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Reservoir characterization and the possibility of compartmentalization in the Kalloni Field, Niger Delta, Nigeria

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Abstract
The work examined the petrophysical characteristics of fault-bounded sand tops of the Kalloni oil field as they affected the sealing capacity and possibility of having compartments. The methods applied were lithostratigraphic correlation, seismic interpretation, and evaluation of the reservoir sealing tendencies. A total of twenty-three (23) faults were picked from the 3D seismic volume and 2 major reservoir units were recognized from the suit of well logs. Structural modelling of the sand units (C6000 and C13000 reservoirs) showed intra-reservoir faults that could result in flow restrictions. The sands were seen sandwiched between shale beds having a good spread with a relative shale thickness of 150-300ft measured depth. The results of the petrophysical analysis showed the C6000 and C13000 sands had a net-to-gross of 0.5, an average volume of shale of 0.4, an average porosity of 28.5% and an average permeability of 2,100mD. The results of the fault analysis showed a shale gouge ratio (SGR) of 0.5 - 0.8 on the fault planes. The stratigraphic juxtapositions showed sand-against-sand as well as sand-against-shale. The analysis of the reservoir configuration showed that the shales largely contributed to the sealing having served as the caprock sequence. A hydrocarbon column height of 266.6ft was estimated in the reservoir C6000 sand while the hydrocarbon column heights of 269.5ft and 333.54ft were estimated on separate stratigraphic crests in the C13000 sand. The significance of these results points to the possibility of having compartments in the field.

Keywords: Reservoir Compartmentalization, Fault Seal, Niger Delta Basin

Background to the Study
Most sedimentary beds were deposited in horizontal or near horizontal layers before they became distorted. Rock deformation refers to any change in a rock's volume, shape or attitude. A rock may be brittle or ductile and faulting is a form of brittle deformation. It is predominant in the shallow depths of the earth and common among rigid rocks e.g., sandstone, limestone, granite etc. The resultant fault deformational structure may be capable of transmitting fluid or become a baffle to the continuous migration of fluid. Faults are targets of exploration and can divide a wide area of stacked sands into compartments. According to [10], the sealing configuration of compartments results from a wide range of geological and fluid dynamic factors. [12] opined that the trap or sealing configuration of rocks is formed when they deform or when their quality becomes altered in such a manner that they create a configuration suitable for keeping hydrocarbon in place over geologic or production time. Compartmentalization is an uncertainty that requires some attention considering the complex distortional and fluid dynamic systems that create it. Its occurrence impacts exploration budgets and, in some cases, results in abandonment. It is described as the possibility of having hydrocarbon in pockets bearing unique fluid, chemical, viscosity or pressure characteristics. It results when the flow is restricted due to the presence of a closed or semi-closed sealing configuration caused by structural or stratigraphic configurations or a combination of both ([10]; [5]). The capacity of the sealing surface is described in terms of the column height, which refers to the vertical measure of the maximum amount of fluid the reservoir can hold under static or dynamic sealing conditions. This is also related to the shale content of the rock sequence. The mercury injection capillary pressure (MICP) analysis is a legacy laboratory technique that measures the sealing capacity and capillary pressure (strength) of rocks. This laboratory technique may be used to simulate oil-water, and gas-water capillary pressures as well as height above free water levels in reservoirs. It could also serve as a lead to estimating contact points of equilibrating fluids. In addition, it may also be used to estimate fluid/rock compartment boundaries when compared to the residing fluid characteristics. The reliability of this technique is dependent on the availability of subsurface cores/data.

A compartment may be suspected when geology, pressure and fluid characteristics or any combination of these scenarios on vertically stacked reservoirs or adjacent sides of a sealing configuration differ significantly. However, when examining hydrocarbon or fluid characteristics from different wells, care must be taken in arriving at this conclusion (compartmentalization). [10] have provided some insights and case studies on how fluid data can be used to understand this complex phenomenon while [5] demonstrated how reservoir modelling and sequence stratigraphy can be integrated to determine compartment levels. However, most authors see this phenomenon as a significant exploration risk. The most reliable approach to understanding its occurrence must be integrated, with inputs from inter-related disciplines. This involves, but is not limited to studying the configuration of the reservoirs, facies distribution, pressure measurements, fluid characteristics as well as contacts, faults and their sealing tendencies ([1]; [10]). Hence, this work aims to deconstruct the possibility of compartments in the field by examining the petrophysical characteristics of the fault-bounded sands. A brief history of the field showed that it was discovered in 1986 and was first explored from a discovery well. It is isolated by an antithetic fault – the Kalloni boundary fault. Hydrocarbon production is supported by natural aquifers and water and gas injection wells.

Geologic Setting of the Niger Delta Basin

The Niger Delta basin is one of the several sedimentary basins in Nigeria. It is located in the terrestrial boundary of the Gulf of Guinea, West Africa (Figure 1). This represents the triple junction between the Benue Trough and the South Atlantic Ocean ([3]; [14]). It is bounded in the South by the Gulf of Guinea and Northward by the older (Cretaceous) Anambra basin, Abakaliki uplift as well as the Afikpo syncline ([2]). In the Eastern and Western regions, a Cameroon volcanic line and the Dahomey basin are seen to bind the Niger Delta respectively ([2]). It is considered to be a sedimentary fill of about 12,000 metres with sub-sea areas reaching up to about 75,000 km^2 ([11]). It is an arcuate-shaped river, wave and tide-dominated prograding deltaic system. It contains only one petroleum system, referred to as the Tertiary Niger Delta petroleum system. According to [13], the summarized vertical lithostratigraphic section through the delta shows a shallow upward trend in the facies sequence. The facies trend shows a continental Benin Formation (delta-top) overlying the paralic Agbada Formation and the marine Akata Formation. In the delta, hydrocarbon deposits are predominantly found in the Agbada Formation and the hydrocarbons are trapped in a series of configurations either as simple un-faulted dip closures or in a combination of fault-dependent traps ([9]).

Figure 1: Location of the Kalloni Field, Western Niger Delta ([8])

Materials and Methods

Materials

Data used for this research was acquired from one of the multinational oil companies operating in Nigeria through the permission of the Nigeria Upstream Petroleum Regulatory Commission (formerly called the Department of Petroleum Resources - DPR). The data provided include 3D seismic data, well logs (resistivity, gamma, neutron, density and sonic), tops and check shots only.

Methods

The Schlumberger Petrel® software application software was used for the data integration and result analysis. Faults were picked and interpreted from a seismic volume, which showed relatively good reflections. The faults were modelled from the interpreted fault sticks. The horizons were mapped on seismic by picking continuous lateral reflections and integrating them into the fault model to show the horizontal continuity and vertical variations in lithofacies. A synthetic seismogram was generated as well as a well-to-seismic tie. The seismic velocity model used in matching the two-way time to depth was the "V_o +K" model.

The lithostratigraphic correlation was carried out using a combination of the gamma, resistivity and density logs. The Schlumberger Petrel® software application allowed the characterization of the sand tops, fault models and reconstruction of the pre-faulted state of the field so that random intersection slices could be taken to understand the geology. The faults were used as pillars in carrying out the gridding of the sand tops. Output models were generated and the different stages of multi-phase fault deformation were conceptualized to understand the sealing configuration of the identified sand tops as well as their deformational history. Recall, that the multiple stages of fault deformation are the extension, shortening, inversion, stress release and re-activation stages in understanding. Any of these stages in deformation history can lead to fault-related compartmentalization. According to [10], fault compartmentalization can be created under two conditions, namely:

1. static fault sealing: This situation arises when a fault is capable of holding hydrocarbon columns over geological time. Static fault sealing in parts of the Niger Delta is widely attributed to fault juxtapositions as well as shale smears ([9]). This often leads to isolated reservoir compartments and flow baffles.
2. dynamic fault sealing: This condition arises when a fault configuration is likely to leak over geologic time. However, flow through the configuration does not prevent commercial production from the compartment. In this situation, the hydrocarbon characteristics are in communication with adjacent compartment(s). This communication is reflected in pressure profiles, fluid contacts, saturation, chemistry, viscosity, density etc. Similarly, when the resident hydrocarbon buoyancy becomes greater than the displacement pressure of the sealing configuration, the hydrocarbon will leak or equilibrate across any adjacent compartment(s). This cross-fault flow will largely depend on the capillary sealing and any reduction in the fault rock porosity and relative permeability.

The rock property evaluation was carried out to determine the quality of the sand and shale intervals. The rock characteristics estimated were the stratigraphic thickness, net-to-gross, volume of shale, total and effective porosities as well as permeability. These rock characteristics were determined from the well logs. The volume of shale was estimated from the shale cut-off of the gamma-ray logs while porosity was calculated from the sonic logs which represented the inverse of velocity through the formation. The high sonic readings implied slow or tight formations while the low sonic readings implied fast or porous formations. Recall that sonic log readings are largely affected by matrix materials as well as fluid content ([6]). These matrix materials were characterized by unique pore sizes that exhibit distinct capillary pressures and a comparison was made between porosity in shales and porosity in the sand. The shale gouge ratio (SGR) was determined as an estimate of the clay content around the fault plane and was used to infer the sealing tendency of the faults. Lastly, the sealing capacity of the C6000 and C13000 sands was inferred by estimating the column height of the resident hydrocarbon on depth contour maps.

Results and Discussion

The predominant deformational structures interpreted from the seismic volume were the faults. A total of twenty-three (23) faults were picked (Figure 2) and the analysis of the deformational pattern showed that they were mostly joints as well as normal faults with varying offset throws (footwall and hanging wall closures). These faults showed minor linkages, extending into a noisy seismic reflection. The results of cross-sections A-A^1 and B-B^1 across the pre-faulted 3D model showed the relationship between the deformational, depositional and post-depositional history (Figure 3). In addition, it reflected the tectonostratigraphic history and timing of deformation. Some of the deformational structures showed stratigraphic juxtapositions on adjacent sides of the faults and these may have created compartments when relating to the results of the fault-sealing tendency. The fault sealing tendency showed a shale gouge ratio (SGR) of 0.5 - 0.8 which implied that the shales largely contributed to sealing along the faults. The depositional structures recognized were the interbedded sand/shale sequences. The post-depositional structures were compaction, buckling and bending of the shales due to space constraints as well as the continuous deposition of sediments. These structures may also be attributed to compaction dis-equilibrium, inefficient de-watering as well as ductile failure of the shales.

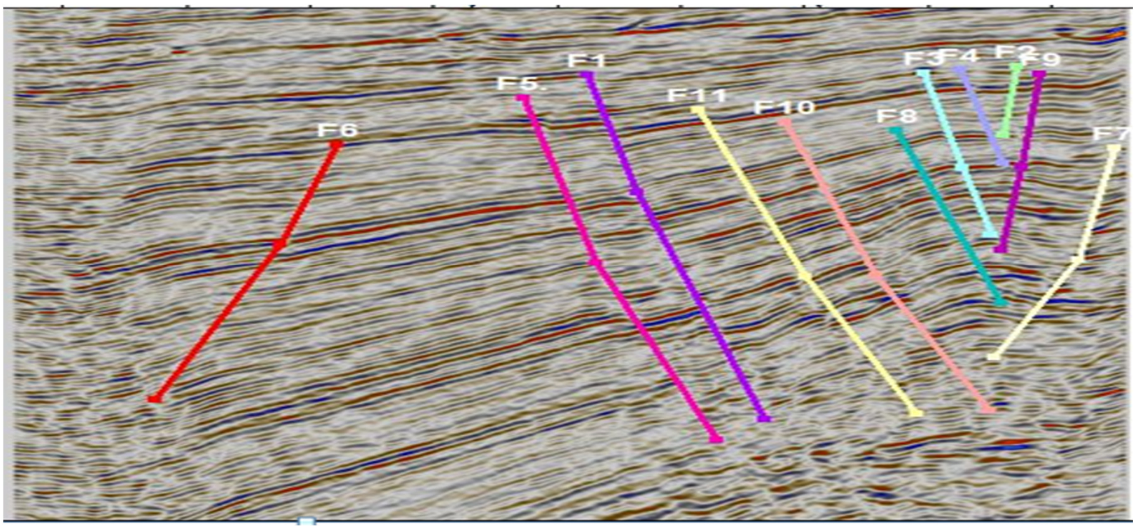

Figure 2: Seismic section, showing some of the interpreted faults ([7] and [8])

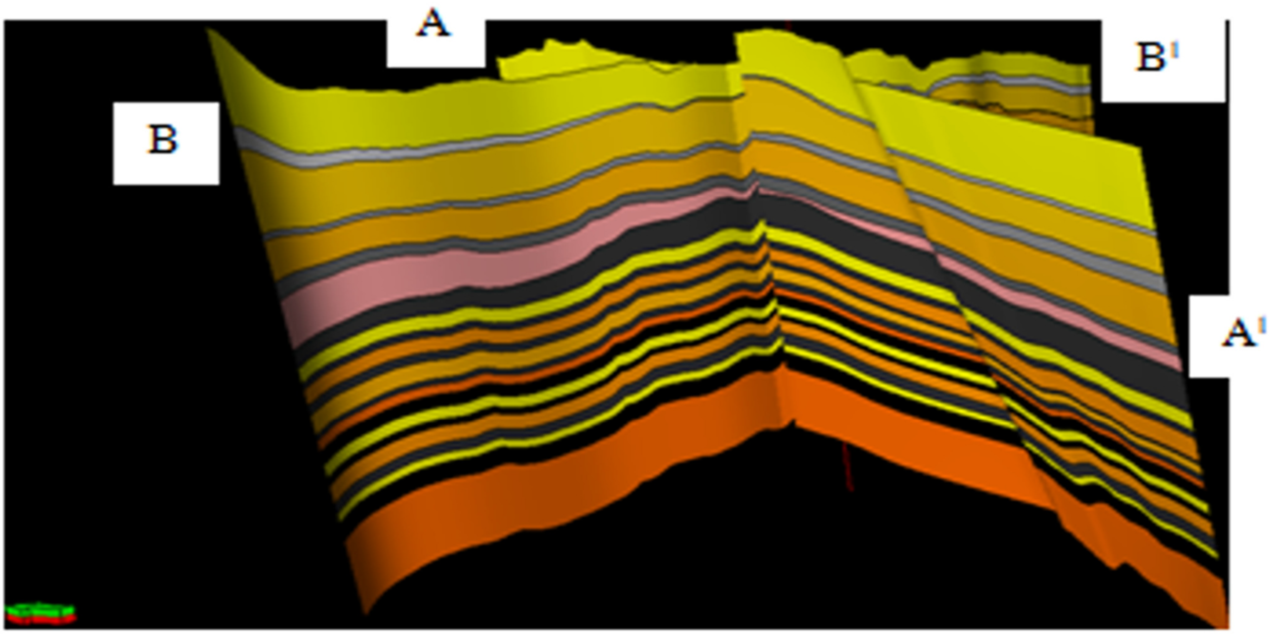

Figure 3: Cross sections A-A[1], B-B[1], field fault architecture as well as some of the stratigraphic juxtapositions ([7] and [8])

Two sand tops were recognized and they were labelled C6000 and C13000 respectively (Figure 4). Results of the petrophysical characteristics of the sand tops are shown in Table 1. The results did not show significant variations while the sediment depositional profiles showed two distinct anticlinal crests on adjacent sides of one of the faults (Figures 5 and 6). The sands were bounded by shale above and below; with a relative shale thickness of 150-300ft measured depth (MD). The sand thicknesses varied across the wells and were seen on all the logs lying at a relative

depth of 8,500ft - 10,000ft measured depth (MD). The C6000 sand was seen at a relative depth of 8,200ft – 8,400ft with an average thickness of 140ft. The C13000 sand was seen at a relative depth of 10,000ft MD with an average thickness of 600ft. The C13000 sand showed massive bedding with thin shale lenses in between.
Petrophysical analysis of the sand tops showed very good to excellent porosities and permeability when compared to the ranges described by Cannon (2018). The structural configuration of the sands showed that they were juxtaposed against shale as well as sand against sand (Figure 3). This may have contributed to the sealing because the shale sequence served as the caprock sequence, and was assumed to also constitute the fault rock materials. The shales showed relatively high gamma counts of about 70 – 150 API with corresponding low resistivity of 1.50 – 10.50 ohms on the resistivity logs. The shale density increased with depth due to compaction and covered a good spread as seen on the well logs. Bulk property plots of the field showed significant distribution of the shale with depth reflecting changes in cycles of deposition as well as energy regimes.

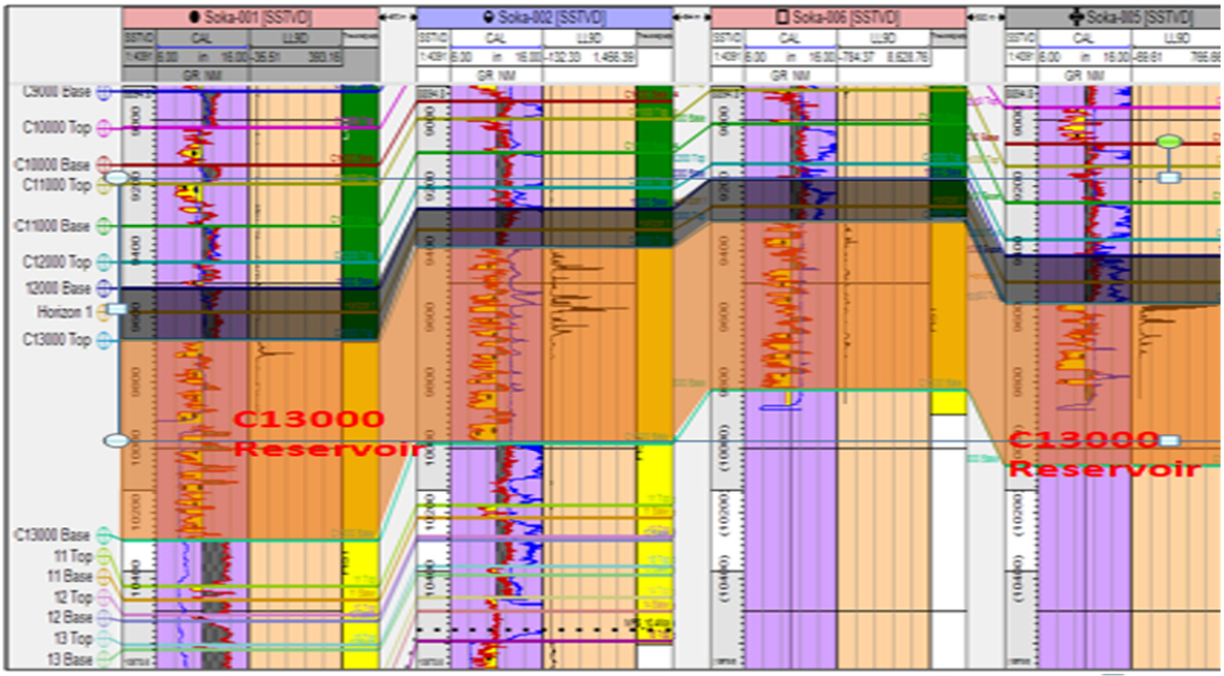

Figure 4: Well correlation of the sand tops and petrophysical evaluation ([7] and [8])

Table 1: Results of the Petrophysical Evaluation of the Sand Tops ([7] and [8])

Properties	**6C sand**	**13C sand**
Average thickness (ft MD)	141.5	587.5
Av. total porosity (µs/ft)	31.5	34.5
Av. permeability (mD)	2,927.76	3,606.11
Av. effective porosity (µs/ft)	0.185	0.225
Av. volume of clay (%)	40.61	34.965
Av. net-to-gross	0.59	0.65

Fault Rock and Property Evaluation
Faults are always targets for exploration and their exploration leads to uncertainty. This is not indifferent in the Kalloni Field as the subsurface uncertainty ranged from complex structural deformations to sealing configuration integrity. The sealing capacity of the reservoir configurations can only be as strong as their weakest points of low displacement pressures. A fine grain mixing threshold of 20% was considered, above which lithology mixing was implied along the faults. Pressure measurements were not available to determine the displacement pressures of the

shale sequence. The C6000 sand top on the depth contour map showed a hydrocarbon column height of about 266.6ft**.** Whereas, the C13000 sand showed hydrocarbon column heights of 469.54ft and 533.54ft on separate crests. The sand tops were extensive across the joints, and faults and were very well juxtaposed partially or completely. This condition in the C13000 sand suggested the possibility of a dynamic leak overproduction as well as geologic time.

An important parameter for sealing is caprock thickness, spread and consistency of fine-grain mixing along the fault-bounded reservoirs. Flow barriers result from significant changes in reservoir properties and the sealing surface. The results showed significant contrasts in reservoir and shale quality. The difference in recorded values can result in high displacement pressures and resistance to flow. This inference is relative as sealing can also be dynamic ([10]). Hence, there is a tendency to have different pressure and fluid characteristics across the recognized structures over geologic time (Figure 5 and Figure 6). Structural re-adjustments may also create instability in these structures over time and the hydrocarbons may seal or leak.

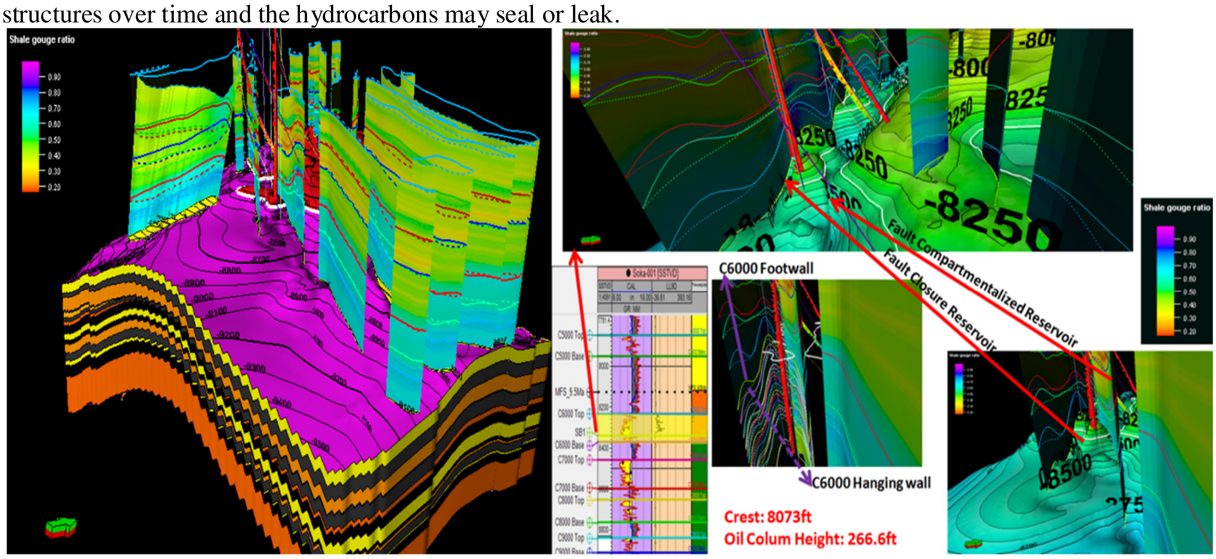

Figure 5: Depth contour map, SGR, column height and fault seal analysis of the C6000 sand ([7] and [8])

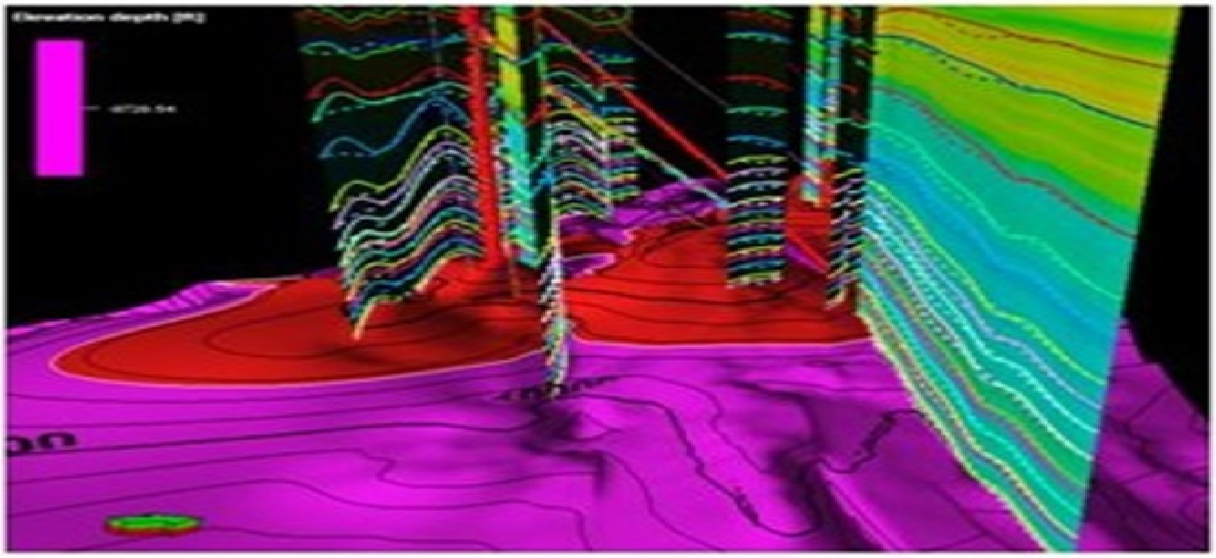

Figure 6: Depth contour map, SGR, column height and fault seal analysis of the C13000 sand ([7] and [8])

Summary and Conclusion

The field is structurally complex with two prominent sand tops. The results of the petro-physical characteristics of the C6000 and C13000 sands did not show significant variations. However, the C6000 sand showed a fault closure, single stratigraphic crest and hydrocarbon column height of about 266.6ft. It showed a moderate to high shale gouge ratio of 0.5-0.8 and an average V_{clay} of 40.61%. The C13000 sand showed two separate crests and hydrocarbon column heights of 469.54ft and 533.54ft on adjacent sides of one of the faults. Moderate to high shale gouge ratio of 0.5 - 0.8 was also seen on the deformational structures. This showed that the sealing capacity of the C13000 sand top may be dynamic and is not fault-dependent but more stratigraphic. However, the possibility of compartmentalization in this field remains an uncertainty that needs to be further unraveled bearing in mind the stacking pattern and complex nature of the fault distribution.

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