Rock physics diagnostic of Eocene Sokor-1 reservoir in Termit subbasin, Niger

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Abstract

Eocene Sokor-1 reservoir is intrinsically heterogeneous and characterized by low-contrast low-resistivity log responses in parts of the Termit subbasin. Discriminating lithology and fluid properties using petrophysics alone is complicated and undermines reservoir characterization. Petrophysics and rock physics were integrated through rock physics diagnostics (RPDs) modeling for detailed description of the reservoir microstructure and quality in the subbasin. Petrophysical evaluation shows that Sokor-1 sand₅ interval has good petrophysical properties across wells and prolific in hydrocarbons. RPD analysis revealed that this sand interval could be best described by the constant cement sand model in wells₂, ₃, ₅ and ₉ and friable sand model in well₄. The matrix structure varied mostly from clean and well-sorted unconsolidated sands as well as consolidated and cemented sandstones to deteriorating and poorly sorted shaly sands and shales/mudstones. The rock physics template built based on the constant cement sand model for representative well₂ diagnosed hydrocarbon bearing sands with low V_p/V_s and medium-to-high impedance signatures. Brine shaly sands and shales/mudstones were diagnosed with moderate V_p/V_s and medium-to-high impedance and high V_p/V_s and medium impedance, respectively. These results reveal that hydrocarbon sands and brine shaly sands cannot be distinctively discriminated by the impedance property, since they exhibit similar impedance characteristics. However, hydrocarbon sands, brine shaly sands and shales/mudstones were completely discriminated by characteristic V_p/V_s property. These results demonstrate the robust application of rock physics diagnostic modeling in quantitative reservoir characterization and may be quite useful in undrilled locations in the subbasin and fields with similar geologic settings.

Keywords Rock physics diagnostic · Rock physics template · Heuristic sand model · Reservoir microstructure

Introduction

Sedimentary rocks are considered as mechanical systems of mineral grains, pores and pore fluids formed by single or combinations of geologic processes. The environment of deposition and burial history controls textural and mineralogical characteristics of the rock and determines their geologic properties. The geologic properties, in turn, affect

seismic elastic parameters through the rock and hence the observable acoustic response on records. Understanding the relationships between geologic properties and the seismic elastic parameters via rock physics is vital to the quantitative reservoir quality and hydrocarbon prospect evaluation from well and seismic data (Avseth et al. 2000; Ødegaard and Avseth 2004).

Rock physics is an indispensable tool for quantitative interpretation in reservoir studies, providing 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 seismic elastic parameters such as P -wave velocity (V_p), S -wave velocity (V_s) and their ratio (V_p/V_s), acoustic impedance (P -Imp), bulk density and elastic moduli (Avseth et al. 2000, 2010; Simm and Bacon 2014). Through rock physics, texture and mineralogy of the reservoir rock can be evaluated and linked to the

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environment of deposition and diagenetic alterations (Avseth et al. 2010, 2014; Bjørlykke 2010).

Termit subbasin situated within the Chad Basin in Niger is filled with lower Cretaceous to Neogene sedimentary rocks (Fig. 1). The subbasin is hydrocarbon bearing with the major finds located in the upper Cretaceous to Paleocene–Eocene sandstones. Tectonic activities affected sedimentary processes such that structural, lithological and textural characteristics of the sediments are grossly impacted (Warren 2009). The reservoir sandstone intervals in some parts of the subbasin are radioactive with high clay content (Chang and Zung 2017), typical of low-contrast low-resistivity reservoirs (LCLRs) (Zhiqiang et al. 2007).

Discriminating reservoir sands from shales/mudstones and hydrocarbon sands from brine sands is complicated and tasking and undermines reservoir characterization in LCLRs using conventional petrophysical methods (Hassane et al. 2021). Therefore, the need for rock physics approach to evaluate reservoir microstructure and quality for enhanced reservoir characterization in the subbasin cannot be overemphasized.

Among the elastic parameters, elastic wave velocities (P- and S-wave velocities) of rocks exhibit heightened sensitivity to reservoir properties especially porosity. Wyllie et al. (1956) established a rock physics model showing a simple linear relationship between slowness (reciprocal of velocity) and porosity (ϕ) for water-saturated sandstones. Avseth et al. (2010, 2014), Bjørlykke (2010), Colin and Lennert (2011), Mahbaz et al. (2012) and Ahmad and Rowell (2013) showed how rock texture, environment of deposition and diagenesis could be evaluated from rock physics models of elastic moduli or velocities versus porosity crossplot planes. Generally, sediments exhibit distinct trends or clusters on the elastic moduli or velocities vs. porosity crossplots, due to textural and compositional differences (Dvorkin and Nur 1996; Dvorkin et al. 2002; Avseth et al. 2005). Therefore, rock physics models that relate elastic parameters to porosity and mineralogy form a critical part of rock physics diagnostics (RPD).

RPD implies the use of rock physics models to predict rock texture from elastic properties vs. porosity crossplots (Avseth et al. 2005). A variety of models such as the theoretical, empirical, and heuristic can be used in rock physics analysis, each with its advantages and drawbacks (Mavko et al. 2009; Avseth et al. 2010). The heuristic model, which is a combination of theoretical and empirical rock physics models, provides better description of the reservoir microstructure and quality (Avseth et al. 2010). This includes the friable sand model (Dvorkin and Nur 1996), contact cement model (Dvorkin et al. 1994) and constant cement model (Avseth et al. 2005). These heuristic rock physics models provide a simple and practical way to model a wide range of elastic property–porosity trends describing depositional, sorting and cementation trends. This is done by fitting the observed data trends on elastic property versus porosity crossplot planes to appropriate rock physics models, to adequately characterize sediment texture (diagenetic cement, grain size, sorting, and clay content), evaluate reservoir quality and reservoir characterization (Avseth et al. 2005).

The prediction of a rock physics model that explicitly describes the reservoir is of particular importance, and this can be used to build RPT of V_p/V_s ratio versus acoustic impedance crossplot (Ødegaard and Avseth 2004), consistent with the local geology (Dvorkin and Nur 1996). 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 at well and away from well control points (Avseth et al. 2005; Bosch et al. 2017; Kabanda 2017).

The present study integrates petrophysics and rock physics modeling through rock physics diagnostics to characterize LCLR Eocene sandstone reservoir interval. This will significantly reduce exploration risk and improve reservoir mapping in Termit subbasin.

Geology of the study area

Termit subbasin consists of Donga, Yogou and Madama Formations in the upper Cretaceous, Sokor-1 in the Paleocene–Eocene and Sokor-2 in the Oligocene (Fig. 2). These formations were deposited in fluvial, lacustrine and marine environments during the various tectonics, with thickness ranging from about 3000 m to more than 12000 m (Genik 1992, 1993; Harouna and Philp 2012). The Donga Formation consists of marine sandstones at the base, mudstones, shales and siltstones in the middle and upper intervals.

The Yogou Formation consists mainly of mudstone and shale with disseminated sandstone intervals deposited in marine and transitional environments. The Upper Cretaceous marine mudstones of the Donga and Yogou

Fig. 1 Location map of the study area (Genik 1993)

Fig. 2 Composite stratigraphic column of the Termit basin (Zhou et. al. 2017)

formations are the main source rock recognized in the basin (Zhou et al. 2017). The Madama Formation is characterized by massive fluvial sandstones interbedded with thin layers of muddy sandstones and coal seams (Liu et al. 2012, 2015; Wan et al. 2014). The Paleocene–Eocene Sokor-1 Formation consists of sandstones interbedded with shales/mudstones. Sokor-1 sandstones comprise six sand groups from top to bottom: *E0*, *E1*, *E2*, *E3*, *E4* and *E5*, which are the main producing intervals in the subbasin. The Sokor-2 Formation is mainly composed of lacustrine mudstones with the upper part consisting mainly of sandstone (Zhou et al. 2017; Wan et al. 2014). The overlying Neogene to Quaternary stratigraphic sequence consists of thick continental sediments, including alluvial, fluvial, deltaic and lacustrine sediments (Genik 1992, 1993).

Two petroleum systems Yogou-Sokor-1 and Sokor-1-Sokor-2 were identified, with most of the hydrocarbon discoveries located in the upper Cretaceous Yogou and Sokor-1 Formations (Liu et al. 2015, 2019). The second member of the Sokor Formation (Sokor-2) acts as the regional seal in Sokor-1-Sokor-2 petroleum system, while the interbedded shale/mudstone in Sokor-1 and inter-channel mudstone in Yogou acts as local barrier/seal, respectively (Zhou et al. 2017).

These formations are penetrated and dissected by north-west–southeast (NW–SE) synthetic and north-northwest

south-southeast (NNW–SSE) antithetic normal faults, respectively (Fig. 3), and northeast–southwest (NE–SW) transpressional anticlines (Lai et al. 2020). The trap mechanism is mostly structural that favors hydrocarbon migration and accumulation with minor expressions of stratigraphic traps (Wan et al. 2014; Genik 1992).

Method of study

The principal data used for this study are well-log data from five wells (2, 3, 4, 5, and 9) spread across the field (Fig. 4). The well data are comprised of sonic (DT), gamma ray (GR), resistivity (LLD and LLS), neutron (NPHI/CNL) and density (RHOB) logs.

The study was carried in three main steps. The first step was the petrophysical analysis of the well logs. In this step, reservoir evaluation and analysis were carried out using gamma ray, resistivity and crossplots of shallow (LLS) vs. deep (LLD) resistivity and density vs. neutron logs to identify and map reservoirs and characterize pore fluids. The mapped reservoir interval was evaluated to estimate reservoir properties such as volume of shale (*V_{sh}*), porosity (*φ*) and water saturation and subsequently correlated across all the five wells in the field. Furthermore, pseudo-logs of shear wave velocity (*V_s*), bulk modulus,

Fig. 3 Structural and stratigraphic framework of Termit basin (Genik 1993; Wan et al. 2014; Zhou et al. 2017)

Fig. 4 Base map of the study the study area showing the well locations

shear modulus and Poisson's ratio were generated through petrophysical rock physics transforms (Fig. 5). The shear wave velocity (V_s) was estimated from the measured compressional velocity (V_p) using Greenberg and Castagna (1992) empirical relations for porous rock.

The second step consists of rock physics diagnostics of the delineated reservoir interval. The reservoir interval was fluid substituted to 100% brine in order to bring the entire reservoir interval to a common fluid denominator. This was done to remove the effect of pore fluid variations in the wells that could affect the elastic properties so that effects due to texture and mineralogy could be examined explicitly. Fluid substitution modeling (Gassmann 1951) was carried out to estimate elastic waves velocities (V_p and V_s) and density (ρ) for the brine-saturated interval and crossplots of V_p versus ϕ (por) were developed and several heuristic diagnostic sand models (friable sand model, contact cement model and constant cement model) were fitted and evaluated to appropriately describe the reservoir interval.

Finally, the fitting rock physics sand model was employed and constrained by the local geology, to generate a suitable RPT of V_p/V_s versus acoustic impedance in the subbasin. Geologic constraints on rock physics model include lithology, mineralogy, burial depth, diagenesis (cementation), pressure and temperature.

Results presentation

Reservoir sand_5 was delineated and pore fluids were characterized by low-to-medium GR and low-resistivity log responses with fairly large density-neutron and LLS versus LLD crossover and separations, respectively, across the five wells. The mapped reservoir interval consists of fairly thick sandstone beds with intercalations of thin shales/mudstones within Sokor-1 Formation. Results of the petrophysical evaluation show that the reservoir interval has average reservoir properties of 61.4 m, 16.4%, 83.6%, 24.4% and 16.6% for thickness (t), volume of shale (V_{sh}), net-to gross

Fig. 5 Elastic and petrophysical logs for Well_2 Sand_5 reservoir interval

(N/G), porosity (ϕ) and water saturation (S_w), respectively (Table 1).

These results suggest that sand_5 reservoir interval has good reservoir characteristics across wells and prolific in hydrocarbons (oil). The reservoir interval was correlated across wells and result shows continuous but varying reservoir thicknesses and depths from well to well, which could be related to the tectonics of the subbasin (Fig. 6). Of the five wells evaluated, well_2 sand_5 reservoir interval has the best reservoir properties and therefore has been chosen as the representative well for RPT analysis.

Rock physics diagnostic plot of V_p versus ϕ (Por) for sand_5 reservoir interval color coded with V_{sh} produced distinct data trends in each well (Fig. 7). Wells_2 and _3 exhibit better data cluster and well-defined trends than wells_4, _5 and _9. The data trends generally fall fairly 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. The sandstones and shales/mudstones are mostly dominated by quartz and clay mineral grains, respectively.

Reservoir velocities varied from 2700 to 3800 m/s and porosities from zero end point (mineral point) to the second end point at high porosity 36%. On the basis of the V_p versus ϕ crossplot, reservoir matrix mostly of clean sandstones (low V_{sh}) dominates at $V_p > 3700$ m/s and reservoir $\phi > 22\%$ in wells_2 and _3, while the shaly sands and shales/mudstones increase in the direction of moderate $V_p < 3250$ m/s and $\phi < 20\%$ (Fig. 7a, b). In wells _4, _5 and _9, the sandstones increase in the direction of moderate $V_p < 3250$ m/s and $\phi > 22\%$ and the shaly sands and shales/mudstones at $V_p > 3250$ m/s and $\phi < 20\%$ (Fig. 7c–e). These apparent variations in elastic wave velocities of the three lithofacies (sandstones, shaly sand and shales/mudstones) could be ascribed to varying degrees of compaction, clay content and diagenetic cementation of the reservoir matrix in the wells. Results suggest that the reservoir sandstones in wells_2 and

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

Fig. 6 Sand_5 reservoir interval correlated across wells

_3 are more compacted than in wells_4, _5 and _9, but at comparable reservoir porosities. In the diagnostic plot for the all five wells (Fig. 7f), the data point's plots horizontally on the $V_p - \phi$ plane are in line with the results of the individual crossplots in the respective wells/intervals validating the initial results. Result show that sand_5 reservoir interval is highly heterogeneous with respect to clay content and diagenetic cementation across the wells.

Results of the rock physics diagnostics revealed that of the three heuristic sand models evaluated (friable sand model, contact cement model and constant cement model), the constant cement sand model satisfactorily and quantitatively honors data points in wells_2, _3, _5 and _9 (Fig. 7a–e), while the friable sand model honors data points in well_4 (Fig. 7c). This suggests that reservoir sandstones are contact cemented with a constant cement volume throughout the rock in wells_2, _3, _5 and _9, and friable in well_4.

To validate the result of the RPD and situate sand_5 reservoir interval to their appropriate depth points in the representative well_2, a crossplot of ΦN versus ΦD color-coded with V_{sh} , depth and V_p , respectively, was generated (Fig. 8a–c). The crossplot with V_{sh} color code (Fig. 8a) distinguished clean and well-sorted sandstones (green ellipse) from shaly sands (red ellipse) and shales/mudstones (blue

ellipse). Two distinct sandstone packs are recognizable from the crossplots with depth and V_p color codes, respectively, (Fig. 8b, c). These are the upper, low-velocity uncemented sands at subsurface depth < 1990 m (purple ellipse) and basal high-velocity cemented sandstones at subsurface depth > 2020 m (black ellipse). The shaly sands occur at subsurface depths < 1990 m, while shales/mudstones occur partly at depths < 1990 m and > 2000 m (Fig. 8b, c).

The plot shows decreasing density porosity with increasing diagenetic cementation of the grain contacts at relatively low-neutron porosity for the consolidated and cemented sandstones with associated $V_p > 3250$ m/s, whereas unconsolidated and friable sandstones show high-density porosity and corresponding low-neutron porosity with $V_p < 3250$ m/s within the reservoir interval. The shaly sands and shales/mudstones exhibit decreasing density porosity but with increasing neutron porosity due to the increasing effect of clay mineralogy in the reservoir interval.

RPT plot of V_p/V_s versus P -Imp based on the constant cement model for representative well_2 sand_5 reservoir interval (Fig. 9) shows distinct lithology and pore fluid discriminations by the clustering of data points for a range of porosities (0–35%) and saturations (0–100%), with well-defined sand and shale lines. The sand line indicates the

Fig. 7 Diagnostic plots of V_p versus 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

formation compaction trend, and the direction orthogonal to this line is the fluid saturation trends parallel to each other at distinct porosities. Above the sand line is the shale line

indicating shale compaction trend. Both lines are characterized by increasing compaction of the sediments for decreasing porosities. Porosity increases in the low impedance

Fig. 8 Crossplots Φ_N versus Φ_D : **a** color-coded with V_{sh} , **b** color-coded with depth, **c** color-coded with V_p

Fig. 9 RPT for well_2 sand_5 reservoir interval

direction, while hydrocarbon saturation increases in the low V_p/V_s direction, and clay content (shaleness) increases in the high V_p/V_s direction. Result shows hydrocarbon sandstones were diagnosed with medium-to-high impedance and low V_p/V_s ratio, with average hydrocarbon saturation and porosity values of 82.5% and 24.5%, respectively. Brine shaly sands were diagnosed with medium-to-high impedance with moderate V_p/V_s and the shales/mudstones with medium impedance and high V_p/V_s .

Discussion of results

Reservoir rocks (sandstones, shaly sands and shales/mudstones) and pore fluids were discriminated and characterized by poor property contrast in the log responses. Petrophysical analysis delineated and mapped Sand_5 reservoir interval by moderate GR and low-resistivity log signatures, whereas shales/mudstones were mapped by moderately high GR and low-resistivity log signatures. These characteristic log responses are attributed to high clay and radioactive mineral content in the rocks; typical of most wells in the Termit subbasin are obvious characteristics of LCLR reservoirs (Zhiqiang et al. 2007; Chang and Zung 2017). Further petrophysical evaluation revealed that Sand_5 interval exhibits fairly good reservoir properties (thickness, porosity, volume of shale, water saturation and hydrocarbon saturation values of 61.0 m, 24.4%, 16.4%, 16.6% and 83.4%, respectively) and continuous across the five wells but with varying thicknesses and depths.

Reservoir characterization of LCLR sand_5 interval using only conventional petrophysical method could give failed results due to poor property contrasts at the well scale. Therefore, rock physics approach was adopted to evaluate Eocene sandstone reservoir microstructure and quality for robust quantitative reservoir evaluation in the subbasin. Rock physics diagnostic plot of V_p versus ϕ for sand_5 reservoir interval produced distinct data trends that tend to be fairly horizontal suggesting grain size distribution of different lithologies related to the environment of deposition and burial history (Avseth et al. 2010). From the crossplots, reservoir sandstones increase in the direction of increasing V_p at fairly high reservoir ϕ in wells_2 and_3, while the shaly sands and shale increase in the direction of moderate V_p and ϕ . In wells_4, _5 and_9, the sandstones increase in the direction of moderate V_p and high reservoir ϕ and the shaly sands and shales at moderate V_p and low ϕ .

These results suggest a cleaner and more consolidated reservoir sandstone interval in wells_2 and_3 than in wells_4, _5 and_9. These variations could be attributed to differences in the environment of deposition, burial depths and diagenetic alterations across wells resulting to increased matrix stiffness at reduced porosity and high elastic wave

velocities in wells_2 and_3 than the low velocity sands in wells_4, _5 and_9 (Avseth et al. 2000, 2010; Chopra and Marfurt 2006; Lai et. al. 2020). RPD analysis revealed that of the three heuristic sand models evaluated (friable sand, constant cement and contact cement sand models), the constant cement sand model quantitatively described reservoir microstructure in wells_2, _3, _5 and_9, and the friable sand model in well_4. These results suggest that reservoir sandstones in wells_2, _3 _5 and_9 are consolidated and contact-cemented, while in well_4 reservoir sandstones are unconsolidated and uncemented.

These results were subsequently validated for representative well_2 sand_5 interval by crossplotting ΦN versus ΦD color-coded with V_{sh} , depth and V_p , respectively. Result shows distinct sandstone packs, namely the upper low-velocity unconsolidated sandstones at subsurface depth < 1990 m and basal high-velocity consolidated and cemented sandstones at subsurface depth > 2020 m. The upper unconsolidated and friable sandstones exhibit high-density porosity and low-neutron porosity with $V_p < 3250$ m/s, whereas the basal consolidated and cemented sandstones exhibit decreasing density porosity due to increasing diagenetic cementation of the grain contacts at relatively low-neutron porosity with associated $V_p > 3250$ m/s. The low-neutron porosity of both sands in the reservoir is an indication of clean and well-sorted sandstones with insignificant clay content. The shaly sands occur at subsurface depths < 1990 m, while shales/mudstones occur partly at depths < 1990 m and > 2000 m. The shaly sands and shales/mudstones exhibit decreasing density porosity but with increasing neutron porosity attributed to increasing clay content in the matrixes.

The reservoir matrix varies between very clean and well-sorted unconsolidated sands as well as consolidated and cemented sandstones of high-energy depositional environment to deteriorating and poorly sorted shaly sands and shales/mudstones of low-energy depositional environment (Avseth et al. 2010, 2014; Chang and Zung 2017). These observations suggest that sand_5 reservoir interval is composed of sediments from many sedimentary cycles in which both well to poorly sorted sandstones were deposited into interchanging energy depositional environments and burial history. The present analysis shows 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 versus P-Imp for the representative well_2 and sand_5 interval built from the constant cement sand model shows 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 V_p/V_s ratio. 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. These results reveal that hydrocarbon sandstones and brine shaly sandstones cannot be discriminated completely on the basis of the impedance property as do the shales/mudstones since they exhibit similar impedance characteristics. However, hydrocarbon sandstones, brine shaly sands and shale/mudstones are completely discriminated by characteristic V_p/V_s property in the subbasin.

These revelations are especially important in the Termit subbasin where most of the reservoirs are less than one quarter of a wavelength thick with associated complexities in structure and poor matrix property contrasts. Based on RPT analysis, average hydrocarbon saturation and reservoir porosity are predicted to be 82.5% and 24.5%, respectively, which correlates with the 83.4% and 24.4% hydrocarbon saturation and porosity values, respectively, from well-based petrophysical measurements, validating the adequacy of the models.

Conclusion

Petrophysics and rock physics diagnostic modeling have been adopted in an integrated scheme to evaluate reservoir microstructure and quality for quantitative reservoir characterization in Termit subbasin. Sand_5 reservoir interval exhibits good reservoir characteristics and prolific in hydrocarbons, especially oil. RPD analysis revealed that sand_5 reservoir interval can be best described by the constant cement sand model in wells_2, _3, _5 and _9 and friable sand models in well_4. The matrix structure varied mostly from clean and well-sorted unconsolidated sands as well as consolidated and cemented sandstones of high-energy depositional environment to deteriorating and poorly sorted shaly sands and shales/mudstones of low-energy depositional environment. Through RPT analysis based on the constant cement model, the representative well_2 and sand_5 reservoir interval was diagnosed with a medium-to-high impedance and low V_p/V_s attributes characteristic of hydrocarbon saturation. Brine shaly sands and shales/mudstones were diagnosed with medium-to-high impedance and moderate V_p/V_s and medium impedance and high V_p/V_s , respectively.

On the basis of these results, it is obvious that hydrocarbon sandstones and brine shaly sandstones cannot be distinctively discriminated from the impedance property since they exhibit similar impedance characteristics. However, hydrocarbon sandstones, brine shaly sands and shale/mudstones are completely discriminated by their characteristic V_p/V_s property in the subbasin. These results demonstrate the robust application of RPD in evaluating

reservoir microstructure and quality for quantitative reservoir characterization in Termit subbasin.

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Declarations

Conflict of interest On behalf of all the co-authors, the corresponding author states that there is no conflict of interest.

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