curve shale indicators:

The indicator when only one type of logging data used to evaluate the volume of shale. The gamma ray log is the best single indicator of shale especially after correction of log responses from bad hole condition effect, and when the rate of radioactivity of shale is constant. Shale volume is calculated as:

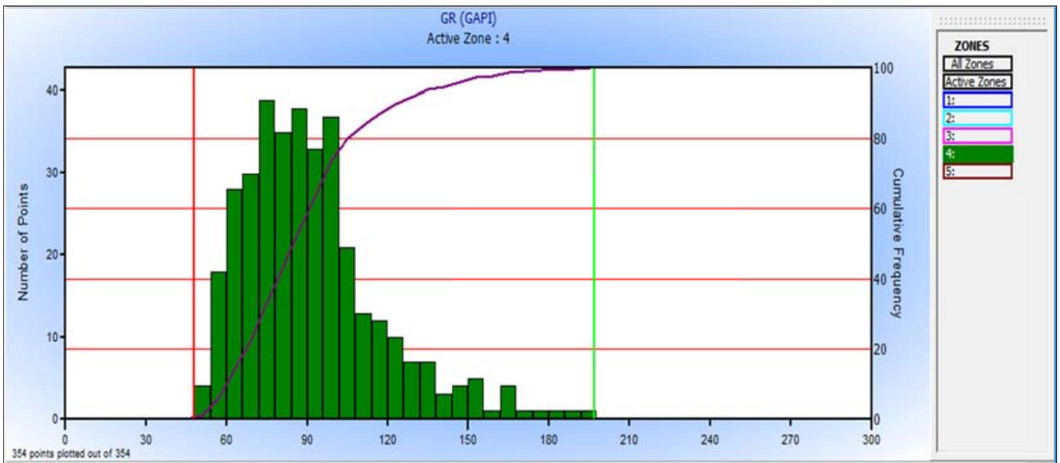
$$IGR = (GRlog - GRmin) \div (GRmax - GRmin) \qquad (1)$$

For taking the GR max and GR min values, a histogram is run on the well data in order to mark the maximum average value of (clay or shale) and minimum average value of (sand), as shown in Jake South -3Fig (8), where the red line is for the gamma ray minimum (48 API) and the green line at right end of the scale is for the gamma ray maximum (180 API). In well Jake South-33, see Figure 9> the data obtained for one zone for the gamma ray minimum (48 API) and the green line at right end of the scale is for the gamma ray maximum (198 API).



Curve	Well	Zone	Top	Bottom	Min	Max	Std Dev	Mean	Mode	P10	P50	P90
GR	Jake S-3	1	403.56 M	1476.6 M	49.711	160.01	29.147	106	123	63.524	120.74	132.73
GR	Jake S-3	2	1476.6 M	1512.72 M	48.794	165.68	32.627	105.97	69	64.603	103.45	149.62
GR	Jake S-3	3	1512.72 M	1583.28 M	58.919	177.01	33.268	116.49	141	69.393	126.57	153.26
GR	Jake S-3	4	1583.28 M	1637.08 M	49.999	194.3	26.066	91.798	75	63.615	87.334	126.01
GR	Jake S-3	5	1637.08 M	1685.24 M	44.271	277.31	28.844	118.48	99	83.803	116.21	149.63

Figure 8: Gamma ray histogram m for all zones from (Jake South -3)



Curve	Well	Zone	Top	Bottom	Min	Max	Std Dev	Mean	Mode	P10	P50	P90
GR	Jake S-3	4	1583.28 M	1637.08 M	49.999	194.3	26.066	91.798	75	63.615	87.334	126.01

Figure 9: Gamma ray histogram for one zone from (Jake South-3)

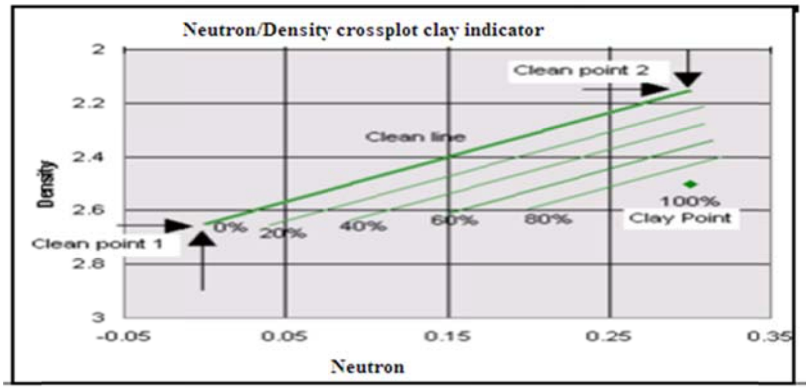


Figure 10: Density-Neutron cross plot

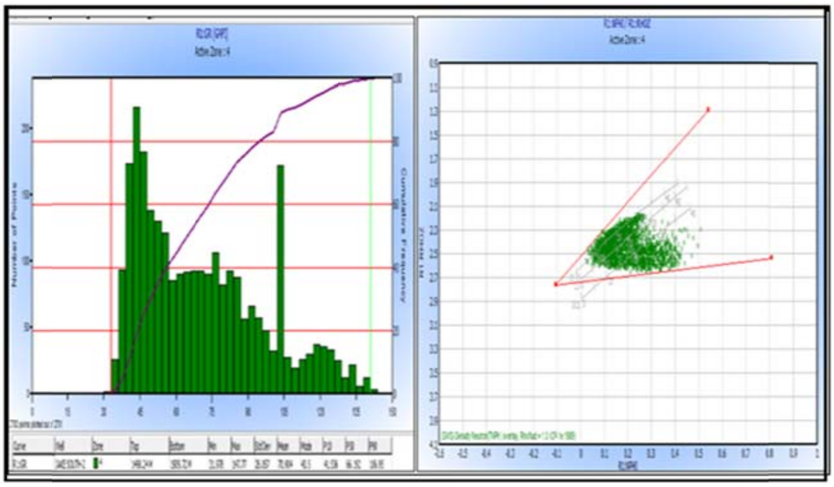


Figure 11: Density–Neutron cross plot compared with histogram well (Jake South -2).

Double curve shale indicators:

In this method two types of logs were used in combination to obtain the volume of shale. The density – neutron technique has been preferred two curves shale indicator method to calculate shale volume, where radioactive sand occurs. Sand- shale models of density and neutron cross plots are used to determine the percentage of shale. A clean sand is typically established using the common sandstone parameters for density (2.65gm/cm^3) and neutron » -0.07. A clay line is established from dry solid point (density = 2.2 – 2.7gm/cm^3), neutron » 0.1 -0.4) to the 100% porosity fluid point Figure 10.

Density (RHOB) – Neutron (NPH) cross plot were used to estimate the shale volume for Bentiu formations, the shale parameters for Bentiu formations have been determined statically using the cross plots and compared with histograms for the all wells Figure 11.

Porosity model:

The density neutron cross plot is the most accurate log analysis method for determining porosity. Both neutron and sonic tools are calibrated against awater-filled limestone basic calibration fixture (standard method). The density log measurement is more sensitive to pore space and the neutron measurement is more sensitive to lithology change. For the shaly sand models, the following sets ofequations were used and the results were displyed in Figure 12.

$$RHOB = RHOBmartix + (RHOBshale - RHOBmatrix)^{*}Vshale + (RHOBfluid - RHOBmatrix)^{*}\phi\text{effective} \quad (2)$$

And

$$\phi\text{Total} = \phi\text{effective} + \text{WCLP} * \text{Vshale} \quad (3)$$

where, RHOB is the density log, ϕ Neutron is the neutron log. WCLP is the wet clay porosity from core analysis. Applying this technique for porosity calculation, the porosity model has been constructed for Bentiu formations Figure 12.

Determination of water saturation:

Water saturation (S_w) determination is the most challenging job of petrophysical calculations which is used to quantify its more important complement, the hydrocarbon saturation (1 – S_w). Water saturation is one of the basic objectives of well log analysis which is used to determine the saturation percentage of oil, gas and water occupying the pore space of reservoirs rocks.

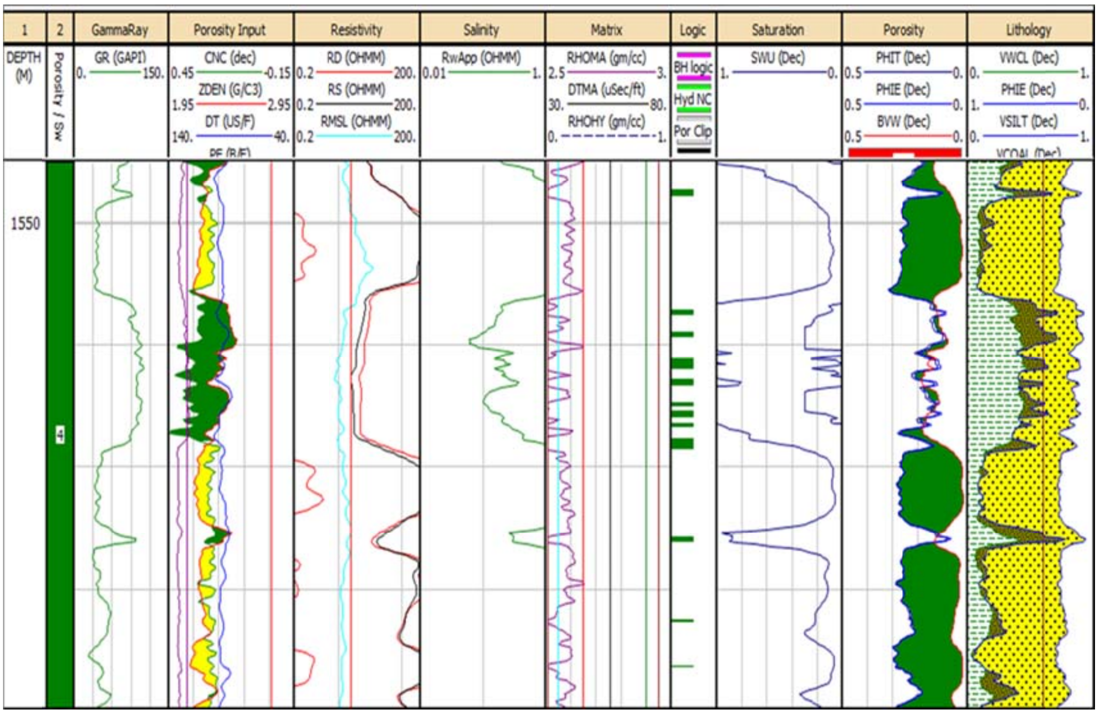


Figure 12: Porosity log for well Jake South -15

Techniques for calculating water saturation:

S_w in wellbores can be determined by the following primary methods:

1. S_w calculations from resistivity well logs by applying a model relating Sw to porosity, connate-water resistivity, and various rock electrical properties.
2. S_w calculations from laboratory capillary pressure/saturation (Pc/ S_w) measurements by application of a model relating Sw to various rock and fluid properties and height above the free-water level.
3. S_w calculations using oil-based mud (OBM)-core-plug Dean-Stark water-volume determinations.
4. Combinations of these methods.

Hydrocarbon Estimation (net-pay):

Estimation of hydrocarbon in place or oil in place (OIP) involves the determination of the thickness of each reservoir, computation of porosity, water saturation, selection of cut-off and determination of reservoir geometry. Hydrocarbon saturation can be computed as in following relation.

$$S_o = 1 - S_w, \quad S_{or} = 1 - S_{xo}, \quad S_{om} = 1 - S_{hr} \qquad (4)$$

where: So = hydrocarbon saturation. S_{om} = movable hydrocarbon. S_{or} = residual hydrocarbon saturation. S_{xo} = hydrocarbon saturation**V-Shale and porosity cut-off:**

From the chart plot of zone against V-Shale and Phi that the volume of shale cut-off shows the net sand lost is less than 1.1% of gross sand hence, from this chart, the Vsh cutoff ≤ 50% was utilized in the study area as V-Sh cutoff for Bentiu reservoirs, While from porosity cutoff the net sand lost less than 1.3% of gross sand, hence, the porosity cutoff value of ≥ 12% was utilized as porosity cutoff for Bentiu reservoirs Figure 13, where it is clear that increasing in porosity accompanied by a decreasing in V-shale.

Water saturation (S_w) and porosity cut-off:

For water saturation cut-off between water saturation (S_w) and porosity against zones as shown in Figure 14, and Figure 15 the water saturation (Sw) cut off values ≤ 50% was adopted in this study for Bentiu formation.

Reservoir summation and interpretation of results:

The sequential integration and calibration procedures used to minimize the errors and uncertainties in the final results. Errors and uncertainties were addressed at each stage of the interpretation from data selection and preparation through to normalization and the final calibration and validation of shale volume, porosity, saturation and parameters.

The overall petrophysical analysis was then reviewed with respect to variables and parameters that contribute the largest uncertainty to the computed results. In many cases, the greatest uncertainty is associated with the data itself, like well with limited data and intervals of poor quality or missing data due to hole problem. This kind of uncertainty was minimized by using appropriate data preparation, reconstruction and interpretation procedures.

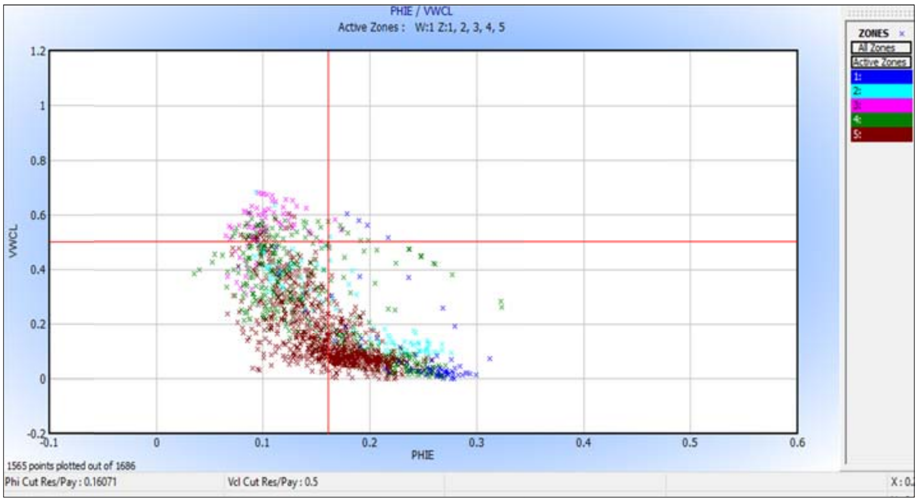


Figure 13: Shale volume and porosity cut-off versus zones – (Jake South -3)

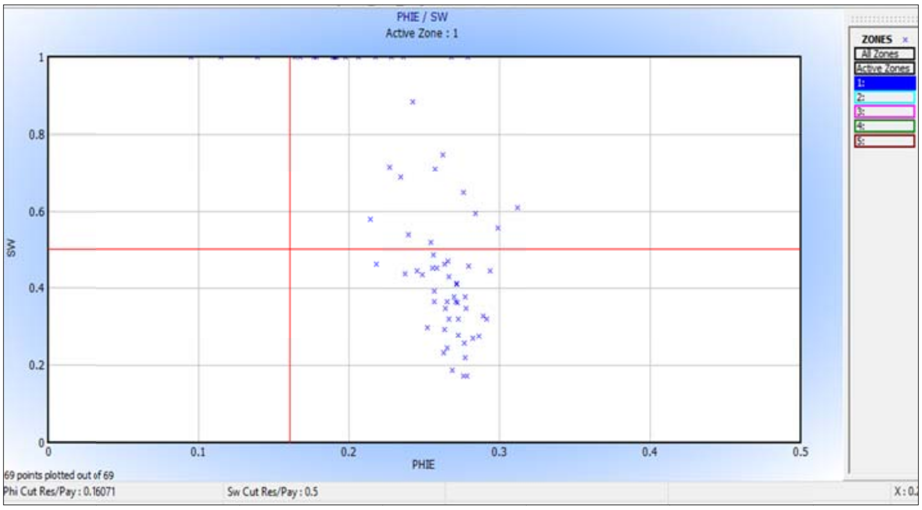


Figure 14: Water saturation (S_w) and porosity cutoff versus zone for one zone (Jake South -3).

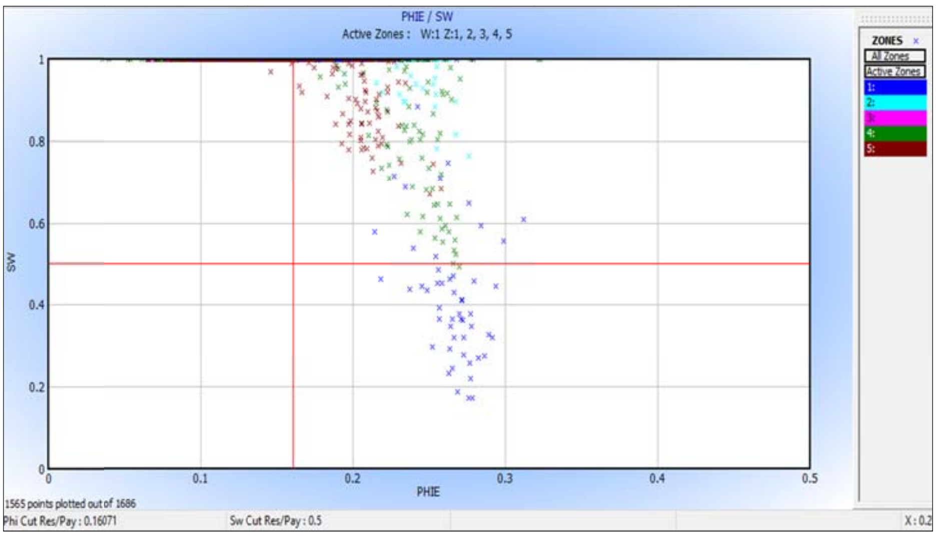


Figure 15: Water saturation (S_w) and porosity cut off versus zone for all zones – (Jake South -3).

Discussion:

The calculated reservoir parameters such as gross sandstone thickness, net pay thickness, average porosity, shale volume and average water saturation, were obtained for each well. The assumption of using the cutoff values is that any zone where porosity > 16% and V-shale > 50% and Sw > 50% is not reservoir. The final interpretation results are listed in tables below for each well. The characteristics of Bentiu reservoirs were studied zone by zone for whole section of the formations. Tables (2-3-4-5-6-7) show that the oil pays mainly distributed in Bentiu formation. Oil in Bentiu formation appears in Jake South -2 and Jake South -15 wells. While Jake South -3 is mainly shows high water saturation. In Jake South -2 well the maximum net pay thickness for Bentiu reservoirs is 48.2m and minimum thickness is 3.66m, The average effective porosity is 17%, and the average water saturation is 48% Table (2 and 3).

CONCLUSION

A comprehensive integrating petrophysical data and reservoir engineering data were collected for Jake South oilfield area, which lies on the north western part of the Fula sub-basin, at the Muglad Basin. To identify and to interpret the reservoir quality of Jake South area successively all kinds of petrophysical parameters have been selected from log interpretation in the area of the study. The sequential integration and calibration procedures were used to minimize the errors and uncertainties in the final results.

Petrophysical evaluation and brief summary of the study can be summarized as the log analysis performed which indicate that the reservoir sand units of wells in Jake South field contain significant accumulations of hydrocarbon., the chart plots of zone against V-Shale, Phi and the volume of shale cut-off show that the net sand lost volume is less than 1.1% of gross sand, hence from the plot charts, in the study area the utilized Vsh cutoff for Bentiu reservoirs ≤ 50%, while from porosity cutoff the net sand lost less than 1.3% of gross sand, hence, the porosity cutoff value of ≥ 12% was utilized as porosity cutoff for Bentiu reservoirs.

For water saturation cutoff between S_w and porosity against zones, the water saturation (S_w) cutoff values ≤ 50% was adopted in this study for Bentiu formation.

. In Jake South -2 (the maximum net pay thickness for Bentiu reservoirs is 48.2m and the minimum thickness is 3.66m, the average effective porosity is 17%, and the average water saturation is 48%), in Jake South -3 (the maximum net pay thickness for Bentiu reservoirs is 4.72m), the average porosity is 22%, and average water saturation is 86%), hence in Jake South -15 (the maximum net pay thickness for Bentiu reservoirs is 28.12m, the minimum thickness is 4.5m, the average porosity is 18% and the average water saturation is 33%).

The delineated zones of interest have the net sand thickness of between 3.66m to 48.2m, average effective porosity in the range of 17% to 27% and water saturation (S_w) ranging from 15% to 39% and volume shale (V_{sh}) from 2% to 38% which are favorable indicators for commercial hydrocarbon accumulation.

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TABLE 2: RESERVOIR SUMMARY OF WELL JAKE SOUTH -2

Zone No.	Zone Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl	Phi*H	PhiSo*H
1	Bentiu	1434.5	1441.6	7.01	5.11	0.73	0.21	0.428	0.378	1.07	0.61
2	Bentiu	1441.6	1471.6	30.02	12.3	0.41	0.234	0.487	0.315	2.89	1.48
3	Bentiu	1471.6	1504.3	32.77	25.3	0.77	0.208	0.392	0.3	5.27	3.21
4	Bentiu	1504.3	1519.1	14.78	5.33	0.36	0.253	0.199	0.238	1.35	1.08
5	Bentiu	1519.1	1551.4	32.31	22.9	0.71	0.154	0.453	0.313	3.52	1.92
6	Bentiu	1551.4	1604.5	53.04	33.4	0.63	0.197	0.432	0.239	6.58	3.73
7	Bentiu	1604.5	1762.2	157.7	121	0.77	0.145	0.576	0.212	17.52	7.44
8	Bentiu	1762.2	1811	48.77	41.7	0.86	0.139	0.522	0.146	5.79	2.76
9	Bentiu	1811	1840.1	29.11	28.4	0.98	0.181	0.353	0.122	5.13	3.32
10	Bentiu	1840.1	1868.7	28.65	20.9	0.73	0.147	0.441	0.204	3.07	1.71
	All Zones	1434.5	1868.7	434.2	317	0.73	0.165	0.477	0.219	52.2	27.28

TABLE 3: PAY SUMMARY OF WELL JAKE SOUTH -2

Zone No.	Zone Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl	Phi*H	PhiSo*H
1	Bentiu	1434.5	1441.6	7.01	3.66	0.52	0.221	0.336	0.383	0.81	0.54
2	Bentiu	1441.6	1471.6	30.02	6.55	0.22	0.249	0.218	0.206	1.63	1.28
3	Bentiu	1471.6	1504.3	32.77	17.2	0.53	0.221	0.259	0.249	3.81	2.82
4	Bentiu	1504.3	1519.1	14.78	4.88	0.33	0.263	0.165	0.225	1.28	1.07
5	Bentiu	1519.1	1551.4	32.31	12.2	0.38	0.19	0.291	0.284	2.32	1.64
6	Bentiu	1551.4	1604.5	53.04	24.4	0.46	0.214	0.337	0.211	5.22	3.46
7	Bentiu	1604.5	1762.2	157.7	48.2	0.31	0.193	0.366	0.136	9.29	5.88
8	Bentiu	1762.2	1811	48.77	20.3	0.42	0.169	0.383	0.109	3.42	2.11
9	Bentiu	1811	1840.1	29.11	25	0.86	0.188	0.318	0.114	4.7	3.21
10	Bentiu	1840.1	1868.7	28.65	13	0.45	0.186	0.302	0.108	2.41	1.68
	All Zones	1434.5	1868.7	434.2	175	0.4	0.199	0.321	0.17	34.89	23.7

In Jake South -3 well the net pay thickness for Bentiu reservoirs is 4.72m, the average porosity is 22%, and average water saturation is 86%.

TABLE4: RESERVOIR SUMMARY OF WELL JAKE SOUTH -3

Zone No.	Zone Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl	Phi*H	PhiSo*H
1	Bentiu	1447.50	1457.86	10.36	4.88	0.47	0.27	0.33	0.02	1.33	0.88
2	Bentiu	1457.86	1476.60	18.75	6.25	0.33	0.24	0.96	0.11	1.51	0.06
3	Bentiu	1476.60	1489.25	12.65	0.53	0.04	0.13	1.00	0.43	0.07	0.00
4	Bentiu	1489.25	1557.83	68.58	23.39	0.34	0.22	0.90	0.07	5.20	0.54
5	Bentiu	1557.83	1703.68	145.85	$$16.76	0.12	0.20	0.97	0.04	3.32	0.09
	All Zones	1447.50	1703.68	256.18	$$51.82	0.20	0.22	0.86	0.06	11.43	1.59

TABLE5: PAY SUMMARY OF WELL JAKE SOUTH -3

Zone No.	Zone Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl	Phi*H	PhiSo*H
1	Bentiu	1447.50	1457.86	10.36	4.72	0.46	0.27	0.33	0.02	1.28	0.86
2	Bentiu	1457.86	1476.60	18.75	0.00	0.00	---	---	---	---	---
3	Bentiu	1476.60	1489.25	12.65	0.00	0.00	---	---	---	---	---
4	Bentiu	1489.25	1557.83	68.58	0.00	0.00	---	---	---	---	---
5	Bentiu	1557.83	1703.68	145.85	$$0.00	0.00	---	---	---	---	---
	All Zones	1447.50	1703.68	256.18	$$4.72	0.02	0.27	0.33	0.02	1.28	0.86

In Jake South -15 the maximum net pay thickness for Bentiu reservoirs is 28.12m and minimum thickness is 4.5m, the average porosity is 18% and the average water saturation is 33%.

TABLE 6: RESERVOIR SUMMARY OF WELL JAKE SOUTH -15

Zone No.	Zone Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl	Phi*H	PhiSo*H
1	Bentiu	1586	1597.4	11.35	7.51	0.661	0.177	0.353	0.278	1.33	0.86
2	Bentiu	1597.4	1605.3	7.92	6.25	0.788	0.199	0.424	0.276	1.24	0.72
3	Bentiu	1605.3	1622.1	16.76	10.25	0.611	0.118	0.815	0.334	1.21	0.22
4	Bentiu	1622.1	1660	37.95	30.33	0.799	0.187	0.256	0.289	5.69	4.23
5	Bentiu	1660	1675	15.01	11.05	0.736	0.183	0.156	0.32	2.02	1.7
	All Zones	1586	1675	89	65.38	0.735	0.176	0.327	0.299	11.48	7.73

TABLE 7: PAY SUMMARY OF WELL JAKE SOUTH -15

Zone No.	Zone Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl	Phi*H	PhiSo*H
1	Bentiu	1586	1597.4	11.35	5.72	0.503	0.181	0.298	0.276	1.04	0.73
2	Bentiu	1597.4	1605.3	7.92	4.50	0.567	0.215	0.389	0.243	0.97	0.59
3	Bentiu	1605.3	1622.1	16.76	0.00	0.00	---	---	---	---	---
4	Bentiu	1622.1	1660	37.95	28.12	0.741	0.194	0.236	0.279	5.46	4.17
5	Bentiu	1660	1675	15.01	10.9	0.726	0.184	0.152	0.318	2.01	1.7
	All Zones	1586	1675	89	49.23	0.553	0.192	0.24	0.284	9.47	7.19