Quantitative Fault-Seal Prediction In ‘Ikeuka’ Field, Onshore Niger Delta Nigeria

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Abstract

Studies have indicated the preponderance of dry holes and abandonment of several wells arising from very complex reservoir geometries and other characteristics relating to compartmentalization as a result of the presence of faults in a field. The main objective of this study is the reduction of uncertainties associated with hydrocarbon exploration by a quantitative interpretation of the sealing properties of faults in ‘Ikeuka’ Field so as to enhance hydrocarbon recovery. The study was conducted using well logs and 3D seismic data which respectively correlated reservoirs across the field in order to define the areal extent within which analyses were conducted and fault-dependent traps determined for the analysis of sealing integrity. Depth converted surfaces were subjected to structural closure interpretation which, among other things, involved fault analysis and the determination of Shale Gouge Ratio (SGR) using the Petrel software environment. Four horizons labelled C, D, F and G were mapped. Horizon C has two separate fault-dependent closures with an average SGR of 35 %. Fault surface at horizon F has moderate seal with an average SGR of 40 % despite reservoir on reservoir juxtaposition. At horizon G, the fault surface has poor seal with average SGR of 33 %. The thickness and lateral extent of the overlying shale units for each of the studied reservoirs showed characteristics of good top seals. In conclusion, the analysed fault surface in ‘Ikeuka’ Field shows a variation in sealing potential, this indicates that the seal could still impede fluid flow but may leak at some weak points. Fault seal analysis of ‘Ikeuka field’ has therefore, provided data that will guide in making informed decision on well planning and field development in order to maximize recovery and reduce risks associated with fault-related hydrocarbon exploration and exploitation in the Niger Delta.

Keywords: Areal, fault, geometry, hydrocarbon, horizon, seal, shale, reservoir

INTRODUCTION

The aim of hydrocarbon exploration is to locate economic quantities of hydrocarbon in the subsurface and to consider viable ways to develop them. The accumulations are usually found to be trapped within certain stratigraphic as well as structural or combined features. One of such structural features are fault-dependent traps and other stratigraphic and structural features comprise of salt or shale diapirs, sand lenses, stratigraphic pinch-outs, unconformities and anticlinal structures. Faults do not only control the presence of hydrocarbons in a trap, but they also control the volume of the hydrocarbons that have accumulated as well as their distributions among a series of stacked sands and within a single sand body amongst many fault compartments (Adagunodo et al., 2017).

For petroleum to accumulate within a fault trap, the faults constituting that trap must be sealing. Sealing mechanism can result from reservoir against non-reservoir juxtaposition whereby permeable rocks occur against non-permeable rocks across a fault surface. It can also form when the reservoir is juxtaposed against another reservoir, but in this case, the materials within the fault itself serve as barriers to hydrocarbon migration (Freeman et al., 1998).

It is common practice to depict faults as single straight lines of even thickness. Faults are in practice, not exactly simple surfaces or zones of the constant thickness (Babangida and Yelwa, 2015). Most faults are complex structures consisting of several structural elements (Haakon, 2016). The deformation along the fault surface is also not usually smooth but rather complex, hence, referred to as a fault zone. The fault zone consists of materials that emanate from the lithologies that have slid past the fault plane.
These materials are known as fault rocks and could either be non-sealing (permeable) or sealing and impermeable (Oyedele and Adeyemi, 2009; Bamidele and Ehinola, 2010; Quentin et al., 2018).

Sealing faults play a major role in traps of many hydrocarbon reservoirs; they can turn a relatively large and continuous hydrocarbon reservoir into compartments which become collections of smaller reservoirs. Each compartment may have its pressure and fluid characteristics, which, in turn, may affect efficient and effective field development and subsequent hydrocarbon recovery. When faults do not form seals, they can hinder the accumulation of hydrocarbons because they ultimately become migration pathways. Faults that occur within an established reservoir may also cause serious loss of circulation during drilling operations, as was the case with the Prudhoe Bay field in Alaska (Cerveny et al., 2005). The loss of drilling mud can be expensive and dangerous and can result in the abandonment of wells. Faults can also restrict hydrocarbons to only a few of the many potential reservoir intervals; they can also divert hydrocarbons away from a prospect (Dolson, 2016).

The sealing fault of a producing reservoir could be overcome by pressure changes in that reservoir, thereby resulting in leakage. Improper sealing of the fault plane might enhance hydrocarbon leakage, which will deplete hydrocarbon reserves and even result in dry holes. Leaking faults can, on the other hand, promote fault communication, which is beneficial for hydrocarbon production because a well drilled into one compartment can be used to also produce the other compartments, thereby reducing cost.

The Niger Delta is packed with syn-sedimentary faults and folds which are responsible for the hydrocarbon traps in the area. These structures include growth faults and their associated anticlines (Corredor et al., 2005). The main objective of this study, therefore, is to evaluate the sealing integrity of faults in the study area to reduce uncertainties associated with hydrocarbon exploration by a quantitative interpretation of the sealing properties of faults in ‘Ikeuka’ Field.

**GEOLOGIC SETTING**

The study area is located in the Coastal Swamp Depo belt of the Niger Delta Basin (Fig.1). The Niger Delta sedimentary basin is a Tertiary basin situated in the Gulf of Guinea on the west coast of Africa. The Niger Delta lies between Latitudes 3° and 6° N and Longitudes 5° and 8° E, with a subaerial extent of about 75,000 km². It covers a total area of 300,000 km² and sediment fill of about 500,000 km³. The Niger Delta is bounded to the north and northeast by the Benin Flank and the Abakaliki Anticlinorium, respectively. To the east, it is bounded by the Calabar Flank and the south by the Cameroon Volcanic Line and the Dahomey Basin (Fig.2). The northern part constitutes the On-shore portion, while the southern part constitutes the Off-shore portion (Tuttle et al., 1999).

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**Fig. 1.** Map of the Niger Delta Showing the Location of the study area (Adapted from Ukpong et al., 2018)

**Fig. 2.** Location of Niger Delta in the Gulf of Guinea showing its boundaries with other surrounding Basins (Adapted from Tuttle et al., 1999)
The formation of the Niger Delta basin is connected to the opening of South Atlantic that occurred between Late Jurassic and Mid Cretaceous resulting in a failed rift junction known as the Benue Trough. In Santonian, after the filling of the Southern Benue Trough with sediments, the area experienced a thermo tectonic event that involved the folding, faulting and uplift of all the pre-Santonian deposits resulting in the formation of the deformed Abakaliki Anticlinorium that trends NE-SW and the creation to its west and east, the Anambra Basin and the Afikpo Syncline, respectively. These basins received Campanian to Tertiary sediments. Deposition in the Niger Delta started in the Eocene when River Niger became the main transportation medium instead of the Cross River. Niger Delta is composed of three diachronous siliciclastic units (Reijers, 2011). At the base of the Delta is the Akata Formation, which is of marine origin. It is overlain by the paralic Agbada Formation which is Eocene to Recent in age. The Agbada Formation is overlain by the continental Benin Formation; Eocene to Recent in age and made up of Alluvial sands (Fig. 3).

Only one identified petroleum system exists within the Niger Delta petroleum Province. This system is known as the Tertiary Akata–Agbada (!) Petroleum System, which has a maximum geographic extent of about 300,000 km² and stratigraphic extent of about 12,000 m (Tuttle et al., 1999). Petroleum source bed evaluation of the Niger Delta Basin conducted by Ekweozor and Okoye (1980) identified the shales of Akata Formation as the major source rock that generates hydrocarbon within the basin. Petroleum is produced from the sandstones of the Agbada Formation making it the major reservoir unit in the basin (Tuttle et al., 1999). The diverse trapping mechanisms in the Niger Delta include structures with multiple growth faults, antithetic faults, simple rollover structures; clay-filled channels and collapsed crest structures (Doust and Omatsola, 1990; Chukwu, 1991). Intraformational shales in Agbada Formation act as good top seal as well as clay smears along fault planes (Tuttle et al., 1999).

The workflow in Fig. 4 outlines the major steps that were embarked on to quantitatively analyse the fault seal integrity of ‘Ikeuka’ Field.
Data Loading and QC
The data used for this work include well log data (gamma-ray, resistivity, sonic, neutron and density) from 10 wells (Ikeuka 1 to Ikeuka 10). 3D seismic and biostratigraphic results. The well data also included directional information and checked shot data. The seismic data used for the study is 3-D Pre-stack Time Migration Data. While the results from biostratigraphy provided key stratigraphic surfaces. Data were analysed using the Schlumberger Petrel Software.

Lithology Identification
Gamma-ray (GR) log scaled from 0 to 150 API was used to discriminate between shale and non-shale units. High GR, which indicated high radioactive content was interpreted as shale while low GR readings indicative of low radioactive content were identified as non shaly lithology. Bearing in mind that the study area is in a siliciclastic environment, the non shaly units were interpreted to be sandstone (Fig. 5).

Reservoir Identification and Fluid Typing
Resistivity logs were used to determine the presence of hydrocarbon within the interpreted sandstone units. High resistivity readings were indicative of hydrocarbon bearing sands (reservoir), while those containing saline water showed very low resistivity readings (Fig. 6).

In the hydrocarbon column, an overlay neutron logs were used to between gas and oil, and to hydrocarbon water contacts (Fig. neutron and a corresponding low was interpreted as gas. When track along close to each other resistivity reservoir, it was oil.
Fig. 6: Hydrocarbon identification and fluid typing. Separation of neutron and density logs within the hydrocarbon reservoir indicates presence of gas.

**Stratigraphic Correlation**

Stratigraphic correlation for the study was conducted along an open ended correlation transect line as shown in Fig. 7. This was used to ensure that wells in close proximity and rocks that are stratigraphically related were considered first during correlation.

![Stratigraphic Correlation](image)

Biostratigraphic results from well 3 provided the depths of the key stratigraphic surfaces which were integrated in the stratigraphic correlation to constrain the strata within chronostratigraphic units. Facies analysis and stacking patterns were subsequently used to insert the intervening systems tracts (Fig. 8).

![Major Stratigraphic Surfaces and the Systems Tracts](image)

**Volume of Shale (Vshale) Calculation**

Shale volume was calculated using gamma-ray logs to determine the gamma-ray index based on the equation below:

\[
GR_{index} = \frac{GR - GR_{min}}{GR_{shale} - GR_{min}} \tag{Eqn. 1}
\]

The GR index was then incorporated in the Larionov equation for Tertiary rocks (Larionov, 1969):

\[
V_{sh} = 0.083 \times (2^{(3.7 \times GR_{index})} - 1) \tag{Eqn. 2}
\]

Where GR is the gamma-ray (GR) log reading in the zone of interest; 
GR<sub>matrix</sub> is the GR log reading in 100% matrix rock; 
GR<sub>shale</sub> is the GR log reading in 100% shale; 
GR<sub>index</sub> is the gamma-ray index; 
V<sub>sh</sub> is the volume of shale.

**Fault Interpretation**

This involved picking faults on the seismic data to unravel the structural framework of the study area. On the seismic data, faults were seen as discontinuities in the seismic reflections (Fig. 9) Seismic attributes helped to reveal changes in dip magnitude, dip...
azimuth and reflective amplitude. The seismic interpretation was carried out using a 3-D seismic volume and extracted semblance volume. The extracted semblance volume was dip guided to capture the actual orientation of the faults. This was cut at several time slices to ascertain the range and time penetrations of the faults in milliseconds to capture the original geology in the fault interpretation stage. The lateral extents of the faults were also ascertained using the semblance map. Semblance is a discontinuity attribute that was implemented on the seismic volumes to detect edges in the data and accentuate faults.

Fig. 9: Showing discontinuities in seismic reflections as indications of faults

**Horizon Mapping**
Reservoir tops that were identified from the wells with the use of well logs were then positioned on a seismic section. The top corresponded with the peak of the seismic trace, which marks the seismic event to be traced throughout the seismic volume. The tracing was achieved by using various interactive tools such as auto-pick and manual pick on the interpretation window of the Petrel software. Horizons were picked line by line at specified increments both on inlines and cross lines. As the horizons were being picked, a grid was also being generated and displayed on the 2-D window; this helped to monitor the progress of the interpretation. After picking the horizon, a time structure contour map was then generated.

**Fault Seal Analysis**
This fault analysis was focused on the relationship between stratigraphic juxtaposition and fault rock properties to form seal across the identified fault surface. Juxtaposition diagrams were plotted to determine the stratigraphic relationship across the fault surface. The displacement of major and minor fault segments within the reservoir juxtaposed the reservoir across the fault surface against dissimilar lithologies, which could impact the fluid flow. Integrating identified lithologies with mapped horizons and faults, the stratigraphic distribution across the fault was determined using the Allan Diagram (Allan, 1989; Fig. 10). The technique involved selecting a fault surface and mapping the positions of both footwall and hanging-wall on it. The Trap and spill points were then determined from the juxtaposition of the lithologic units.

Fig.10: Allan diagram technique showing stratigraphic juxtaposition across the fault surface (Crevery et al., 2005)

The property of the fault rock was determined using Shale Gouge Ratio (SGR) algorithm (Eqn. 3) to calculate the fault zone shale content and to quantitatively evaluate fault rocks seal. SGR is a function of the volume of shale, thickness of each lithologic unit as well as the throw (Fig.11)

\[ SGR = \frac{\Sigma(V_{sh} \cdot \Delta z)}{\text{Throw}} \times 100\% \quad \text{Eqn. 3} \]

Where \( V_{sh} \) = Volume of Shale
\( \Delta z \) = Change in thickness of the lithologic units
Values between 15 and 20 % represented a threshold value between non-sealing and sealing faults (Yielding and Freeman, 2010). SGR < 20 % (or a ratio of < 0.2) are typically associated with cataclastic fault gouge and sealing of the fault is considered as unlikely. Higher values of Shale Gouge Ratio correlate with greater fault seal potential. SGR 0.2-0.4 (20 %–40 %) is associated with phyllosilicate framework and some clay smear fault rocks. Here fault is taken as poor seal and will be retarding to fluid flow. For SGR 0.4-0.6 (40 %–60 %) fault is considered to be moderate seal. It will be associated mainly with clay smears. For SGR > 0.6 (60 %) is taken as a likely sealed fault.

RESULT AND DISCUSSION
Well Correlation and Reservoir Description
Seven (7) reservoirs were identified and correlated from the wells in the field, however, only three reservoirs (C, D and F) were studied and discussed.
Generally, the stratigraphic units were observed to be quite extensive with some disparity in thickness which could be a result of interactions between the available accommodation space created by the faults and the rate of sediment supply. The depositional sequence depicting the reservoir distributions are shown in Fig. 12.

Reservoir C occurs within the High Stand Systems Tract. It is laterally extensive as it is observed to extend throughout the wells but with some variation in thickness. The lateral extension of the unit is limited to the correlation panel; this may not be the case outside the correlated section. The effect of faulting was observed between wells 6, 9 and 8 (Fig. 13). The shallowest portion of reservoir C is seen to occur between 2165 and 2205 m in Ikeuka well 9 while the deepest portion is between 2215 and 2255 m in Ikeuka well 7. Reservoir C therefore has an average thickness of about 40 m (Table 1). Thickness of the reservoir increases from the east towards the north while the thickness of the overlying shale increases from west towards the north (Fig. 14). This suggests that the impact and magnitude of the faults were more in the north-west direction to have created more accommodation space which has led to more strata thicknesses in the north-west part of the reservoir.

Table 1: Reservoir Thickness in Each Well
The thickness of the overlying shale on the other hand which can serve as the top seal is relatively good enough to impede any up-dip migration in reservoir C, but around well 9 the shale is about 20 m thick, which was not as thick as other portions. Reservoir D, another reservoir of interest was found to be laterally discontinuous unlike the younger counterpart. Reservoir D is observed to be present in wells 6 and 9 but absent in wells 7 and 8, most likely an indication of pinch-out stratal termination (Fig. 15). The absence of reservoir D in wells 7 and 8 explains why hydrocarbon production should not be expected in those wells at that point. Reservoir D occurs within the High Stand Systems Tract. The top of reservoir D in well 9 is at 2220 m while the base is at 2265 m but in well 6, the top is at 2235 m while the base is at 2290 m indicating a deeper occurrence in well 6. Average thickness of reservoir D is about 50 m (Table 1) and it is observed to increase towards the East; the same is seen happening with the overlying shale (Fig. 16). This is indicative of a better top seal towards the eastern part of the field.
Fig. 15: Correlation of reservoir D across the wells showing an indication of stratigraphic pinch-out.

Fig. 16: Isochore showing reservoir D and overlying shale increasing in the same direction indicating a good top seal. Reservoir F is seen to occur within the Low stand - Transgressive Systems Tracts. Reservoir F is laterally extensive as it is seen to be present in all the wells within the correlation panel (Fig. 17). The deepest occurrence is observed in well 7 between depths 2475 and 2600 m while the shallowest occurrence is observed in well 6 between depths 2455 and 2550 m. The thickness of reservoir F ranges from 95 m to about 125 m, increasing from north to south of the field. The same applies to the overlying shale (Fig. 18). The reservoir unit is quite thick across the wells and may suggest the reason why the vertical relief of the reservoir may be large in the map scale. Also the strata thickness is more in the hanging wall compared to the foot wall (Fig. 17).

The variation in thickness suggests different mini depo-centers; meaning that the accommodation space changed from a point to another, therefore, thickness is not concentrated at one point though a general trend of the stratal thickening could be ascertained as indicated in the southern direction. The overlying shale represents a good lateral top seal due to its relatively consistent thickness.
Fault Mapping

The interpreted faults which were incorporated in a 3D structural static model revealed four (4) major segments (Fig. 19). Each fault segment is expected to have its own distinct properties and characteristics. From the semblance time slice, Ikeuka field shows a complex faulting system of several major faults which are trending in the NE-SW direction. Some of the faults tend to die out with increasing depth (Fig. 20). The north-south trend of the faults suggests that more accommodation space and strata infill are expected to be seen southwards compared with any other side of the reservoir.
HORIZON MAPPING

A typical seismic interpretation carried out in the field is shown on a seismic section (Fig. 21). It is observed that growth faults (syndepositional faults) associated with synthetic and antithetic faults are predominant in the field. This makes it imperative that care must be taken in reservoir interpretation as virtually all the reservoirs are affected by faults.

A high profile quality check / control was conducted within the seismic sections in the 3D volume and as such all the interpreted horizons and surfaces were quality checked with the volume at different time values penetrated before depth converting the interpreted outcomes. Typical of QC is demonstrated with different styles of 3D cropped volume as shown in Fig. 22.

Fig. 20: Semblance map at time slice 2380 milliseconds and 3000 milliseconds showing complex faulting within the field

Fig. 21: Inline 5890 showing interpreted horizons and faults depicting that the field is dominated by growth faults, synthetic and antithetic faults. All the horizons are affected by the faults.

Fig. 22: Mapped horizons C, D, F & G displayed within the 3-D volume showing similar faulted anticlinal structure.
Four horizons (C, D, F and G) were also mapped within the study area (Fig. 23 to 26) and observed to have similar faulted anticlinal structure (Fig. 22) with structural closures occurring in the north and north-eastern parts of the mapped horizons (Fig. 23 to 26).

The depth converted surfaces were then subjected to the interpretation of structural closures which included vertical relief, spill points, structural model and fault analyses.

Fig. 23: Surface map of horizon C showing the fault dependent closures

Fig. 24: Surface map of Horizon D showing the fault dependent closure
Fig. 25: Surface map of Horizon F showing a fault dependent closure and an identified prospect.

Fig. 26: Surface map of horizon G showing the fault dependent closure

FAULT SEAL ANALYSIS

Fault seal analysis becomes expedient due to the type and nature of the reservoirs encountered in the field. All the interpreted reservoirs are fault dependent. The impressions, significance and controls of these faults to the reservoirs have been ascertained in order to have a better understanding of the reservoirs and as well give clues to better predictions of reservoir fluid accumulations and trapping.

However, it is likely that the displacement along the fault surface must have generated an impression which may be any of the mixed clastic events. These may be the stratigraphic juxtaposition, cataclastics, sediment occlusion, pressure interplay/hydraulic seal, smearing of the shale/clay component, immobile fluid seal or any other possible event.

The integration of these geomechanisms were incorporated within a seal parameter known as shale gouge ratio (SGR) in the sense that this algorithm is independent of the interpreter and as well measures the entrapment of the shales that might have slipped past a point within the fault gouge. This algorithm can be attributed to any of the prevailed geology depending on the outcome of the interpreted seismic, well logs, property models and any associated available data.

The fault dependent closures observed in Fig. 23 to Fig. 26 are analysed to determine their sealing capacity at each horizon level (Fig. 27). The hanging wall / footwall juxtapositions are displayed on the fault surfaces with an overlay of the shale gouge ratio (SGR) indicator (Fig. 28).
At horizon C, two (2) separate accumulations are observed (Fig. 29) one at the eastern part and the second at the central part of the field. At horizon F, a prospect is identified along with the already discovered accumulation at the crest of the faulted anticline (Fig. 30). Horizon G also shows accumulation at the faulted crest (Fig. 31). The SGR determined from V-shale were modelled to fit the 3-D volume so as to get V-shale information in areas where there are no well controls. Sealing occurs along the fault surface when a fault cuts through different lithologies juxtaposing permeable rocks against impermeable rocks. Sealing may also form due to low permeability of the rock within the fault zone.
According to Yielding et al., 1997, fault seal can be classified based on SGR values thus: < 20 % is an unlikely seal usually associated with cataclastic fault gouge. 20 % to 40 % is considered as a poor seal which could still impede fluid flow across the fault. It is usually associated with phyllosilicate material and some clay smear fault rocks. 40 % to 60 % is considered to be moderate seal. It will be associated mainly with clay smears. Higher SGR, leads to better sealing potential. SGR > 60 % results in a good seal.

At horizon F, the juxtaposition of the hanging wall and footwall has a SGR of about 40 % along the fault surface (Fig. 32) indicating the likelihood of greater form of grain crushing that produced more of fine-grained gouge material. This implies that the fault has a moderate seal despite the reservoir on reservoir juxtaposition observed on the fault surface and it is able to hold hydrocarbon with a column height of about 15m given that the crest is at 2493 m and oil-water contact is at 2620 m.
Fig. 32: Hanging wall and foot wall juxtaposition of reservoir F across the fault surface with average SGR of 40%.

At reservoir G along the same fault surface, the hanging wall and foot wall juxtaposition shows an average SGR of 33% (Fig. 33) which is classified as a poor seal that could still retard fluid flow across the fault, but some hydrocarbon columns with weak points in few places may have minor leakage.

Fig. 33: Hanging wall and foot wall juxtaposition of reservoir G across the fault surface showing average SGR value of 33%.

Still, on the same fault surface, reservoir C shows an average SGR of 35% (Fig. 34), which also falls within the range of poor seals. Poor seals can result to leakage if the pressure differential is altered.

Fig. 34: Hanging wall and footwall juxtaposition of reservoir C across the fault surface with average SGR value of 35%.
CONCLUSION

From structural interpretations, it is observed that a complex fault system exists within the study area giving rise to structural closures with hydrocarbon accumulation on the up-dip parts of the faults. Several reservoirs are present in the field, however three (3) were the focus of this study. Despite the good quality of reservoirs as observed from the stratigraphic sequences, failure to incorporate seal analysis (both fault seal and top seal) may render such interpretation inadequate and as such pose high level of uncertainty and the very low geologic chance of success in hydrocarbon exploration. With the presence of fault dependent traps identified within the Ikeuka field, it becomes imperative that seal analysis be conducted to find out if the faults are leaking or not because faults could pose a great challenge in hydrocarbon exploration and exploitation. The thicknesses and lateral extent of the overlying shale units for each of the studied reservoir show characteristics of good top seals. As a result of variation in displacement between hanging wall and foot wall as well as lithology juxtaposition, the sealing potential across a single fault surface can range from good seal to poor seal as was observed in the study area. Shale gouge ratio was determined from the volume of shale in the wells and modelled to fit the 3-D volume to get SGR for areas without well control. Two separate hydrocarbon accumulations were observed at horizon C having similar hydrocarbon contacts but with different hydrocarbon column heights. The fault surface has an average SGR of 35 %. At horizon F, the fault surface has a moderate seal with an average SGR of 40% despite the reservoir on reservoir juxtaposition. At horizon G, the fault surface has a poor seal with average SGR of 33%, which could still impede fluid flow but may leak at some weak points.

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