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Rock Physics and Gassman Fluid Substitution Analysis for Reservoir Characterization: A Case Study of Ky Field Chad Basin North-Eastern Nigeria.

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Abstract: This study investigates the application of rock physics and Gassmann fluid substitution analysis for reservoir characterization in the KY Field of the Chad Basin, Northeastern Nigeria. The primary objective is to evaluate the impact of fluid saturation on seismic elastic properties, such as P-wave and S-wave velocities, and density, to better understand reservoir potential and fluid distribution. The research utilizes 3D seismic data and well log suites, including gamma ray, density neutron, resistivity, and sonic logs, from four wells (XY-1, XY-2, XY-3 and XY-4). Gassmann's equations are employed to model fluid effects on rock velocity and density, enabling the identification and quantification of fluid types and saturations within the reservoir. The study highlights the challenges of estimating water saturation from seismic data and emphasizes the importance of rock physics modeling in interpreting seismic amplitude anomalies. Results from crossplots of Acoustic Impedance (AI) versus Vp/Vs and LambdaRho versus MuRho reveal distinct lithological and fluid trends, with hydrocarbon-bearing sands showing significant deviations from brine-saturated sands. Fluid substitution analysis demonstrates that changes in fluid saturation, particularly gas content, significantly affect seismic responses, indicating partially gas-saturated reservoirs with patchy distributions. The findings provide valuable insights into the reservoir's elastic properties and fluid dynamics, offering a robust framework for future exploration and development in the KY Field. This research underscores the critical role of rock physics and fluid substitution in enhancing seismic interpretation and reservoir characterization in complex sedimentary basins.

I. Introduction

Fluid saturation provides a way for identification and quantification of fluid in reservoir (Abid, Riaz, Zafar, khan& Shakir, 2020).The principal cause of failure of development wells is the rise of water saturation. It is very challenging to estimate water saturation from seismic data unless through rock physics analysis. Rock physics facilitates the evaluation of fluid depletion impact on different elastic properties such as primary and secondary wave velocity as well as density. Rock physics models play a crucial role in seismic reservoir characterization studies. The fluid substitution method is the most used technique using the application of Gassmann's equation (Gassmann, 1951).Each step in the fluid substitution process yields new elastic properties of the reservoir for certain initial conditions that include fluid saturation. Fluid substitution is an important part of interpreting seismic data because it helps the interpreter to model the properties of various fluids that can cause an observed seismic amplitude anomaly (Tad, Smith, Carl Sondergeld,Chandra & Rai, 2003) that is, if a reflection amplitude increases or decreases. In the reservoir, change in P-wave velocity can be affected by several factors such as mineral composition, porosity, salinity, temperature and of course, fluid type. Gassmann equation takes these effects into account to compute velocity (Avseth, Mukerji &Mavko, 2010).

Gassmann equation is sequential, and different equations are used at different levels. Two important steps are usually taken to apply the Gassmann equation: calculating the bulk modulus of the porous rock frame (K_{frame} – rock drained of any pore-filling fluid) and secondly computing the bulk modulus of the rock saturated with any desired fluid(K_{sat})(Smith et al, 2003). The porous rock frame is calculated first because it is an input in the estimation of the saturated bulk modulus. Bulk modulus is defined as the ratio of hydrostatic stress to volumetric strain that the stress will impact on the rock (Avseth et al, 2005). In other words, it is the resistance of various earth materials to stress. The higher the bulk modulus the stiffer the rock. However, the bulk modulus (k) for in situ condition needs to be calculated before one can determine the bulk modulus of porous dry frame. To do this initial field V_p and V_s velocity must be known (Smith et al, 2003)

In the field of study, most elastic information available is from laboratory measurements. It is essential to derive a log model of these elastic properties as these are more detailed. Comprehensive information on velocity is then available. In addition, the identification of fluids based on the common Petrophysical overlay of neutron and density log is quite ambiguous in a practical sense. (Adeoye et al, 2021). Many times, the neutron-density log fails to deliver reliable results during fluid contact mapping due to lithology effects (Adeoye et al, 2021). However, the computation of the elastic properties of velocities in the formation and comparison with real field data gives more straight forward responses. This research will facilitate the study of fluid depletion impact on different seismic elastic properties (P-wave and S-wave velocities and density)when substituted with another fluid. This will help to deepen the understanding of the reservoir fluids and as well quantify reservoir potential in the selected reservoir intervals in KY field Chad Basin Northeastern Nigeria.

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Geological Setting

Geology of the Nigeria Chad Basin Sedimentary sequences were deposited from the Paleozoic to Recent, accompanied by several stratigraphic gaps. The sediments transport is from fluvial to shallow marine as indicated in Figure 1. The first sedimentary deposits are mainly continental, sparsely fossiliferous, poorly sorted, and medium-to coarse-grained, feldspathic sandstones called the Bima Sandstone. A transitional calcareous deposit Gongila onset of marine incursions into the Basin, overlies the Bima Sandstones. These are overlain by graptolitics Formation that accompanied the Shale (Okosun,1995). The oldest rocks in the Chad Basin belong to Bima Sandstone and the youngest to the Chad Formation as shown in the stratigraphic column of the study area (Table 1). The lithology of the area is made up of six major formations as explained below:

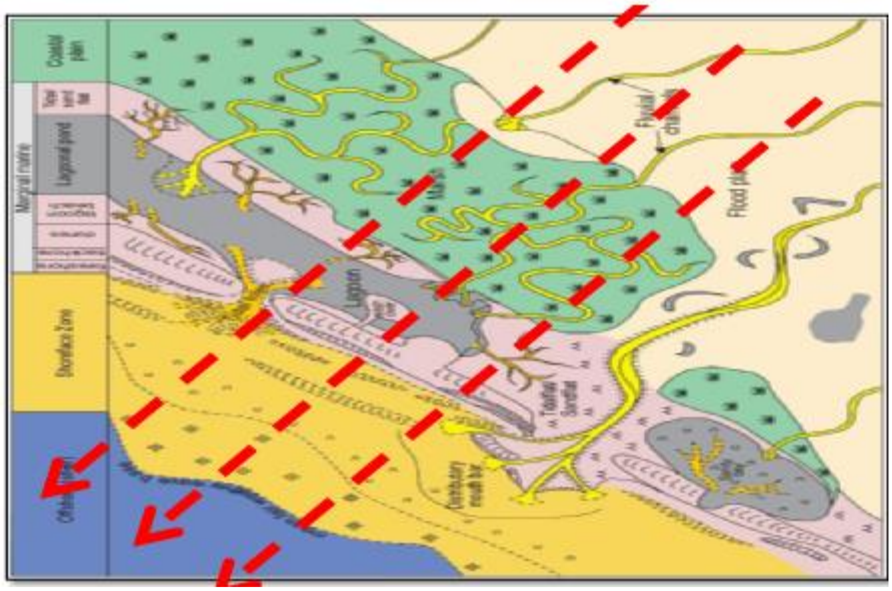

Figure 1. Generalise Depositional Environment Chart (modified from Reinect & Singh, 1980

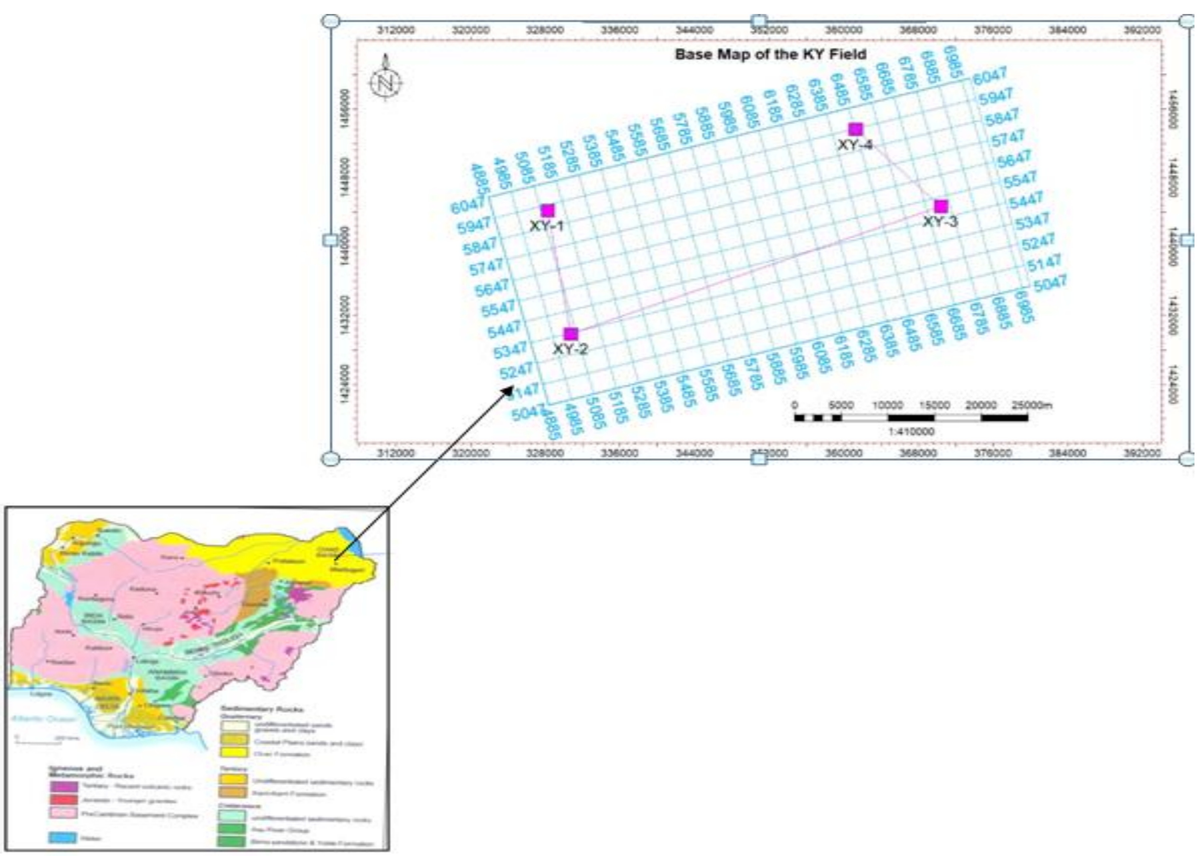

Figure 2. Geologic map of Nigeria showing the Chad Basin and the base map of the Basin showing the study wells

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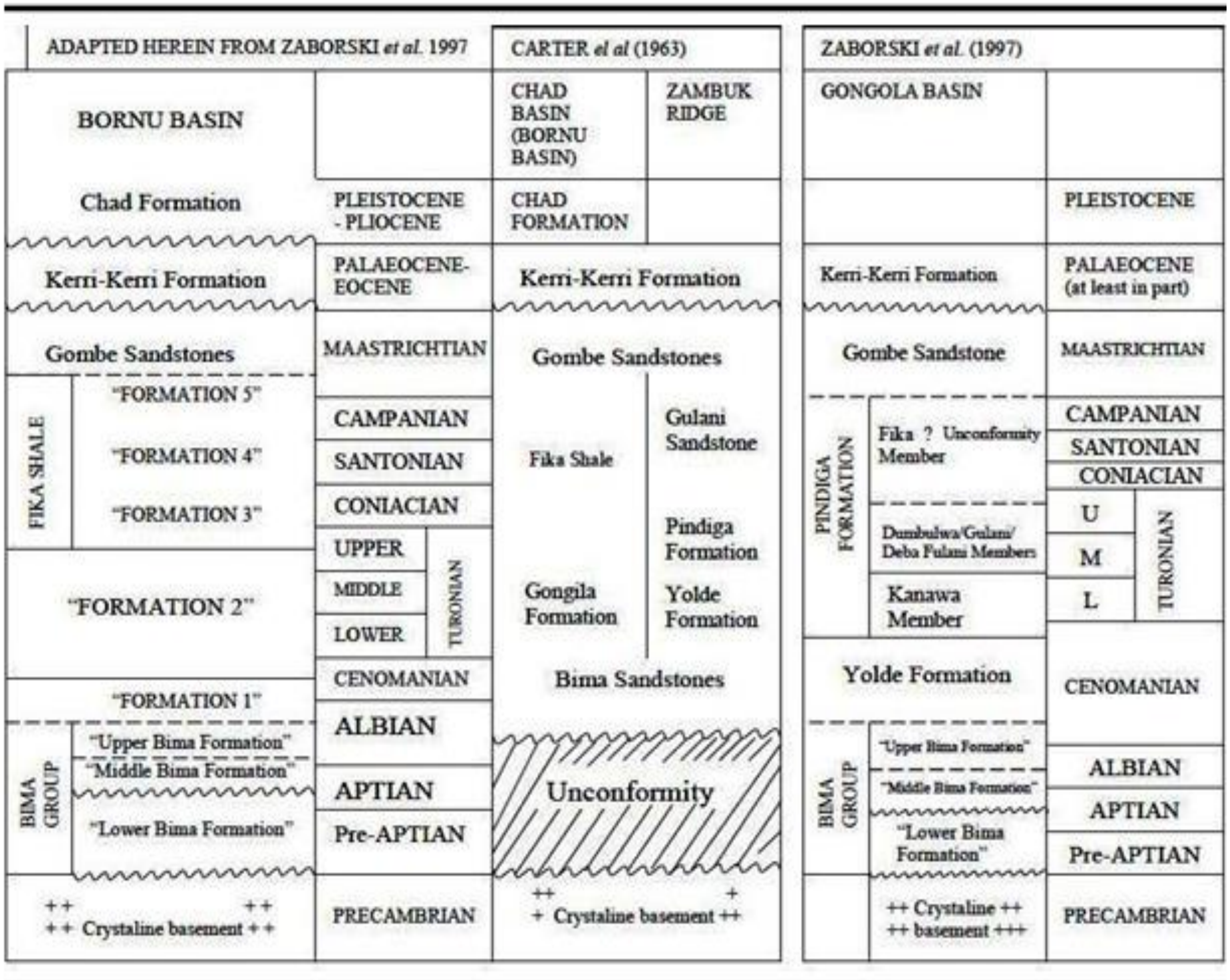
Table 1. Lithostratigraphic succession for the Nigeria Chad Basin proposed herein and compared with that of Carter et al. (1963) and Zaborski et al. (1997) of the neighbouring Gongola Basin.



Bima Sandstone This formation has essentially the same lithology as in the upper Benue Basin. It is largely comprised of coarse feldspathic and cross-bedded sandstones. It is, however, thinner in the Nigeria Chad Basin. It has been dated Albian. Formation This unit consists of sandstones, clays, shales and limestone layers. It varies laterally into massive grey limestone overlain by sandstone, siltstones, limestone and shales with shaly limestone. To the south at Kupto, however, a thick limestone is overlain by sandstones, mudstones and shales with limestones (Carter et al., 1963). The limestone horizons are richly fossiliferous with abundant ammonites, pelecypods and echinoid remains and based on these, Carter etal. (1963) assigned an Early Turonian age to the formation. Fika Shale This formation consists of blue-grey shale, at times gypsiferous; with one or two non-persistent limestones horizons. A maximum thickness of 430m has been penetrated in by boreholes near Maiduguri. Fossils of the Fika Shale consist mainly of fish remains and fragments of reptiles suggesting a Cenomanian to Maastrichtian age (Dessauvagie, 1975). However, Dessauvagie (1975) suggests a pre-Santonian upper age limit for the formation based on stratigraphic evidence. Gombe Sandstone This unit is a sequence of estuarine and deltaics and stone, siltstone and subordinate shale. Thin coal seams are locally present. In outcrop many of the sandstones and siltstones are ferruginised forming low-grade ironstones. The macro fauna is limited and consists of a few indeterminate lamelli branchs (Carter et al., 1963). Shell- BP palynologists dated the coallate Senonian - Maastrichtian. Kerri-Kerri Formation Chekube et al 318 This consists of loosely cemented, coarse to fine-grained sandstone, massive claystone and siltstone; bands of ironstone and conglomerate occur locally. The sandstone is often cross bedded. The sediments are lacustrine and deltaic in origin and have a maximum thickness of over 200m (DuPreezandBarber,1965). The coal in the formation has yielded palynomorphs on the basis of which Shell-BP palynologists dated it Paleocene and later by Adegoke et al. (1986). Chad Formation This formation is a succession of yellow and grey clay, fine-to coarse-grained sand with intercalations of sandy clay and diatomites. Its thickness considerably varies. It is estimated to be about 800m thick on the western shore of Lake Chad. Vertebrate remains (Hippopotamus imaguncula) and diatoms collected from it indicate an Early Pleistocene (Villa franchian) age. However, its age is considered to range from Pliocene to Pleistocene. The Chad basin is capped by Tertiary volcanic rocks. The Biu plateau basalts underlie the Pleistocene diatomite deposits near Bulbaba but overly Cretaceous rocks (Carter et al.,1963). They are thus most probably of Tertiary age. The basalts consist of fine-grained, dense olivine-bearing varieties.

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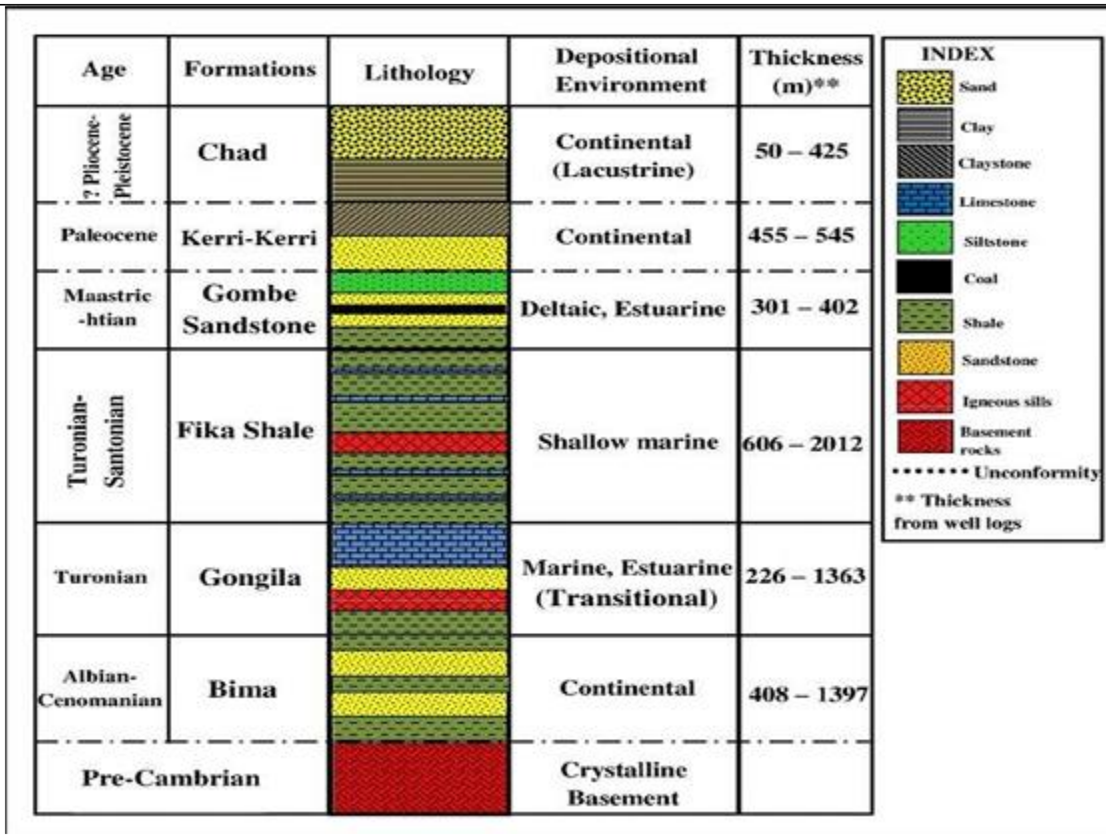

Figure 3. Stratigraphic data sheet of the Nigeria Chad Basin (after Okosun 1995; Avbovbo et al., 1986; Carter et al., 1963)

Stratigraphic Setting of the Nigeria Chad Basin Sedimentary sequences began from the Paleozoic to Recent, accompanied by several unconformity surfaces. Sediments are mainly continental, sparsely fossiliferous, poorly sorted, and medium- to coarse-grained, feldspathic sandstones called the Bima Sandstone. A transitional calcareous deposit – Gongila Formation - that accompanied the onset of marine incursions into the basin, overlies the Bima Sandstones. These are overlain by graptolitic shale (Okosun, 1995). The oldest rocks in the Nigeria Chad Basin belong to Bima Sandstone and the youngest is the Chad Formation as shown in the stratigraphic column of the study area (Table 1). The Cretaceous sediments in the Nigeria Chad Basin are almost entirely concealed below the continental Pleistocene Chad Formation. Cretaceous outcrops are confined to its Southern periphery. Carter et al. (1963) ascribed the outcropping sediments in the Southwest of the Nigeria Chad Basin previously described by Jones (1932) and Raeburn and Jones (1934) to the Gongila Formation, Fika Shale and Gombe Sandstone. At Damagum and Maiduguri, 100m and 450m respectively of beds belonging to the Fika Shale were identified in boreholes which bottomed within the unit. In the Dumbulwa-Bage High area, Zaborski et al. (1997) subdivided the Cretaceous outcrops into the Kanawa, Dumbulwa and Fika Members of the Pindiga Formation above the "Lower Bima Sandstone". Avbovbo et al. (1986) identified seven "seismic sequences" in the Maiduguri depression. Okosun (1995) and Olugbemiro (1997) provided direct lithological data from boreholes located to the north of Maiduguri. Three Cretaceous units were identified by Okosun (1995). Umar (1999) proposed the stratigraphic succession recognizing the Gombe and Kerri-Kerri Formations and proposing different ages for most of the formations as compared with Carter et al. (1963) and Okosun (1995). Correlation of the Cretaceous succession in the basin remains controversial. Okosun (1995) and Olugbemiro (1997) respectively suggested Albian to Turonian and Albian to Cenomanian ages for sedimentary unit of the Bima Group; Lower Turonian and Turonian ages for the Gongila Formation; and Turonian to Mastrichtian and Turonian to Santonian ages for the Fika Shale. Although Okosun (1995) indicated that Kanadi-1 well bottomed in the basement rocks, Olugbemiro (1997) reported arenaceous foraminifers were recovered from "Bima" deposits in the Kanadi-1. Inspite of all these observations, it is unlikely that the Bima Group was penetrated by the above-mentioned wells. The wells actually bottomed within the Fika Shale or the equivalent of what is referred to herein as "Formation 1". Microfossils were only recovered in the present study from the Fika Shale. The earliest Cretaceous marine beds in the Upper Benue Trough South of the Nigeria Chad Basin and the Mega Chad Basin to the North are Cenomanian (Bellion et al, 1989; Genik, 1993). It is unlikely that the Albian "pre-Bima" shales of Avbovbo et al. (1986) are marine deposits or that the "pre-Bima" shales of Olugbemiro (1997) are pre-Albian marine deposits. Olugbemiro (1997) suggested that sedimentation in the Nigeria Chad Basin began only in the Albian to Cenomanian. Based on field evidence in the southwestern section of the Nigeria Chad Basin (Dumbulwa-Bage High), together with subsurface borehole lithostratigraphic studies Northeast of Maiduguri, a newly proposed lithostratigraphic succession (Hamza, 2007) has been set up. This agrees with the new proposed lithostratigraphic succession of the Gongola Basin in the Upper Benue Trough by Zaborski et al., (1997). Carter et al. (1963) and Avbovbo et al. (1968) presented the generalised stratigraphic scheme for the Nigeria Chad Basin (Table 1). The scheme indicated Cenomanian Bima Sandstone as the oldest formation which overlies an unnamed „Pre

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Bima" Formation on the Basement. Bima Sandstone was a product of weathering of the Basement rocks and represents the Continental deposit in Nigeria (Adepelumi et al., 2012). Bima Sandstone is overlain by Gongila Formation deposited from the Turonian transgression and comprised of alternating sand and shale layers with limestone interbeds. Santonian marine Fika Shale overlies the Gongila Formation and marked the end of Cretaceous deposition in the basin. Subsequent regression deposited Gombe Sandstone which was overlain by Tertiary Kerri-Kerri Formation made up of iron rich sandstone and clay with lateritic cover. Quaternary Chad Formation is the topmost layer consisting of alternating sequence of clay with sand interbeds

Materials

The following materials were used to carry out the research successfully

- 3-D Seismic cube
- Well log suites (gamma ray, density neutron, resistivity, sonic (compressional)) for four wells; XY-1, XY-2, XY-3 XY-4 Location of the wells were illustrated on the base map in fig .2
- Schlumberger Petrel software
- Schlumberger Techlog software
- Well tops

The data was obtained from Nigerian National Petroleum Coorporation Limited Exploration Services(NNPC ENSERV)

II. Methodology

Gassmann's Fluid Substitution Analysis

To extract fluid type or saturations from seismic, crosswell, or borehole sonic data, we need a procedure to model fluid effects on rock velocity and density. Numerous techniques have been developed. However, Gassmman's equations are by far the most widely used relations to calculate seismic velocity changes because of different fluid saturations in reservoirs. The importance of this grows as seismic data are increasingly used for reservoir monitoring.The principal cause in failure of development well is rising water saturation (Akhter,et al; 2015) .It is very challenging to evaluate water saturation information from seismic data unless we include rock physics modeling. Rock physics will facilitate the modelling of fluid depletion impact on different seismic elastic properties such as P- and S-wave velocity as well as density (Asveth, et al, 2010). Fluid substitution analysis shall involve the following:

- Calculate bulk and shear modulus at in situ saturation conditions
- compute dry rock bulk modulus that was calculated by using formula given by (Zhu and McMechan,1990)
- Determination of mineral and fluid parameters.
- Determination of Inverse Gassmann relation to bring rock at dry conditions
- Calculation of new Vp.
- Calculation ofVs at desiredsaturation using Greenbergand Castagna (1992) mathematical model

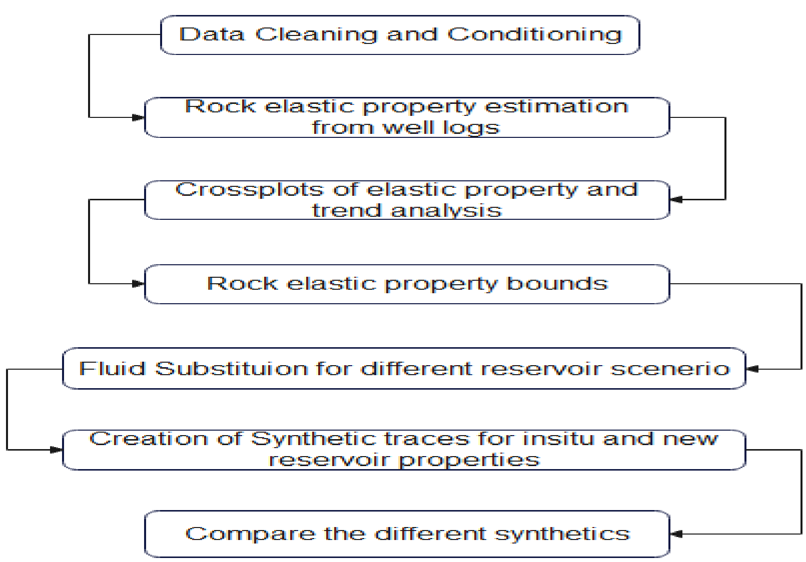

Figure 4. Workflow of methodology

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Numerous assumptions are involved in the derivation of Glassman's equation:

- Porous material is isotropic, elastic, monomineralic and homogenous
- Pore space is well connected and in pressure equilibrium (zero frequency limit)
- Medium is a closed system with no pore fluid movement across boundaries
- No chemical interactions between fluids and rock frame (Shear modulus remains constant)

Many of these assumptions may not be valid for hydrocarbon reservoirs, and they depend on rock and fluid properties and in-situ conditions.

$$K_{dry} = \frac{k_{sat}\left(\frac{\phi Kmat}{Kfl}+1-\phi\right)-Kmat}{\frac{\phi Kmat}{Kfl}+\frac{Ksat}{Kmat}-1-\phi} \quad \ldots\ldots\ldots\ldots 1$$

In equation (1) Kmat, Kfl, Ksat, and Kdry are the bulk modulus of mineral m ectively. The ϕ is effective Porosity acquired from petrophysical analysis.

When we have dry rock bulk modulus by using original equation of Gassmann, we can get desired saturated bulk modulus.

$$K_{sat} = K_{dry} + \frac{\left(1-\frac{K_{dry}}{K_{mat}}\right)^2}{\left(\frac{\phi}{K_{fl}}+\frac{(1-\phi)}{K_{max}}-\frac{K_{dry}}{K_{max}}\right)} \ldots\ldots\ldots\ldots 2$$

$$\mu_{sat} = \mu_{dry} \quad \ldots\ldots\ldots\ldots 3$$

The µsat and µdry represent shear moduli of saturated and dry rock. T om presence of fluid. Saturated density was calculated by relations of Kumar, 2006.

$$\rho_{sat} = \phi\rho_{fl} + (1-\phi)\rho_{mat} \quad \ldots\ldots\ldots\ldots 4$$

In equation 4

ρsat is saturated density, Ø represents porosity, ρfl is fluid density and

ρmat is matrix density. For saturated P and S-wave velocity equation (5) and (6) were used.

$$Vp = \sqrt{{k + 4/3\mu}/{\rho}} \quad \ldots\ldots\ldots\ldots 5$$

To estimate S- wave velocity (Vs) from other petrophysical parameters Greenberg and Castagna (1992) presented a mathematical model based on linear relations of Vp., applied on brine saturated monomineralic rock using a coefficient provided in the table(2)which satisfy the expression

$$V_s = \frac{1}{2}\left\{\left[\sum_{i=I}^{L} fi \sum_{j=0}^{N_i} a_{ij}V_p\right] + \left[\sum_{i=1}^{L}\left(\sum_{j=0}^{L} a_{ij}V_p^{\;-1}\right)\right]^{-1}\right\}$$

Where L is the number of monomeric components, fi is the volumetric fraction of the i-th component, a-ij are the coefficients of the empirical regression, Ni is the degree of the polynomial for i-th lithology constituent, Vp and Vs are the compressional and shear velocities(km/s), respectively.

Obtained by Castagna et al. (1993), the empirical coefficients in table (2) were calculated for 100% brine saturation and for this reason; to estimate Vs in the in-situ condition it is very necessary to apply fluid substitution calculations. The original procedure of the method involves performing several iterations starting from assumption of Vp for brine until reaching a significant convergence, thus ensuring the quality Vs estimation.

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Table 2 Regression coefficients of Vs presented by castagna et al. (1993)

Lithology	a_{i2}	a_{i1}	a_{i0}	R^2
Sanstone	0	0.80416	-0.85588	0.98352
limestone	-0.05508	1.01677	-1.03049	0.99096
Dolomite	0	0.58321	-0.07775	0.87444
Shale	0	0.76969	-0.86735	0.97939

III. Result and Discussions

Rock physics analysis was done starting with a crossplot of AI vs VPVS and then LambdaRho vs MuRho (figure 5 to 16). The two plots indicated a trend for both sand and shale but the lithological discrimination was more distinct on the LambdaRho vs MuRho crossplot (figure 9). The effect of fluid was better seen on the AI vs VPVS plot. On both plots, vertical changes in the observed trend was found to be controlled by age, rock type, cement content and porosity while the horizontal changes in the observed trend was attributed to a change in fluid type and saturation (figure 5 and 9). Hydrocarbon bearing sand within the Gombe Formation showed a distinct deviation from the brine-sand and appeared to form a cluster that was identified with the green slightly deformed elliptical shape (figure 5). The plots were made with theoretical trendlines superimposed on them, and the result was compared to the interpreted ones with both showing great similarity (figure 13 and 14).

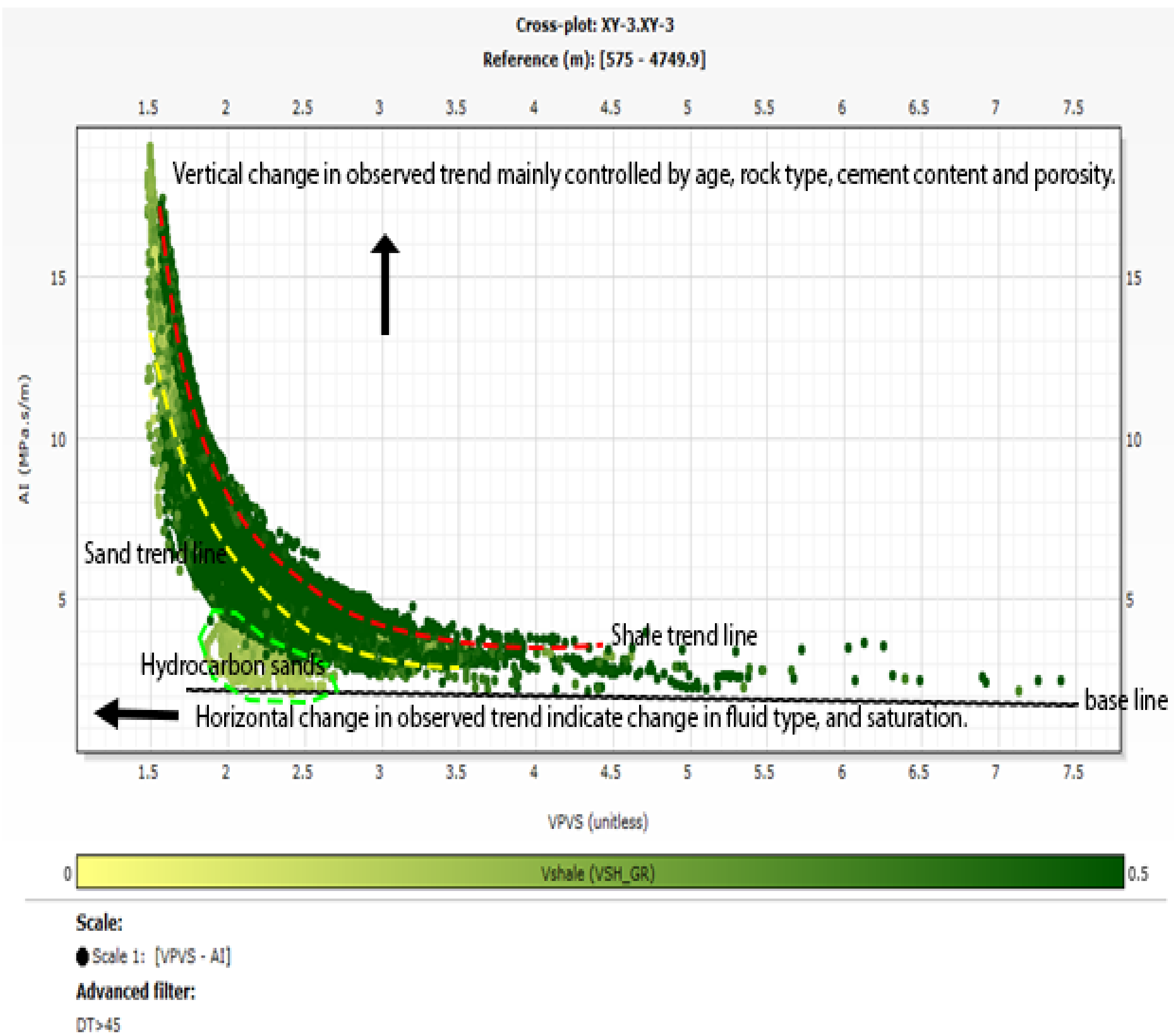

Figure 5: AI vs VPVS plot with trendline for sand and shale. Colour represents changing facies in terms of shaliness (volume of shale). The background masks the overall response making it difficult to identify the trend.

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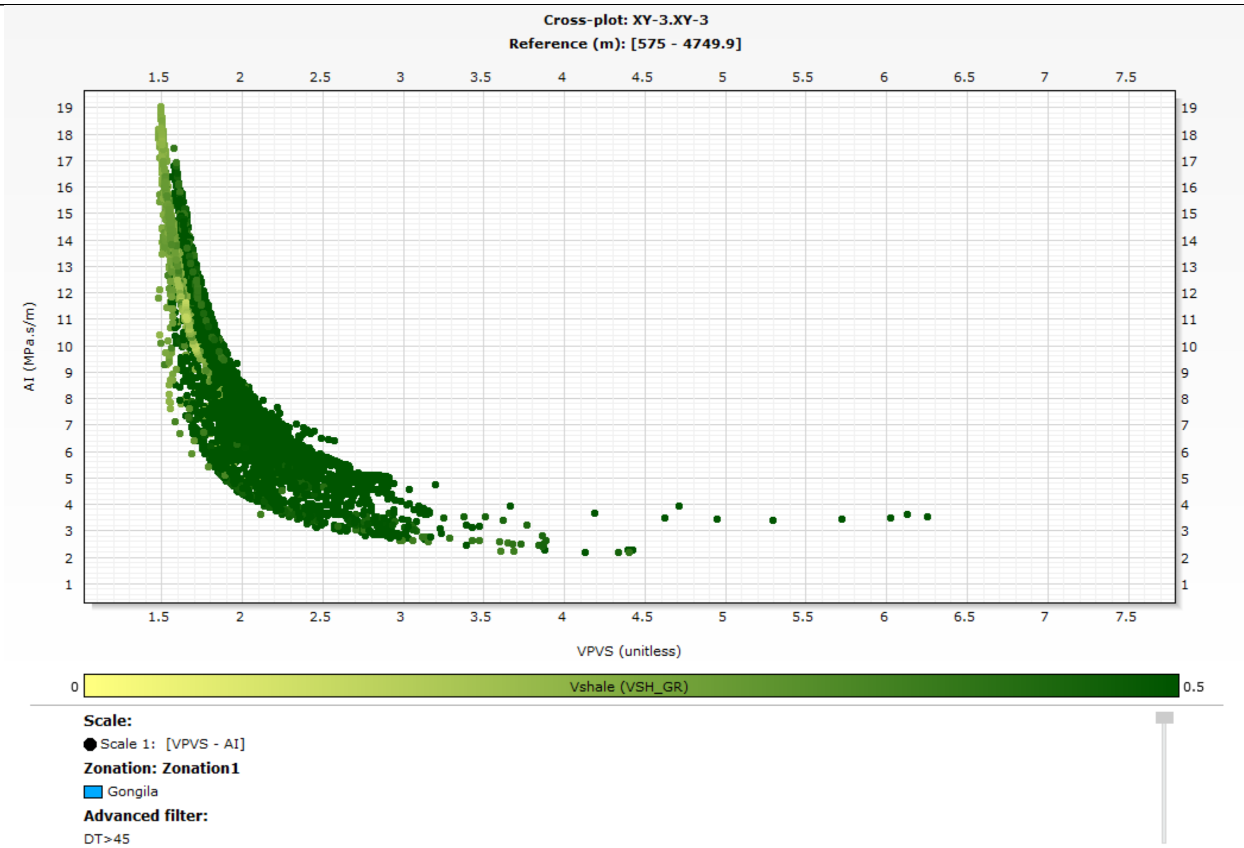

Figure 6: AI vs VPVS plot with background removed. The plot represents the measurements or responses from only the Gongila Formation reservoir interval.

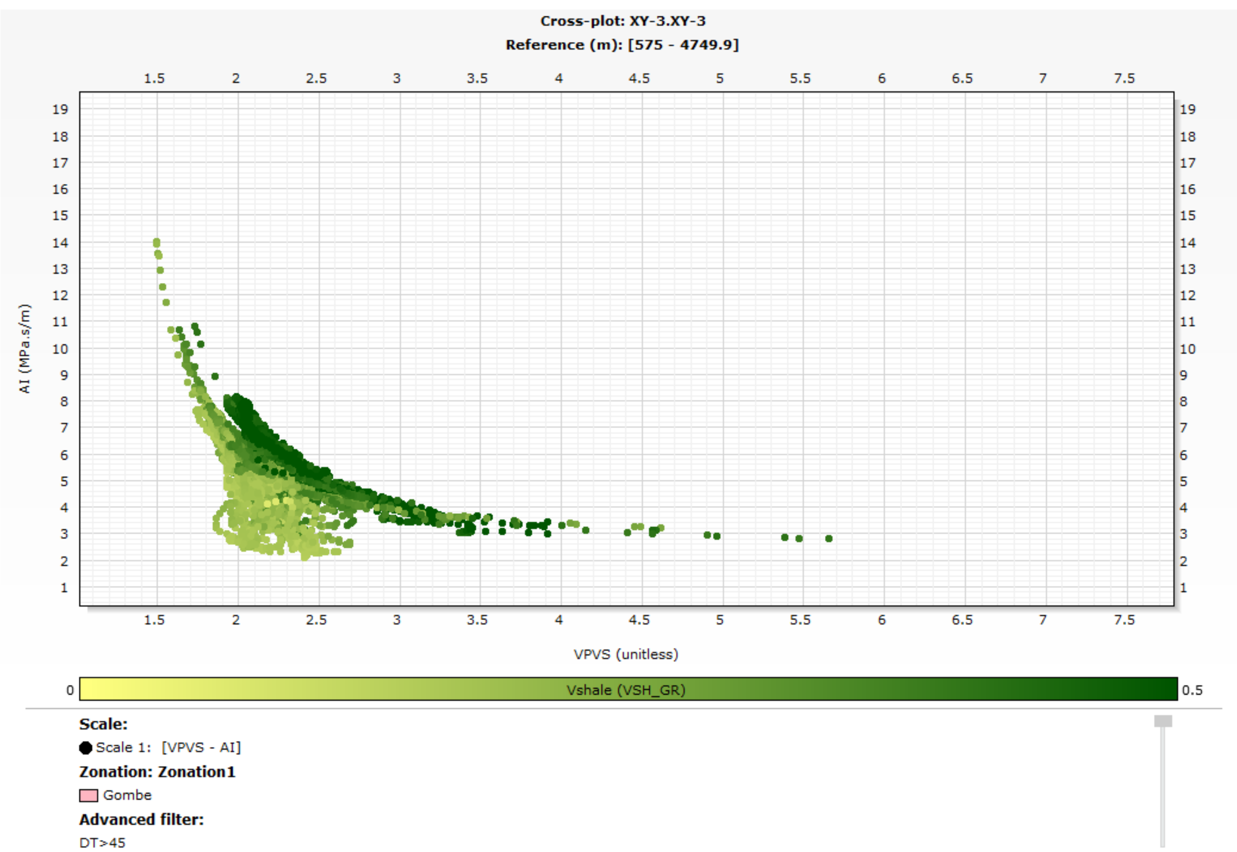

Figure 7: AI vs VPVS plot for the Gombe Formation reservoir interval.

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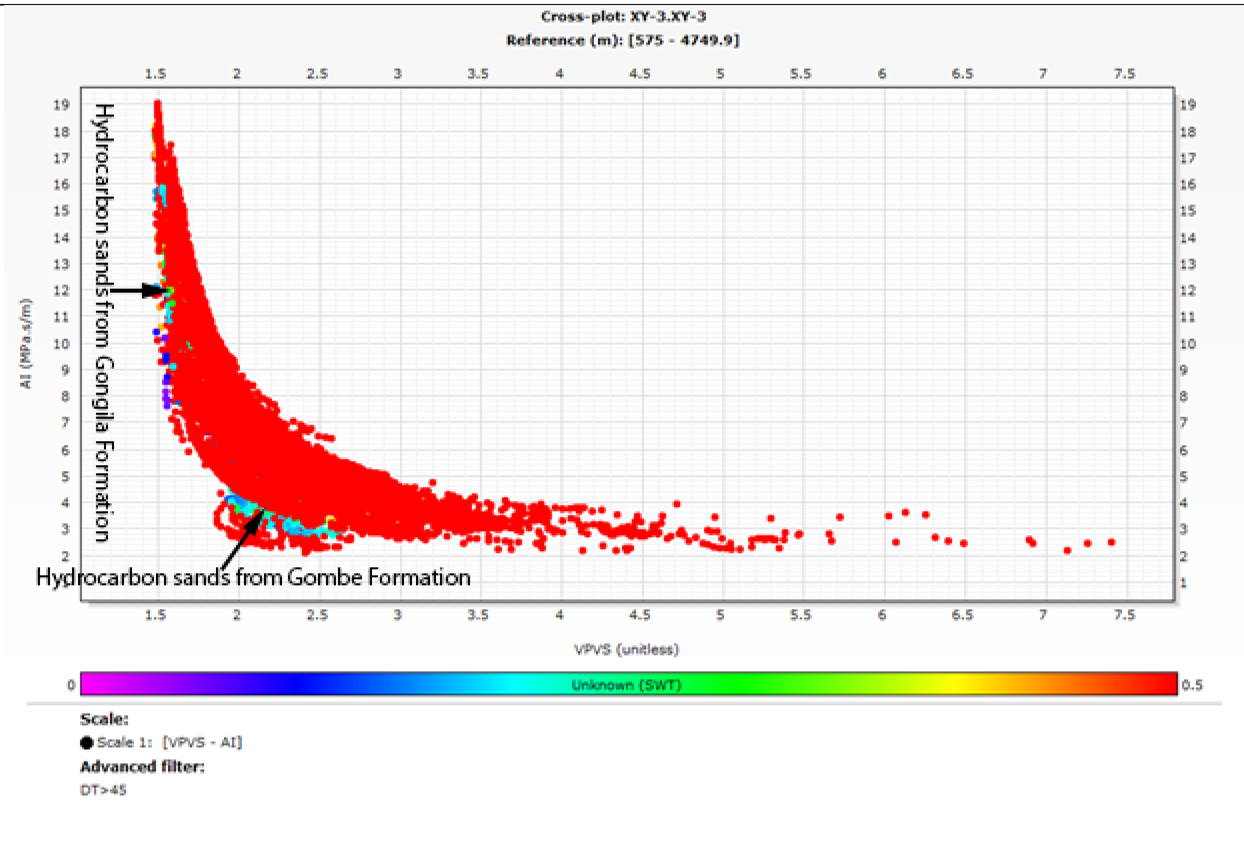

Figure 8: AI vs VPVS plot. The colour is water saturation to aid the identification of potential hydrocarbon sands.

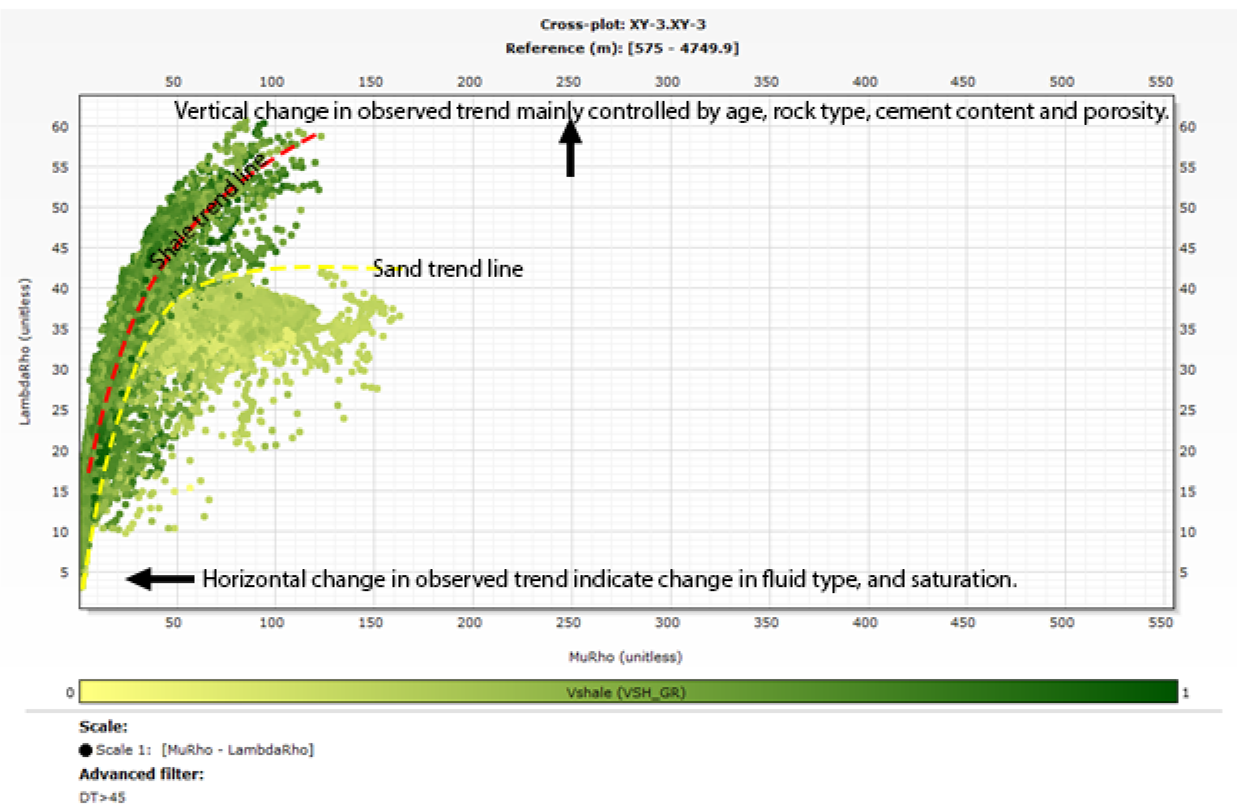

Figure 9: LambdaRho vs MuRho plot with trendline for shale and sand. The colour is shaliness (volume of shale).

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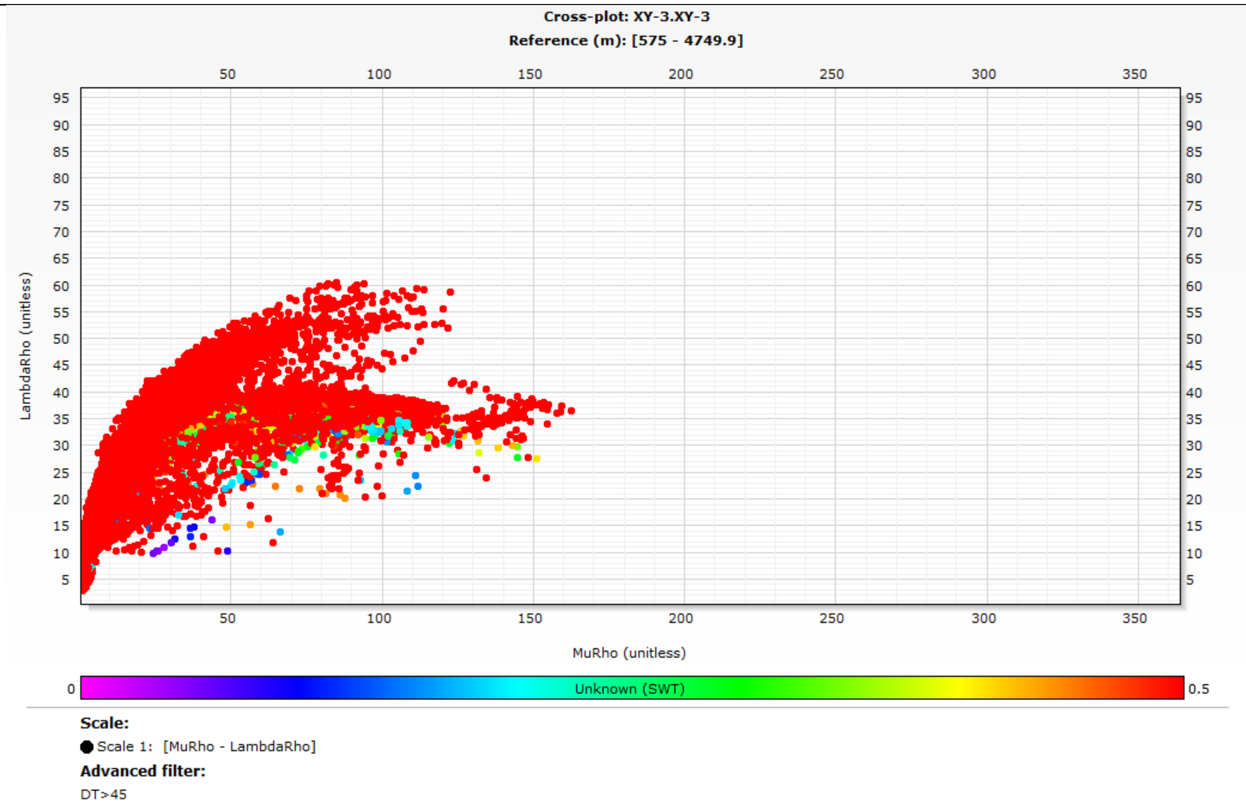

Figure 10: LambdaRho vs MuRho plot coloured by water saturation.

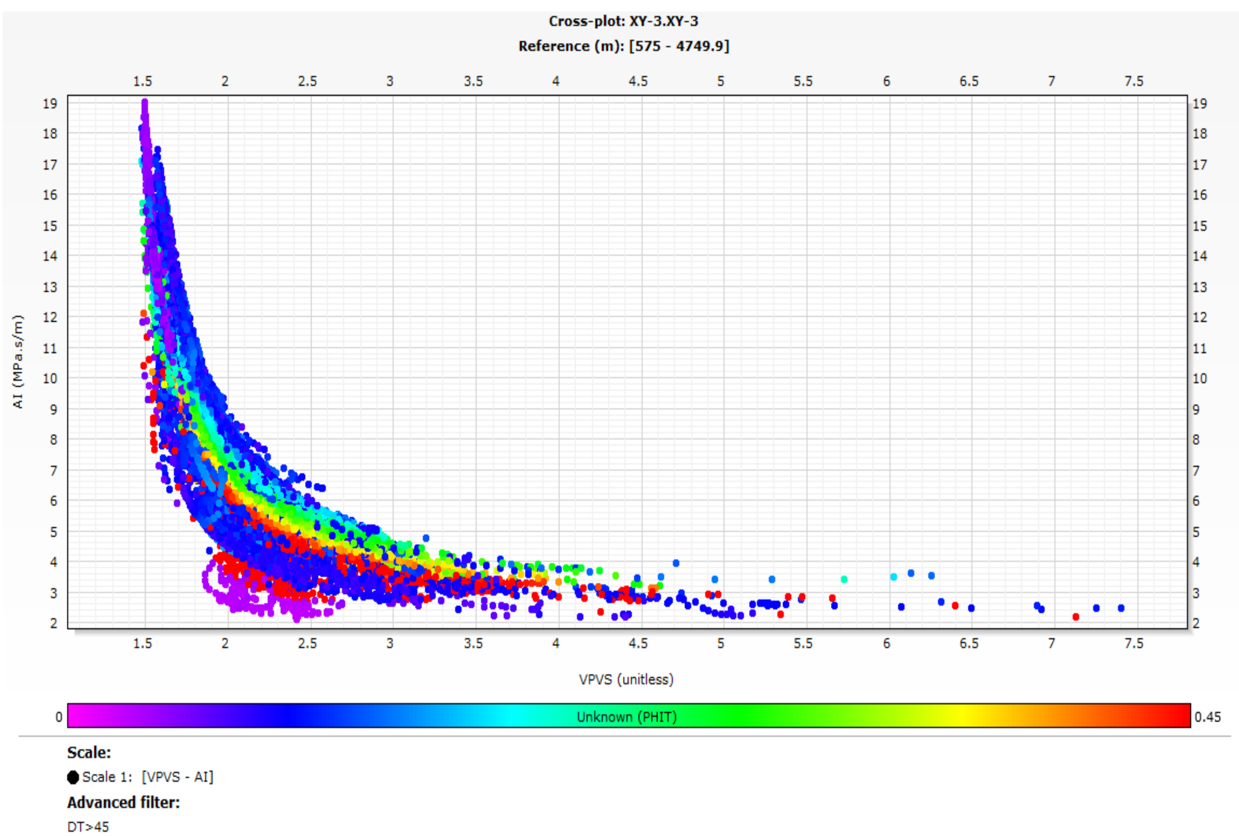

Figure 11: AI vs VPVS plot coloured by porosity

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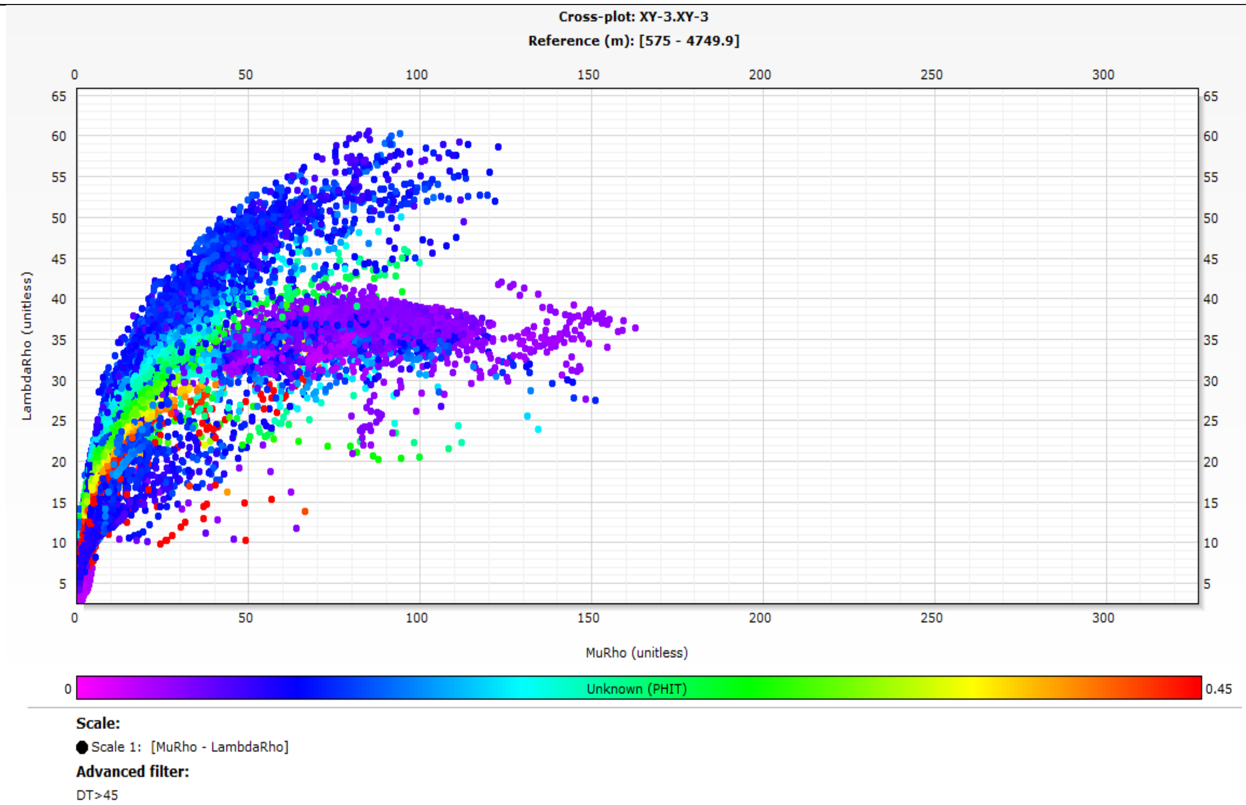

Figure 12: LambdaRho vs MuRho plot coloured by porosity

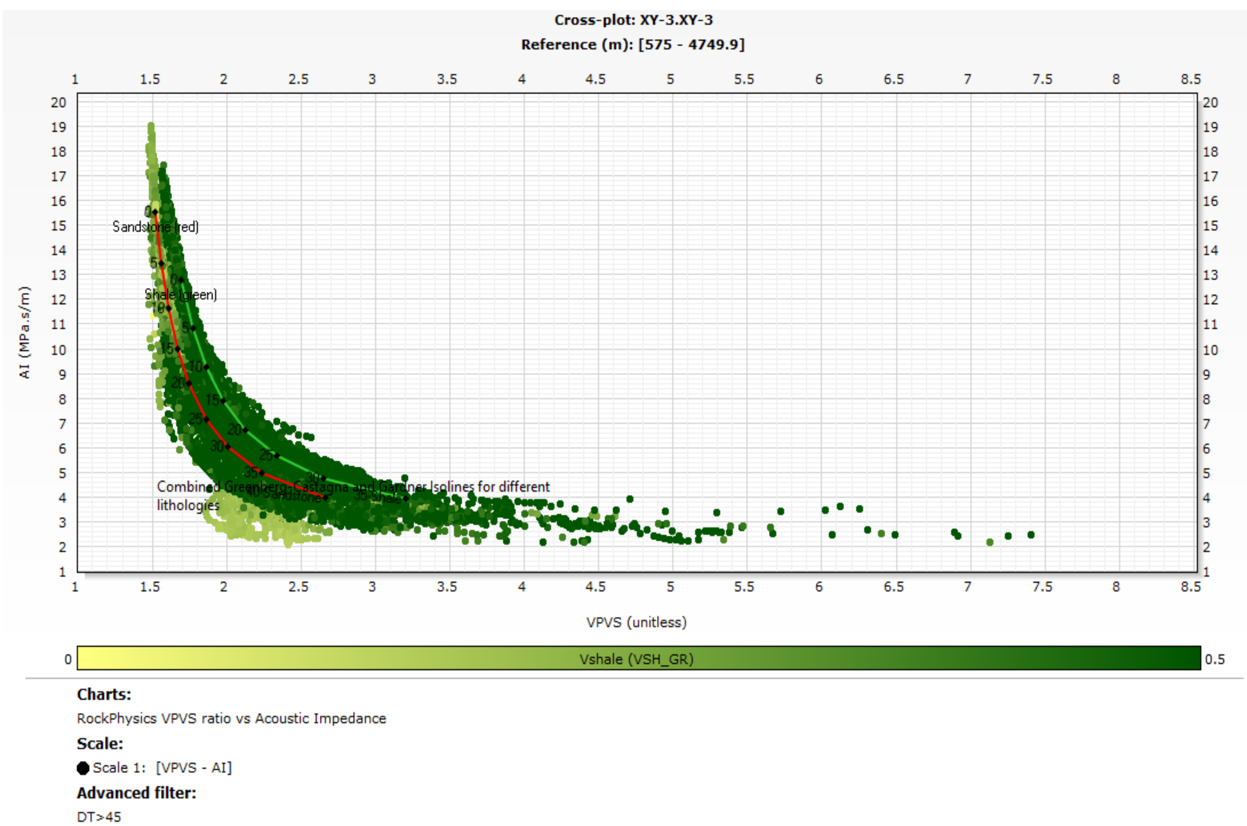

Figure 13: AI vs VPVS plot coloured by volume of shale with theoretical lithology trendlines for shale and sand.

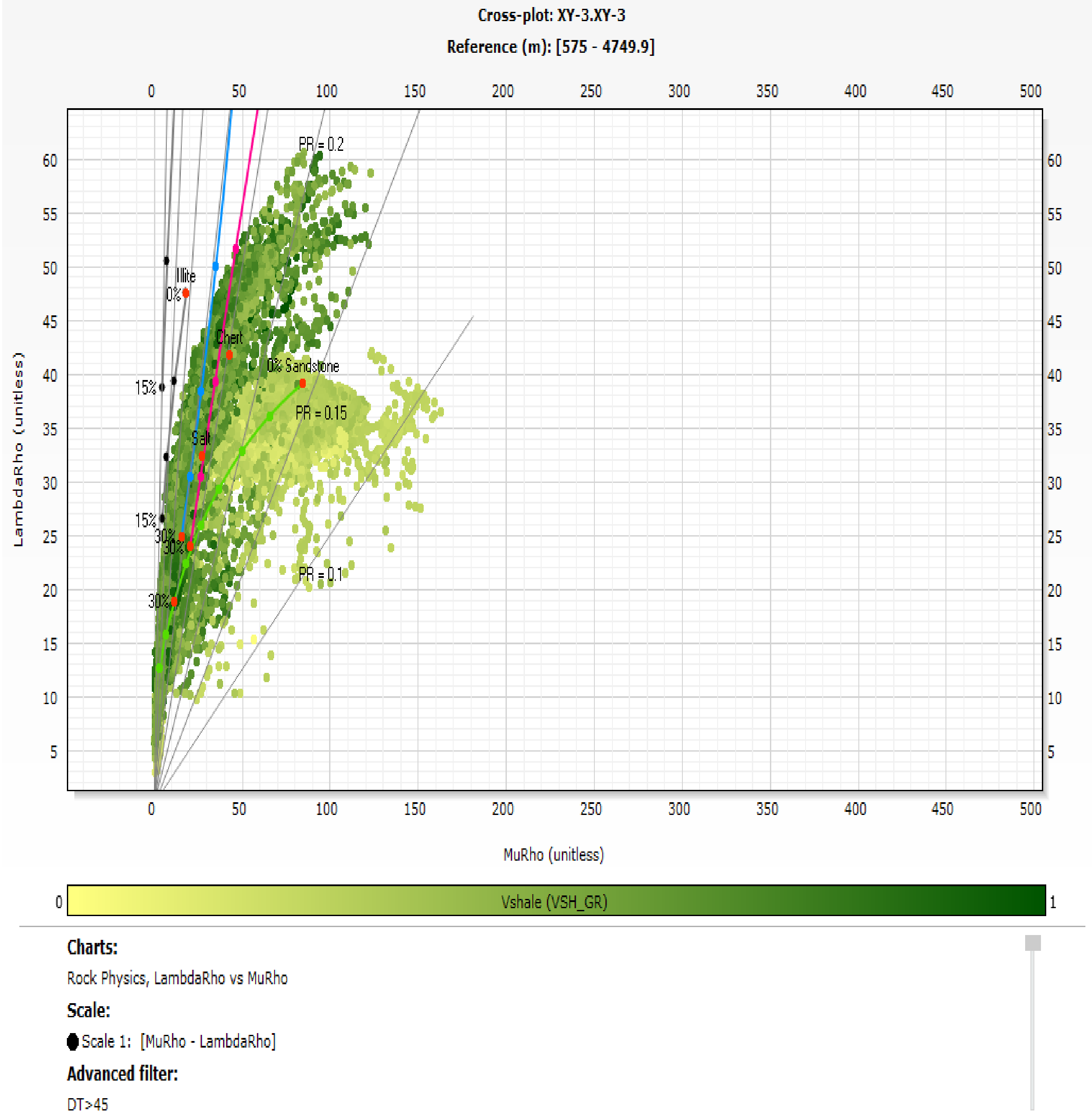

Figure 14: LambdaRho vs MuRho plot coloured by volume of shale with theoretical trendlines for lithology.

Gassman fluid substitution was then carried out to understand the effect of reservoir fluid content, saturation and porosity on the seismic response. This was done by first determining the mixing method to be used by placing bounds on plot of VP vs RHOB (figure 15 and 16). Hill method was then used since it accounts well for most of the rock measurement after the effects of other factors have been filtered out. Five case scenario was set up with the initial assumption starting with a uniform oil saturation of 10 percent since the hydrocarbon content of the reservoirs were assumed to be predominantly gas, with the rest being filled with brine. The first case substituted 100 percent brine saturation for the in-situ or original saturation, the second case was for 80 percent gas and 10 percent oil, the third for 40 percent gas and 10 percent oil, the fourth was for 30 percent gas and 70 percent brine, fifth was for 45 percent oil and 25 percent gas (figure 17). The results were compared to the original saturation using a synthetic trace gotten from the new rock properties after substituting the fluids. It was observed that fluid content had a major effect on the seismic response when comparing the 100 percent brine saturated synthetic trace to the 80 percent gas saturated trace and the original. Big differences in fluid saturation such as going from 80 percent gas saturation to 40 percent saturation also reflected on the seismic response. The higher gas saturated reservoir (see sand B within the Gongila Formation in figure 17) showed a dimmer seismic response. The brine synthetic and the 40 percent and 30 percent gas saturated synthetic match better with the in-situ. This is indicative of partially gas saturated reservoir with also the possibility that the reservoir is patchy explaining the appearance of the water saturation log.

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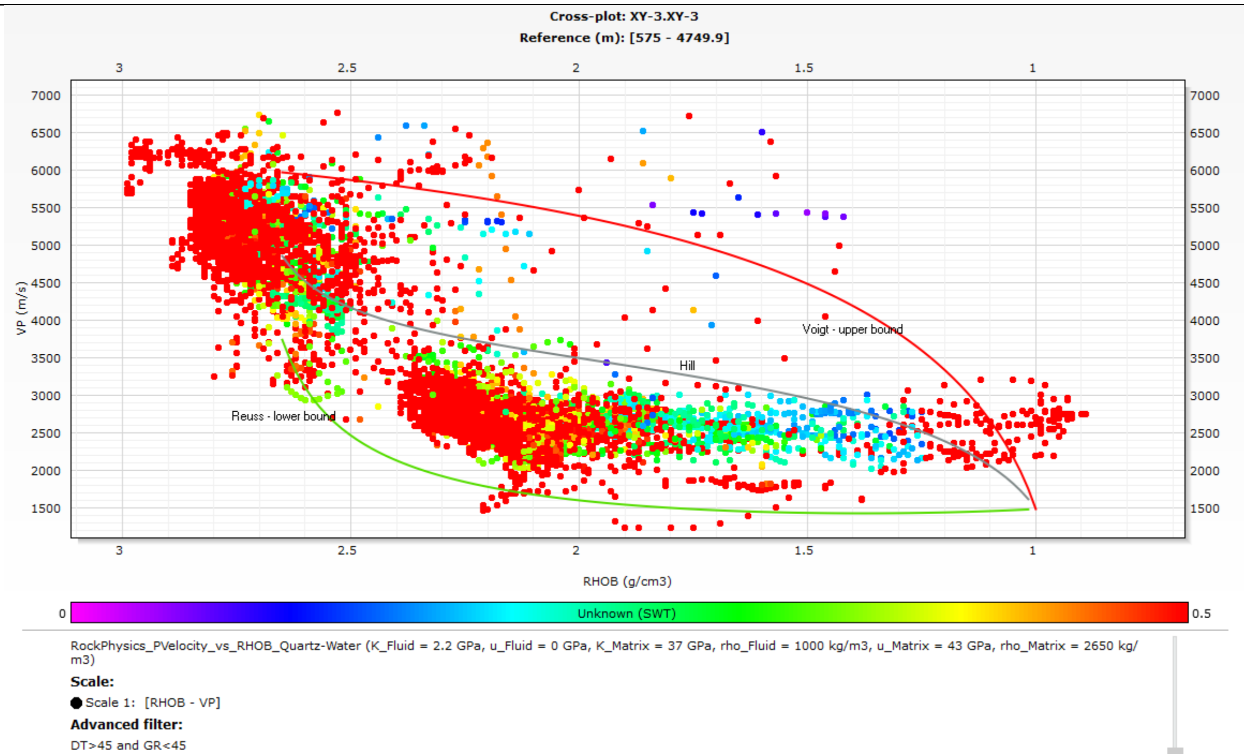

Figure 15: VP vs RhoB plot coloured by water saturation with the Voight-Hill-Reuss bound. The large variance or variability observed in the plot is due to the effect of the background.

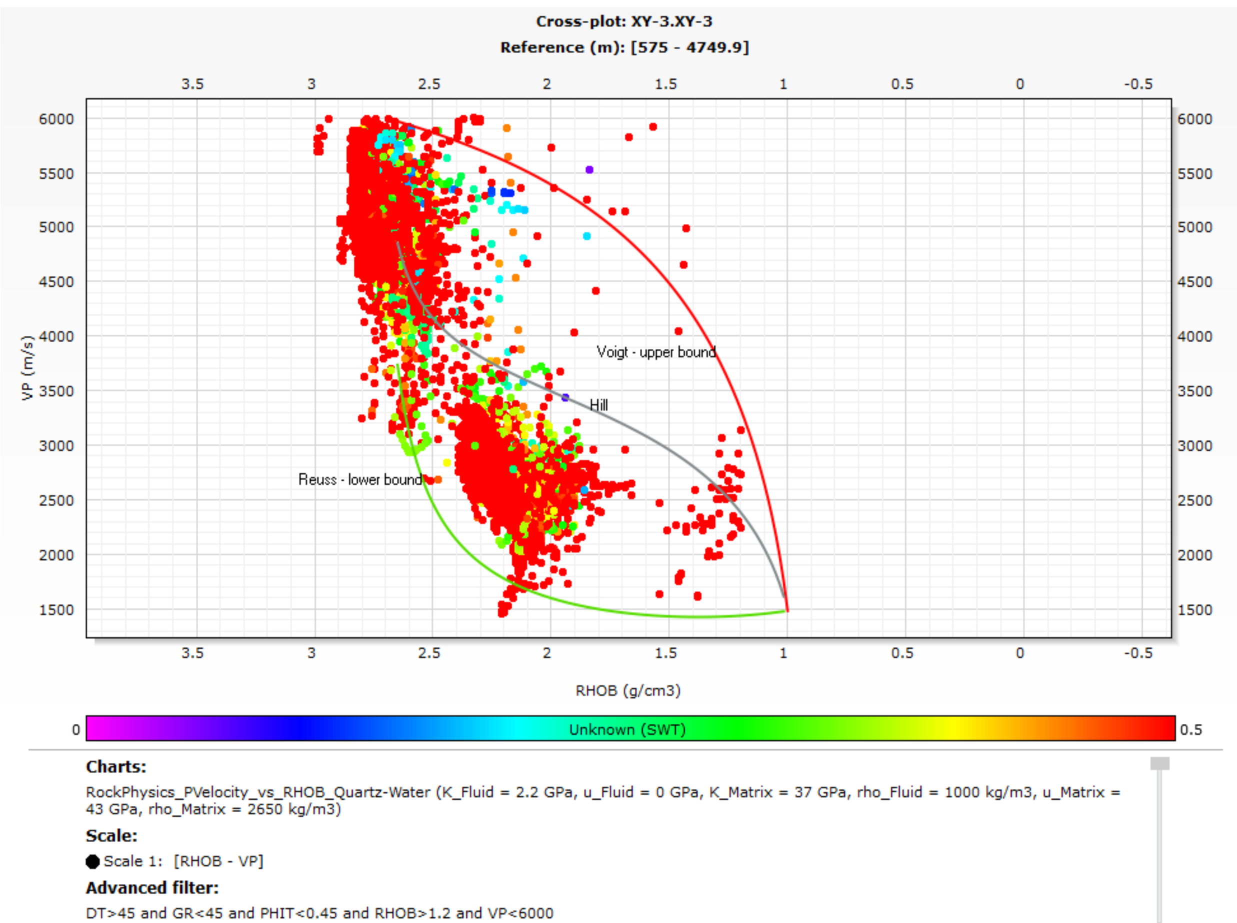

Figure 16: VP vs RhoB plot with the Voight-Hill-Reuss bound with filters applied to remove some of the effects of the background.

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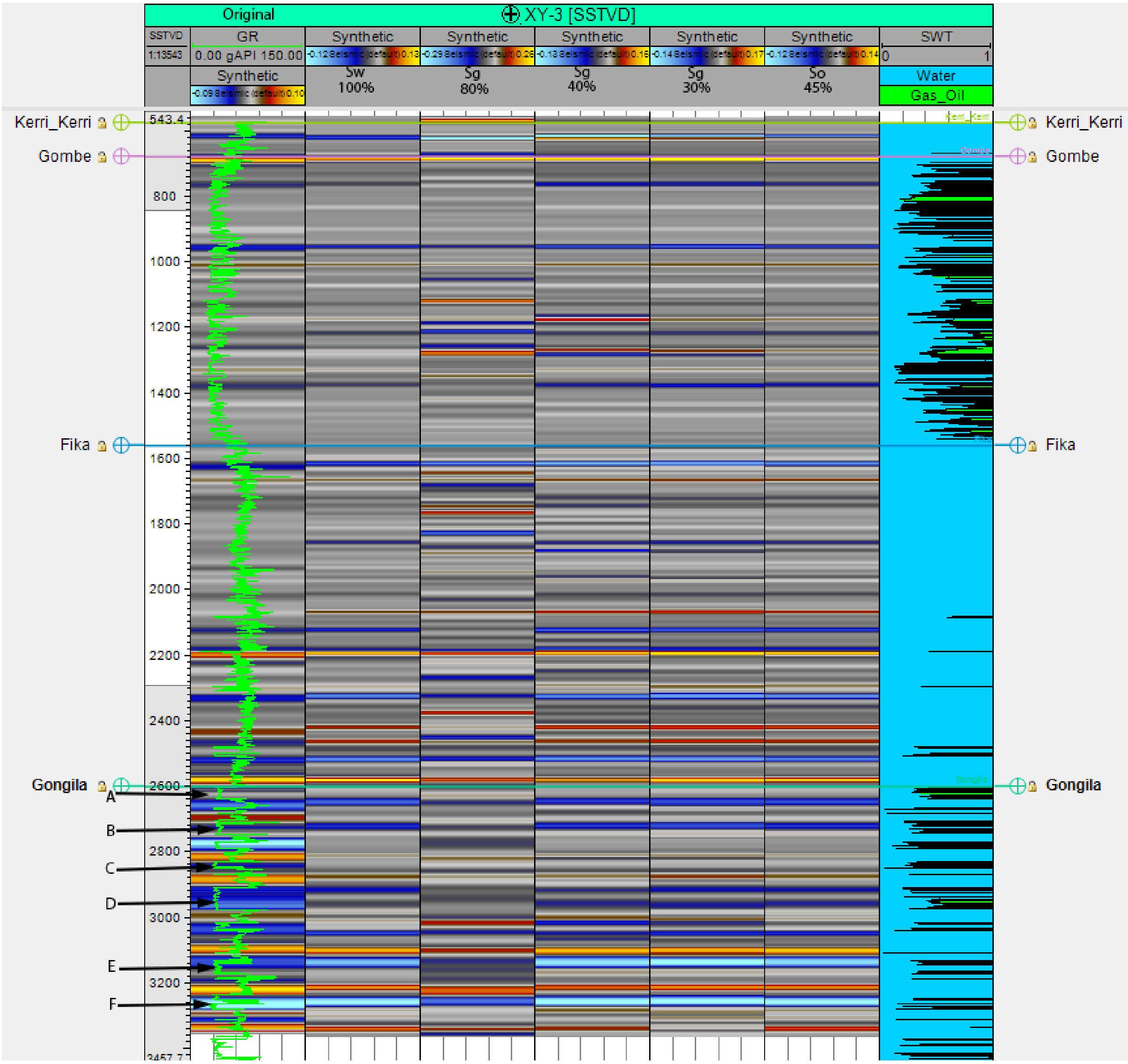

Figure 17: Seismic traces along well XY-3 for the original or in-situ measured data and those of the fluid substituted response for each of the scenario chosen to be tested.

IV. Summary

Fluid substitution provides away for the identification and quantification of fluid in reservoir. The principal cause in failure of development wells is rising water saturation. It is very challenging to evaluate water saturation from seismic data unless we include rock physics modeling. Rock physics modelling facilitate the evaluation of the impact of fluid depletion on different seismic elastic properties such as P- and S-wave velocity as well as densityRock physics analysis, including crossplots of AI vs. VP/VS and LambdaRho vs. MuRho, highlighted lithological and fluid effects. Gassmann fluid substitution demonstrated significant seismic response variations with changes in fluid saturation, confirming partially gas-saturated reservoirs with patchy distributions.

V. Conclusion

This study investigates the application of rock physics and Gassmann fluid substitution analysis for reservoir characterization in the KY Field of the Chad Basin, Northeastern Nigeria.

Rock physics analysis was done starting with a crossplot of AI vs VPVS and then LambdaRho vs MuRho . The two plots indicated a trend for both sand and shale but the lithological discrimination was more distinct on the LambdaRho vs MuRho crossplot.

The effect of fluid was better seen on the AI vs VPVS plot. On both plots, vertical changes in the observed trend was found to be controlled by age, rock type, cement content and porosity while the horizontal changes in the observed trend was attributed to a change in fluid type and saturation.

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Gassmann fluid substitution demonstrated significant seismic response variations with changes in fluid saturation. This is indicative of partially gas saturated reservoir with also the possibility that the reservoir is patchy explaining the appearance of the water saturation log.

The study provides a comprehensive understanding of the field's reservoir properties, offering valuable insights for future exploration and development.

Limitation/Uncertainties

1. Several of the wells drilled penetrated thick sequences of coarse clastics. A number of other wells targeted thick volcanic plugs and/or sills which occur parallel to the bedding planes. This might have affected the result of the seismic elastic properties
2. Inconsistency between seismic shotpoints and well locations might lead to significant geologic misinterpretations.

VI. Reccomendations

1. The most recent model that involve extensions and modifications to the classic Gassmann equation, incorporating more complex factors like rock physics, microstructural details and specific rock types like Cheetah optimizer Algorithm should be adopted to improve accuracy.
2. Nuclear magnetic resonance (NMR) based models is also recommended to reconstruct fluid distribution based on nuclear magnetic resonance data
3. Close deeper wells that penetrate all the formations should be drilled across the study area to provide more information about the subsurface stratigraphy of the area.
4. Checkshot data should be provided for all the wells for accurate studies.

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