Reservoir characterization using multi geophysical data for Cretaceous sediments in the Shelungo Oil Field, Muglad Rift Basin, Sudan

Caracterização de sedimentos cretácicos do reservatório do campo petrolífero de Shelungo através de métodos geofísicos, Bacia de Muglad Rift, Sudão

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Abstract: The study area is part of the Late Jurassic to Early Cretaceous Sudanese Rift Basin; covering an area of ~3825 km². A more than 4000 meter thick sequence of Mesozoic to Tertiary sediments has been penetrated in the study area. The main objectives of this study are to build facies and petrophysical property models from data and geological knowledge in Shelungo field in order to have a clear definition of the sediments characteristic of Aradeiba sandstone and Bentiu sandstone formations (main reservoir rock). The structural system was dominated by northwest trending faults with different throws which are generally strike NNW-SSE and NW-SE. This trend is possibly a reactivation of the late Precambrian to Early Paleozoic Pan African Shear Zone. Stratigraphically, the succession is composed of sand-shale intercalations of continental origin varying in sand and organic content. The reservoir rocks were originally derived from the Precambrian and Cambrian gneissic basement. The facies description and the analysis of well logs from the Bentiu and Aradeiba Formations in the Shelungo field revealed the presence of five major siliciclastic lithofacies interpreted as fluvial, deltaic and lacustrine deposits. Shale cut-off (Vsh) and porosity cut-off (Phi) were calculated for the two studied sands intervals. The analyses showed that Vsh of 50% is reasonable for Aradeiba and Bentiu sands. However, a higher value of about 55% could have been used. The Phi Cut-Off was estimated to be 10% and 12% for Bentiu and Aradeiba sands respectively. The distribution of porosity in the wells generally shows a predictable continuous decrease with depth but actually this gradual decrease changes in some of the deeper horizons and is locally reversed. This progressive reduction is probably due to the diagenetic processes, which include: mechanical compaction factors, Feldspar/quartz overgrowths, precipitation of cements and precipitation of intergranular clays.

Keywords: 3D, dados geofísicos multidisciplinares, Shelungo, Bacia Muglad, Sudão

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1. Introduction

The study area is part of the Late Jurassic to Early Cretaceous Sudanese Rift Basin (Fig. 1 and 2). It covers an area of approximately 3825 Km². A more than 4000 meter thick sequence of Mesozoic to Tertiary sediments has been penetrated in the study area. The field comprises twelve (12) wells, namely, Garaad 1, Garaad 2, Garaad 3, Garaad West 1, Shmmam 1, Jamous 1, Shelungo 1, Shelungo 2, Shelungo East 1, Shelungo North 1, Assal 1, and Azrq South 1. (Fig.1). The Field is located within Block 4A of the GNPOC concession area. The primary hydrocarbon source rock is the lacustrine shale of the Abu Gabra Formation. The high-energy fluvial sandstones of the Bentiu Formation are the main reservoir and the Aradeiba lacustrine shale is the potential seal. Structurally, it is a fault bounding structure. The structure of the Muglad basin is located at the tilted up thrown side of the normal fault block. The three-way faulted anticline dip to NW-SE direction.

This paper presents 3D geo-modelling with gOcad software of thick continental clastic sequences of Cretaceous reservoir sediments deposits in the Muglad rift basin using sequence stratigraphy, petrophysical well log characteristics, geological facies model and 2D seismic data.
The main targets of this study are to build facies and petrophysical property models from data and geological knowledge in Shelungo field (Fig. 1) in order to have a clear definition of the sediments characteristic embrace the target layers of Aradeiba sandstone and Bentiu sandstone formations (main reservoir rock). For this purpose software gOcad has been used. An integrated multidisciplinary geo-model characterization has been conducted in high-resolution 3D where distributions of reservoir properties were generated, accounting for inherent inter-relationship among reservoir property data and the three main data scales of log, sub-sequence layer and sequence interval. As a case study, Shelungo field is selected for the development and benchmarking of this technology to be expanded later to other fields in this basin.

2. Tectonic and Structural Setting

The development of oil-bearing basins in Sudan is closely associated with the global phenomenon of plate tectonics and particularly with the Africa-South America rifting (Fairhead, 1988; Schull, 1988). The development of the rift basins of southern Sudan is related to processes that operated not only within central Africa, but also along the western and eastern continental margins (Fig. 2). The Sudanese Interior basins are interpreted to be of Mesozoic to Tertiary age. Thus the Late Jurassic to Early Cretaceous Muglad Basin forms part of the West and Central African Rift-System. The basin evolution has been divided into pre-rift and rift phases (Schull, 1988). The rifting is divided into three major phases:
- Phase 1 – Late Jurassic Early Cretaceous (140-95 Ma).
- Phase 2 – Late Cretaceous (95-65 Ma).
- Phase 3 – Paleocene (65-30 Ma).

In the area of study the structural system is characterized by northwest trending faults with different throws with overall NNW-SSE and NW-SE strikes. This trend is possibly a reactivation of the late Precambrian to Early Paleozoic Pan African Shear Zone. In seismic lines and cross-sections the faults present planar normal faults and listric normal faults in rotated fault zones (Fig. 2). These faults totally control structure evolution, generating oil-trapping fault blocks. Tensinal movements, resulting in a tilted fault–block structural style, marked the early phase in the history of the basin.

The styles of the structures mainly include rotated tilted fault blocks, faulted anticlines and horst blocks (Schull, 1988). The faults usually juxtapose the sands of the upper Bentiu against Aradeiba shale section.

3. Stratigraphic Setting

Stratigraphically the succession composed of sand/shale intercalations of continental origin varying in sand and organic content upon the environment of deposition. The multiple phases of rifting lead to episodic variations in basin subsidence that influence the stratigraphic evolution of the study area. Eleven (11) lithostratigraphic units have been established in the Muglad basin: Abu Gabra Formation, Bentiu Formation, Darfur Group (Aradeiba Formation, Zarqa Formation, Ghazal Formation and Baraka Formation), Amal Formation and Kordofan Group (Nayil Formation, Tendi Formation, Adok Formation and Zeraf Formation) in ascending order. Table (1) shows a schematic representation of the generalized stratigraphy and petroleum geology of the Sudanese Muglad basin. No rocks of Paleozoic to Jurassic age have been recognized in the drilled wells.

The oil is accumulated in the Lower Cretaceous Abu Gabra and Bentiu Formations (divided into two members) and the Upper Cretaceous Darfur Group (Aradeiba Formation). The Aradeiba Formation is divided into three members (Aradeiba upper shale, Aradeiba sand and Aradeiba lower shale).

3.1. Bentiu formation

Bentiu Formation is the main oil-bearing unit in the study area, with average thickness of 317 m. The Bentiu Sandstone consists of a series of sandstones interbedded with claystone. Sandstone are medium to coarse grained and less consolidated than the overlying Formations, generally deposited in a braided stream environment with high Rw (RRI, 1991). The reservoir qualities are good according to the petrophysical evaluation and adjacent productive field (Heglig Field).

According to Mohammed (2003) the core analysis of Bentiu sandstone in Shelungo North_1 shows that the porosity ranges from 23% to 31.2%, averaged 29.4%.
3.2. Aradeiba formation

Aradeiba Formation sandstone is the main secondary reservoirs in the study area, with average thickness about 43 m. The Upper Cretaceous Darfur Group is predominantly composed of claystones and thin interbeded sandstone. The claystone is reddish brown to dark brown and moderately hard. Sandstone from core description is light brown-grey colour, massive to large trough cross-bedded. Core analysis of Aradeiba sand in Shelungo North_1 shows that the porosity of the Aradeiba E range from 21% to 27% averaged 26.2% (Mohammed, 2003). Generally Aradeiba sands are deposited in lower energy environment (Late Cretaceous (95-65 Ma)) with a much lower Rw. (RRI, 1991).

4. Petrophysical Evaluations

The Shelungo field is selected for the petrophysical evaluation and benchmarking of this technology to be expanded later to other fields in this basin. The main use of logs is for the identification of the depths of stratigraphic formation boundaries and their correlation between wells. In addition, logs also provide valuable information on the Shelungo field because they can be used for Rock type recognition: Sandstones can usually be distinguished easily from shales in the Muglad on most logs. This information can be used to give both depth and thickness of sandstones at the well location, as well as for tracing them between wells. The objective of the petrophysical evaluation of the study area is to prepare the petrophysical and engineering data needed for building the 3D geological model of the Shelungo field. The following tasks were carried out for this evaluation:
- Property Transforms/Analogue model.
- Cutoff values Determination.

4.1. Property Transforms/Analogue model

All the logs illustrated have been taken from a single well, so that the properties and inter-relationships can be understood more easily.

The Gamma-Ray Log was widely used as a record to locate the depth of key stratigraphic formations and to subdivide the Shelungo field (Muglad basin) into units of sandstone and shale (Fig. 3).

Once the stratigraphic boundaries of the Muglad basin are located (Fig. 3), the gamma-ray log can be used to mark the depth intervals of sandstones and shales. As a general rule-of-thumb, experience has shown that a value of 50 API units is a satisfactory boundary to differentiate sandstones (below 50 API) and shales (above 90 API).

Two types of logging tools were used to estimate the amount of pore space in a rock in the study area: the neutron (NPHI) and density (RHOB). The neutron log records counts the collisions between neutrons that radiate from a tool source and hydrogen atoms within the rock of the borehole wall. So, the log is mainly a measure of hydrogen concentration (mostly contained by the pore fluids of the formation). The neutron logs are scaled directly in units of porosity. Shales appear to have high porosities on the neutron log (Table 2), mostly because of bound water, rather than effective porosity. However, porosities recorded in shale-free sandstones are a reasonable estimate of pore spaces that contain water that can be produced in a well.

Fig. 3. Facies classification of Aradeiba and Bentiu formations in Shelungo field (the Muglad basin) based on well log pattern and geological well description; the porosity (colour cylinder) indicated by NPHI and RHOB logs. Sh_N1 = Shelungo North_1, Sh_2 = Shelungo_2, Sh_E1 = Shelungo East_1 and Asl_1 = Assal_1. Show the relationship between several wirelines.

Fig. 3. Classificação de fácies das formações Aradeiba e Bentiu no campo Shelungo (Bacia de Muglad) baseada no padrão dos logs e na descrição geológica dos poços; a porosidade (cilindro colorido) indicada por logs NPHI e RHOB. Sh_N1 = Shelungo North_1, Sh_2 = Shelungo_2, Sh_E1 = Shelungo East_1 e Asl_1 = Assal_1. Mostra as relações entre diferentes linhas.
The density log is a measure of apparent density of the rock and is computed from the absorption of gamma rays emitted from a tool radioactive source by the formation (Rider, 1996). The density of quartz is about 2.65 gm/cc, and that of water is approximately 1.0. These two values correspond to the density of sandstone with zero porosity and hypothetical sandstone with a porosity of 100%.

<table>
<thead>
<tr>
<th>Lithology</th>
<th>Vsh</th>
<th>GR in API</th>
<th>RHOB in gm/cc</th>
<th>NPHI</th>
</tr>
</thead>
<tbody>
<tr>
<td>sandstone</td>
<td>0.4</td>
<td>low (50)</td>
<td>high (2.4-3.0)</td>
<td>low (&lt; 0.2)</td>
</tr>
<tr>
<td>shaly sand</td>
<td>med</td>
<td>med</td>
<td>med (2.2-2.4)</td>
<td>med</td>
</tr>
<tr>
<td>shale</td>
<td>0.6</td>
<td>high (90)</td>
<td>low (1.8-2.2)</td>
<td>high (&gt; 0.320)</td>
</tr>
</tbody>
</table>

4.2. Determination of Cut-Off values

The objectives of utilizing Cut-Off values are to eliminate the non-reservoir rocks and calculate the net reservoir rocks, in the Shelungo field. The non-reservoir rocks of Aradeiba formation and Bentiu formation reservoirs in Shelungo field is shale (Fig. 3). Therefore, the intent is to set the Cut-Off criteria needed to eliminate these non reservoir rocks from the logged reservoir intervals. Generally, there are two types of cut-off values used in this study Shale Cut-Off (Vsh Cut-Off) and Porosity Cut-Off (phi Cut-Off).

The determination Cut-Off values are modelled by krigging conditioned to Vsh content, porosity (phi), and created for each subsequence unit by first analyzing well lithology and wire line (porosity, density, gamma ray and spontaneous potential) logs to describe their spatial correlation and statistical properties. Second, a 2D multivariate statistical was constructed for applying data analysis and geostatistical procedures within reservoir framework. Third, two data integration scenarios in each reservoir phase were applied: while the first scenario utilized well data only, the other integration scenario combines wells data with the 2D seismic data. Both integration scenarios generate petrophysical realizations (such as porosity) based on lithology distribution. Fourth, reservoir characteristic for each petrophysical realization are computed. Fifth, the results by statistical methods (i.e. descriptive statistic, Crossplots) are analyzed. Lastly, calculations of shale volume were constructed on the basis of the well-log-based facies distribution using multivariate statistical 2D Cross plots between two Properties. The determination of the values of this Cut-Offs for Bentiu and Aradeiba reservoirs will be handled with more details in the following sections.

4.2.1 Shale (Vsh) Cut-Off

The calculation of shale volume, Vsh, was done mainly by using the normalized GR curves and standard petrophysical algorithms (Hurst, et al., 1992). For these calculations: minimum GR recording for sand = 50 API, maximum GR recording for clean shale = 90 API, apparent shale neutron porosity = 0.320 and apparent shale density porosity = 0.18 (Table 2).

A cross plot of GR readings against computed Vsh indicated that Vsh <0.4 largely corresponds to Aradeiba Sand, and hence is used as a Cut-Off criterion for sand definition. Vsh >0.6 represents shale, and 0.4 < Vsh <0.6 indicates sand.

Figures (4, 5, and 6) are plots of NPHI against RHOB and RHGA against GR for well Shelungo_2, Shelungo East_1 and Assal_1 respectively for Aradeiba and Bentiu formations. The Vsh cut off values were calculated from this figures using the average RHOB, NPHI and GR readings against Aradeiba sand and Bentiu sand shale intervals. Table (2) presents the RHOB used in calculating Vsh cut off values for Bentiu sand and Aradeiba sand reservoirs.

From this method, the Vsh cut off for Aradeiba is 48.5% and for Bentiu is 52%, as shown in Table (3). Therefore, a Vsh cut-off value of 50% will be utilized in the study. The effect of utilizing higher Vsh cut-off value of 55% will be tested as well.

4.2.2 Porosity (phi) cut off

The porosity (phi), a combination of volume-weighted sand and shale porosities, was computed from neutron (NPHI) and
density (RHOB) logs at 0.25 m resolution by the following equation (standard petrophysical methods) (Schlumberger, 1989a):

\[
\phi = \frac{(0.763 \times RHOB + 103.4 \times NPHI)}{100}
\]

An average of quartz theoretical readings are used in these calculations; namely: matrix travel time of 15.76 msec/m, the neutron porosity index of 2 % lower than clean quartz, and matrix density of 2.65 gm/cc. The minimum porosity value is kept at 2%, consistent with log measurement and independent of tool selection. The best porosity value among these methods is the one requiring least manipulations to original logs. The corresponding phi-shale values in neutron and density log calculations are 0.32, 1.7, respectively.

Therefore, a porosity Cut-Off value of 12% will be used for Aradeiba Sand in the study area (Table 3). It is worth noting that the silt, which is the target for elimination by applying porosity Cut-Off, has porosity up to 12%. Also, Aradeiba sand size ranges from fine to medium, whereas that of Bentiu ranges from medium to coarse, in Shelungo field (Muglad Basin). Therefore, the above Cut-Off values are in full harmony with this basic information.

Table 3. Determination of Cut off values for Aradeiba sand and Bentiu sand reservoirs.

<table>
<thead>
<tr>
<th>Shale Cut-Off (Vsh)</th>
<th>Formation</th>
<th>%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bentiu</td>
<td>52</td>
<td></td>
</tr>
<tr>
<td>Aradeiba</td>
<td>48</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Porosity Cut-Off (phi)</th>
<th>Formation</th>
<th>%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bentiu</td>
<td>10</td>
<td></td>
</tr>
<tr>
<td>Aradeiba</td>
<td>12</td>
<td></td>
</tr>
</tbody>
</table>

5. 3D Modelling

5.1. Facies Modelling

Facies were classified and divided based on log facies analysis and additional geological well log descriptions. Log facies were classified mainly based on log patterns of GR and RHGA logs, and then they were correlated to on seismic sections analysis and geological well log in order to determine the lithology and intrinsic sedimentary facies. Based on wire line logs, and seismic sections, the Cretaceous strata in Fields can be classified into five different units of first-order sequences that represent: fluvial-dominated unit, lacustrine-dominated unit and deltaic-dominated unit. The fluvial-dominated sequence unit characterizes the whole of the Bentiu Formation as well as the lowermost part of the Aradeiba Formation, the middle part of the Aradeiba Formation in Shelungo-2 well and the upper part of Aradeiba Formation in Shelungo Field (Figs. 3 and 7). Fluvial sequences unit is also found throughout the Bentiu Formation in Shelungo Field, in the lower and middle parts of Aradeiba Formation in Shelungo-1 well (Figs. 3 and 7). Whereas, the lacustrine-dominated sequences unit occurs in the lower and upper parts of the Aradeiba Formation in Shelungo-2 well, in the lower part of the Aradeiba Formation in Shelungo East-1, Shelungo North-1 wells. Moreover, this sequences unit characterizes the lower part of the Aradeiba Formation in Shelungo East-1, Shelungo North-1 wells. Also some lacustrine sequences occur in the strata near the middle part of the Aradeiba Formation in Shelungo-1 well. However, the deltaic-dominated sequences unit occurs near the middle and near the upper part of the Aradeiba Formation in Shelungo-2 well, in the middle part and near the upper part of the Aradeiba Formation in Shelungo East-1 well. Moreover, this sequences unit characterizes the middle part and the strata near the upper horizons of the Aradeiba Formation in Shelungo East-1 well, the top of the Aradeiba Formation in Shelungo North-1 well.

The distribution of porosity in the wells generally shows a predictable continuous decrease with depth but actually this gradual decrease changes in some of the deeper horizons and is locally reversed. According to Mohammed (2003), this progressive reduction is due to the diagenetic processes, which include: mechanical compaction factors, Feldspar/quartz overgrowths, precipitation of cements and precipitation of intergranular clays.

Lastly, the reservoir quality of the study intervals was affected not only by the above mentioned diagenetic processes but also in a large-scale by the depositional environments, which had controlled the distribution of the facies and sediment thickness within the basin as well as by the subsidence of the basin besides

Fig. 7. Geostatistical Vsh distributions and geological facies 3D model for the upper sequence (Aradeiba formation) and lower sequence (Bentiu formation). Histogram shows normal distribution and Probability Distribution Function (PDF) of shale porosity.

Fig. 7. Distribuições geostatísticas Vsh e modelo de fácies geológicas 3D para a sequência superior (formação Aradeiba) e sequência inferior (formação Bentiu). Histograma apresenta uma distribuição normal e uma Função de Distribuição Probabilística (FDP) da porosidade do xisto.
the structural relief variations that had happened during the initiation of the second rifting phase (Mohammed, 2003), which gave rise to the quick transportation and the rapid burial of the sediments.

**Comparison with Deterministic Geological Models:**
Geostatistically generated Vsh distributions in the fields of study area were analyzed for patterns of sand distribution and were compared with deterministically mapped distributions of facies from geology on the basis that facies Aradeiba sand and Bentiu are sandier and that facies Aradeiba upper and lower shale are shalier. Figure (7) shows geostatistical Vsh distributions and geological facies 3D model for the upper sequence (Aradeiba formation) and lower sequence (Bentiu formation). The models show the sediment supply routes, lacustrine sediments and channels that are present at these locations. Figure (7) shows general relation between the geological model and the geostatistically distributed properties. The low Vsh regions match areas defined by the Bentiu sand and Aradeiba sand facies. The geostatistical models, however, are more detailed and are extendable to larger areas.

**5.2 Property Modelling**

Stochastic method was applied for modelling the distribution of petrophysical properties in a reservoir model. Scaled up well logs and trend data were used as input. For each property, all cells received a value. The well and trend values distributed in the volume defined by the 3D grid. Stochastic petrophysical property models are generated in gOcad based on the Sequential Gaussian Simulation method (sGsim).

**Porosity modelling:** Porosity (effective) models have been generated in depth and time; the intention was to use the model in the static and dynamic modelling. Figure (8) show 3D model of porosity generated from seismic lines and wells effective porosity in density display. As indicated by the legend, the Red colour is the minimum porosity. The method of Sequential Gaussian Simulation (sGsim) collocated with Vsh is used. The required correlation coefficients between porosity (phi) and Vsh are constructed from well data, ranging from -0.25 to -0.75 and generally improving from lower deposits to upper deposits.

Figure (9) shows a typical vertical variograms of normal score porosity within Facies (Aradeiba upper shale, Aradeiba sand and Aradeiba lower shale) in the upper sequence of Shelungo field.

Figure (8) shows that channel type clean sands are present in lower sequence of Aradeiba sand with minor alterations in porosity. The probability of sand occurrence correlates strongly with the probability of connected sand geobodies. Although sand in the upper sequence (Aradeiba sand) is blanket type they form discontinuous bodies due to diagenesis and cementation of primary porosity.

Porosity maps in time have also been constructed for layers 20 ms below each horizon of total (Umm Ruwaba, Amal, Baraka, Gazal, Aradeiba and Bentiu) respectively as shown in (Fig. 10) below. The Porosity estimated by simple kriging. These maps are indicative of porosity quality in the area. In each figure, porosity range is from 0.1 to 0.6.

![Fig. 8. 3D model of shale porosity simulated with Sequential Gaussian Simulation (sGsim). As indicated by the legend, the red to light green colour is the minimum porosity represented by Aradeiba and Bentiu sandstone formation (the main reservoir).](image1)

![Fig. 8. Modelo 3D da porosidade do xisto com uma Simulação Gaussiana Sequencial (SGS). Tal como indicado na legenda, as cores vermelha a verde-claro são a porosidade mínima representada pela formação arenosa Aradeiba e Bentiu (o reservatório principal).](image2)

![Fig. 9. Vertical variogram model of porosity value computed from well logs. a) GR and b) RHGA.](image3)

![Fig. 9. Modelo variograma vertical da porosidade computada a partir de logs de poços. a) GR e b) RHGA.](image4)
6. Conclusions

The basin wide deposition of high-energy fluvial sandstones of the Bentiu Formation and the Aradeiba sandstones exhibit excellent reservoirs in the study area.

Facies was build using a deterministic interactive approach to incorporate the geological model, wireline logs, and geological well information data and seismic attributes results and porosity was populated using Stochastic methods that constrained to facies. As result, four major sedimentary facies were recognized; these are Aradeiba upper shale, Aradiba lower shale, Aradeiba sandstone and Bentiu sandstone.

The Cut-Offs concluded are as follows: Shale Cut-Off (Bentiu formation: 52%, Aradeiba formation: 48%) and Porosity Cut-Off (Bentiu formation: 10%, Aradeiba formation: 12%). Therefore, reservoir quality of the Bentiu Formations in general is better than that of the Aradeiba Formation. Since the sandstones of the Bentiu Formations are mainly cemented with quartz, this formation had suffered less from compaction.

The distribution of porosity in the wells generally shows a predictable continuous decrease with depth but actually this gradual decrease changes in some of the deeper horizons and is locally reversed. This progressive reduction is probably due to the diagenetic processes, which include: mechanical compaction factors, Feldspar/quartz overgrowths, precipitation of cements and precipitation of intergranular clays.

Lastly, the reservoir quality of the study intervals was affected not only by the above mentioned diagenetic processes but also in a large-scale by the depositional environments, which had controlled the distribution of the facies and sediment thickness within the basin as well as by the subsidence of the basin besides the structural relief variations that had happened during the initiation of the second rifting phase, which gave rise to the quick transportation and the rapid burial of the sediments.

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