



Rock physics analysis as a tool for enhancing characterization of Niger Delta deep water sands

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Abstract

This study is aimed at enhancing characterization of deepwater reservoir sands as a way of de-risking the exploration prospect in “N” field. The data used for the analysis consist of logs from suites of four wells. The petrophysical analysis of the two reservoirs (RES-1 and RES-2) of interest revealed that reservoir (RES-1) has fair to good petrophysical attributes while reservoir (RES-2) has good to excellent petrophysical attributes. Statistical relationships between compressional and shear velocity (V_p and V_s) were evaluated from dipole sonic log present in N-002 well using linear regression analysis. This localized relation with a correlation coefficient of 0.96 predicts V_s from V_p with high level of precision and fits a large population analysis of the wells. Compaction studies revealed that at depth of 3.2 km, quartz cementation of sands and velocity of sandstones became higher than that of shales. This depth represents a transition from mechanical to chemical compaction zone and therefore represents a significant seismic boundary in the studied field. Porosity-velocity crossplot of the reservoir sands revealed that only reservoir sand data points which contained 30 to 40% porosity plunge across the 15% clay line with most data points falling between 0.25 and 0.35 fraction and below 0.35 clay trend lines. This suggest high clay fraction within the sediments. Rock physics templates of constant, contact and friable showed that the reservoir sands are poorly cemented to unconsolidated. The two models indicate that the reservoir sands are both influenced by depositional and depth related diagenetic effects. This suggests that proper care has to be taken during the development of these reservoir sands due to high clay fraction which could affect oil and gas production.

Keywords Localized equation · Compaction trend · Clay fraction volume · Reservoir characterization · Cementation

Introduction

The recent increases in global demand for hydrocarbons and declining production from mature provinces are driving a new phase of international exploration for petroleum resources in deep offshore basin (Lewis et. al., 2008). These deep-water systems may include large volumes of unexplored hydrocarbon in several areas of the world (Pettingill, 1998).

The need to thoroughly evaluate prospects so as to determine optimal production strategies and also minimize risk that may be associated with hydrocarbon exploration has driven the development of an array of techniques in reservoir characterization. Similarly, the need to improve the physical understanding of seismic information through rock physics before using it in reservoir characterization has also been emphasized by many authors.

Rock physics is the link between rock properties and seismic interpretation. It is the fundamental constituent to the quantitative integration of surface seismic data, well logs and core information. It relates reservoir parameters such as porosity, permeability, fluid and lithology to depositional and diagenetic trends of sands, shales and shaly sands.

Various authors have established important relationships between seismic properties and reservoir parameters. Such include Han et al. (1986); Marion (1990); Yin (1992); Dvorkin and Nur (1996); Castagna et al. (1985); and Batzle and Wang (1992). Their approaches have

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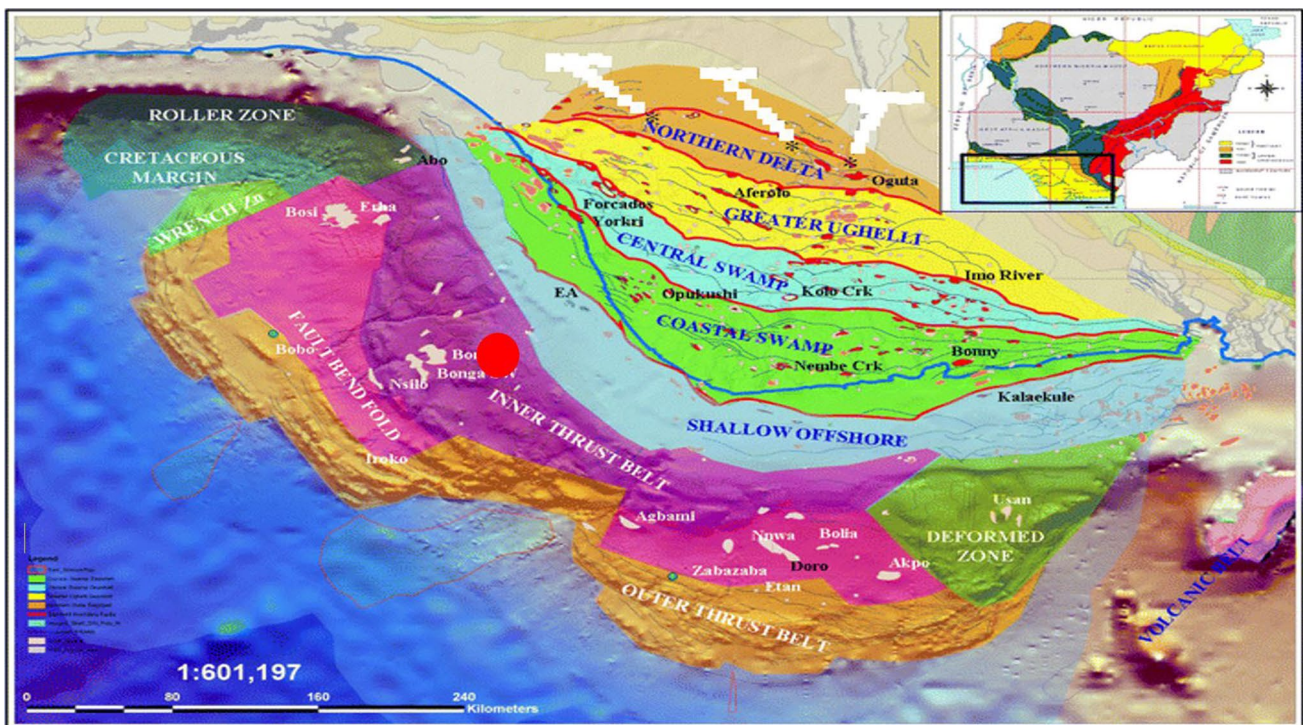
demonstrated the need for integrated approach in developing rock and fluid acoustic properties for the quantitative interpretation of seismic data.

Furthermore, the existing rock physics theories and models can be applied to predict reservoir parameters from seismic data and well logs with greater success than just pure statistical conversions or interpretations of seismic amplitudes (Avseth et al., 2003). Moreover, the physical link should be combined with statistics to account for uncertainties related to variability in the rock physics parameters (Abe et al., 2018).

Finally, by understanding the link between geological parameters and rock physics properties, we can avoid certain ambiguities in seismic interpretation, including fluid-lithology, sand-shale and porosity-saturation ambiguities. The link between rock physics and various geologic parameters, including cement volume, clay volume and degree of sorting, allows us to perform lithology substitution from observed rock types at a given well location to rock types assumed to be present nearby. This study demonstrated how reservoir sands can be quantitatively understood by exploiting the quantitative tool of rock physics.

Location and geology of Niger Delta

The field is located about 120 km offshore Niger Delta basin in water depths ranging from 900 to 1300 m (Fig. 1). It was discovered in 1997 deep offshore western Niger Delta. The Niger delta is a large, arcuate delta of the typical, wave and tidal-dominated type (Weber and Daukoru, 1975; and Doust and Omatsola, 1990). It is situated in the Gulf of Guinea and extends throughout the Niger Delta Province as defined by Klett et al. (1997). From the Eocene to the present, the delta has prograded southwestward, forming different depobelts (Fig. 1) that represent the most active portion of the delta at each stage of its development (Doust and Omatsola, 1990). These depobelts form one of the largest regressive deltas in the world with an area of some 300,000 km² (Kulke, 1995), a sediment volume of 500,000 km³ and a sediment thickness of over 10 km in the basin depocenter (Kaplan et al., 1994). The Niger Delta Province contains only one identified petroleum system (Kulke, 1995). This system is referred to as the Tertiary Niger Delta (Akata–Agbada) Petroleum System. The maximum extent of the petroleum system coincides with the boundaries of the province. The minimum extent of the system is defined by the areal extent of the fields and contains known resources



● -Study Location (N-Field)

Fig. 1 Mega-structural framework map of Niger Delta with study location

(cumulative production plus proved reserves) of 34.5 billion barrels of oil (BBO) and 93.8 trillion cubic feet of gas (TCFG) (Petroconsultants, 1996a). Among the provinces ranked in the US Geological Survey’s World Energy Assessment (Klett et al., 1997), the Niger Delta province is the twelfth richest in petroleum resources, with 2.2% of the world’s discovered oil and 1.4% of the world’s discovered gas (Petroconsultants, 1996a). These deposits have been divided into three large-scale lithostratigraphic units. The most basal unit of this Formation is the Akata Formation composing mainly of marine shales of Late Cretaceous to Paleocene age. Its thickness ranges from 2000 m at the most distal part of the delta to 7000 m thick beneath the continental shelf (Doust and Omatsola, 1990; and Weber, 1987). This is overlain by the Agbada Formation that is more than 3500 m. It is made up of intercalations of sands and shales, which are Eocene to Pliocene in age (Doust and Omatsola, 1990; and Weber, 1987). The uppermost of this Formation is the Benin Formation, which is composed of Late Eocene to Holocene continental sand deposits, including alluvial and coastal plain deposits that are up to 2000 m (Avbovbo, 1978). The primary source rock in this basin is the marine-shale facies of basal Akata Formation of the delta, with possibly contribution from interbedded marine shale of the lowermost Agbada Formation. Oil is produced from sandstone facies within the Agbada Formation; however, turbidite sand in the upper Akata Formation is a potential target in deep water offshore and possibly beneath currently producing intervals onshore. The aim of this research work is to enhance the characterization of this turbidite sands reservoir using quantitative analysis of rock physics.

Methodology

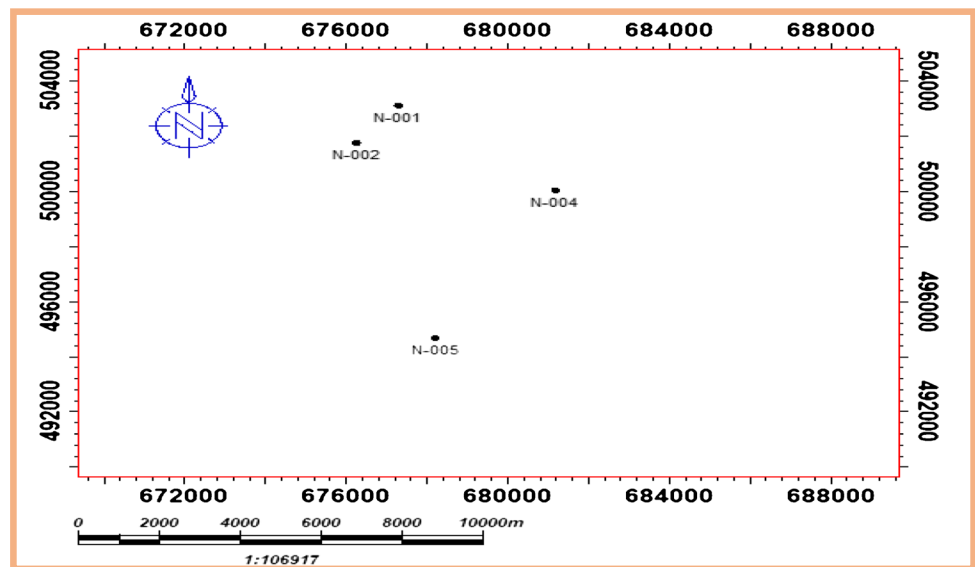
The data used for this study consists of a suite of well logs from four wells, base map and check shot. The suite of well logs comprised gamma ray, deep resistivity, density, neutron, compressional sonic log and one dipole sonic data from N-002 well. Figure 2 depicts the base map showing the distribution, orientation and relative positions of the wells. The methods of analysis employed for this study include petrophysical analysis, regression analysis, Gassmann fluid substitution, rock physics modelling and crossplots.

Petrophysical analysis

Prior to petrophysical analysis, qualitative log interpretation was done and this entails the visual inspection and description of anomalous regions on the logs. Gamma ray log was used for lithology delineation which comprised alternation of sand and shale. The deep resistivity log was used for fluid identification in reservoir rocks. The reservoir sand units were then correlated across the four wells to know their lateral continuity and vertical thicknesses (Fig. 3). Similarly, fluid contact depths of the various fluids (gas, oil and water) were identified from crossplots of neutron and density logs. Quantitative analysis involved the computation of reservoir physical properties such as effective porosity, permeability, hydrocarbon saturation and volume of shale from well-established equations consistent with Niger Delta geological setting. Porosity estimation was done using average porosities of neutron and density logs as shown below:

$$\phi_{Avg} = \sqrt{\frac{\phi^2 \text{Density} + \phi^2 \text{Neutron}}{2}} \tag{1}$$

Fig. 2 Base map of the study area showing the relative locations of the four wells



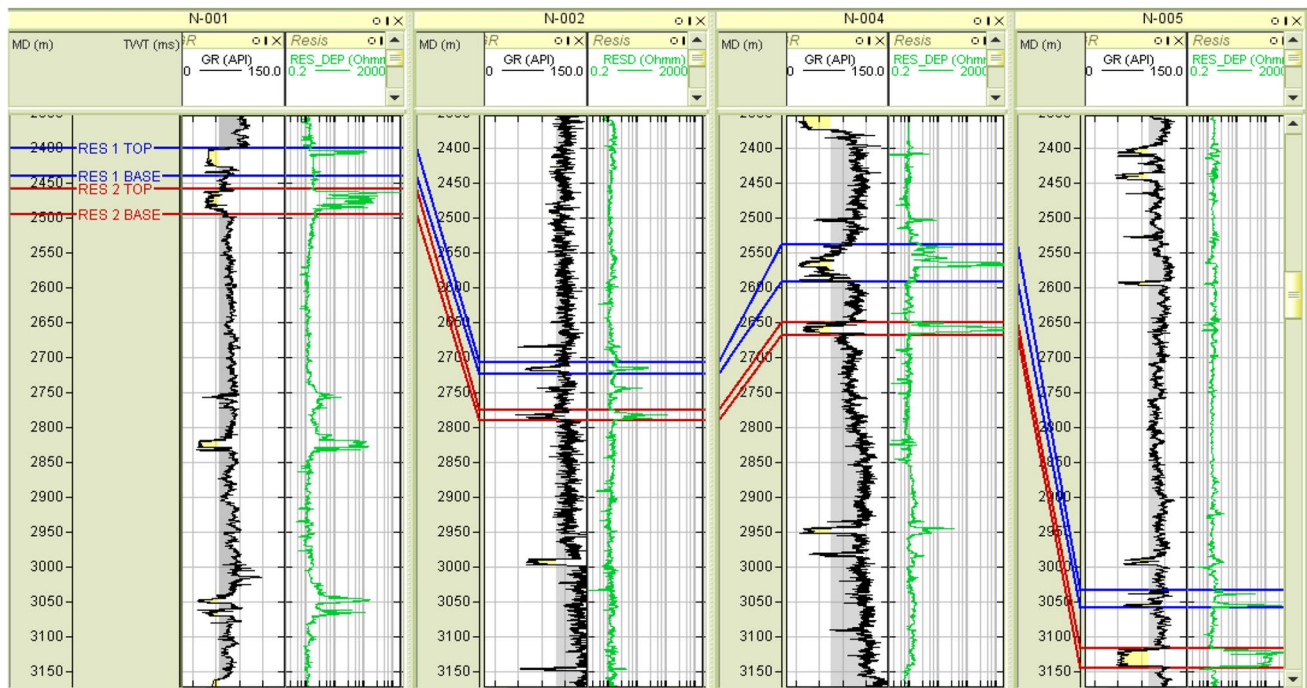


Fig. 3 Lithological correlation of the two hydrocarbon-bearing sands

where ϕ_{Neutron} is neutron porosity and ϕ_{density} is density porosity

$$\text{Effectivenessporosity}(\phi_{\text{eff}}) = \Phi_{\text{Avg}} * (1 - V_{\text{sh}}) \tag{2}$$

where ϕ_{Avg} is average porosity and V_{sh} is volume of shale. Permeability was computed using;

$$K = \sqrt{\frac{250 \times \phi_{\text{eff}}^2}{S_{\text{wirr}}}} \tag{3}$$

where S_{wirr} is irreducible water saturation, ϕ_{eff} is effective porosity, K is permeability in millidarcy.

Hydrocarbon saturation was derived from equation:

$$S_h + S_w = 100 \tag{4}$$

where S_h is hydrocarbon saturation and S_w is water saturation.

Volume of shale was also derived from Larionov (1969) equation:

$$V_{\text{sh}} = 0.083 * (2^{3.7 \times I_{\text{GR}}} - 1.0) \tag{5}$$

where V_{sh} is volume of shale and I_{GR} is gamma ray index.

Regression analysis

The four wells under consideration for rock physics analysis do not have shear wave log information, except N-002

well. Therefore, shear velocity (V_s) has to be estimated for the other three wells. Castagna et al., (1993) gave the empirical relationships that are used to estimate shear wave velocity (V_s) from compressional wave velocity (V_p). These relationships are localized or basin specific and therefore are not used universally for other basins. In order to reduce the uncertainty associated with the estimation of V_s from V_p to the barest minimum to improve the reliability of rock physics analysis results, an empirical relationship between V_p and V_s for this field was established by carrying out localized regression analysis. This was done using dipole sonic logs comprising compressional and shear velocities data in N-002 well to derive a V_p - V_s relationship that is suitable for deep offshore sediments of Niger Delta (see Eq. 6).

Gassmann fluid substitution

To be able to compare the theoretically modelled results with in situ data (density log, velocities and moduli), fluid substitution was applied. Gassmann (1951) fluid substitution was applied for the calculation of elastic properties of clean sands with uniform water saturation at different saturation values and for porosities from zero to initial/critical porosity. The density and bulk modulus of water are functions of temperature, pressure and salinity. The properties of hydrocarbons are more variable and depend strongly on temperature, pressure and composition (Murphy, 1993). RokDoc software (based on Batzle and Wang, 1992) was used to re-calculate

fluid properties at reservoir conditions. The estimated fluid properties of the reservoirs are given in Table 1.

Rock physics modelling and crossplots

Rock physics model is based on the assumption that if well log data points fall close to a theoretical line in velocity-porosity planes, and then the internal structure of a rock is similar to the idealized structure predicted by the theoretical model. Three theoretical models of Dvorkin and Nur (1996) which include friable sand, constant cement, and contact cement sand models were used for rock physics analysis in this research.

Friable-sand model is a model for unconsolidated sediments assumes porosity reduction from the initial sand pack value (critical porosity) due to the deposition of solid matter away from the grain contacts that result in gradual stiffening of the rock (Dvorkin and Nur, 1996). This porosity reduction for clean sandstone is caused by depositional sorting and packing. The zero porosity point represents the mineral point. The unconsolidated line is represented by the modified lower Hashin–Shtrikman (MLHS) model (Hashin and Shtrikman, 1963; Dvorkin and Nur, 1996) and connects the critical porosity end-point. The velocity near critical porosity is determined by the Hertz-Mindlin theory (Mindlin, 1949), whereas the mineral end-point is defined by the elastic moduli of the mineral. Porosity reduction between points will be a gradual stiffening of the rock, as smaller grains fill the pore-space between the larger grains.

For a clean sandstone, porosity reduction is caused by deteriorating sorting (depositional), grain crushing (mechanical compaction) and/or packing (depositional and compaction). This non-contact additional solid matter weakly affects the stiffness of the rock. During burial of a sandstone, the rock is also likely to become cemented. This cement may be diagenetic quartz, calcite, albite, or other minerals. Cementation produces a strong stiffening effect, because it acts to weld grain contacts.

The contact cement model describes the porosity reduction from initial sand pack due to uniform deposition of cement layers on the surface of grains that results in a sharp increase in velocity with decreasing porosity. The contact cement dramatically increases the stiffness of the sand by reinforcing the grain contacts. In particular, the initial cementation effect will cause a large velocity increase during a small porosity decrease (Dvorkin and Nur, 1996). This assumes that sands of varying porosity all have the same amount of contact cement. Porosity variation within this group of sands is solely due to non-contact pore-filling material (e.g., deteriorating sorting).

Constant cement model is a combination of the friable-sand model and the contact cement model. It assumes that the sands of varying sorting (and therefore varying porosity) have the same amount of contact cement and that variation within this group is due to non-contact pore-filling (e.g., sorting). Considering a given reservoir, this is the most likely scenario, because the amount of cement is often related to depth, whereas sorting is related to lateral variations in flow energy during sediment deposition. However, it is possible that cement has a local source, and therefore it may cause a considerable lateral variation in velocity.

Results and discussion

The analysis and discussion of results obtained from this work are premised around the properties that define a reservoir as being prolific or not for hydrocarbon exploitation. These parameters were computed using petrophysical equations after correlation was done.

Petrophysical analysis

Petrophysical properties were determined for the two reservoirs (RES-1 and RES-2) to define hydrocarbon storage

Table 1 Estimated properties of the reservoirs using Batzle and Wang (1992) relationship

Input parameters					
Temperature = 80 °C	Effective pressure = 30 MPa			Salinity = 80,000 ppm	
Output parameters					
	Brine properties	Oil properties	Gas properties	Mineral properties (%)	
				Clay	Quartz
Density (g/cc)	1.041	0.815	0.22	2.35	2.65
Bulk Modulus (GPa)	2.773	1.432	0.075	11.6	36.6
Shear Modulus (GPa)	-	-	-	3.86	45
Oil gravity	-	30	-	-	-
Gas gravity	-	-	0.7	-	-
Oil–gas ratio (v/v)	-	1	-	-	-

Table 2 Computed average petrophysical parameters of reservoir

Well	N-001	N-002	N-004	N-005
Gross thickness(ft)	100.54	121.70	171.39	234.42
Net thickness(ft)	84.37	56.45	116.06	94.50
NTG	0.84	0.46	0.68	0.40
V_{sh}	0.09	0.25	0.15	0.12
Porosity (ϕ)	0.20	0.22	0.25	0.23
Effective porosity (ϕ_{eff})	0.19	0.18	0.21	0.20
Permeability (mD)	546	224	570	180
S_w (%)	96	65	9	56
S_h (%)	4	35	91	44

Table 3 Computed average petrophysical parameters of reservoir 2

Well	N-001	N-002	N-004	N-005
Gross thickness(ft)	101.54	58.21	49.48	121.71
Net thickness(ft)	95.67	42.04	42.61	110.54
NTG	0.94	0.72	0.86	0.91
V_{sh}	0.08	0.18	0.11	0.16
Porosity (ϕ)	0.33	0.25	0.28	0.32
Effective porosity (ϕ_{eff})	0.30	0.21	0.25	0.29
Permeability (mD)	1660	432	1091	878
S_w (%)	7	43	4	12
S_h (%)	93	57	96	88

capacity, deliverability and hydrocarbon saturation of the reservoir. The average porosities in the two reservoirs are good and permeability in the range of good to excellent (according to Rider, 1986). The computed petrophysical parameters of the studied reservoirs are shown in Tables 2 and 3.

Localized compressional wave velocity equation

The localized relationship between V_p and V_s was derived via the statistical linear regression analysis (Fig. 4). The derived localized relationship (Eq. 6) when compared with most widely used Castagna's mud-rock line relationship was found to be more suitable for Niger Delta deep water sediments. This localized relation predicts V_s from V_p with high level of precision and fits a large population analysis of the wells with a correlation coefficient of 0.96 (Fig. 5). The result revealed that shear wave velocities predicted by the Castagna's mudrock line are much lower than their measured values for deep offshore sediments of Niger Delta. The localized expression is as shown below:

$$V_s = 0.8903 \times V_p - 1080.61 \quad (6)$$

Compaction trend analysis

The acoustic properties of rocks which are the product of velocity and density are greatly affected by both mechanical and chemical compaction. Generally, for a given lithology,

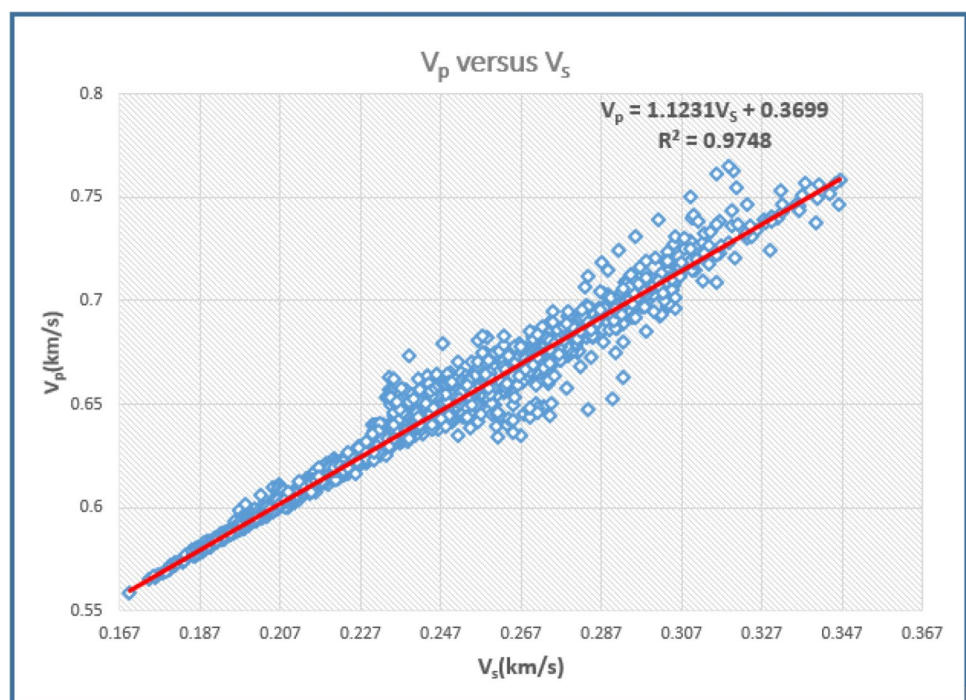
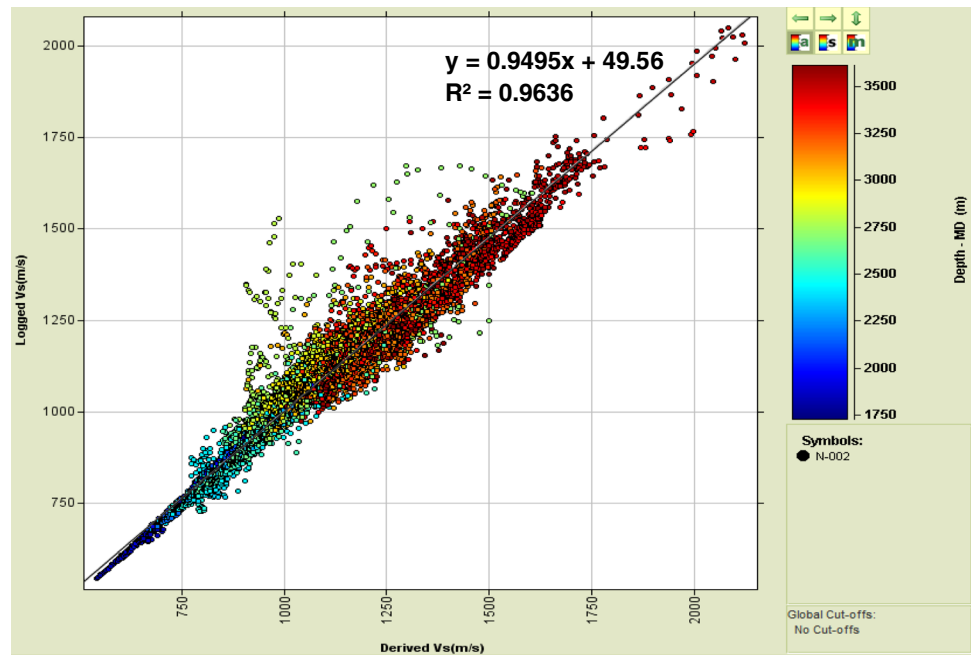
Fig. 4 Localized linear regression analysis of Niger Delta sediments

Fig. 5 Logged Vs versus derived Vs crossplots



there will be an increase in seismic velocity with depth as porosity decreases and effective pressure increases. Figure 6 shows porosity and P-wave velocity data from N-001 well. The porosities of the sands and shales gradually decrease with depth (Fig. 6a). The primary wave velocity in shales also gradually increases with depth (Fig. 6b). In the sands on the other hand, there is a pronounced jump in the velocity occurring at about 3200 m.

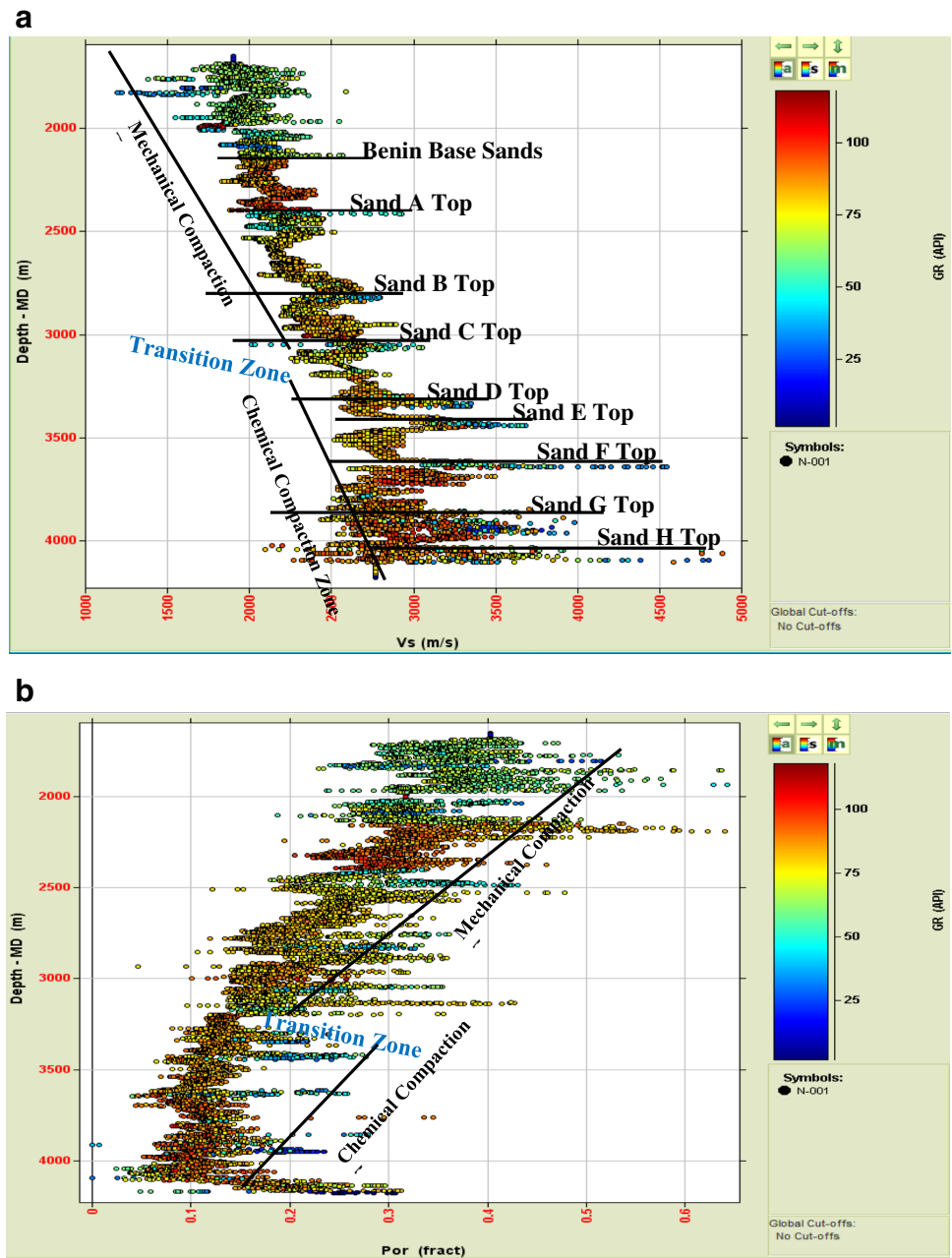
This dramatic increase in velocity with depth for sands below this depth (3200 m) cannot be explained by purely mechanical compaction and corresponding porosity reduction with depth. Purely mechanical compaction would have resulted in a gradually increasing velocity and a decreasing velocity gradient with depth, as observed in the shales. The jump in velocity observed in this sands can however be explained by chemical compaction. These sands most likely have slight quartz cementation, which produces a velocity increase through a stiffening effect on the grain contacts. The onset of cementation is therefore interpreted to occur at about (3200 m) depth. It is assumed that mechanical compaction dominates above this depth, whereas quartz cementation dominates below the depth. This interpretation fits with the simulation results of Lander and Walderhaug (1999). This overall velocity contrasts between sands and shales in the mechanical compaction zone (below 3200 m) are relatively weak but strong contrast in velocity between sands and shales is observed as the sands enter the chemical compaction zone. The transition from mechanical to chemical compaction

will therefore represents very significant seismic boundary in the field.

Velocity-porosity-clay relationship

The velocity-porosity (clay relationship) data plotted with Han (1986) experimental curves model was done to understand the effect of clay in reservoir sands. Han (1986) model demonstrated the relationship between the porosity and velocity, due to the effect of clay particles. This allows studying the variation and the effect of velocity and porosity due to presence of clay materials. Four categories of clay composition 0.05 (5%) (light green line), 0.15 (15%) (black line), 0.25 (25%) (red line) and 0.35 (35%) (blue line) clay contents were used for the analysis. Figure 7a shows the plotting of reservoir rocks data set of porosity and velocity colour-coded with the porosity superimposed on various Han (1986) models built and constrained to the geology of the study area. It is easily observed that most of the field data do not follow the Han (1986) experimental curve model. Only reservoir sand data points which contained 30–45% porosity plunge across the 15% clay line with most data falling between 0.25 and 0.35 fraction and below 0.35 clay trend lines. This affirm that the reservoir sands are typical mass transported deposits (turbidite sands) containing large proportion of clay fraction (greater than 35%) from shelf environment. When the same data colour-coded with depth (Fig. 7b), it is easily observable that low porosity points majorly belong to the deeper part, while higher porosity fits

Fig. 6 **a** Crossplots of depth against P-wave velocity for N-001 well colour coded with GR. **b** Crossplots of depth against porosity for N-001 well colour coded with GR



mostly to the shallower part. There are also some data points from the deeper depth having high porosity. This shows that compaction of sediments in this field has both depth related diagenetic and depositional environment influences. This suggests that proper care has to be taken during the development of these reservoir sands due to high clay fraction within the reservoir formation.

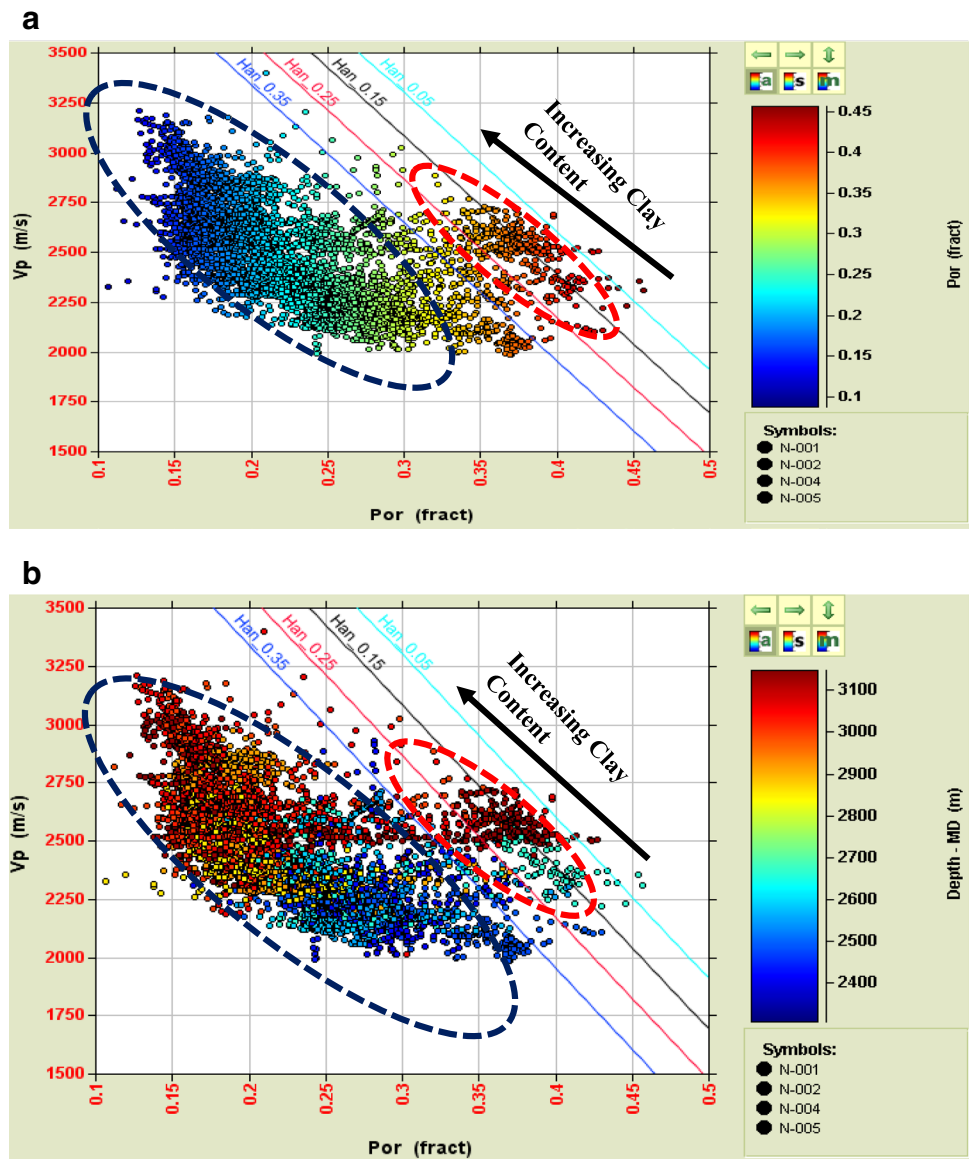
Rock physics cement models

The reservoir sands across the four wells were investigated for the degree of cementation (quartz cement) they exhibited and the effect on porosity. To investigate this, rock physics

cement models of Dvorkin and Nur, 1996, were utilized. The models of contact cement, constant cement and friable sands are colour coded green, blue and pink, respectively; with 3.5%, 2.5% and 1.5% cement volume, respectively.

Figure 8a shows the plotting reservoir rocks data set of porosity and velocity colour coded by the volume of shale with the three rock physics cement models utilized for this study. It can be observed that most of the data points from the wells scattered on or below the friable sand model specifying that these reservoir sands are not cemented. This could also be due to the interval saturated with hydrocarbon because hydrocarbons have tendency to decrease sonic velocity (Avseth et al., 2005).

Fig. 7 a: Crossplots of velocity against porosity colour coded by porosity. **b** Crossplots of velocity against porosity colour coded by depth



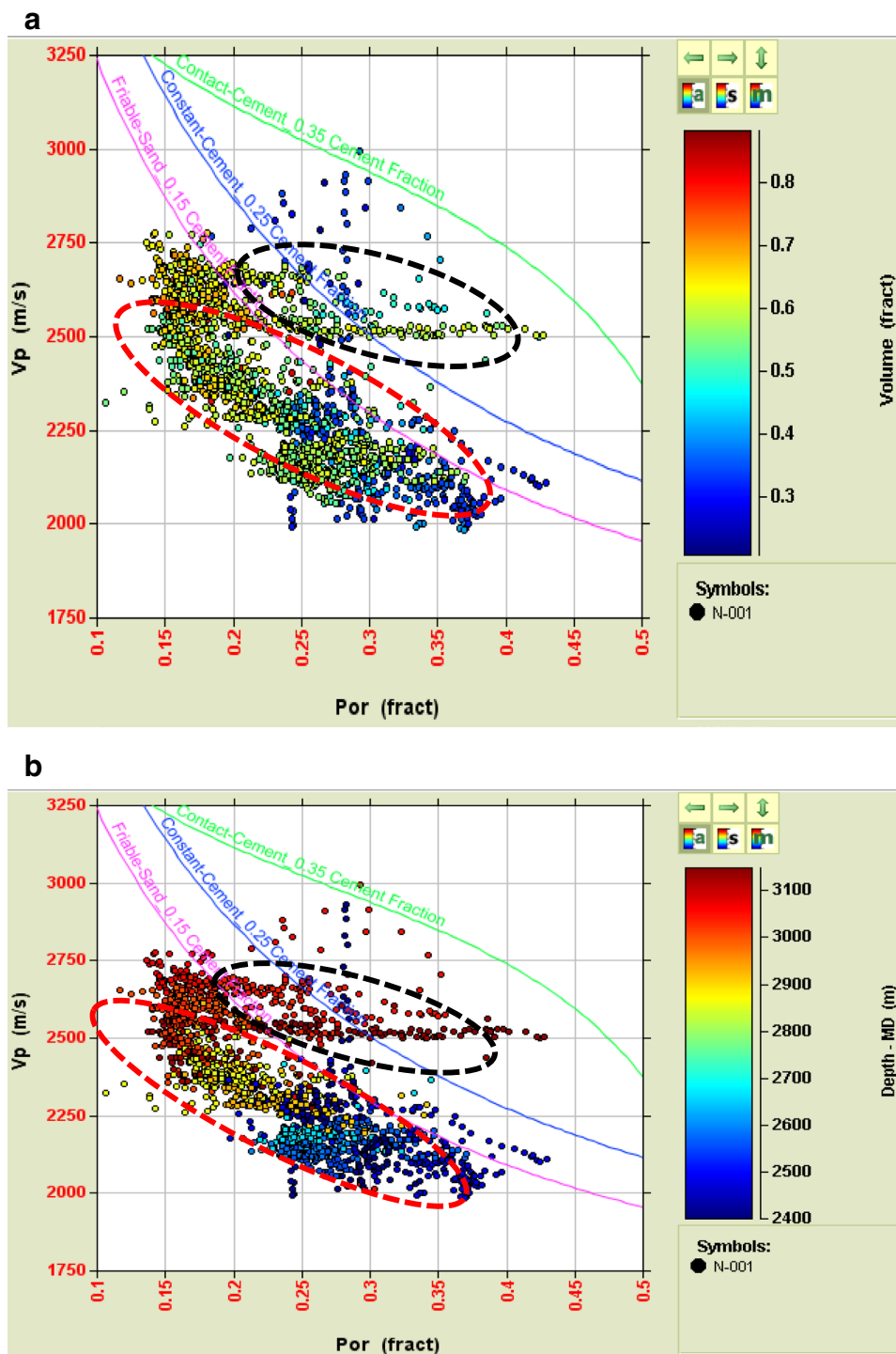
Theoretically, there are two possibilities of data set positions on friable sand model. Data set on the right side of friable sand model plot represents clean sand possessing high porosity and low velocity, while the left side illustrates that porosity decreases as clay content increases between the sand particles. This orientation of clay content in sand particles may reduce porosity and reduce the sorting, which results in increase of sonic velocity (at certain volume of clay) (Avseth, 2010; Dvorkin and Nur, 1996; Marion, 1990). Hence, the reservoir sand data set mostly concentrated on the left side of the friable sand model suggesting high clay content in the reservoir sands which agreed with the interpretation above.

Figure 8b shows the crossplot of reservoir rocks data set of porosity and velocity colour coded by depth with the

three rock physics cement models utilized for this study. It can be observed that little data set from the deeper depth in the region of 3100 m plunge around the constant cement sand model which is an indication that the intervals experienced cementation. But porosity values are considerably high indicating the initial cementation stage (Avseth et al., 2005). This data set is suspected to be from N-004 and N-005 wells which also show higher velocity, indicating the early stage of quartz cementation (Avseth et al., 2005).

Generally, the higher porosity values plunge across the constant sand line, while lower porosity values plunge across the friable cement line. These reservoir formations can therefore be interpreted as poorly cemented sand to unconsolidated sands, which can be good quality reservoirs.

Fig. 8 **a** Crossplots of velocity against porosity colour coded by volume of shale. **b** Crossplots of velocity against porosity colour coded by depth

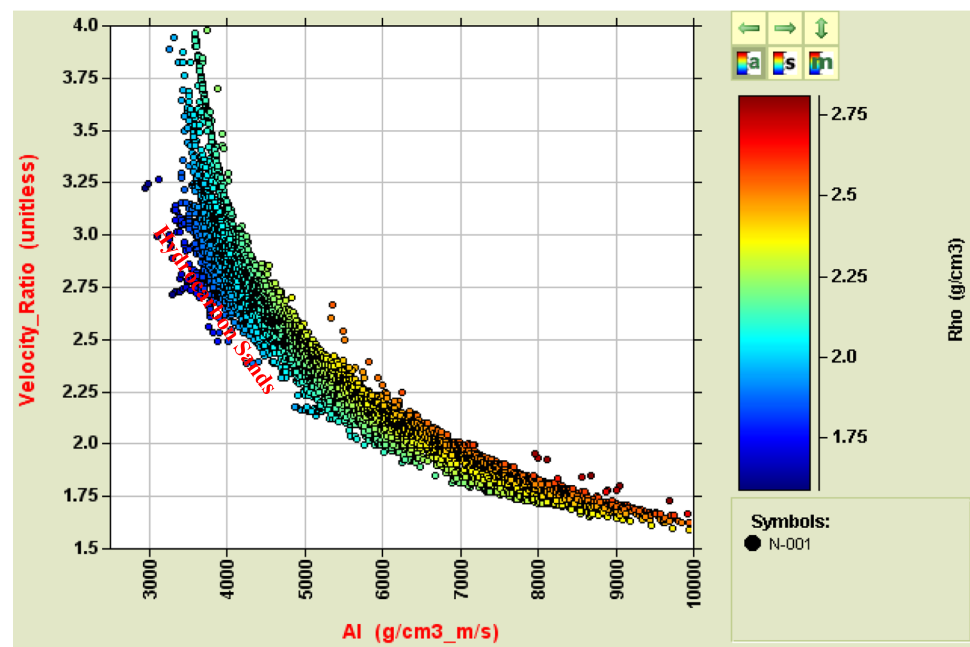


Rock physics template acoustic impedance versus V_p/V_s

The rock physics template of V_p/V_s ratio versus acoustic impedance crossplots calculated from well log data after the application of Gassmann fluid substitution were used to diagnose the reservoir rocks further. It is easily observable that the reservoir formations show very high values of

V_p/V_s ratio in the region of 2.15 to 3.35 and low acoustic impedance of 3000 to 5000 $g/cm^3 \times m/s$ (Fig. 9). This may be interpreted that the hydrocarbons saturated intervals may have slight cementation at their grain contacts, which made these sediments stiffer (Avseth et al., 2005). This stiffness gave peaks in the V_p values, which may mask the light hydrocarbon effect on V_p and V_s values to some extent. This masking due to cementation increased V_p/V_s ratio and

Fig. 9 Crossplots of V_p/V_s against AI of N-001 well colour coded by density (Rho)



brings the cluster of data right across the contact cement line and water saturated sandstone line. This may therefore confirm the reservoir rocks to be turbidite sands because of slight cementation.

Conclusion

Rock physics diagnostics was carried out in this study to quantitatively analyse lithologies encountered in order to de-risk exploration prospects in this field. The petrophysical analysis revealed that the reservoir sands possess good pore interconnectivity and sufficient hydrocarbon saturation for commercial production. The derived localized relationship between V_p and V_s via statistical linear regression analysis predicts V_s from V_p with high level of precision and fits a large population analysis of the other wells and therefore is suitable for the Niger Delta deep offshore sediments. Compaction study revealed that at a certain depth, quartz cementation of sands occurred and velocity of sandstones became higher than that of uncemented sands at the mechanical zone. This depth represents very significant seismic boundary in the field.

Porosity-velocity crossplot accounts for the percentage of clay content in the reservoir sands. The model quantitatively revealed that the reservoir sand data points contained percentage of clay content typical of turbidite sands. The cement models (constant, contact and friable models) revealed depositional and depth related diagenetic influences on reservoir rock properties. The reservoir sands occurring majorly at the mechanical zone are poorly cemented to unconsolidated. The two models indicate that the reservoir

sands in the study area are both influenced by depositional trends and depth related diagenetic effects. Finally, rock physics template of acoustic impedance and V_p/V_s crossplot were also used to study fluid as well as cementation effect on the rock properties. These plots indicate that the reservoir intervals have slight cementation at their grain contacts, which made the sediments stiffer. This stiffness gave peaks in the V_p values, which may mask light hydrocarbon effect on V_p and V_s values to some extent.

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