Original Research

Volume 06, Issue 01, pp 54-66, April, 2024

ACHIEVERS JOURNAL OF SCIENTIFIC RESEARCH

Opecn Access Publications of Achievers University, Owo

Available Online at www.achieversjournalofscience.org

APPLICATION OF MOVE FAULT ANALYSIS MODEL FOR PREDICTING FAULT SEALS IN 'SWAN' FIELD NIGER DELTA, NIGERIA

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Submitted: February, 2, 2024, Revised: March 22, 2024, Accepted: March 29, 2024, Published:April 8, 2024

Abstract

Fault seal analysis is utilized to evaluate the degree of interconnection within a specific reservoir due to fault segments, which is crucial for reservoir management and productivity assessments in the Niger Delta region. This study aims to assess fault seal integrity in the 'SWAN' field in the Niger Delta to improve hydrocarbon recovery. Well logs and 3D seismic data were employed for this study. Various factors influencing fault seal, such as fault throw, lithology of the hanging wall and footwall, and shale gouge ratio, were analyzed using MOVE software. These analyses helped determine the potential of faults to impede hydrocarbon flow into and out of the mapped reservoirs. Three horizons were identified (labeled H1, H2, and H3), with only two faults (Faults 5 and 13) intersecting all three horizons. In the SWAN 5 well, the throw of the reservoir bed along the fault plane is 763.5m, resulting in a robust seal with an average shale gouge ratio (SGR) of 44%. In SWAN 7, SWAN 10, and SWAN 11 wells, the throw of the reservoir beds ranges from 731.2m to 816.9m, with SGR values indicating moderate sealing conditions (ranging from 35% to 36%). The lithological arrangements observed include shale on sand, sand on sand, and shale on silt. The findings suggest a significant proportion of the fault plane is effectively sealed, potentially impeding fluid flow through fault gouges. This comprehensive analysis provides valuable insights for reservoir management and strategies to enhance hydrocarbon recovery in the Niger Delta's SWAN field.

Keywords: Hydrocarbon; Lithology Juxtaposition; Shale Gouge Ratio; Throw

1.0 Introduction

A precise comprehension of subsurface faults is essential for various aspects of the hydrocarbon exploration and production sector. According to the definition provided by Cerveny *et al*. (2004), a fault can be characterized as a planar discontinuity or a fractured plane within a rock mass, exhibiting visible displacement or slip. The resulting structure could either facilitate fluid transmission or obstruct the ongoing movement of fluid (hydrocarbon). A fault becomes sealed when the sealing capacity of the fault rock or the juxtaposed lithofacies is not surpassed. After surpassing the capillary seal, the flow rate through the fault is governed by the effective permeability of the fault rock or the juxtaposed lithofacies (Russel et al 2017). The sealing mechanism may occur due to the juxtaposition of reservoir and non-reservoir formations, where permeable rocks are positioned adjacent to 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). The determining factors are the permeability and porosity characteristics of rocks within the fault zone.

For numerous decades, fault seal analysis has been a significant focus of research within the oil and gas sector. Established methods like the shale gouge ratio which predicts the sealing capacity of faults and traps in closure (Yielding, 1997) and Allan diagrams used for the determination of juxtaposed reservoirs (Allan, 1989) play a crucial role in assessing fault seal quality, often serving as the sole means of estimation. Calibration has demonstrated that faults with SGR values > 20% have a higher chance of seal (Childs *et al*., 1997; Yielding *et al*., 1997). Iheaturu *et al* (2022) assessed the sealing of the fault bounded stratigraphy of the Gabo Field, Niger Delta, Nigeria using the X-ray diffraction analysis and shale gouge ratio. The result of the research reduced the fault seal uncertainty in the planning of oilfield development projects and enhanced pressure support for the recovery of bypassed hydrocarbons, most especially in compartmentalized reservoirs. Onyekuru *et al* predicted fault seal quantitatively through shale gouge ratio and Allan diagram. The research concluded that the analyzed fault surface in 'Ikeuka' Field shows a variation in sealing potential, which indicated that the seal could still impede fluid flow but may leak at some weak points. Nonetheless, there persists a considerable level of uncertainty associated with these techniques (Yielding et al., 2003).

This study aims to determine the fault seal integrity in the "Swan" field, Niger Delta (Figure. 1) by delineating hydrocarbon bearing reservoirs, mapping of faults and horizons, characterizing faults in terms of their orientation and throw and predicting fault seal behavior of the study area from MOVE model. The MOVE model allows for the rapid analysis of faults seal integrity by factors that control faults, such as fault throw, lithological juxtaposition, and shale gouge ratio. However, in many cases, only one of such factors is considered and this cannot accurately predict fault seal which is influenced by multiple factors in a complex way.

2.0 Methodology

The analysis and interpretation of the data analyzed from the 'SWAN' field Niger Delta involves the use of computer software such as petrel ™ 2017 and Move 2018.

2.1 Geologic Setting of Niger Delta

The Niger Delta represents one of Nigeria's seven sedimentary basins, characterized as a deltaic system primarily influenced by fluvial, wave, and tidal forces (Elliot, 1986; Miall, 1999). The Niger Delta resides within the Gulf of Guinea, on the West Africa Margin and spreads all through the Niger Delta province as defined by Klett et al., (1997) between longitude 5°E to 8°E and 4°N to 6°N. It spans across a combined area of 300,000 square kilometers and sediment fill of about 500,000 km^3 (Hospers, 1965). The Niger Delta is bounded to the north and northeast by the Benin Flank and the Abakaliki Anticlinorium, respectively. On its eastern side, it is delineated by the Calabar Flank, while to the south, it is bordered by the Cameroon Volcanic Line and the Dahomey Basin. (Figure. 1). The northern part constitutes the On-shore portion, while the southern part constitutes the Off-shore portion (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 (Whiteman, 1982). During the Santonian period, following the sedimentary deposition in the Southern Benue Trough, the region underwent a thermo-tectonic event characterized by folding, faulting, and uplift of all the pre-Santonian deposits resulting in the formation of the deformed Abakaliki anticlinorium extending in a northeast to southwest direction, with the formation of the

Anambra Basin to its west and the Afikpo Syncline to its east respectively.

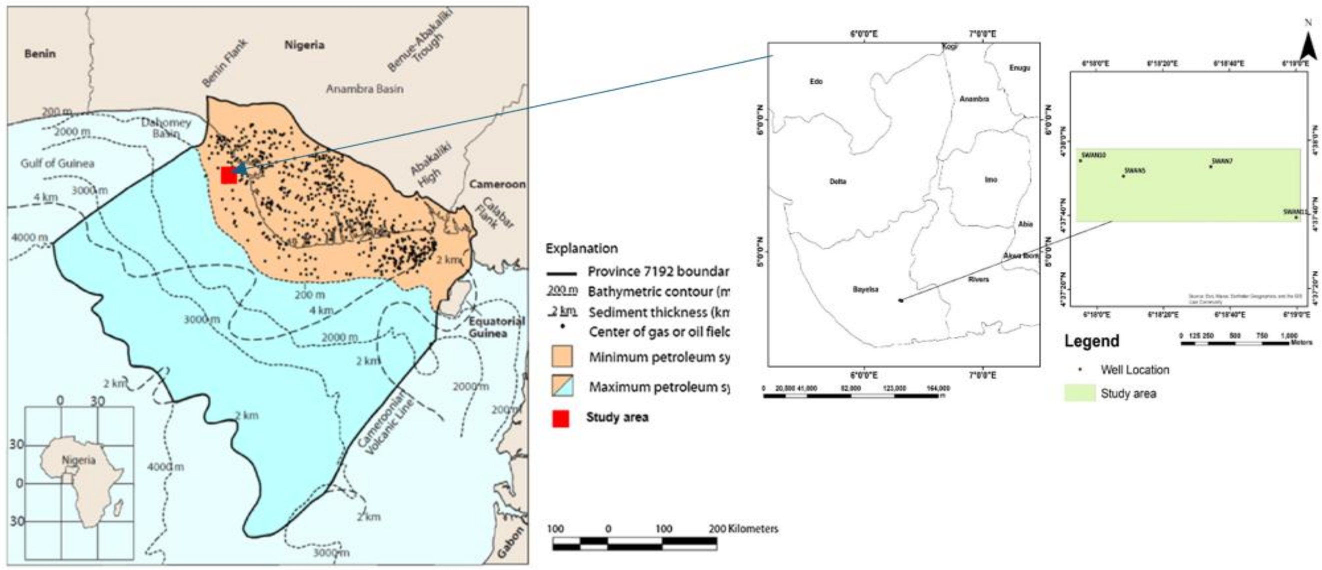


Figure 1: Location of Niger Delta in the Gulf of Guinea Showing its Boundaries with Other Surrounding Basins (Adapted from Tuttle *et al*., 1999)

These basins accumulated sediment from the Campanian to the Tertiary period. Deposition within the Niger Delta commenced during the Eocene era, coinciding with the shift of the primary transportation route from the Cross River to the River Niger. Niger Delta is composed of three diachronuous siliciclastic units (Reijers, 2011). At the delta's foundation is the Akata Formation, which originates from marine sources, is covered by the overlying Agbada Formation, ranging in age from Eocene to Recent times (Doust and Omatsola 1990). The Agbada Formation is followed by the continental Benin Formation, which spans from the Eocene to the Recent period and consists of alluvial sands. (Figure. 2).

Figure 3 presents the workflow of the study. The techniques used include log interpretation, seismic structural analysis, and fault seal analysis via MOVE model.

The log interpretation and seismic structural analysis were carried out on the petrel software.

Gamma ray log was used in delineating lithology (sand and shale unit). The gamma ray log is mostly presented in track 1 and the calibration was set to a scale of 0-150 API with a central cut-off of 73 API units such that values less than 73 denote sand while those higher than 73 API denote shale. Gamma ray and deep resistivity logs were employed to identify potential hydrocarbon-bearing reservoirs.

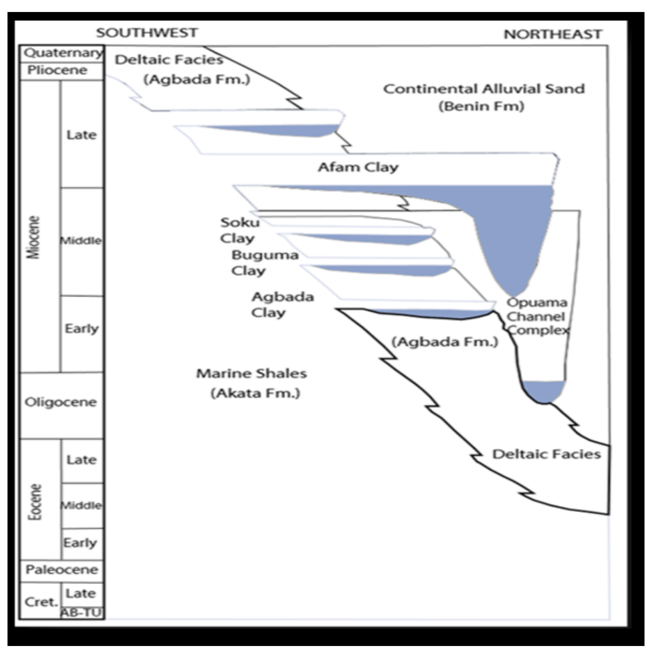


Figure 2: Niger Delta Lithostratigraphic Section Showing the Three Lithologic Units (Adapted from Doust and Omatsola, 1990).

Given that hydrocarbons act as electrical resistors, elevated resistivity values associated with low gamma ray readings were interpreted as likely hydrocarbon-bearing sand units. The well logs were also correlated in other to identify structural or stratigraphic units that share equivalence in terms of time, age, and stratigraphic position according to (Tearpocks and Bischke, 1991).

Well to seismic tie was carried out to integrate the well information with seismic date. The density log was multiplied with sonic velocity log to produce the acoustic impedance log which was then convolved with a wavelet extracted from 3D seismic volume to generate the synthetic seismogram. The identification of faults in this project relied on specific criteria, including discontinuities of events, discrepancies in tying reflections around loops, distortion, or absence of reflections beneath suspected fault lines, interruptions in events along faulted planes, displacement or distortion of reflections, and geologically significant changes in dip near the fault (Telford et al., 1990). The study was conducted in a previously explored region, utilizing borehole data to identify key stratigraphic horizons. The spatial distribution and lap-out patterns of seismic events were examined and picked throughout the study area. Reflectors indicating potential hydrocarbon-bearing reservoirs were established through log interpretation, selecting them based on the strength and continuity of the reflectors. This selection process was applied consistently from trace to trace, considering peaks, troughs, or zero crossings. In this project, the troughs were specifically used for horizon mapping. Time maps which illustrate the two-way reflection time for the identified horizons were generated by correlating the top of the sand mapped in the well log with the two-way reflection time. The time map was converted to a depth map through the application of a suitable velocity function. In the process of generating a depth map, the two-way travel time to specific horizons is initially converted into depth.

Using the fault Analysis module in Move, the sealing capacity of a fault can be rapidly analyzed through three fault controlling factors namely, fault throw, lithology juxtaposition and shale gouge ratio. The calculation of the several throws which represent vertical displacement on the faults of interest were calculated and averaged directly from the move software by inputting the mapped fault from petrel into the move software. The lithology juxtaposition was achieved through the seal proxy command after inputting the gamma ray log into the move software.

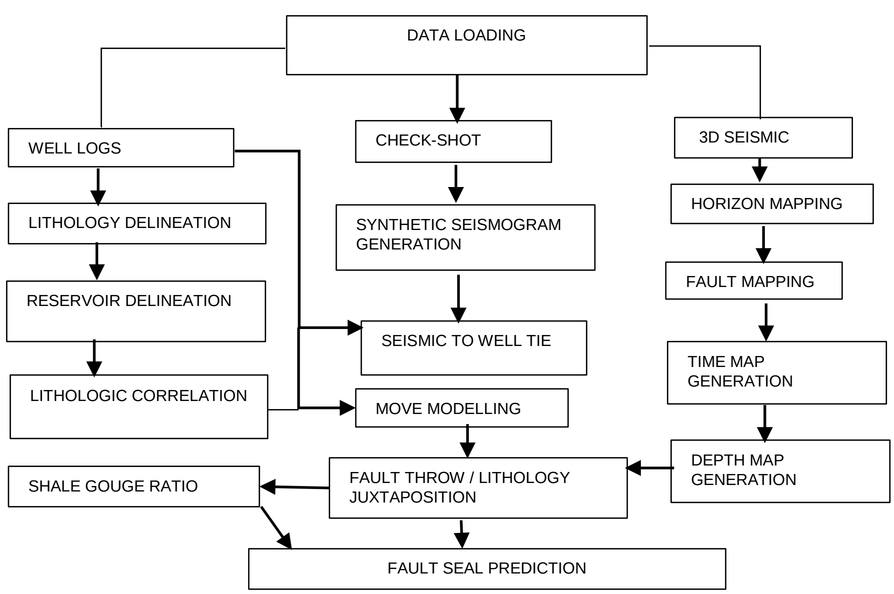


Figure 3: Workflow of the study

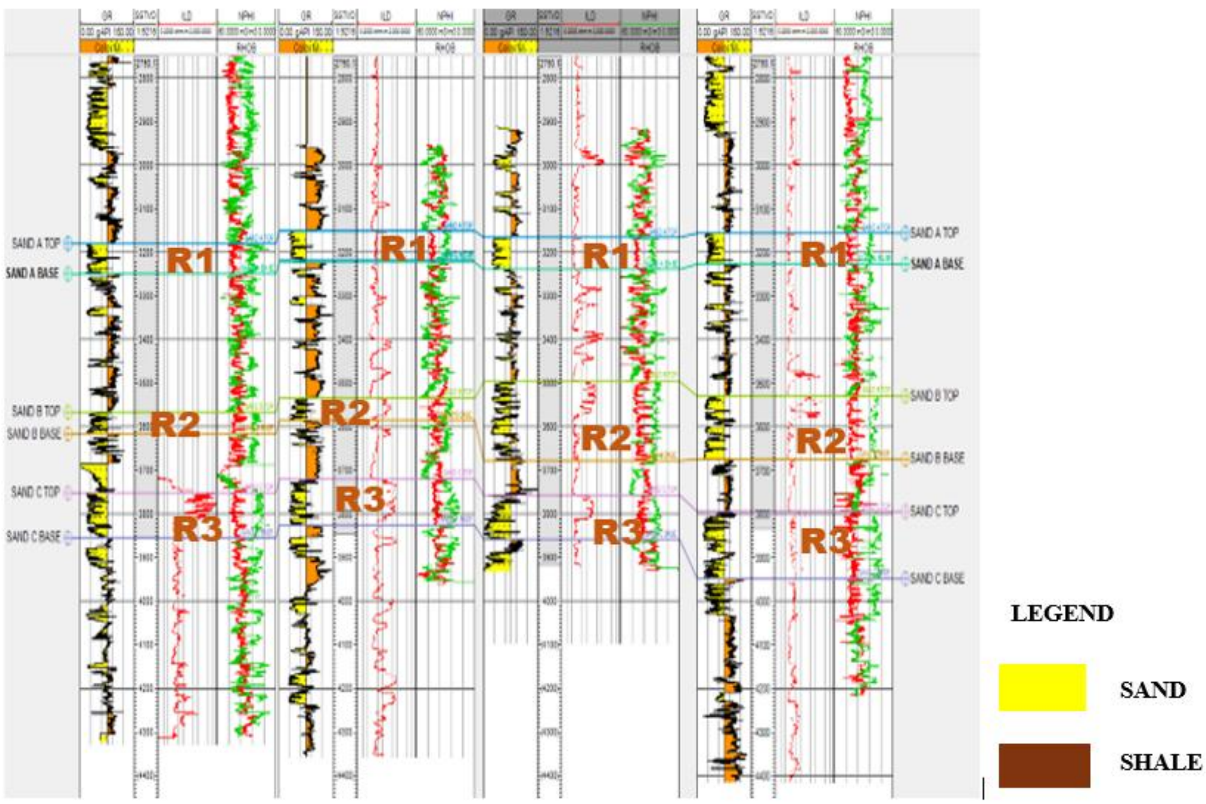
The calculation of SGR was performed considering the thickness of the bed and the average volume of shale present in both the hanging wall and the footwall of the fault. It's important to note that the volume of shale was directly determined from move software using gamma ray log.

3.0 RESULT AND DISCUSSION

The results obtained was discussed appropriately and presented as logs, maps, and sections.

3.1 Lithologic Identification and Well log Correlation

Figure 4 showed the lithologic interpretation and correlation of the studied wells. Alternation of sand and shale was observed from the well log information, most specifically from the gamma ray log. Gamma ray log response between 0 – 70 API indicated the presence of sand formation color coded as yellow, whereas Gamma ray log response between 70 – 150 API indicated the presence of shale formation color coded as brown. The correlation panel consist of four wells and three hydrocarbon bearing reservoirs (R1, R2and R3) located at average depths of 3200, 3600 and 3800 respectively which is observed across all the wells. The reservoirs were observed to occur at varying depth from one well to another and this is indicative of tectonic process.



R1, R2 and R3 are Reservoirs

Figure 4: Lithologic Correlation Panel of the Studied Wells

3.2 Fault and Horizon Mapping

The interpreted faults trends in different directions throughout the seismic section (Figure 5). The Swan field shows a complex faulting system of several major faults and few minor faults. Horizons 1, 2 and 3 were identified and mapped using well data tops and it is important that care be taken in reservoir interpretation as most of the reservoirs are affected by faults (figure 6).

Figure 6a showed the structural depth map of horizon 1. The contour interval is 50 ft, and the contour range were from 2800 to 3750 ft. Fifteen faults were evident on the structure and a structural high was observed at the Northeastern part. Figure 6b showed the structural depth map of horizon 2. The contour interval is 50 ft and the contour ranged from 3150 to 4250 ft. A structural high was observed at the North-Eastern part. The anticlinal structure which is the possible hydrocarbon trap is fault assisted..

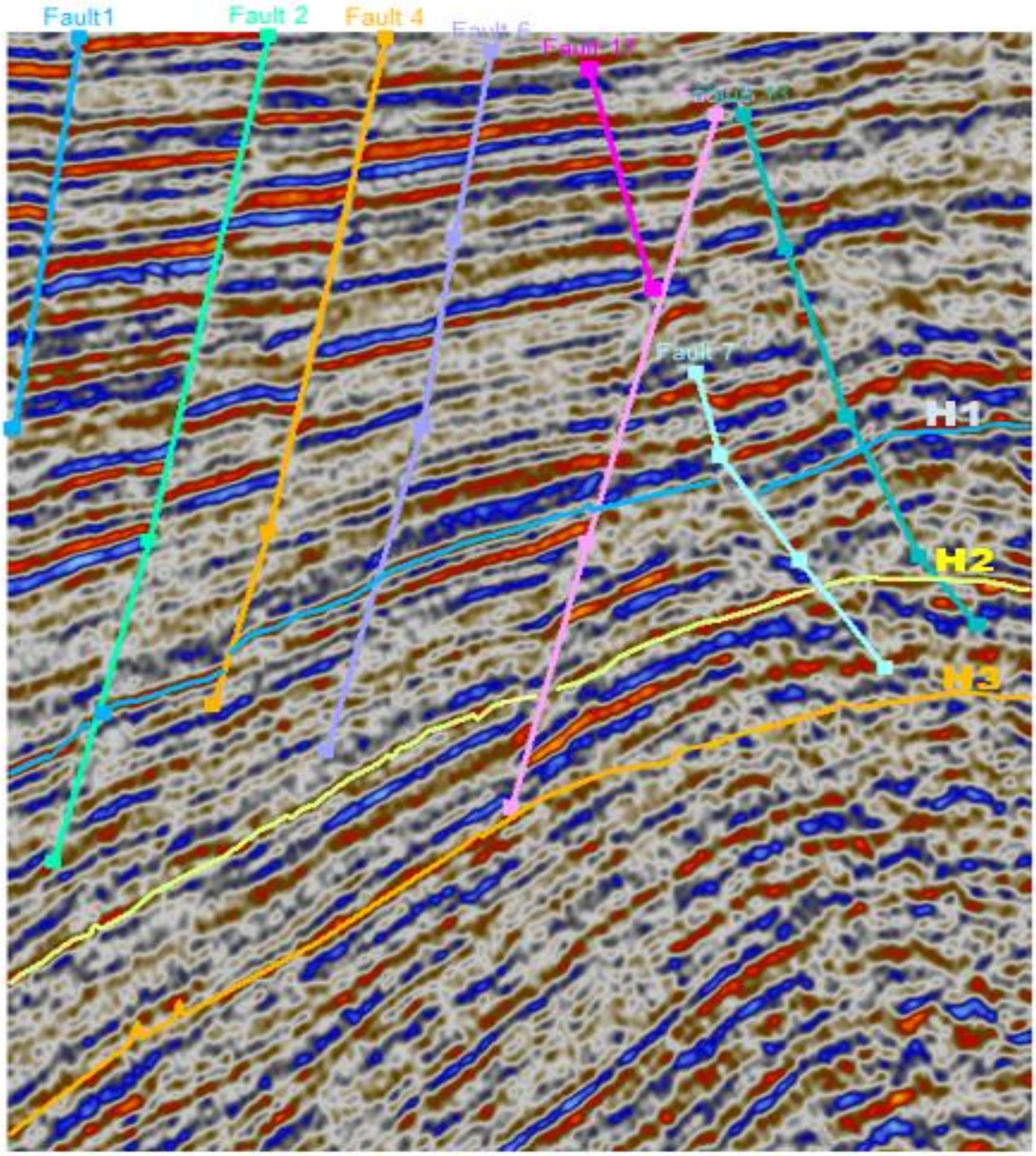


Figure 5: Interpreted Seismic Section on Inline 5801

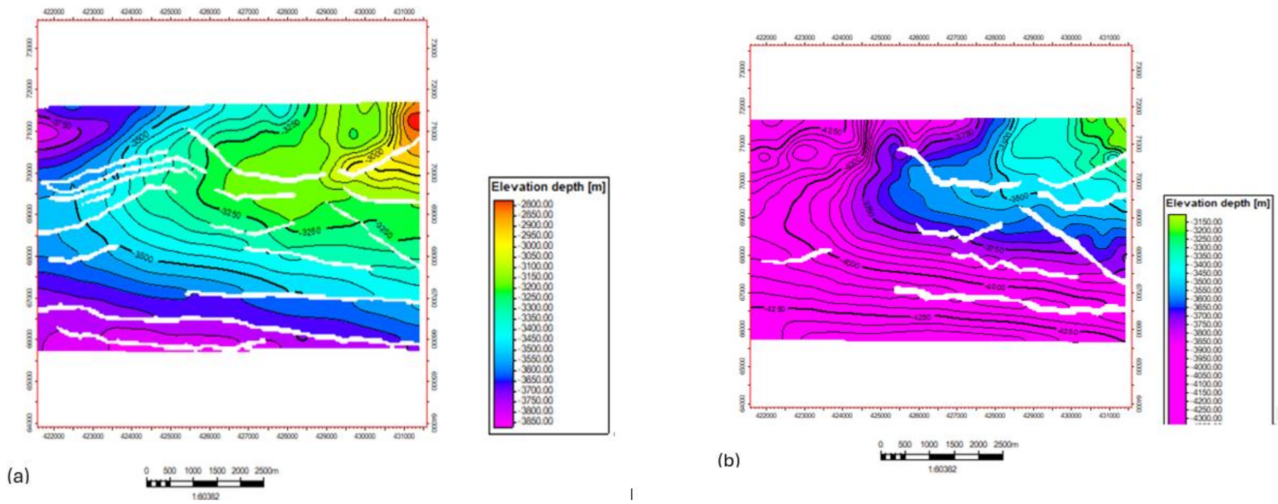


Figure 6: Structural Map for (a) Horizon 1 (b) Horizon 2

3.3 Fault Seal Analysis

Fault seal analysis becomes necessary due to the type and nature of the reservoirs encountered in the field. All the interpreted reservoirs are fault dependent. The faults (fault 5 and fault 13) that cut across each reservoir unit delineated were examined for possible leakages. The sealing capacity of the faults were examined through the evaluation of the throw, shale gouge ratio and lithology juxtaposition using well log.

4.4 Lithologic Juxtaposition Mapping

Juxtaposition involves meticulously mapping an area to recognize the positioning of reservoirs in relation to each other and the potential for non-permeable lithology to create a barrier to reservoirs along a fault plane. Figure 7 present the lithologic juxtaposition for reservoir 1, 2 and 3 in Swan 5 well displaying color brown, yellow and grey which indicate juxtapositions such as shale on sand, sand on sand and shale on silt respectively. Areas on the fault plane with sand-on-sand juxtaposition containing low clay content may develop poor permeability seals and this is like the distinct classification of fault rocks done by (Cerveny *et al* 2004). The shale on sand and shale on silt juxtapositions may develop good seals because shales are known to act as seal rocks in the form of shale smears (Aydin and Eyal 2002).

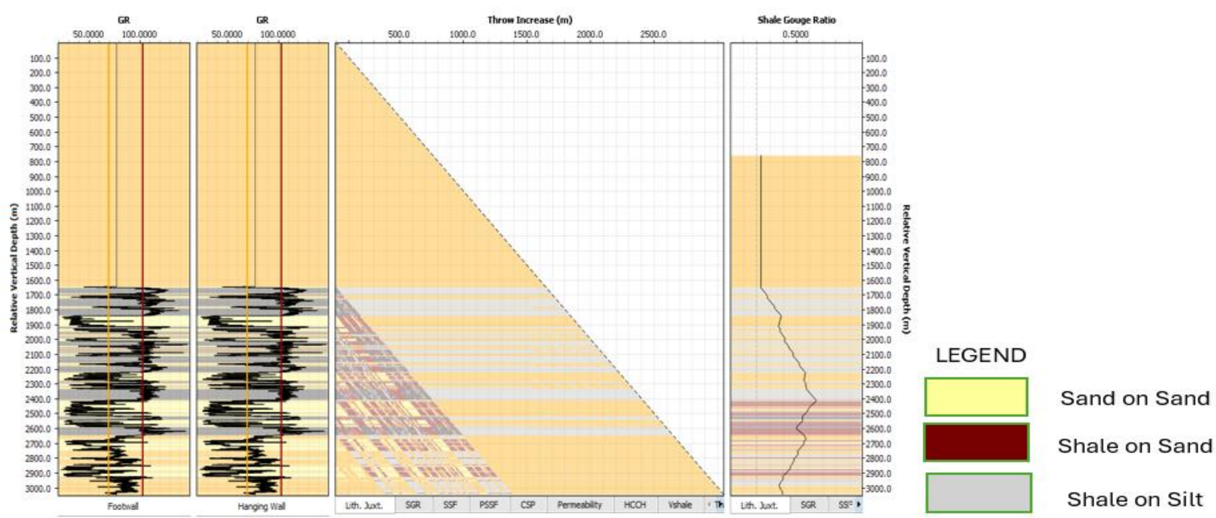


Figure 7: Lithologic Juxtaposition of Reservoirs 1, 2 and 3

3.5 Fault Throw Calculation

The displacement of the reservoir beds across the fault plane (fault 5 and 13) were analyzed. The throw value for Swan 5 well is 763.5m, Swan 7 well is 731.2m, Swan 10 well is 815.7m and Swan 11 well is 816.9m. The red color at the bottom of the plane shows maximum throw followed by color green and blue indicating medium and low respectively (Figures 8, 9, 10 and 11). The areas with the medium to maximum throw have a better sealing capacity because as the throw accumulates gradually the shale gouge ratio increases and this was also observed in (Xianqiang *et al* 2020).

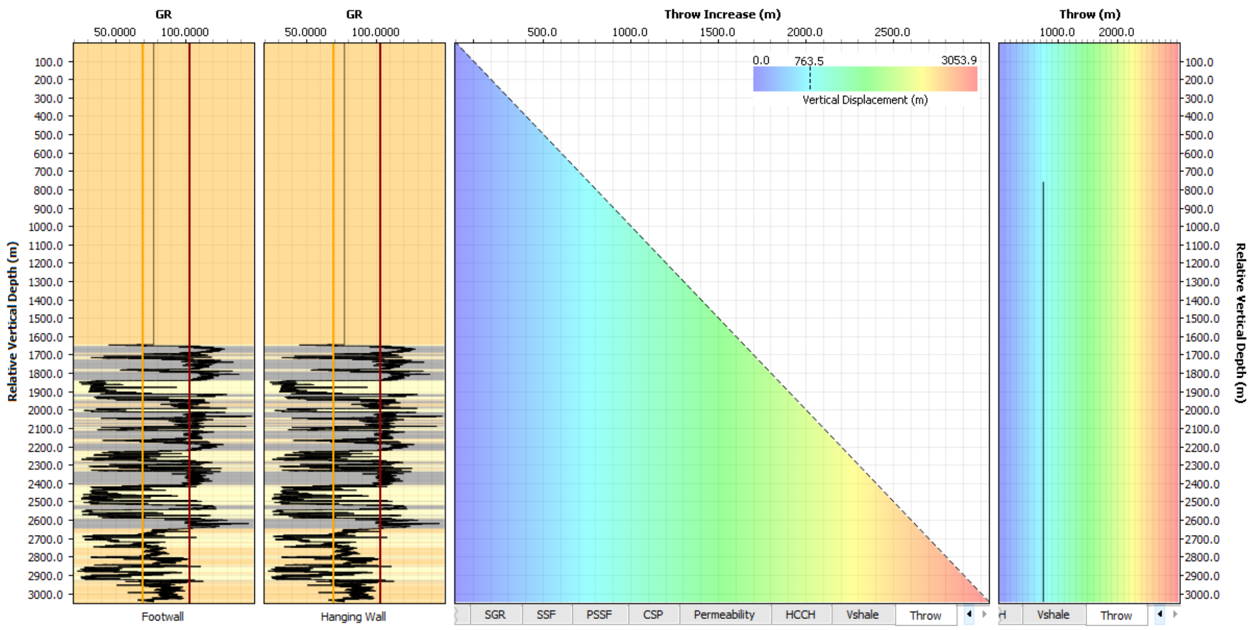


Figure 8: Throw of Swan 5 Well

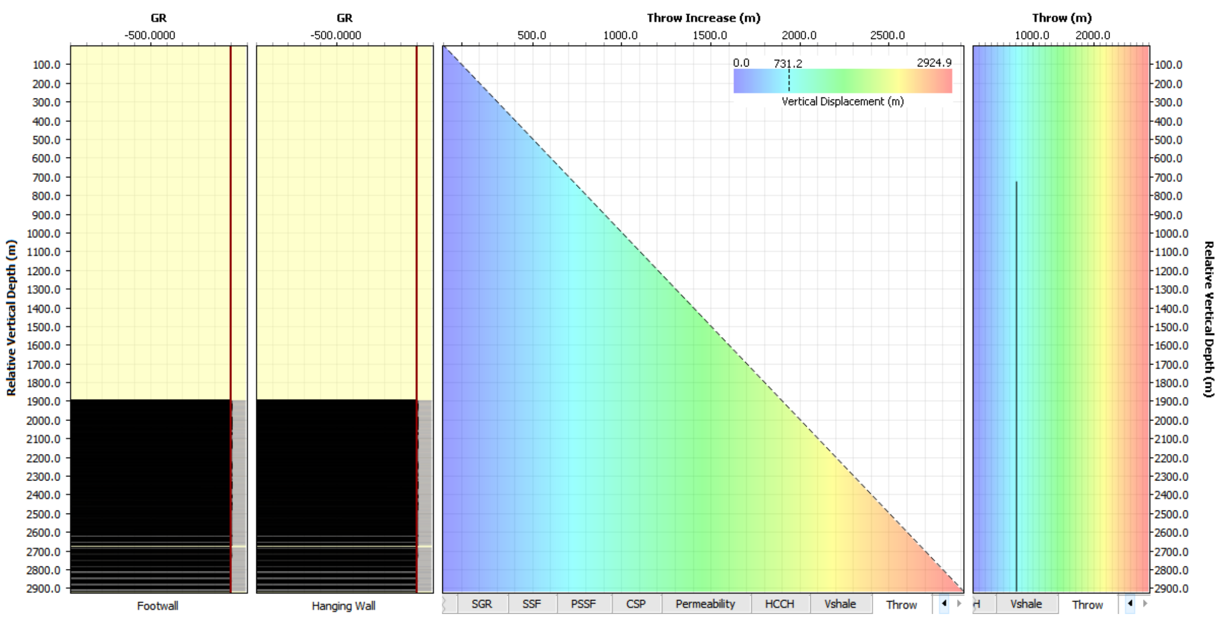


Figure 9: Throw of Swan 7 Well

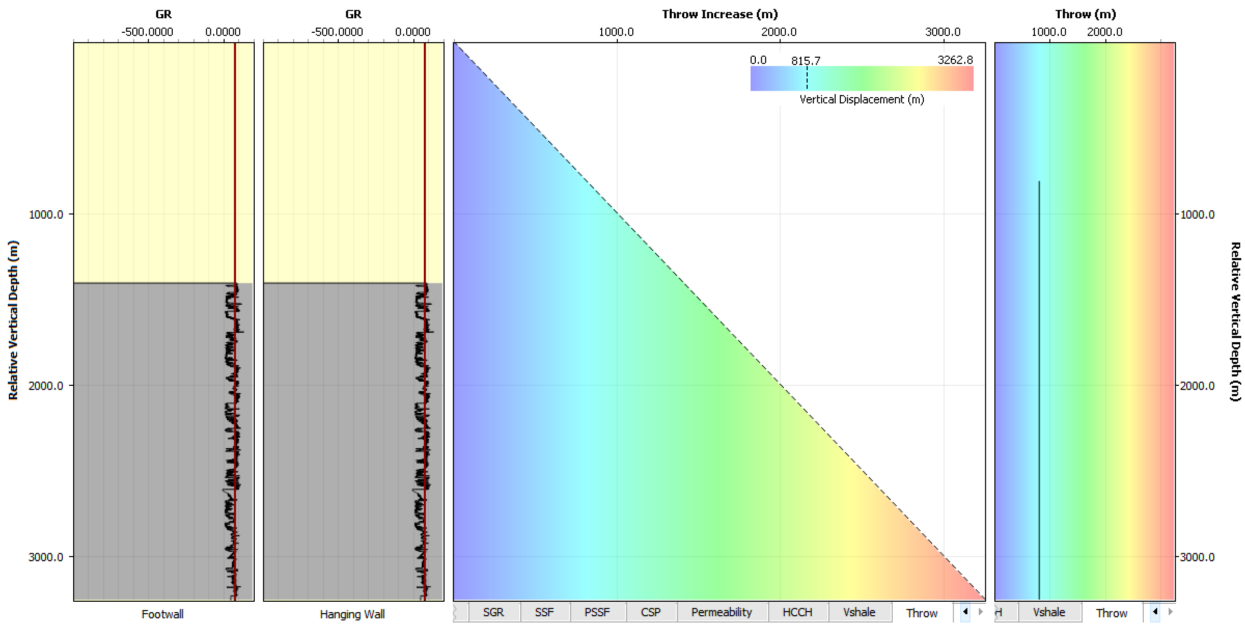


Figure 10: Throw of Swan 10 Well

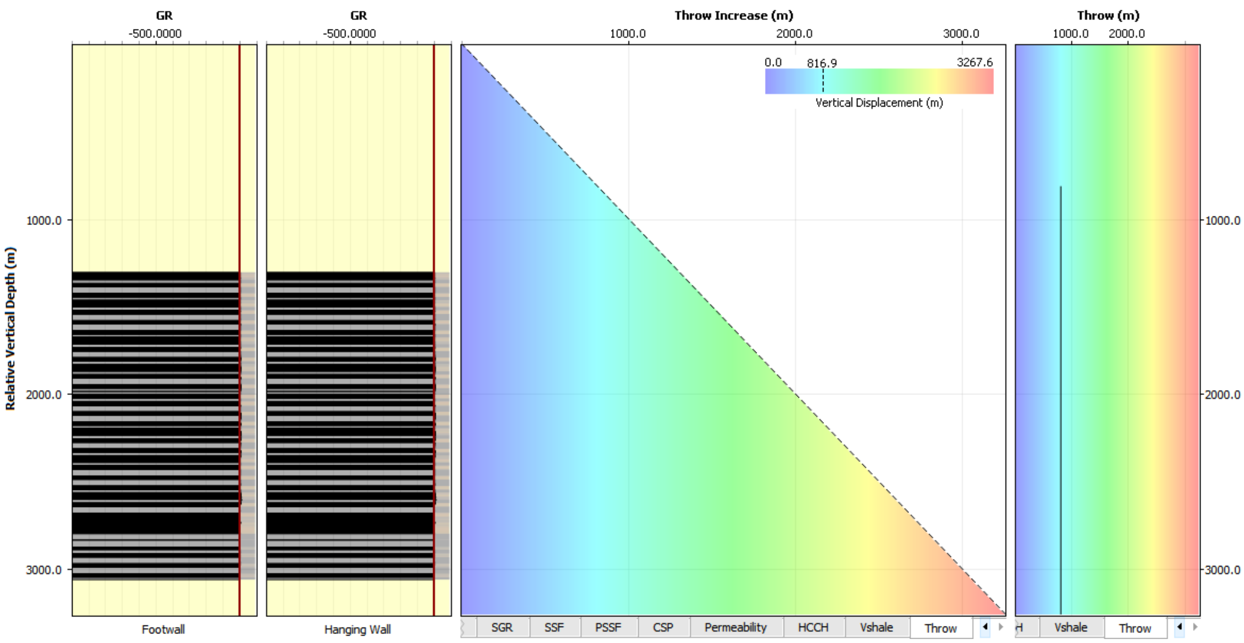


Figure 11: Throw of Swan 11 Well

3.6 Shale Gouge Ratio Interpretation

A seal parameter known as shale gouge ratio (SGR) measures the entrapment of the shales that might have slipped past a point within the fault gouge. Figure 12 showed the map of SGR for the faults 5 and 13 in Swan 5 well having the SGR interpreted to be high (>40%) across the fault plane. The SGR can be categorized into three zones, as illustrated using color codes: poor seal displays green color, moderate sealing displays yellow color, good sealing displays red color. Swan 7 and 11 wells displayed SGR ranging from poor to good sealing zones with an average of 35% (Moderate seal) along the fault plane (Figures 13 and 15). Swan 10 well is interpreted to be moderate (36%) across the fault plane (Figure 14).

However, areas exhibiting a low SGR are indicated by green color along the fault plane, whereas regions with a high SGR are marked by red color along the fault plane. The faults were categorized as zones with poor, moderate, and good sealing properties.

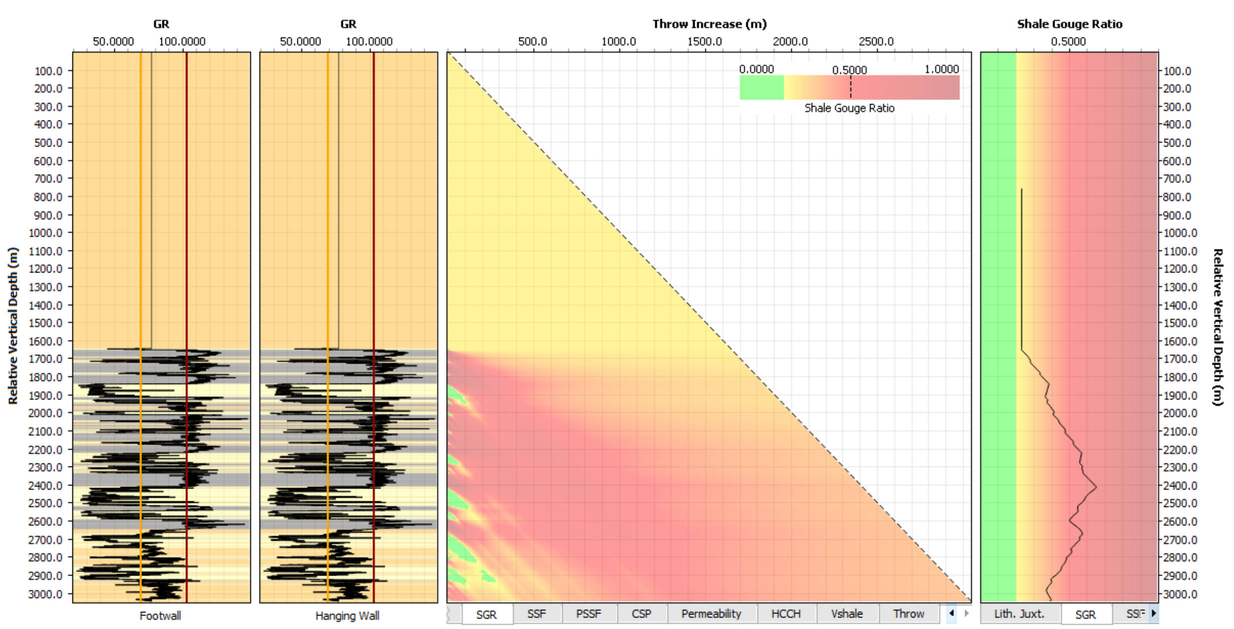


Figure 12: SGR of Swan 5 Well

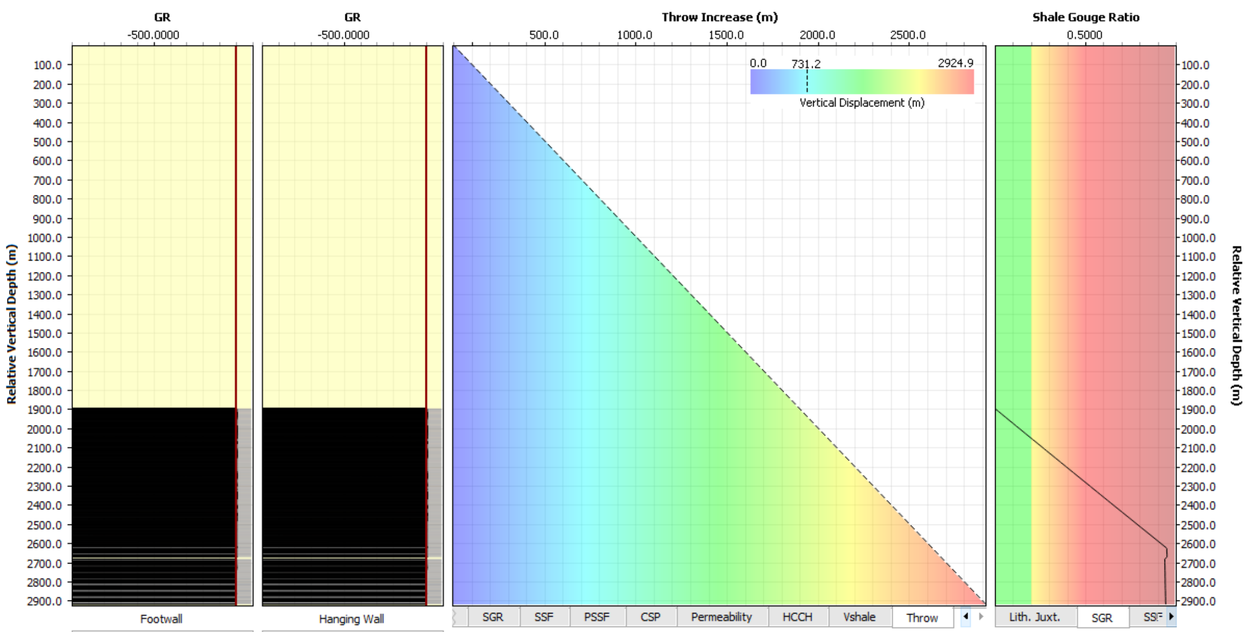


Figure 13: SGR of Swan 7 Well

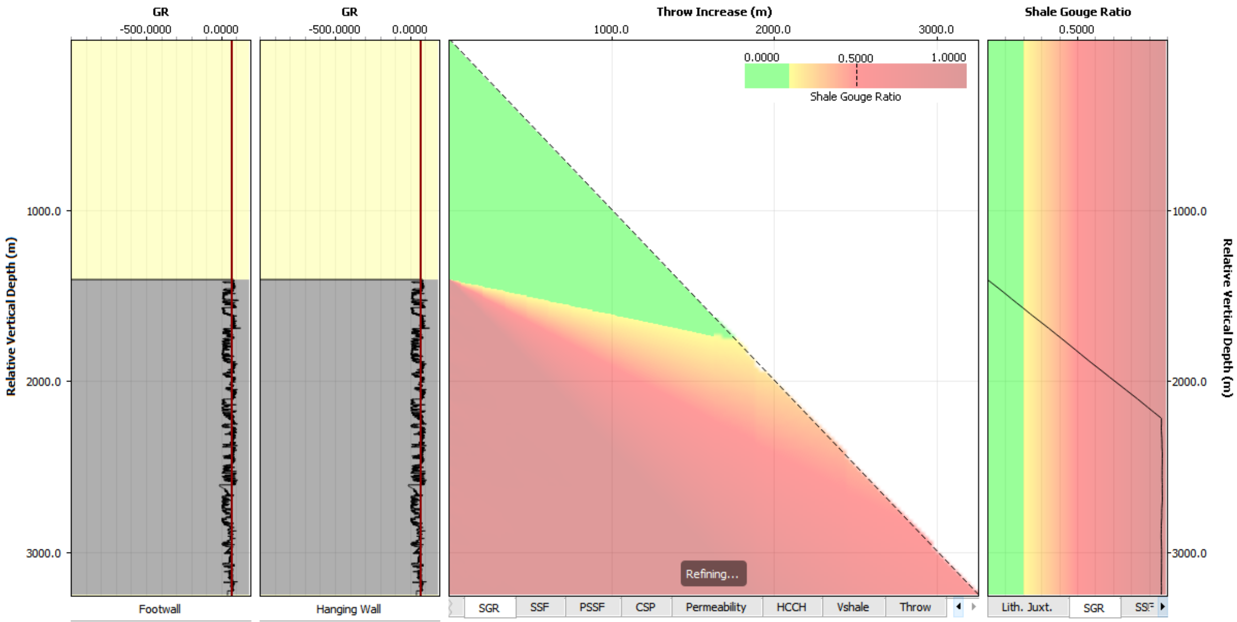


Figure 14: SGR of Swan 10 Well

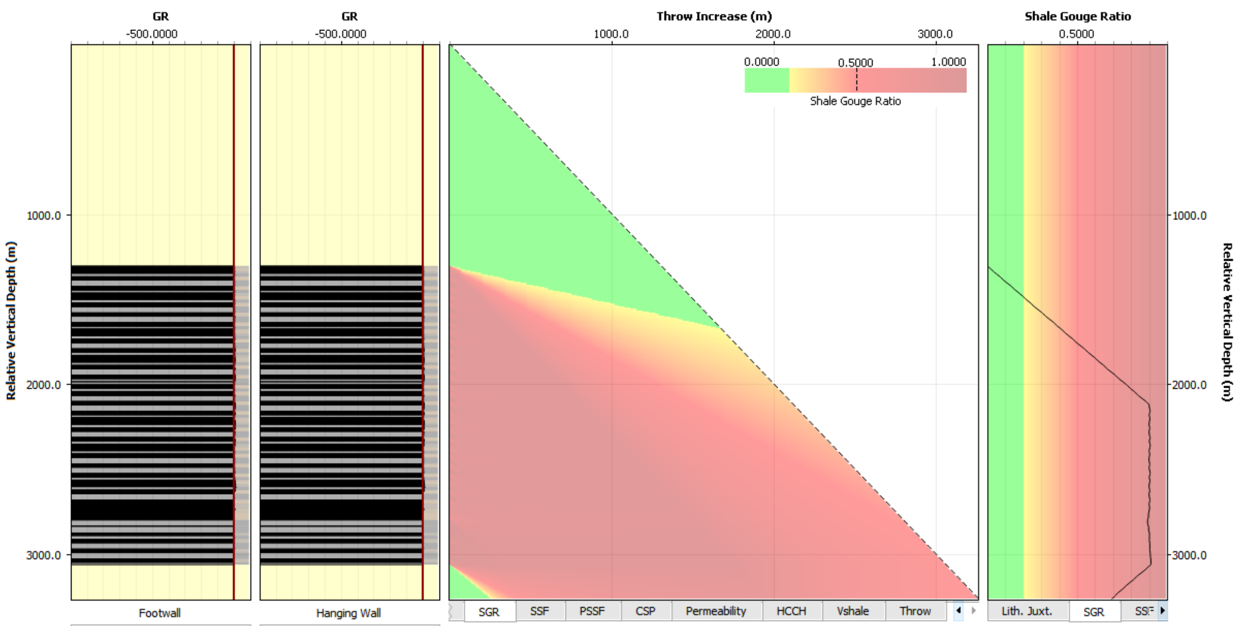


Figure 15: SGR of Swan 11 Well

4. CONCLUSIONS

From structural interpretations, it is observed that a complex fault system exists within the study area giving rise to structural closures. Three reservoirs are present in the field, despite the good quality of reservoirs as observed from the lithostratigraphic correlation, failure to incorporate fault seal analysis 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 'SWAN' 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 fault seal analysis showed that the stratigraphic juxtapositions are predominantly sand to sand, shale to sand and shale to silt. The throw of the reservoir beds along the fault plane ranges from 731.2 m to 816.9m. Shale gouge ratio (SGR) of 20% – 40% is interpreted as phyllosilicate fault rock, which implies that sealing may have occurred because of compaction and mixing of the clays (Fisher and Knipe, 1998; Yielding et al., 1997; Yielding, 2002; Cerveny et al., 2004). Shale gouge ratio (SGR) > 40% implies shale smear, juxtaposition is shale to sand and shale to silt. The shale layer may have been dragged along the fault plane (Aydin and Eyal 2002). Therefore, the 'SWAN' field fault seal is observed to be poor in the upper part of the fault plane, but the sealing potential is higher in the intermediate to lower parts. This corresponds to the throw of the fault observed in the study area as the lower part has the maximum throw and the upper part has the minimum throw. As a result of variation in displacement between hanging wall and foot wall, shale gouge ratio as well as lithology juxtaposition, the sealing potential across a single fault surface can range from poor seal to good seal as was observed in the study area.

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