International Journal of Geosciences, 2025, 16(4), 264-286
https://www.scirp.org/journal/ijg
ISSN Online: 2156-8367
ISSN Print: 2156-8359

Subsurface Reservoir Properties Assessment and Fluids Discrimination from Rock Physics and Seismic Inversion in Termit Basin, Niger

Amadou Hassane[1,2], Chukwuemeka Ngozi Ehirim[3], Tamunonengiyeofori Dagogo[3]

[1]Ministère du Pétrole, Immeuble Ex-ONAREM, Niamey, République du Niger
[2]The World Bank, ACE-CEFOR, University of Port Harcourt, Port Harcourt, Nigeria
[3]Geophysics Research Group, Physics Department, UNIPORT, Box 122, Choba, Port Harcourt, Nigeria
Email: amabark@yahoo.com

How to cite this paper: Hassane, A., Ehirim, C.N. and Dagogo, T. (2025) Subsurface Reservoir Properties Assessment and Fluids Discrimination from Rock Physics and Seismic Inversion in Termit Basin, Niger. *International Journal of Geosciences*, **16**, 264-286.
https://doi.org/10.4236/ijg.2025.164014

Received: January 2, 2025
Accepted: April 27, 2025
Published: April 30, 2025

Abstract

Sokor Formation reservoir intervals are intrinsically anisotropic, heterogeneous and with a characteristic of Low Contrast Low Resistivity (LCLR) log responses in parts of the Termit basin. Discriminating sands from shales/mudstones and hydrocarbon sands from brine sands as well as accurately evaluating the distribution of relevant reservoir properties using conventional seismic interpretation are complicated, and undermines reservoir characterization in such reservoirs. To enhance reservoir evaluation and reduce development planning and production risks, rock physics analysis was intergrated into the petrophysical workflow, which fed higher fidelity inputs into a post stack seismic inversion workflow. Rock Physics Diagnostics (RPD) analysis revealed that the reservoir interval of interest has grain size distribution of different lithologies, which is related to the environment of deposition and burial history, and could be best described by the constant cement sand model. The rock physics analyses revealed that facies were most effectively discriminated based on their V_p/V_s ratios and acoustic impedance. Particularly, hydrocarbon saturated sandstones, brine saturated shaly sandstones and shales/mudstones which exhibit similar acoustic impedance characteristics, were clearly discriminated by their V_p/V_s. The inverted seismic attributes as well as Seismic Based-Rock Physics Templates (RPT), clearly delineated the hydrocarbon fields, predicted new prospects beyond the existing well locations, which could be considered for field appraisal or development opportunities in the basin. These results demonstrate the value of the robust application of rock physics diagnostic modeling and seismic inversion in quantitative reservoir characterization and may be quite useful in undrilled locations in the basins and fields with similar geology.

Keywords

Crossplots, Rock Physics Template, Elastic Parameters, Seismic Inversion, Seismic Attributes, Reservoir Characterization, Reservoir Properties Prediction

1. Introduction

The facies discrimination of reservoir rocks from non-reservoirs and estimation of reservoir properties, detection of pore fluids and their characteristics is one of the most important focal points in petroleum exploration and efficient field development. This is much done through reservoir characterization which is the process of preparing a quantitative representation of a reservoir using data from many sources and disciplines [1]. In characterizing reservoirs, it is best advantageous to recognize the lithology, associated porosity of rock, fluid content and lithofacies variation in target interval.

Although reservoir petrophysical properties can be studied from well logs, over the past few years, they have been mapped through quantitative seismic interpretation with the use of seismic attributes calibrated against the available data, including wells in the study area [2]. Hydrocarbon reservoir rocks are distinguished based on their quality and exceptional petrophysical (reservoir) properties. The quality of the reservoir is dependent on the rock type, environment of deposition and burial history, which determines their specific character and properties. Reservoir properties such as lithology, porosity, clay volume, grain size, fluid saturation, permeability among many others, are essential for the characterization of hydrocarbon reservoirs.

The environment of deposition and burial history controls textural and mineralogical characteristics in the rock and determine their geologic properties as well as the quality of reservoir rocks. The geologic properties in turn, affect seismic elastic parameters through the rock and hence, the observable acoustic response on records. Among the different elastic properties of the rock, seismic velocities exhibit heightened sensitivity to porosity than the other properties. Understanding the relationships between geologic properties and the seismic elastic parameters via rock physics are vital to the quantitative interpretation of reservoir quality and hydrocarbon prospect evaluation from well and seismic data [3]-[5]. It provides better understanding of the relationships between geologic properties and seismic elastic parameters. It represents the bridge that links geologic properties of porosity, clay content, saturation, lithology and texture and elastic properties such as compressional (P)-wave and shear (S)-wave velocities and their ratio (V_p/V_s), acoustic impedance (I_p), bulk density and elastic moduli [3] [6] [7]. Elastic rock properties generally, depends on the primary rock composition, which is in turn controlled by the textural and mineralogical characteristics, depositional environment, burial and diagenetic histories of the rock. Thus, through rock physics, texture, mineralogy and fluid types of the reservoir rock can be evaluated and linked to the environment of deposition and diagenetic alterations [6] [8]. These seismic elastic parameters can be used to map these intricate subsurface sedimentary properties/characteristics by employing robust methods developed to relate sedimentary properties such as porosity or pore fluid to seismic observables such as velocity, impedance or reflectivity.

The elastic properties of the rock used in building RTP can be derived from seismic data. Since seismic data is a gross continuous spatial information about the mechanical properties of the subsurface, showing basic information such as travel time, amplitude and frequency, most of these required details are not readily obtainable. Derived seismic attributes are very useful for reservoir evaluation, characterization or property mapping from 3D seismic data. These attributes can be obtained by the inversion of seismic data, which is a process that replaces the seismic signature with a blocky response, corresponding to acoustic and/or elastic impedance layering that facilitate the interpretation of meaningful geological boundaries in the subsurface. This increases the resolution of conventional seismic in many cases and puts the study of reservoir parameters at a different level, resulting in optimised volumetric estimates, improved ranking of leads/prospects, better delineation of drainage areas and identifying 'sweet spots' in field appraisal and development studies [9].

Different sedimentary rocks exhibit different such seismic properties and show little variation even for different depths of burial. For most sedimentary rocks, seismic properties depend on the intrinsic seismic properties in the minerals constituting the solid rock matrix, the porosity, the pore pressure and the fluid filling the pore spaces. They may also be dependent on the composition of the cementing material between the grains of the primary rock constituents [10].

Seismic properties of hydrocarbon bearing sandstone reservoirs are essential for improved quantitative analysis and interpretation of reservoir quality in sedimentary basins. Sandstone reservoirs have generally passed through mechanical and chemical processes of compaction that cause a large change in textural and structural properties and reduction of their initial porosity from the time of deposition, and hence changes in elastic attributes. Seismic elastic properties are very useful in identifying lithology and pore fluids, predicting reservoir properties and for mineral identification [4].

Attributes such as velocity and moduli can be directly related to stratigraphic deposition, tectonic deformation and reservoir properties. Based on their interpretative importance in reservoir characterization, seismic attributes are in general classified as pre-stack or post-stack attributes [11]. In extracting seismic attributes from the data with high resolution, seismic inversion technique is one of the methods used. Seismic Inversion is thus the extraction of subsurface geologic information from seismic data by transforming seismic reflectivity data into a quantitative rock property description of a reservoir [7] [12] [13]. The original reflectivity data as typically routinely recorded as boundary property is converted to layer rock property known as impedance, which is the product of seismic velocity (V) and the bulk density (ρ_b). The velocity itself can be expressed using the Lamé coefficients (λ and μ), or using Bulk Modulus (K), and shear modulus (μ).

Seismic inversion replaces the seismic signature by a blocky response, corresponding to acoustic and/or elastic impedance layering that facilitates the interpretation of meaningful geological and petrophysical boundaries in the subsurface. Both standard seismic post-stack inversion methods, among which model-based increases the resolution of conventional seismic through improved estimation of rock properties [14], including thickness, depth, pore fluid, net-to-gross ratio, net pay, saturation, porosity and permeability. This results to optimised volumetric, improving ranking of leads/prospects, better delineation of drainage areas and identifying 'sweet spots' in field appraisal and development studies [9].

The prediction of a rock physics model that explicitly describes the reservoir texture and behaviour is very important because, it can be used to crossplots V_p/V_s vs. I_p and build a rock physics template (RPT) of V_p/V_s ratio vs. acoustic impedance crossplot, consistent with the local geology based on a rock physics theory by [15]. RPT is a robust rock physics model built for a range of saturations and porosities for a given reservoir interval. It is useful for the prediction of the pore fluid and mineralogical content of a reservoir, reservoir characterization and prospect evaluation both at well and away from well control points [16]-[19]. Rock physics template is a site-specific rock physics model useful for mapping and screening hydrocarbons and allow for fluid and lithology discrimination and characterisation that are consistent with rock physics models [18].

Termit basin reservoir sands in most parts of the basin are hot (radioactive), due to high clay content and radioactive minerals. Also, some hydrocarbon bearing reservoir intervals (pay zones) exhibiting low contrast low resistivity (LCLR) log responses. Additionally, tectonic activities affected sedimentary processes, making the reservoirs in most cases complex and heterogeneous. These heightened reservoir heterogeneities complicate petrophysical analysis and reservoir characterization.

Effort have been made to adopt different approaches to estimate petrophysical properties and their distribution from well log data. Different conventional techniques integrates well and seismic data for fluid and lithology discrimination in reservoir characterizations have been proposed. Discriminating reservoir sands from shales/mudstones and hydrocarbon sands from brine sands as well as accurately evaluating the distribution of relevant reservoir properties using conventional seismic interpretation are complicated and tasking, and undermines reservoir characterization in such reservoirs.

Therefore, in this study, rock physics modelling and seismic inversion are used to relate impedance and elastic attributes derived from seismic to specific rock properties such as lithology. The combination of rock physics and seismic inversion enabled prediction and characterisation of reservoir in terms of the relevant properties such as lithology, fluid content and saturation that help identify hydrocarbon target across the study area. This will be quite useful in exploration and production activities, by improving exploration and reservoir management success, efficient field development, reservoir performance and optimise hydrocarbon recovery.

2. Geology of the Study Area

Termit Basin is a Mesozoic-Cenozoic continental rift basin in the north-western part of West and Central Africa Rift System (WCARS). It is situated within the Chad Basin in Niger (Figure 1) and filled with lower Cretaceous to Neogene sedimentary rocks.

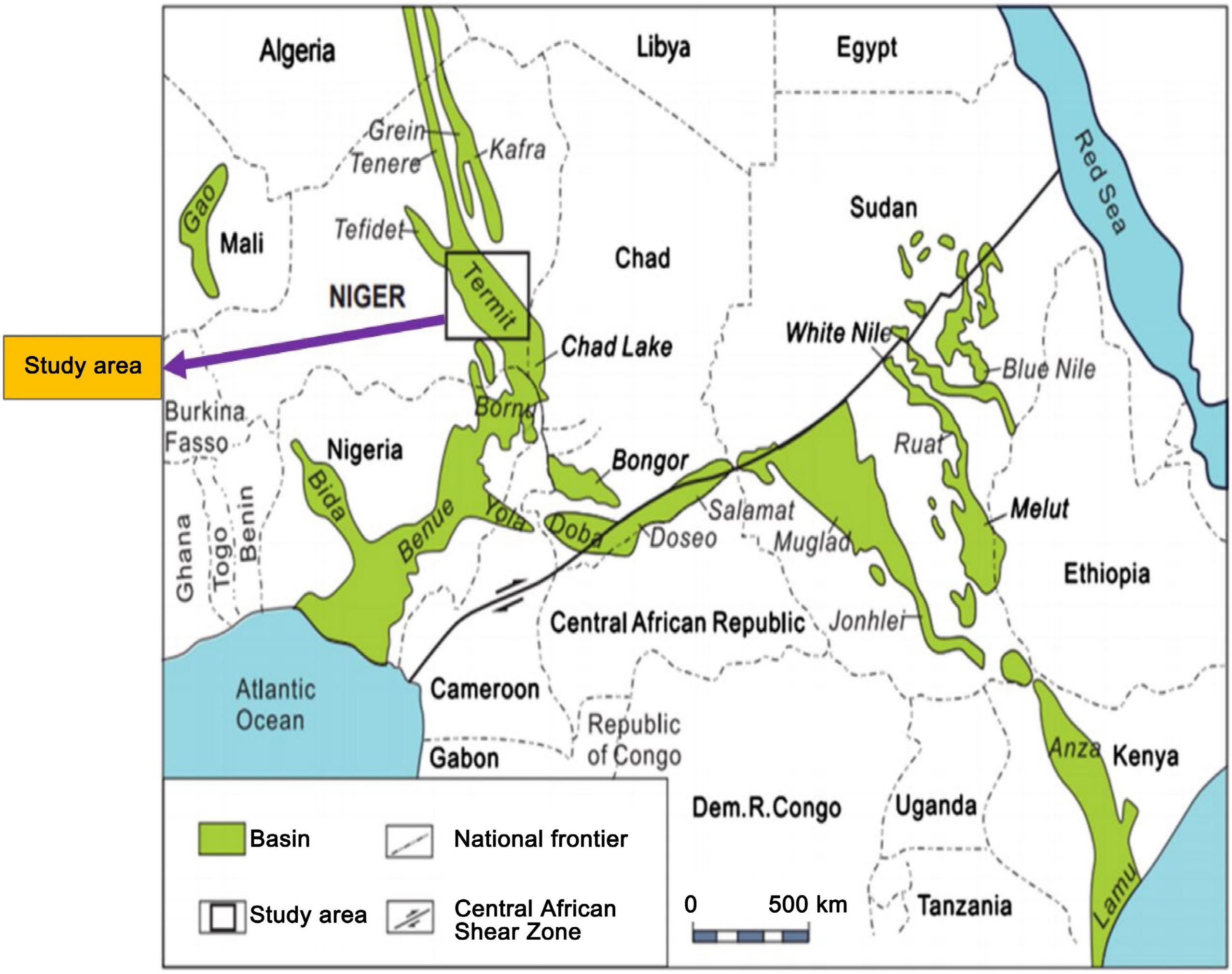

Figure 1. Location map of the study area [20].

The basin is hydrocarbon bearing with the major finds located in the upper Cretaceous to Palaeocene-Eocene sandstones. Tectonic activities affected sedimentary processes such that structural, lithologic and textural characteristics of the sediments are grossly impacted [20] [21]. The reservoir sandstone intervals in some parts of the subbasin are radioactive with high clay content, typical of low contrast low resistivity reservoirs (LCLR) [22]-[24]. Volcanics which have been dated stratigraphically to be older than 85 - 95 Ma. occur within the basin.

The general vertical profile of Termit basin consists of the Precambrian basements which are made of igneous and metamorphic rock. It is overlain by the Lower Cretaceous, Upper Cretaceous, Paleogene, Neogene and Recent sediments (**Figure 2**), known as Donga, Yogou, and Madama (Upper Cretaceous), Sokor-1 (Paleocene-Eocene) and Sokor-2 (Oligocene) [25]. Most of these formations are in general deposited in marine to lacustrine environments and contain varying amounts of higher plant or bacterial and algae organic matter [26] (**Figure 2**).

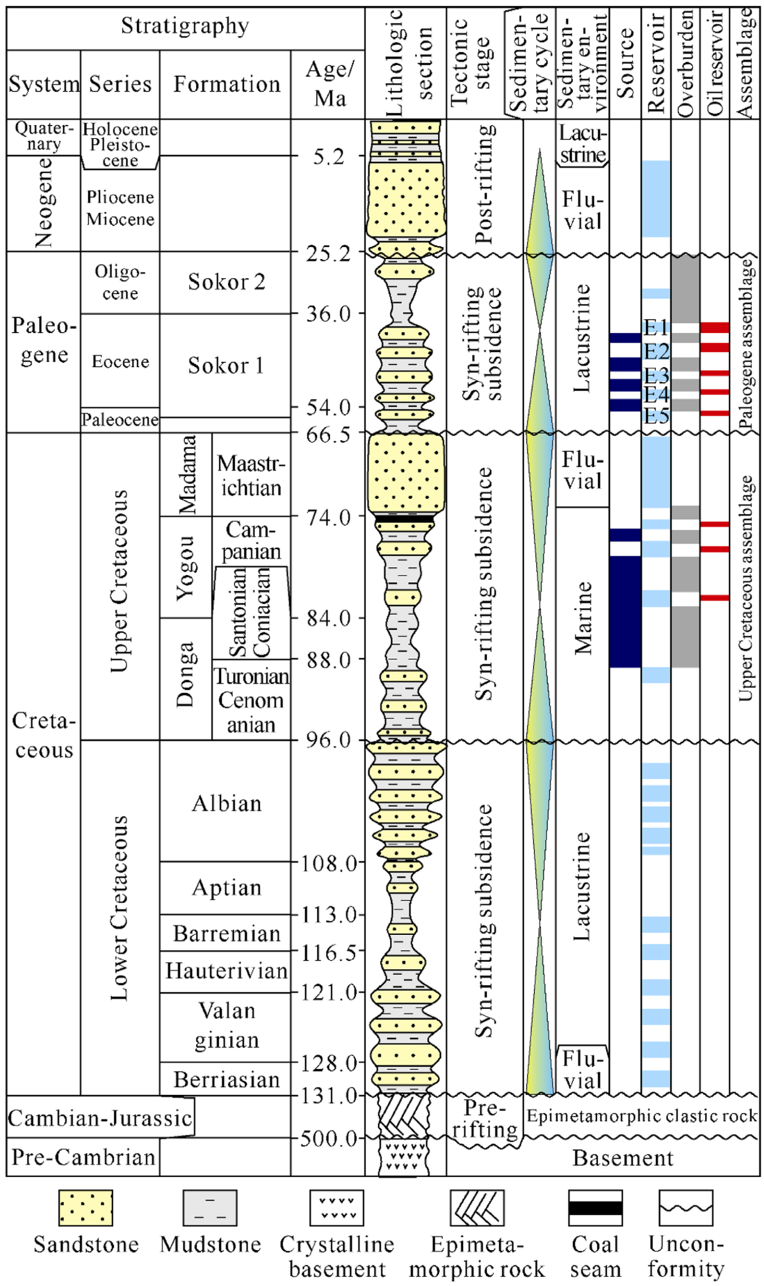

Figure 2. Composite stratigraphic column of the Termit Basin [27].

The subbasin tends to an asymmetrical half graben overall with gentle slope in the east with undeveloped structure and steep slope in the west, with the deepest Dinga graben in the middle (**Figure 3**). The western slope in NW direction is steep comprised of several tilted fault blocks and horst blocks, forming several entrapments. The two main structural styles are observed over the majority of the Termit basin. The first consist of northwest-southeast (NW-SE) synthetic normal fault blocks common in Iaguil platform and in central as well as western Termit area. The second is composed of north-northwest-south-southeast (NNW-SSE) antithetic normal and transtensional fault blocks dominate the eastern and southeastern parts of the basin, associated with this wrenching are northeast-southwest (NE-SW) transpressional [28] [29].

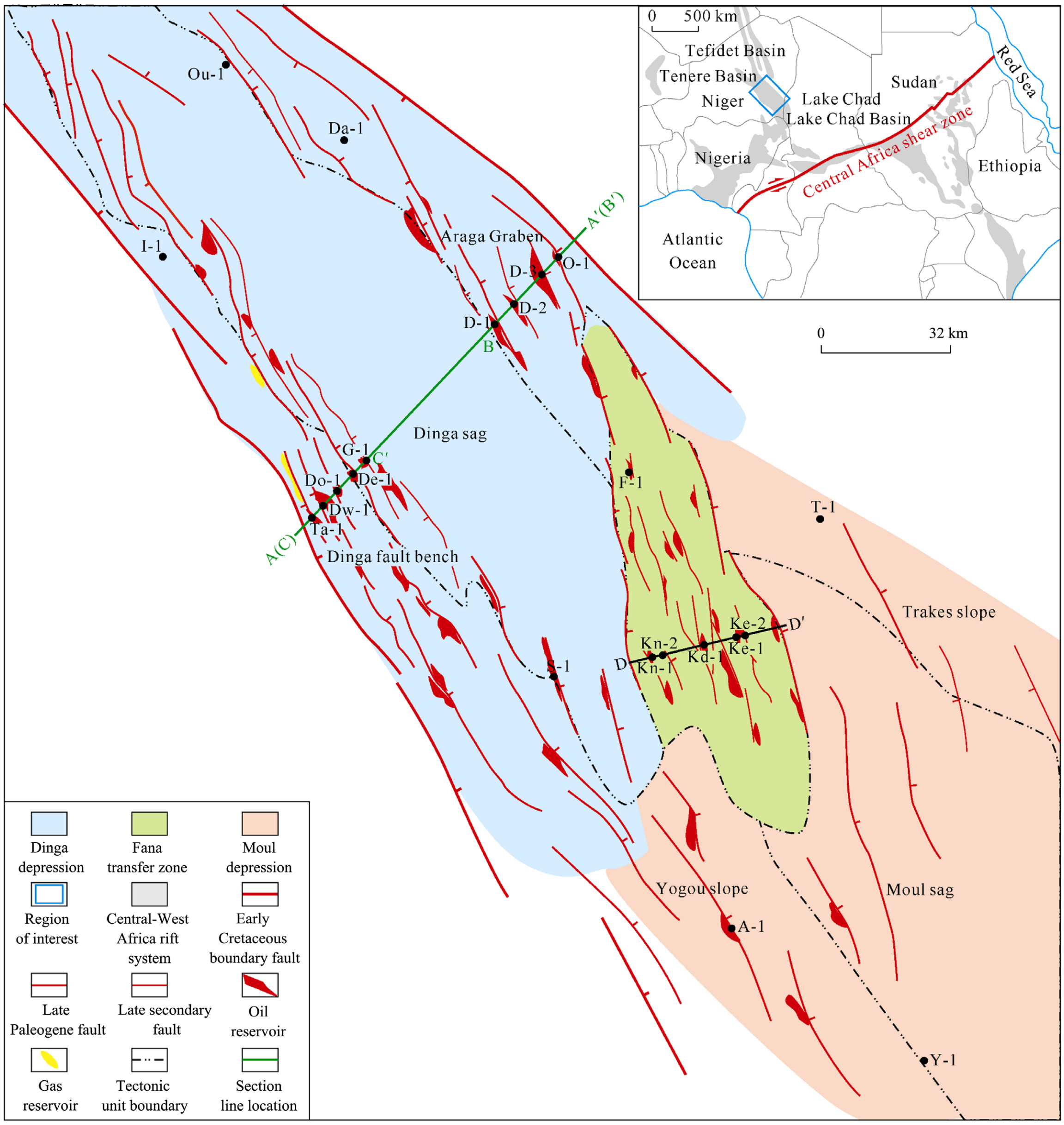

Figure 3. Map of Termit Basin showing structural units and the spatial distribution of faults in the Termit Basin [27].

Exploration works in the Termit Basin mainly directed towards the Sokor-1 and Yogou Formations proved that the petroleum system in Termit Basin are present in the Upper Cretaceous and Paleogene, specifically the Yogou-Sokor-1 and Sokor-1-Sokor-2 systems with most of the hydrocarbon discoveries located in the upper Cretaceous Yogou Formation and E0, E1, E2, E3, E4 and E5 sand groups of the Sokor-1 Formation [30] [31]. The second member of the Sokor Formation (Sokor-2) acts as the regional seal in Sokor-1-Sokor-2 petroleum system, while the interbeded shale/mudstone in Sokor-1 and inter-channel mudstone in Yogou acts as local barrier/seal, respectively [27].

3. Method of Study

A total of five wells (2, 3, 4, 5, and 9) consisting of suits of well logs and 3D pre-stack time migrated (PSTM) seismic data were used in this study. The well logs comprising of sonic (DT), gamma ray (GR), resistivity (RT), neutron (NPHI/CNL) and density (RHOB) logs, constitute the primary logs used in the study. The 3D seismic survey covered an area of 1480.9 km^2, with a total of 1841 crosslines and 2201 inlines. The quality of the data is good as strong reflections are observed across seismic boundaries, especially in the target areas. The wells and their spatial distributions in relation to the seismic lines are shown on the base map of the study area (**Figure 4**).

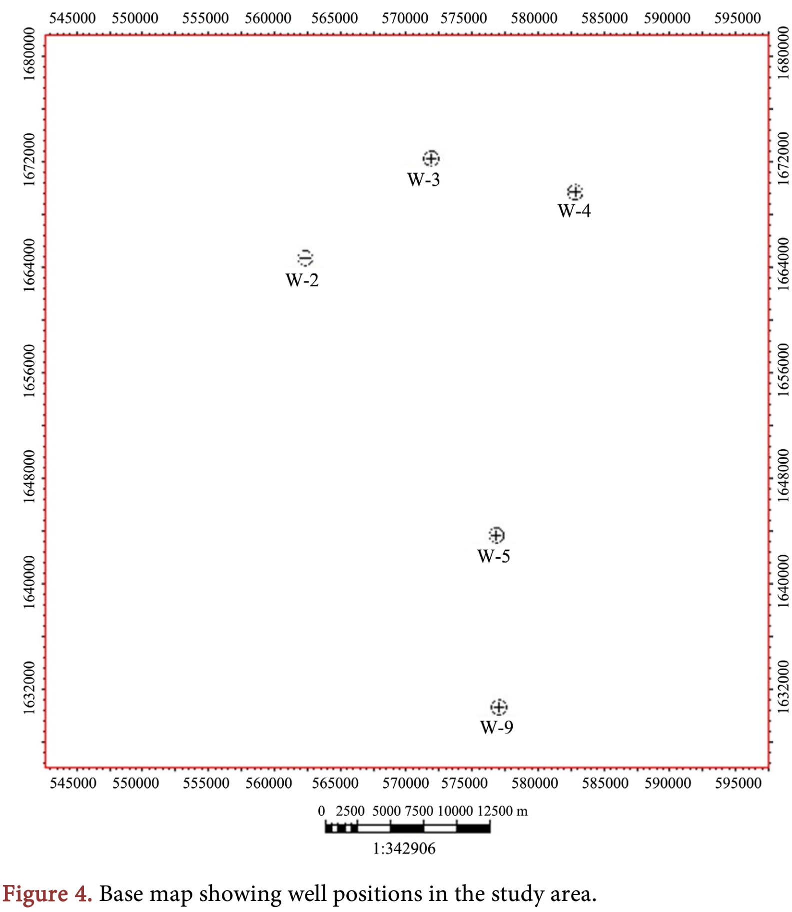

Figure 4. Base map showing well positions in the study area.

Pseudo logs (shear wave velocity (V_s), bulk modulus, shear modulus, Poison's ratio, V_P/V_s ratio, P- and S-impedances) were generated from the primary logs through petrophysical transforms (Figure 5). The well logs were analysed and interpreted to identify lithologies, discriminate reservoir intervals and estimate petrophysical properties (porosity, water saturation and shale volume). The reservoir intervals were then correlated across wells to establish their continuity and lateral extension throughout the field.

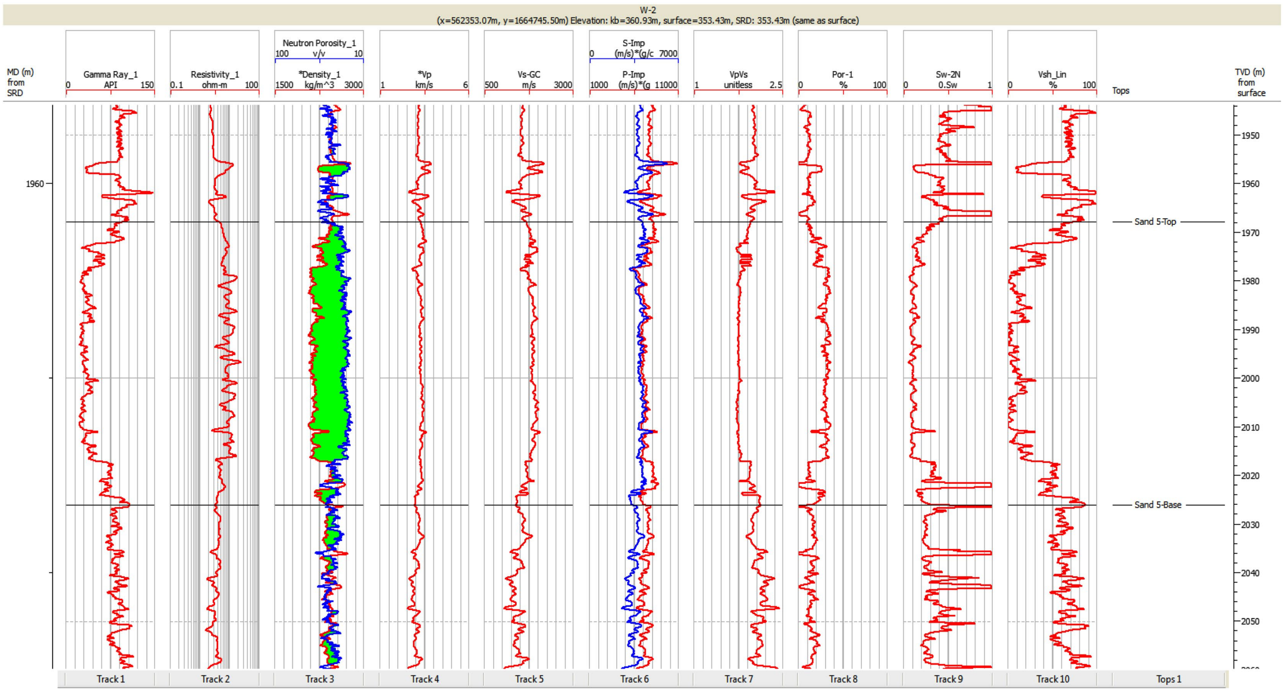

Figure 5. Well-2elastic logs for Sand_5 reservoir interval.

Selected reservoir interval was then diagnosed in cross plot space using rock physics schemes. This entailed performing fluid substitution to back out hydrocarbon saturations so as to eliminate the effect of pore fluid changes and target only on the effects due to rock texture and mineralogy. Crossplots of compressional velocity vs. porosity, colour coded with shale volume were generated and matched with heuristic diagnostic sand models, such as friable, contact cement and constant cement models, to appropriately characterise reservoir texture and mineralogy. Subsequently, rock physics template (RPT) specific to our field was built based on the result of the diagnostic analysis.

After successfully tying the wells to the seismic, detailed seismic interpretation was done to map faults and horizons on the seismic data. Data was inverted using the Model-Based Inversion (MBI) algorithm to generate acoustic impedance volume, which served as input along with the well data into a Neural Network workflow to generate other elastic properties of interest. Finally, appropriate inverted seismic attributes were cross plotted on top of the build rock physics templates (RTP), based on which the prediction of lithology and discriminate pore fluids away from well control points in the field were achieved.

4. Results Presentation

Reservoir lithologies and pore fluids delineated are sands, shaley sands and shales/mudstones and hydrocarbons and brine, respectively. Petrophysical analysis suggests fairly good reservoir properties in the five delineated reservoir intervals. Sand_5 reservoir interval was selected as a representative reservoir interval for further analysis because it has the best reservoir properties and prolific in hydrocarbons (Table 1). This reservoir interval was correlated, and it varied in thickness and depth across wells (Figure 6), which may be related to the tectonics of the Termit Basin.

Table 1. Petrophysical properties of sand_5 reservoir interval.

Well Name	Top (m)	Bottom (m)	Thickness (m)	Vsh (%)	N/G (%)	Porosity (%)	Sw (%)
2	1972	2025	53	10	90	25	14
3	2109	2175	66	7	93	22	17
4	2173	2207	34	18	82	24	19
5	1857	1925	68	25	75	26	17
9	1846	1932	86	22	78	25	16
Average	-	-	61.4	16.4	83.6	24.4	16.6

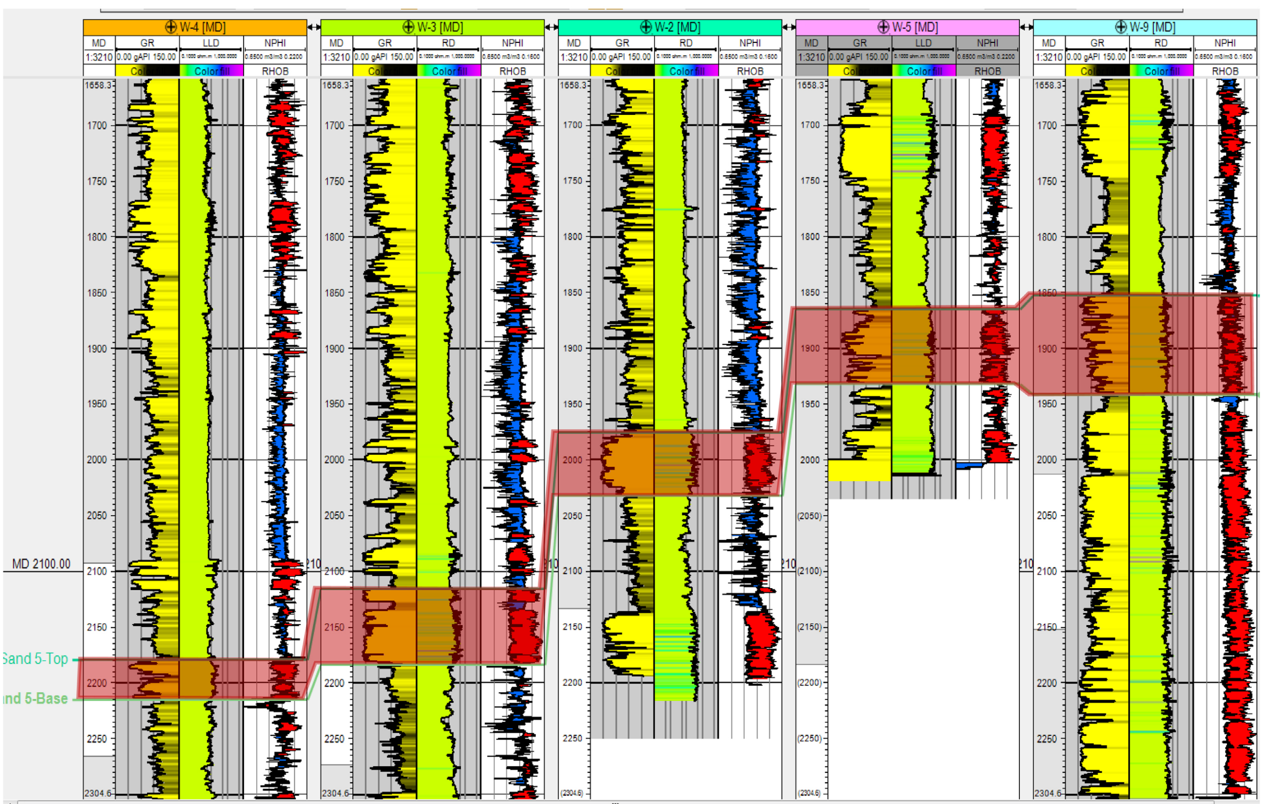

Figure 6. Sand_5 reservoir interval correlated across wells.

Rock physics diagnostic plots of V_P vs. ϕ, show data trends that generally only vary along the horizontal on the $V_P - \phi$ plane, suggesting grain size distribution of different lithologies that vary between very clean and well sorted sandstones to deteriorating and poorly sorted shaly sands and shales/mudstones (**Figure 7**). This indicates that sand_5 reservoir interval is highly heterogeneous with respect to rock texture and minerology across wells. Further analysis of result revealed that our data points most satisfactorily aligns with the constant cement sand model. This suggests that reservoir sandstones are contact cemented with a constant cement volume throughout the rock.

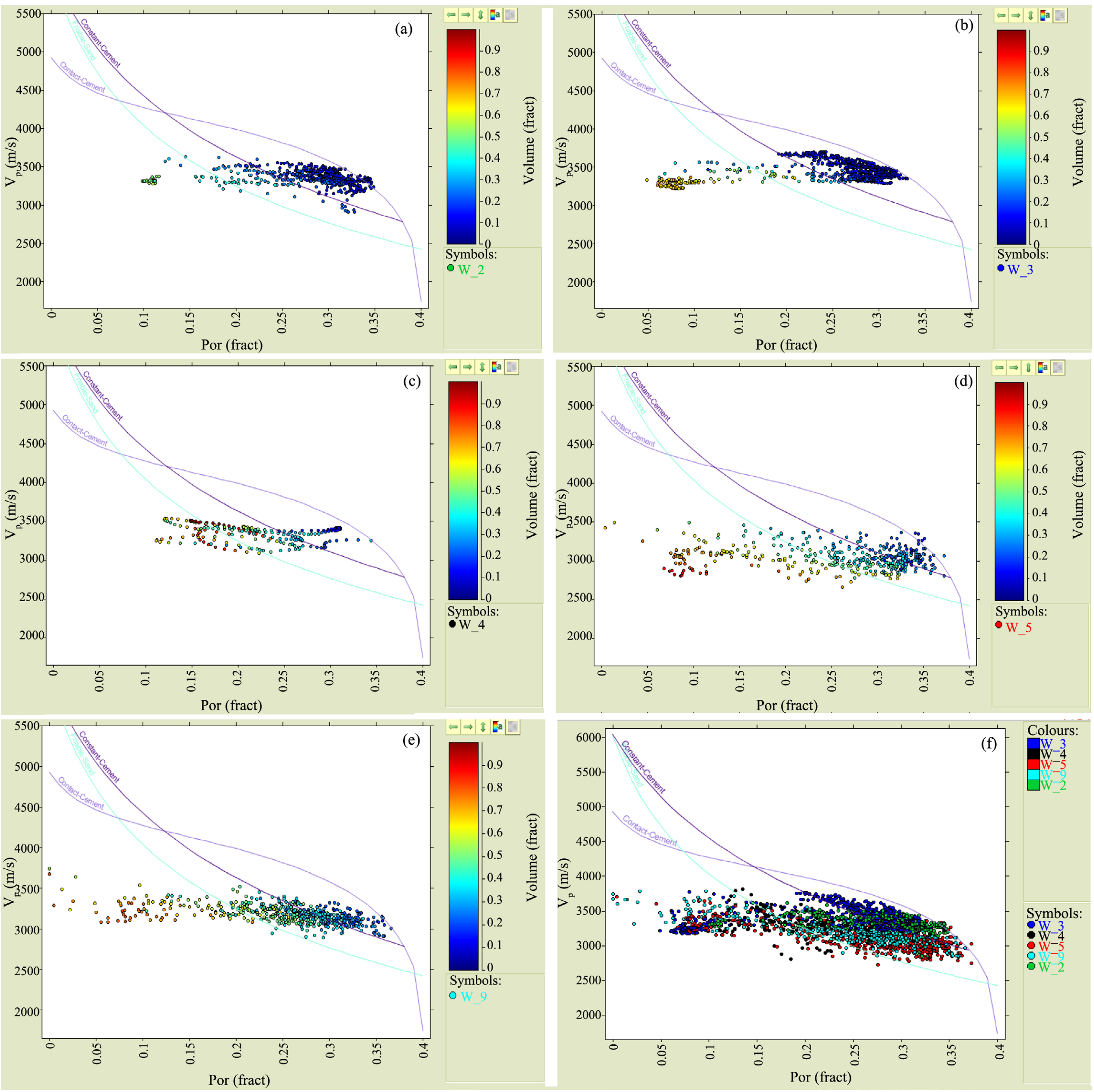

Figure 7. Diagnostic plots of V_P vs. ϕ (Por) for sand_5 with superimposed heuristic sands models in each well: (a) well-2; (b) well-3; (c) well-4; (d) well-5; (e) well-9 and (f) All five wells.

RPT analysis based on the constant cement model of sand_5 reservoir interval show that porosity and hydrocarbon saturation increase in the low impedance and V_p/V_s ratio directions, respectively while clay content (shaleness) increases in the high V_p/V_s ratio direction. Results show hydrocarbon sandstones plot as medium to high impedances and low V_p/V_s ratio, with average hydrocarbon saturation and porosity values of 82.5% and 24.5%, respectively, which correlates with the 83.4% and 24.4% hydrocarbon saturation and porosity values from well-based petrophysical measurements. Brine shaly sands plot as medium to high impedances with moderate V_p/V_s ratio and the shales/mudstones plot with medium impedance and high V_p/V_s ratio (**Figure 8**).

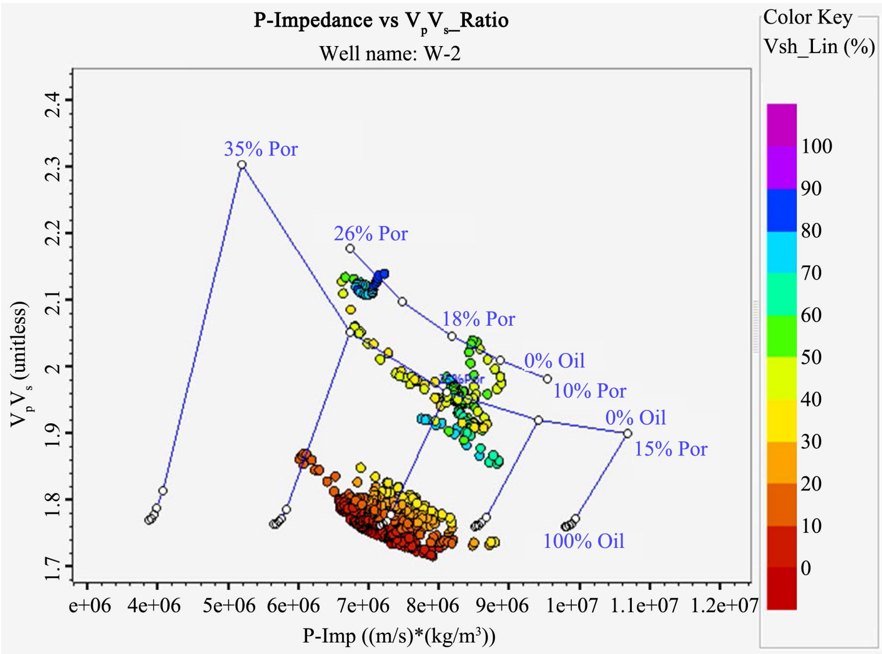

Figure 8. RPT for well 2 sand_5 reservoir interval.

Structural interpretation of the seismic data mapped major faults with big throws, several synthetic and antithetic faults and delineated horizons which correspond to the reservoir top (**Figure 9**). The synthetic and antithetic normal faults form attractive prospective structural traps and are in some cases associated with transpressional anticlines.

From this mapped horizon, time structure map was generated and displayed to show spatial variation in times and identification of anomalous zones in the area. The time structure map of Horizon_5 shows gradual topographical variation from NE-SW with major faults trending NW-SE perpendicular to the topographic gradient (**Figure 10**). The wells are bounded by the NW-SE dominant trending faults to the north and south of the study. Wells_5 and _9 lies on the anticlinal structure to the south (low time), while wells_2, _3 and _4 are located on the flank of anticline to the north (high time). These revelations support the observed variations in depth and thicknesses of the correlated reservoirs across wells in the study.

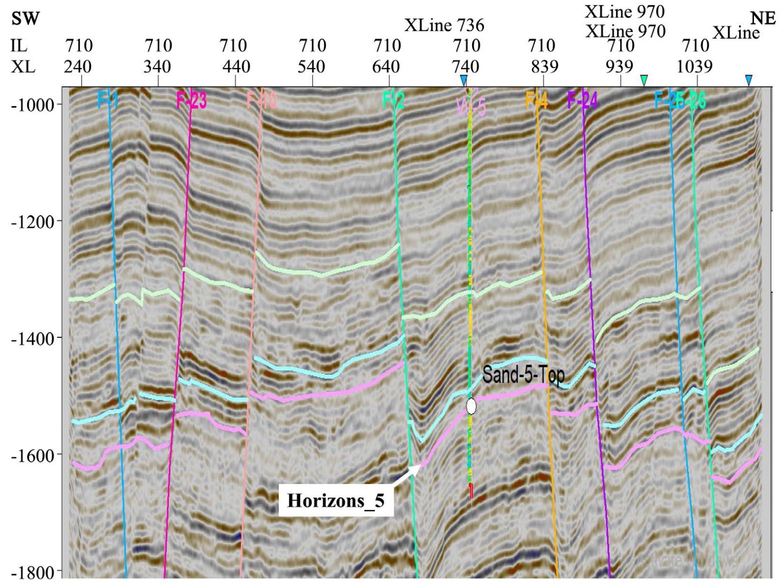

Figure 9. Seismic cross section showing wells, faults and horizons.

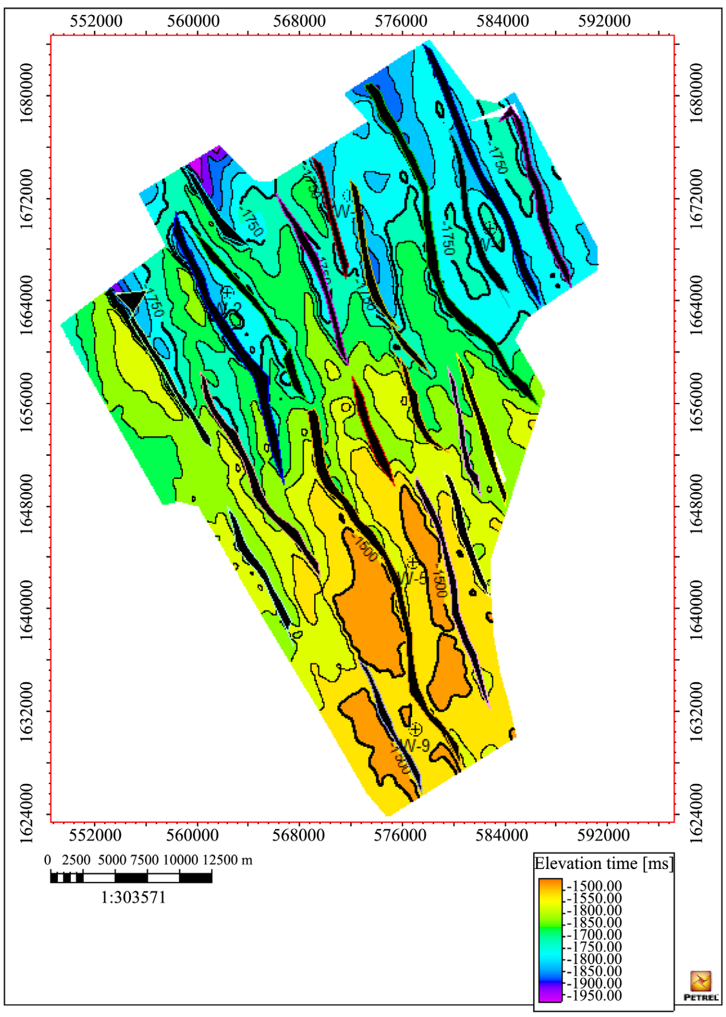

Figure 10. Time structure map along Horizon_5.

Time slices of the inverted seismic attributes, I_p and V_pV_s ratio taken along Horizon_5 show strong lateral variations in lithology and fluid distributions (Figure 11 and Figure 12). Results show that the wells lie in medium to high I_p and V_pV_s ratio zones. Though these attribute properties vary in amplitude values, nevertheless, they indicate hydrocarbon presence in the wells. Their apparent amplitude variations are attributed to variation in consolidation and cementation of the reservoir matrix in Termit basin. The shale/mudstone exhibits low I_p and V_pV_s ratio attribute characteristics in the basin. These medium to high impedance zones are associated with hydrocarbon (oil) charged consolidated and cemented sands in the field. The high I_p zones in the attribute map away from well control points are associated with brine sands and shales/mudstones, respectively.

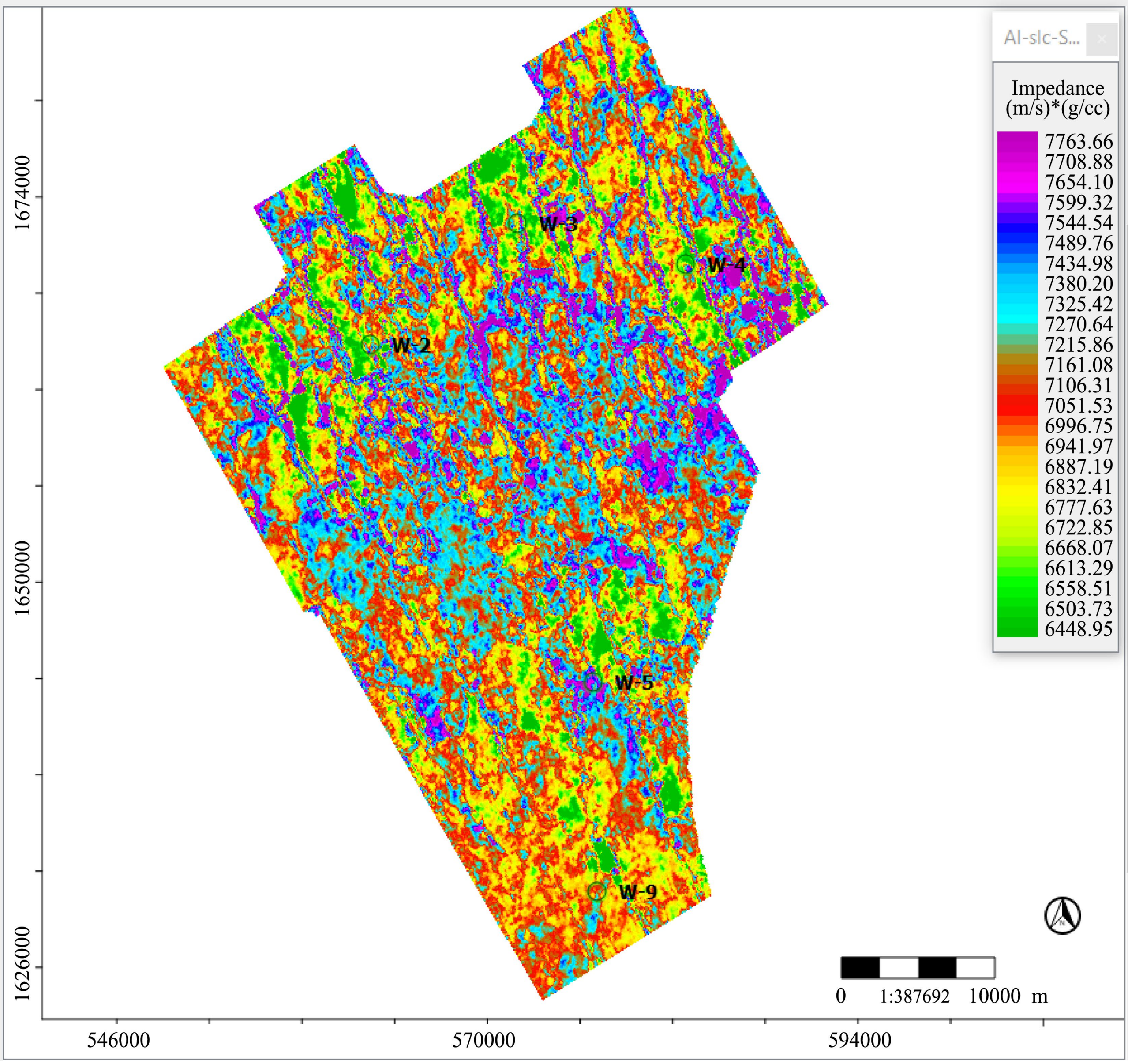

Figure 11. I_p attribute amplitude map for Horizon_5.

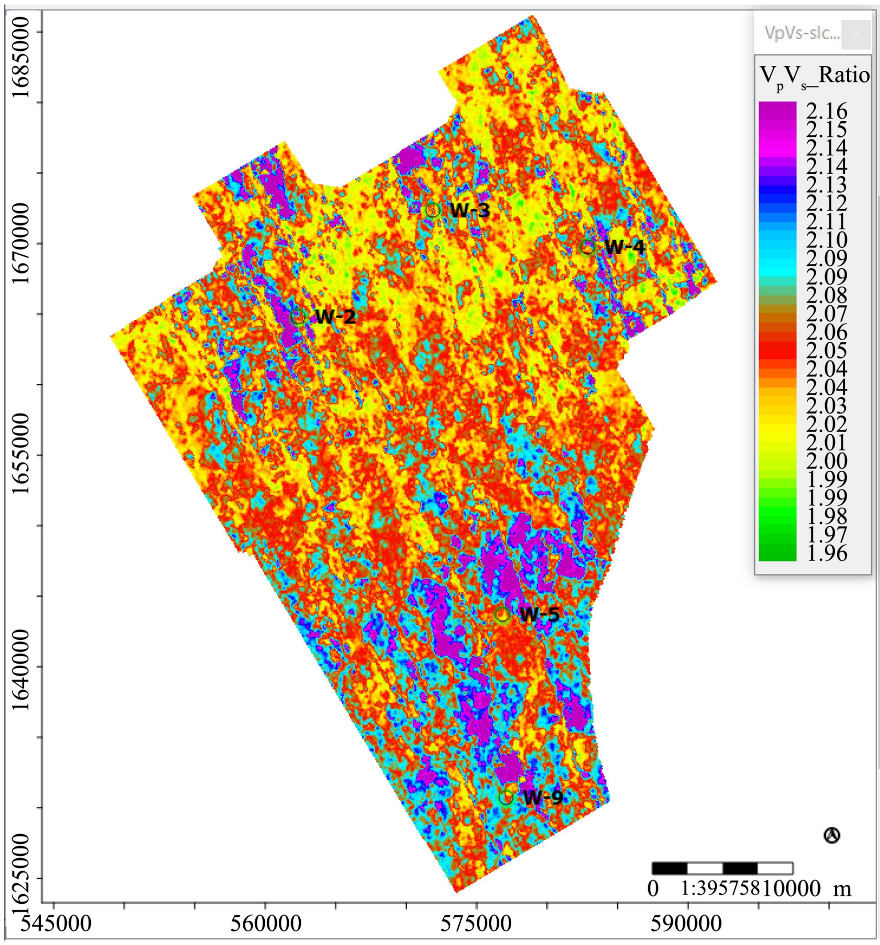

Figure 12. V_p/V_s ratio attribute amplitude map for Horizon_5.

The Vp/V_s attribute horizon map show variations in V_p/V_s characteristics in the field V_p/V_s attribute property is characterized by low (green) to high (purple) anomalous zones in the horizon map. The cross-section of inverted I_p and V_p/V_s ratio with inserts of the GR log and the seismic Horizon_5 (**Figure 13**), indicate lateral and vertical variations in these attribute properties. Three zones corresponding to different reservoir and non-reservoir lithofacies, that is, shale, hydrocarbon sand and cemented sand, respectively were mapped on each section and cross plotted.

The crossplot of the inverted V_p/V_s ratio vs. I_p for the mapped zones (**Figure 14**), reveals that oil sands are characterised by low to moderate V_p/V_s ratio and moderate to high I_p values, while the cemented oil sands exhibit moderate V_p/V_s ratio and high I_p. The shales/mudstones are characterised by high V_p/V_s ratio and low I_p.

The seismic attributes crossplot (**Figure 14**) was superimposed on the locally built RPT in the study (**Figure 15**). Results show distinct data clusters corresponding to different lithologies and pore fluids in the reservoir. The oil saturated sands and cemented oil sands plot below the sand line with characteristic low to moderate V_p/V_s and moderate to high I_p signatures. The porosity of these sands are

24% to 28% for the oil saturated sands and 23% to 17% for cemented oil, with an average of 26% and 20% respectively. Hydrocarbon saturation varying from about 20% < 100% with average of 60%.

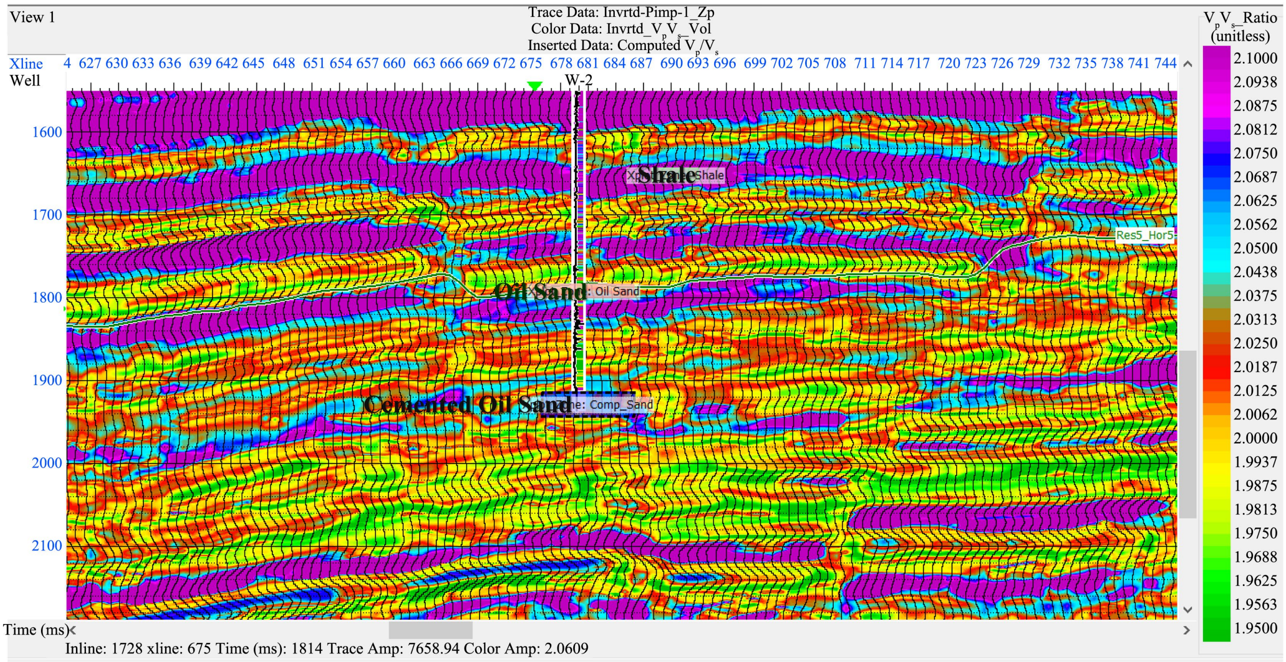

Figure 13. Inverted V_p/V_s seismic section showing picked horizons and the crossplot zones corresponding to shale and hydrocarbon sand.

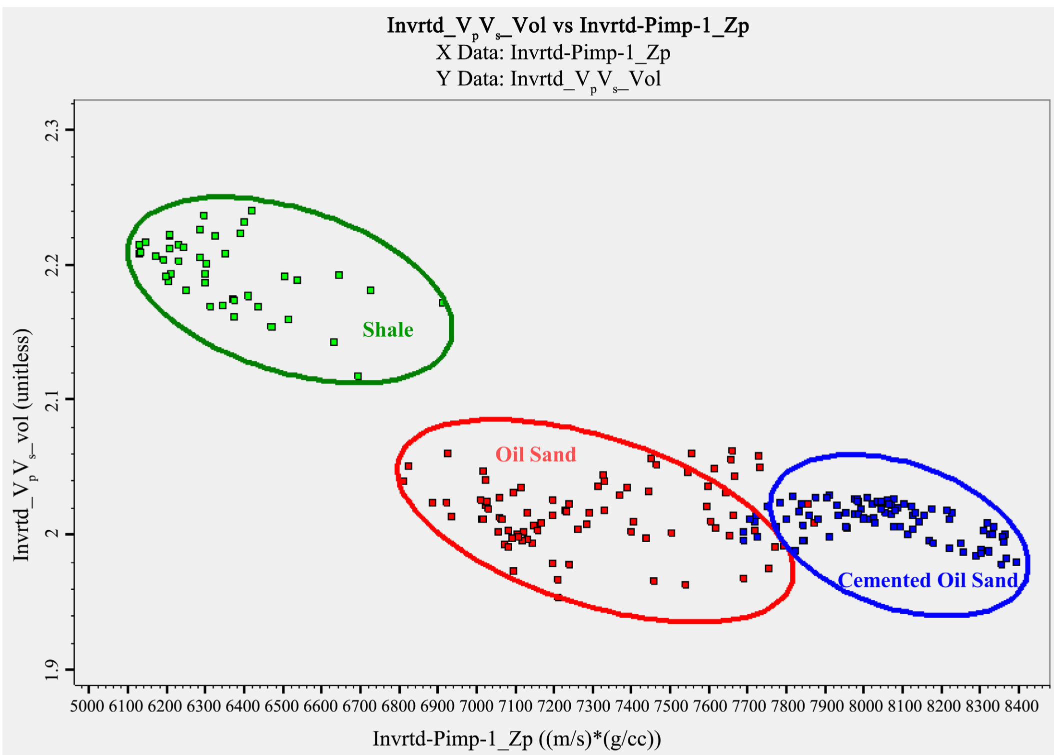

Figure 14. Inverted V_p/V_s vs. I_p crossplot showing shale and hydrocarbon sands.

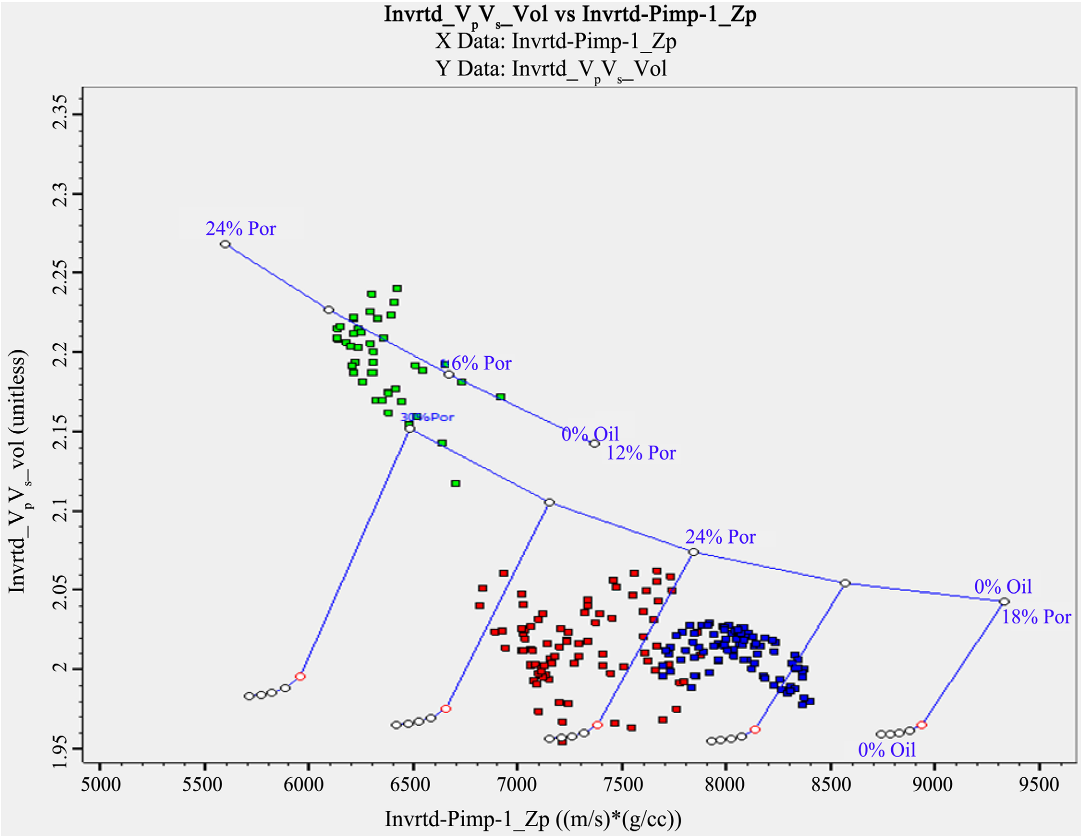

Figure 15. Cross plot of inverted V_p/V_s vs. I_p underlain by localised RPT.

The RPT (V_pV_s vs. I_p), from inverted elastic properties completely discriminated lithology fluid. The shales/mudstones plot mostly below the shale line. The sand and shale lines represent the trends of the sand and shale compactions with decreasing porosities in the increasing I_p direction. The lines perpendicular to the sand line represents the trends of the pore fluid saturation in the reservoir. The hydrocarbon sands discriminate from brine sands and shales by characteristic low to moderate V_p/V_s signature in contrast to the I_p property. However, brine sands plot towards the zero-oil saturation along the fluid line with almost same I_p with the unconsolidated sands in the reservoir. This result indicates that hydrocarbon sands may not be completely discriminated from brine sands on the basis of the I_p property in the basin.

5. Discussion of Results

The analyses and evaluation of the Sokor formation reservoirs of the Termit basin was complex as expected, given the fact that is it known for its inherent heterogeneity and anisotropy. Using the available wells, the mapped reservoir sands were correlated across the field. The correlated wells mapped reservoir sandstones continuously with varying thicknesses and depths across wells. This suggests faulting and uplift associated with tectonics that has considerably impacted sedimentary processes, hydrocarbon generation and maturation in the basin as observed by

[21]. It showed that the sands increased in thickness from point to point and there were also variations in the depth. These depth variations very probably indicate that tectonic activities may have had a significant influence on the sediments and by extension on the generation and maturation of hydrocarbon in the basin as observed by [21]. Each reservoir interval has excellent hydrocarbon potential and quite good reservoir petrophysical parameters. These are best in sand_5 reservoir interval, having estimated thickness, porosity, shale volume, water saturation, and saturation of hydrocarbon values of 61.0 m, 24.4%, 16.4%, 16.6%, and 83.4%, respectively.

Knowing the heterogeneous and anisotropic nature of the basin, the discrimination of reservoir sands from shales/mudstones and hydrocarbon sands from brine sands in such LCLR reservoirs from conventional petrophysical analysis alone could give false results that undermine petrophysical evaluation at the well scale thus impacting the reservoir assessment at field level. Therefore, quantitative rock physics approach is adopted in the present study for enhanced reservoir characterization in Termit basin.

The result of the rock physics crossplot analysis shows that sand_5 reservoirs is characterized by medium to high I_p values within the hydrocarbon bearing sandstone intervals. The low moderate V_p/V_s and high I_p values suggests a cemented and consolidated hydrocarbon reservoir sandstones, while the low to moderate V_p/V_s and moderately high I_p values suggests an unconsolidated but cemented hydrocarbon reservoirs sandstone [32]-[35].

In view of the above, sand_5 reservoir interval is more likely to be heterogeneous, hydrocarbon bearing and productive in the basin. The low I_p suggests that the shales/mudstones are unconsolidated and soft, with high I_p values indicating consolidated and hard shales/mudstones. These variations in texture will affect the sealing capacity of the shales/mudstones in the reservoir interval for each well [5].

Rock physics diagnostic plot of the reservoir interval revealed that grain size distribution of different lithologies is present within the reservoir interval which is related to the environment of deposition and burial history. Reservoir sandstones increases in the direction of moderate to high V_p at high reservoir ϕ, while the shaly sands and shale increases in the direction of moderate V_p and low ϕ. These variations are attributed to differences in burial depths, matrix composition and diagenetic alterations across wells resulting to increased stiffness at reduced porosity and high seismic velocities. RPD analysis revealed that the data points in most of our wells satisfactorily correlates with the constant cement model, suggesting that reservoir sandstones are consolidated and contact cemented with a constant cement volume throughout the rock. Besides, results of RPD emphasized that reservoir matrix varies between very clean and well sorted unconsolidated and uncemented sandstones to consolidated and cemented sandstones of high energy depositional environment to deteriorating and poorly sorted shaly sands and shales/mudstones of low energy depositional environment. In addition, reservoir interval was found to be composed of sediments from many sedimentary cycles in which both well to poorly sorted sandstones were deposited into interchanging energy depositional environments. This established that the reservoir interval is highly heterogeneous with respect to clay content and diagenetic cementation across the wells, resulting to property variations and possible compartmentalization of the reservoir across wells.

RPT plot of V_p/V_s vs. I_p for the representative well (well_2), show distinct lithology and pore fluid discriminations by the clustering of data points for a range of porosity and water saturation values. Hydrocarbon reservoir sandstones were diagnosed with a characteristic medium to high impedances and low to moderate V_p/V_s ratio. Hydrocarbon saturation and reservoir porosity are 82.5% and 24.5%, respectively, which correlates with the 83.4% and 24.4% hydrocarbon saturation and porosity values from the well-based petrophysical measurements. Brine shaly sands and shales/mudstones were diagnosed with medium to high impedances and moderate V_p/V_s ratio and medium impedance and high V_p/V_s ratio, respectively. This crossplot successfully discriminated sand from cemented sand and shale/mudstone in the basin. The results of the present study reflect the efficiency and application of rock physics diagnostics in evaluating reservoir microstructure and texture for quantitative reservoir characterization in Termit basin.

The time structure map shows reservoir topography arising from the NW and dipping towards the NE in the study area. The well locations lie on both low and high travel time values, a clear indication of the effects of faulting and tectonics in the formations. Major and dominant faults trend NW-SE and runs perpendicular to the topographic gradient. The NW-SE striking faults are the boundary faults, and are steep with large fault throws. They are believed to have their origin from the basement rocks and cut through Paleogene Sokor-1 and Sokor-2 formations, the Upper Cretaceous Madama Yogou and Donga Formations below the Neogene–Quaternary sediments [36]. The principal trapping system consists of both fault traps associated with anticlinal structures and stratigraphic traps, with shale/mudstones forming the reservoir seals. The reservoirs are fault bounded as evidenced by the location of the wells which could be providing the migration paths and/or traps for the hydrocarbons. Due to the complex fault geometry the reservoirs may or may not be connected since the wells appear to lie in different fault blocks.

The model-based inverted reflectivity attributes obtained from seismic data map hydrocarbon from non-hydrocarbon zones. The inverted seismic attribute sections and horizon maps show both vertical and lateral variation in the reflectivity attributes (I_p, V_p/V_s), around and beyond the well locations. The lateral and vertical variation in the inverted attributes could be lithologic (sand, shaly sands, mudstone), structures and pore fluid variations. This can be related to the environment of deposition and burial history. The vertical increase in the reflectivity attributes may be due gradual compaction of underlying sediment due to overburden pressure, leading to cleaner and more consolidated reservoir sandstone intervals ([37]).

The moderately high I_p values indicate that the sand is clean and cemented [37]. from rock physics diagnostic which indicated that the reservoir sand is constant cemented. The low to moderate V_p/V_s indicate oil bearing reservoir sand. This clean hydrocarbon reservoir sands have low S_w and V_{sh} and high ϕ, which is in agreement with the results of the petrophysical formation evaluation and well-based cross plot analyses in the basin [5]. Therefore, the study has successfully delineated clean reservoir sands that are possibly hydrocarbon charged beyond the existing well locations that could be regarded as new prospects in the field with low S_w and V_{sh} and high ϕ characteristic. These could be considered for field appraisal or development opportunity [37].

Further investigation of the hydrocarbon bearing zones done using inverted seismic attributes cross plots and well-based rock physics template (RPT) of V_p/V_s vs. I_p for selected zones away from well location show variation in lithology, fluid saturation, porosity and compaction. From the cross plots analysis, lithology and pore fluids can be discriminated and characterised, respectively. Hydrocarbon sands plot with medium to high I_p and low to moderate V_p/V_s ratio, while shales/mudstones plots with low I_p and high V_p/V_s ratio, which is similar to the result obtained from RTP analysis. Besides, the inverted V_p/V_s vs. I_p crossplot with superimposed RPT show distinct lithology and pore fluid discriminations by the clustering of data points for a range of porosity and water saturation values. Hydrocarbon reservoir sandstones were predicted with a characteristic medium to high impedances and low to moderate V_p/V_s ratio as a result of increasing fluid saturation causes a decrease in velocities (V_p and V_s), and decrease in density [4] [7]. In addition, reservoirs properties of porosity and hydrocarbon saturation were predicted and correlated with the well measurements. Again, inverted seismic attribute cross plot analysis and RPT successfully predicted the reservoir rock properties and discriminated the reservoir and its fluid beyond well location which could be regarded as new prospects.

6. Conclusions

Quantitative reservoir characterization has been carried out in the Eocene Sokor-1 Formation reservoir interval in Termit basin through the integration of petrophysics, rock physics models and templates of inverted seismic attributes using well logs and 3D PSTM seismic data.

The analyses suggest that, the mapped reservoir intervals have averagely good petrophysical properties and characterized by LCLR. The time structure map of the study shows reservoir topographic variation from NE-SW, with major faults trending NW-SE and NNW-SSE. The hydrocarbon trapping mechanism in this field is mostly structural with minor expression of stratigraphic enclosures, and shale/mudstone seal, with reservoir being productive in the basin. In the reservoir interval the sandstones are in some part cemented and consolidated, whereas they are cemented but unconsolidated in other part of the field.

Quantitative crossplots and RTP of extracted seismic elastic properties from inverted seismic data describe better the layer property of the mapped reservoir interval and give emphasize of the facies change and fluid saturation of reservoir. The amplitude varies from bright to dim with both continuous and discontinuous amplitude. The predicted reservoir lithology differentiation, porosity and hydrocarbon saturation away from wells points across the field correlated with the well-based RPT crossplot and show concordance with average properties derived from well data analysis.

The study has improved understanding of the reservoir structure, sedimentation, fluid saturation and other geologic or reservoir properties such as burial and diagenetic history in Termit basin. This approach can help in basin and fields with similar geologic settings for exploration and production business. In particular, by new prospects generation, optimizing exploration and reservoir management success, improving wells longevity, optimizing reservoir performance as well as hydrocarbon recovery.

Acknowledgements

We would like to thank The Ministry of Petroleum, Niger Republic, for providing the data for this study. Our thanks also go to World Bank African Centre of Excellence, Centre for Oil Field Chemical Research (ACE-CEFOR), University of Port Harcourt, for giving opportinuty to conduct this research and providing a frame to enhance real sustainable progress in oil and gas industry in Africa.

Conflicts of Interest

The authors declare no conflicts of interest regarding the publication of this paper.

References

[1] Fanchi, J.R. (2002) Fundamentals of Reservoir Characterization. In: Fanchi, J.R., Ed., *Shared Earth Modeling*, Elsevier, 170-181. https://doi.org/10.1016/b978-075067522-2/50010-0

[2] Chopra, S. and Marfurt, K. (2006) Seismic Attributes—A Promising Aid for Geologic Prediction. *CSEG Recorder*, **31**, 111-121.

[3] Avseth, P., Dvorkin, J., Mavko, G. and Rykkje, J. (2000) Rock Physics Diagnostic of North Sea Sands: Link between Microstructure and Seismic Properties. *Geophysical Research Letters*, **27**, 2761-2764. https://doi.org/10.1029/1999gl008468

[4] Avseth, P.A. and Odegaard, E. (2004) Well Log and Seismic Data Analysis Using Rock Physics Templates. *First Break*, **22**, 37-43. https://doi.org/10.3997/1365-2397.2004017

[5] Amadou, H., Ehirim, C.N. and Dagogo, T. (2021) Well-Based Quantitative Reservoir Characterization of Eocene Sokor-1 Formation, Termit Basin, Niger. *International Journal of Geosciences*, **12**, 159-169. https://doi.org/10.4236/ijg.2021.122010

[6] Avseth, P., Mukerji, T., Mavko, G. and Dvorkin, J. (2010) Rock-Physics Diagnostics of Depositional Texture, Diagenetic Alterations, and Reservoir Heterogeneity in High-Porosity Siliciclastic Sediments and Rocks—A Review of Selected Models and

Suggested Work Flows. *Geophysics*, **75**, 75A31-75A47.
https://doi.org/10.1190/1.3483770

[7] Simm, R. and Bacon, M. (2014) Seismic Amplitude: An Interpreter's Handbook. Cambridge University Press. https://doi.org/10.1017/cbo9780511984501

[8] Bjørlykke, K. (2010) Petroleum Geoscience: From Sedimentary Environments to Rock Physics.

[9] Veeken, P.C.H. and Da Silva, M. (2004) Seismic Inversion Methods and Some of Their Constraints. *First Break*, **22**, 47-70. https://doi.org/10.3997/1365-2397.2004011

[10] Olowofela, J.A., Kamiyole, I.C. and Adegoke, J.A. (2004) Effects of Clay Content and Porosity on Wave Velocities in Unconsolidated Media Using Empirical Relations. *Journal of Geophysics and Engineering*, **1**, 234-239.
https://doi.org/10.1088/1742-2132/1/3/009

[11] Subrahmanyam, D. and Rao, P.H. (2008) Seismic Attributes Review. *Seventh International Conference and Exposition on Petroleum Geophysics*, Hyderabad, 2008, 56-200.

[12] Dvorkin, J. and Alkhater, S. (2004) Pore Fluid and Porosity Mapping from Seismic. *First Break*, **22**, 53-57. https://doi.org/10.3997/1365-2397.2004003

[13] Chopra, S. and Castagna, J.P. (2014) AVO. Society of Exploration Geophysicists.
https://doi.org/10.1190/1.9781560803201

[14] Russell, B. (1999) Comparison of Post-Stack Seismic Inversion Methods. SEG Technical Program Expanded Abstracts.

[15] Dvorkin, J. and Nur, A. (1996) Elasticity of High-Porosity Sandstones: Theory for Two North Sea Data Sets. *Geophysics*, **61**, 1363-1370.
https://doi.org/10.1190/1.1444059

[16] Avseth, P., Mukerji, T. and Mavko, G. (2005) Quantitative Seismic Interpretation: Applying Rock Physics Tools to Reduce Interpretation Risk. Cambridge University Press. https://doi.org/10.1017/cbo9780511600074

[17] Bosch, M., Mukerji, T. and Gonzalez, E.F. (2014) 7. Seismic, Rock Physics, Spatial Models, and Their Integration in Reservoir Geophysics. In: *Encyclopedia of Exploration Geophysics*, Society of Exploration Geophysicists, M1-1-M1-56.
https://doi.org/10.1190/1.9781560803027.entry7

[18] Kabanda, A. (2017) Rock Physics Template (RPT) Technology for Reservoir Characterization and 4D Seismic Monitoring. *CSEG Recorder*, **42**, 30-33.

[19] Avseth, P., Veggeland, T. and Horn, F. (2014) Seismic Screening for Hydrocarbon Prospects Using Rock-Physics Attributes. *The Leading Edge*, **33**, 266-274.
https://doi.org/10.1190/tle33030266.1

[20] Genik, G.J. (1993) Petroleum Geology of Cretaceous-Tertiary Rifts Basins in Niger, Chad and Central African Republic. *American Association of Petroleum Geologists Bulletin*, **73**, 153-168.

[21] Warren, M.J. (2009) Tectonic Inversion and Petroleum System Implications in the Rifts of Central Africa. Frontiers and Innovation, CSPG CSEG CWLS Convention, 4-8.

[22] Mao, Z.Q., *et al*. (2007) Identification and Evaluation of Low Resistivity Pay Zones by Well Logs and the Petrophysical Research in China. *Petroleum Science*, **4**, 41-48.
https://doi.org/10.1007/bf03186572

[23] Chang, E. and Zung, L.S. (2017) 3D Reservoir Characterization of Field Deta, Termit Basin, Niger. In: *ICIPEG* 2016, Springer, 323-335.
https://doi.org/10.1007/978-981-10-3650-7_28

[24] Chang, E. and Zung, L.S. (2017) 3D Reservoir Characterization of Field Deta, Termit Basin, Niger. In: *Proceedings of the International Conference on Integrated Petroleum Engineering and Geosciences*, Springer, 323-335. https://doi.org/10.1007/978-981-10-3650-7_28

[25] Eyike, A., Werner, S.C., Ebbing, J. and Dicoum, E.M. (2010) On the Use of Global Potential Field Models for Regional Interpretation of the West and Central African Rift System. *Tectonophysics*, **492**, 25-39. https://doi.org/10.1016/j.tecto.2010.04.026

[26] Harouna, M. and Philp, R.P. (2012) Potential Petroleum Source Rocks in the Termit Basin, Niger. *Journal of Petroleum Geology*, **35**, 165-185. https://doi.org/10.1111/j.1747-5457.2012.00524.x

[27] Zhou, L., Su, J., Dong, X., Shi, B., Sun, Z., Qian, M., *et al.* (2017) Controlling Factors of Hydrocarbon Accumulation in Termit Rift Superimposed Basin, Niger. *Petroleum Exploration and Development*, **44**, 358-367. https://doi.org/10.1016/s1876-3804(17)30042-3

[28] Wan, L., Liu, J., Mao, F., Lv, M. and Liu, B. (2014) The Petroleum Geochemistry of the Termit Basin, Eastern Niger. *Marine and Petroleum Geology*, **51**, 167-183. https://doi.org/10.1016/j.marpetgeo.2013.11.006

[29] Genik, G.J. (1992) Regional Framework, Structural and Petroleum Aspects of Rift Basins in Niger, Chad and the Central African Republic (C.A.R.). In: Ziegler, P.A., Ed., *Geodynamics of Rifting*, Elsevier, 169-185. https://doi.org/10.1016/b978-0-444-89912-5.50036-3

[30] Liu, B., Wan, L., Mao, F., Liu, J., Lü, M. and Wang, Y. (2015) Hydrocarbon Potential of Upper Cretaceous Marine Source Rocks in the Termit Basin, Niger. *Journal of Petroleum Geology*, **38**, 157-175. https://doi.org/10.1111/jpg.12604

[31] Liu, J., Zhang, G., Li, Z., Tang, Y., Xiao, H., Lai, H., *et al.* (2019) Oil Charge History of Paleogene-Eocene Reservoir in the Termit Basin (Niger). *Australian Journal of Earth Sciences*, **66**, 597-606. https://doi.org/10.1080/08120099.2019.1568301

[32] Castagna, J.P. and Swan, H.W. (1997) Principles of AVO Crossplotting. *The Leading Edge*, **16**, 337-344. https://doi.org/10.1190/1.1437626

[33] Dvorkin, J., Gutiérrez, M.A. and Nur, A. (2002) On the Universality of Diagenetic Trends. *The Leading Edge*, **21**, 40-43. https://doi.org/10.1190/1.1445846

[34] Azeem, T., Chun, W.Y., Lisa, M., Khalid, P., Qing, L.X., Ehsan, M.I., *et al.* (2017) An Integrated Petrophysical and Rock Physics Analysis to Improve Reservoir Characterization of Cretaceous Sand Intervals in Middle Indus Basin, Pakistan. *Journal of Geophysics and Engineering*, **14**, 212-225. https://doi.org/10.1088/1742-2140/14/2/212

[35] Avseth, P. and Veggeland, T. (2015) Seismic Screening of Rock Stiffness and Fluid Softening Using Rock-Physics Attributes. *Interpretation*, **3**, SAE85-SAE93. https://doi.org/10.1190/int-2015-0054.1

[36] Wang, X., Wan, L., Jiang, Z., Liu, R., Wang, X., Tang, W., *et al.* (2017) Controlling Factors and Accumulation Model of Hydrocarbon Reservoirs in the Upper Cretaceous Yogou Formation, Koulele Area, Termit Basin, Niger. *Journal of Earth Science*, **28**, 1126-1134. https://doi.org/10.1007/s12583-016-0936-5

[37] Hassane, A., Ehirim, C.N. and Dagogo, T. (2021) Rock Physics Diagnostic of Eocene Sokor-1 Reservoir in Termit Subbasin, Niger. *Journal of Petroleum Exploration and Production Technology*, **11**, 3361-3371. https://doi.org/10.1007/s13202-021-01259-2