Ngr. J. Multi. vol-2, issue-6 (Jun-2026) pp-223-238 ISSN: 3108-2750 (Online)

Nexus Global Research Journal of Multidisciplinary

Journal Homepage: https://nexusglobalresearch.com/journal/ngrjm/

Research Article

Compaction Trend Modeling from petrophysical parameters of Reservoir Wells in the Central Depobelt, Niger Delta.

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ABSTRACT:

Understanding compaction behavior is essential for reliable pore pressure prediction, reservoir characterization, and safe drilling operations in sedimentary basins. The study aimed at evaluating the effect of compaction using petrophysical properties across eight(8) Wells and an accurate prediction of the sub-surface pore pressure, a basic requirement for safety, economics and efficiency in exploratory drilling and production of oil and gas. The capacity of assessing both short- and long-term rock behaviors according to the interaction between distinct parameters of rock texture, petrophysical and mechanical properties are highly instrumental to several geoengineering materials (Askaripour et al., 2022). This study presents a compaction trend modeling approach using well-log data from selected reservoir wells 'Z' field, Central Depobelt of the Niger Delta. Shale intervals were identified and normal compaction trends (NCT) across the study wells were established. The petrophysical characterization estimated across Wells A – H are shown in Table 1, while the compaction trend delineation obtained from petrophysical parameters for Sonic transit time (Dt), Compressional velocity (Vp), Density(ρ), Porosity (ϕ), and Overburden stress (σstress) for wells A - D and E - H are shown in Figs. 3 - 4, 5 - 6, 7 - 8, 9 - 10, and 11 – 12, respectively. From the estimated result for Dt across Wells (A – H), Well A had the highest average value of 117.93 us/ft, while Well H had the lowest average value of 87.64us/ft. For Vp, Well H has the highest average value of 3549.58m/s while Well A had the lowest average value of 264.82m/s. For Density(ρ) and Porosity(ϕ), it was observed to have the highest average value of 2.52gcc and fractional value 0.38 in Well H and A, with lowest average values of 2.21gcc and fractional 0.20 in Well A and H, respectively. Overburden stress(σ), was estimated to have the highest average value of 1.09psi/ft in Well H, with the lowest average value of 0.96psi/ft in Well A. Figs. 3 and 4 indicates that the Dt decreases with depth as compaction of rock increases with increase in ρ and Vp. The increase in Dt directly corresponded to higher ϕ values (slower travel). The Vp against depth profile across Wells A-D and E-H shows that Vp increases with depth, leading to higher compaction, because as sediments are compacted, porosity was observed to decreases across all Wells, hence grains are more tightly packed, and the rock matrix becomes stiffer which led to consolidation. This implies that as formation rocks become more compacted (denser) and less porous, their compressional wave velocity increases with decrease in sonic interval travel time, except where high porous and less dense zones were experienced that could initiate the reverse case of the trend, which possibly suggests the presence of abnormal pressure as observed from other complimentary profiles within the study area.

Keywords: *Compaction trend, Petrophysical characterization, Overpressure, undercompaction, well logs data, Central Depobelt, Niger Delta.*

1.0 INTRODUCTION

Compaction trend analysis plays a critical role in subsurface evaluation, particularly in predicting pore pressure and understanding reservoir behavior (Eaton, 1975). In sedimentary basins such as the Niger Delta, high sedimentation rates and thick shale successions commonly result in abnormal pressure conditions (Doust & Omatsola, 1990). Therefore, the petrophysical evaluation of the rock formation has almost always played a crucial role in not only compaction trend assessment, but also in evaluating and predicting subsurface geopressure. These basic physical properties (Compressional velocity, sonic interval transit time, porosity, density, and permeability) forms fundamental engineering parameters and remain the basic and most reliable tool for quantitative description of subsurface information. The study aimed at evaluating the effect of compaction using petrophysical properties across eight (8) Wells and

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Received: 13 Jun 2026; **Accepted:** 23 Jun 2026; **Published:** 26 Jun 2026

an accurate prediction of the sub-surface pore pressure, a basic requirement for safety, economics and efficiency in exploratory drilling and production of oil and gas. Increasing compaction compressed and deformed the reservoir rocks, leading to decrease in both porosity and permeability, (Xiong et. at. 2018, and Garba et. al., 2025). Failure to adequately evaluate compaction and pressure regimes can lead to drilling challenges such as kicks, blowouts, and borehole instability. The compaction of shale sediments supports the total overlying rock column, leading to anomalous formation pressures. Formation pressure is estimated during well planning, as it affects mud and casing programme (Jurgen, 2015; Alasi, 2025). The Niger Delta Basin is one of the world's most prolific hydrocarbon provinces, characterized by thick clastic sediment accumulation and complex structural styles (Short & Stauble, 1967). The Central Depobelt, where this study was carried out, commonly exhibits variable compaction and pressure regimes due to rapid burial and growth faulting (Avbovbo, 1978). This study therefore applies compaction trend modeling to wireline log data from reservoir wells to improve the understanding of subsurface pressure behavior and contribute to safer drilling practices.

2.0 STUDY AREA.

The Niger Delta Basin is situated along the margin of the West African continental plate, often referred to as one the world's most prolific hydrocarbon provinces (Odesa et.al., 2024, Ideozu et al., 2025; Mba-Otike et al., 2025; and Eyankware et al., 2025). The stratigraphy of the Niger Delta Basin comprises three major lithostratigraphic units: the Benin Formation, Agbada Formation, and Akata Formation (Short & Stauble, 1967). The Benin Formation consists mainly of continental sands and generally exhibits normal pressure conditions. The Agbada Formation contains alternating sand–shale sequences and hosts most hydrocarbon reservoirs in the basin, often showing variable compaction behavior (Doust & Omatsola, 1990). The Akata Formation, composed predominantly of marine shales, is commonly associated with overpressure development due to undercompaction and fluid retention (Avbovbo, 1978).

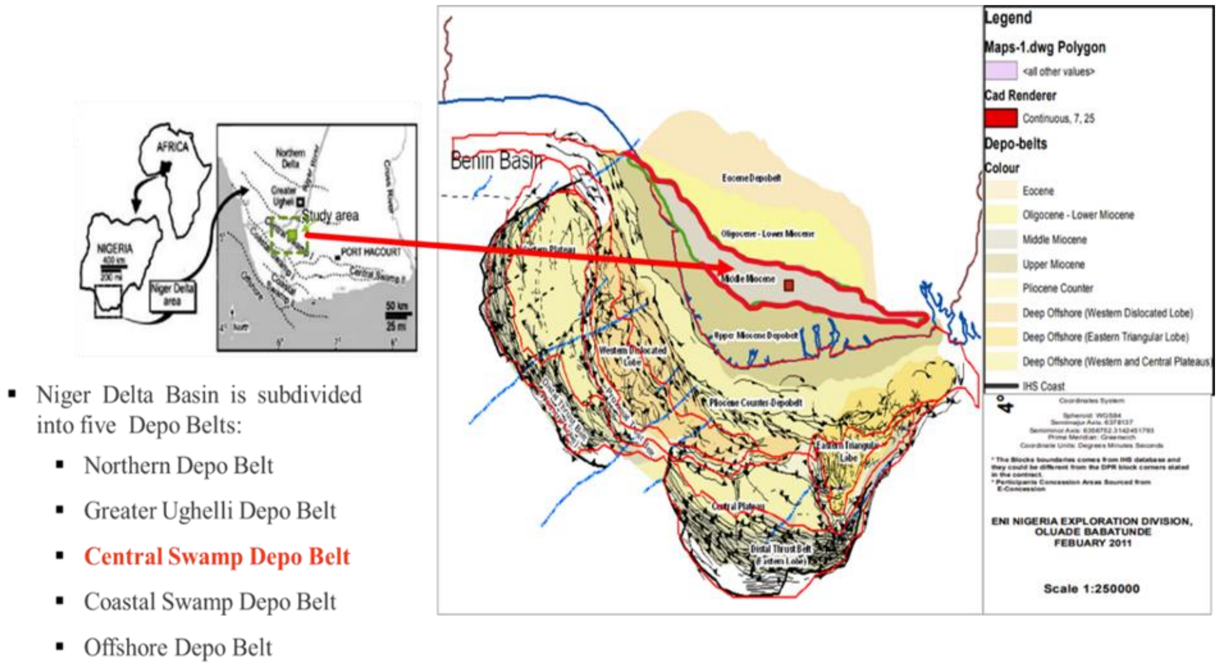


Fig.1: Map of the Niger Delta Showing Field 'Z' in the Central Depobelt of Niger

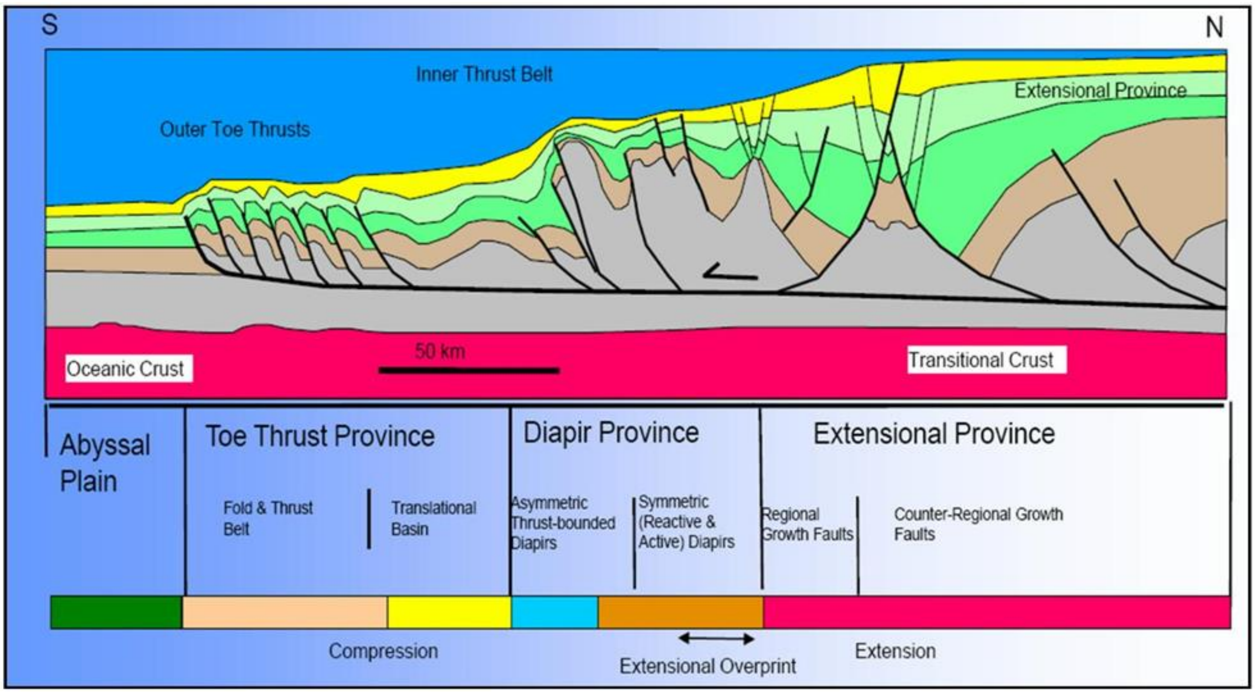


Fig. 2: Structural Map of the Niger Delta Showing the extensional structural zones (after et. al., 2010)

Pore pressures is almost always found within the deeper sedimentary formations and are not increased with depth of overburden to sometimes double of the hydrostatic pressure, and if these abnormal pressures are not accurately predicted prior to drilling, catastrophic incidents, such as well blowouts and mud volcanoes, may occur, Boboye et. al., 2013. The Niger delta is considered one of the highest hydrocarbons producing basins in the world, with the discoveries of giant oil fields in the deep-water areas making it a key target for exploration activities. Seven regional depobelts are defined in the Niger Delta and they succeed each other in the southward direction as the delta progrades (Doust and Omatshola, 1990). They are (1) Northern delta (2) Greater ughelli (3) Central swamp I (4) Central swamp II (5) Coastal swamp I (6) Coastal swamp II and (7) Offshore (Fig. 1). Generally, the Niger Delta is divided into three structural zones of extensional, translational, and compressional tectonics (Fig 2). The study area is located in the central parts of the Central Swamp Depobelt (Fig. 1) of the hydrocarbon rich Niger Delta Basin of Nigeria. It covers an area extent of about 1171.42 KM^2. Structurally, it is within extensional structural zone and the formations penetrated by this study comprise the Akata, Agbada and Benin Formations. Rapid sedimentation rates and structural features such as growth faults in the Central Depobelt significantly influence compaction trends and pore pressure distribution within the basin, (Doust & Omatsola, 1990).

3.0 Materials and Methods

3.1 Materials

The data was approved by the Nigerian Upstream Petroleum Regulatory Commission (NUPRC) and was supplied by the Nigerian Agip Oil Company (NAOC) Limited. The data contains a composite well logs acquired around the entire study area, onshore Central depobelt of Niger delta. A total of 8 wells were selected in the study area with a reliable dataset for the compaction trend assessment from petrophysical study (Tables 3.1 and 3.2). The data distribution is presented in the Table 1, below. A Techlog Workstation, Techlog64, 2015.3 software, a Schlumberger software was used for Data DC, and QC. The well logs were carefully conditioned, checks, edited, normalized, and interpreted in all cases, before being used in a reservoir study. Greater care was taken to correctly treat the log data through shales, across drilling breaks, casing points, and washouts. The data logs were filter and De-spike to remove and correct data points that may be anomalous. Normalize logs from all the selected wells to determine the appropriate ranges and cut-offs for porosity, clay content, water resistivity and Saturation. After all, the data was exported to Excel for petrophysical computation.

3.2 Methods

3.2.1 Compaction Trend Modeling

Normal compaction trends were constructed using shale intervals from shallow depths assumed to be normally pressured. Under normal compaction conditions, sonic transit time decreases with depth, while bulk density and resistivity increase (Eaton, 1975;Lawson-Jack et. at., 2018). These trends were extrapolated to greater depths and used as a baseline for evaluating deviations. If normal compaction trend(NCT) evaluation is not adequately carried out in deeper reservoir formations to accurately assess overpressure potentials from deviated compaction trends prior to drilling, it can greatly cause well control issues and other safety geohazard like (Bowers., 1995, Zhang 2011; Zhang 2013; Sen and Ganguli 2019; Baouche et al. 2020a, b, 2020c; Ganguli and Sen 2020; Radwan and Sen 2020, Alabere, et. al., 2021, Kii et. al., 2024). The prediction of overpressure from sonic, compressional velocity, density, porosity, and overburden stress crossplott were performed by correlating the degree of deviation from the normal compaction trend (NCT) at a given depth with the observed pressure in adjacent reservoir formations. This methodology entails establishing the normal compaction trends (NCT) that correspond to the normal pore pressure regime when shale resistivity or sonic transit time is plotted against depth, and the divergence of observed sonic transit time or resistivity or porosity (Fig. 3 - 12) from the NCT serves as an indicator of the formation pore pressure, (Eberhart-Phillips, et. al., 1989; Onyishi, et al., 2022).

3.2.2 Sonic Compressional Velocity, V_p and Shear Velocity, V_s

The interval transit time values were picked at a chosen depth interval from the Sonic Log. The acoustic (compressional) velocities were computed by taking the inverse of the interval transit time Δt.

$$V_P = \frac{1}{\Delta t}(m[\mu s]^{-1}) \qquad (1)$$

The shear velocities (V_s) were estimated following, Castagna et al. (1985);

$$V_s = (0.8621 * V_p) - 1.1724 \qquad (2)$$

3.2.3 Bulk Density, ρ

Petrophysical analysis shows that the bulk density is an important acoustic indicator for indicating the presence of shale and for geopressured predictions. In the case of abnormal pressure regime and formation evaluation, accurate estimates of density are necessary to determine the location of shales for undercompaction or compaction disequilibrium. An important parameter in geoformation characterization, which can be employed for the differentiation of lithologies, and estimate other petrophysical parameters, such as the fluid content and porosity of a formation, is Density. Therefore, a model which is an important relation in the estimation of density from both Vp and Vs, is the Gardner's empirical Equation or model. However, there are many other empirical and important relationships that describe Vp as a function of density, but very few that compare Vs with densities. The fundamental empirical relationship between density and velocity is as given in Equation (3.3),

$$Vp = \alpha + \beta\rho \qquad (3)$$

Where α and β are empirical parameters and Vp is in Kms^{-1} and ρ is in gcm^{-3}".

Equation (3.3) is the basic relation for many other linear regression analyses.

Gardner et al., (1986), relationship between Vp and ρ. equation (3.4):

$$\rho = \alpha V_p^{\beta} \qquad (4)$$

where ρ is the bulk density, V_p is the P-wave velocity and α & β are empirically derived constants that depends on the geology. (Gardner et al., 1986) further proposed that a good estimate can be obtained of density in g/cc, and α=0.31 (if V is in ms^{-1}) and given velocity in ft/s by taking α = 0.23 and β = 0.25.

$$\rho = 0.23V_p^{0.25}\ kg/m^3 \qquad (5)$$

In this study, Vp values obtained from the sonic logs were used as inputs to the Castagna's relation for the computation of Vs values, while density values obtained from the logs were inputed into the Gardner's relation with the corresponding variables α and β. The density-Vp cross plot was used to confirm the zones of different lithology, as inferred by the densities overlay. The generated density log will be overlaid with the original density log and correlated to indicate zones of different lithology. The Gamma ray was used as a support for this lithological separation. Based on this, the gamma ray log was used as a lithological discriminator to estimate values of α and β for different rock types. Samples with gamma ray values greater than 70 API were considered shales, while those below 70 API were considered sands. This differentiation made it possible for the density-Vp cross-plot to clearly distinguish and delineate zones of different lithology.

3.2.4 Total Porosity, (ϕ_T)

Total porosity is defined as the fraction of the bulk rock volume V that is not occupied by solid matter. If the volume of solids is denoted by V_s, and the pore volume as,

$$V_p = V - V_s. \tag{6}$$

The porosity can be expressed either as a fraction or as a percentage. Two out of the three terms are required to calculate porosity. The initial (pre-diagenesis) porosity is affected by three major microstructural parameters. These are grain size, grain packing, particle shape, and the distribution of grain sizes. However, the initial porosity is rarely that found in real rocks, as these have subsequently been affected by secondary controls on porosity such as compaction and geochemical diagenetic processes. Reliable evaluation of porosity in clean and/or shaly formations requires knowledge of matrix (type and nature), fluid, shale volume and shale transit time affecting the determination of such parameter. If all are linked together in a compatible and quantitative way, good results for porosity are obtained. Porosity can be computed from numerous equations and be transforms. In many situations, there may exist relationships between the value of porosity and acoustic transit time (Δ_t); but such correlations are usually empirically derived for a given formation in an area. One of the first relationships proposed to determine porosity from sonic transit time was by Wyllie et al. (1956 and 1958),

$$\frac{1}{v} = \frac{\phi}{V_f} + \frac{1-\phi}{V_{ma}} \tag{7}$$

Where, ϕ = fractional porosity of the rock; v = velocity of the formation (ft/sec); v_f = velocity of interstitial fluids (ft/sec); v_{ma} = velocity of the rock matrix (ft/sec).” Equation (3.6) is also expressed in terms of transit time as;

$$\phi = \frac{\Delta t - \Delta t_{ma}}{\Delta t_f - \Delta t_{ma}} \text{,,} \tag{8}$$

Where, Δt = acoustic transit time (μsec/ft.);

Δt_f = acoustic transit time of interstitial fluids (μsec/ft.) = 218;

Δt_{ma} = acoustic transit time of the rock matrix (μsec/ft.) = 55.6;

In this study, the following assumptions were made to achieving the obtained results: (i) the interstitial fluid is fresh water, and (ii) the lithology is semi-consolidated sandstone.

3.2.5 Overburden stress (S)

Overburden pressure is the pressure exerted by the weight of rocks and contained fluids above the zone of interest; *it can also be considered as* the pressure on the rock due to the weight of the rock and earth above the rock formation. The common range of rock overburden pressure, in equivalent density, varies between 18 and 22 ppg (2.17–2.64 SG). This range would create an overburden pressure gradient of about 1 psi/ft (22.7 kPa/m). (The 1 psi/ft is not applicable for shallow marine sediments or massive salt.) Mathematically, this pressure can be determined by integrating the formation bulk density from the surface to the depth of interest (Eaton, 1972; Ugwu, 2015; Oloruntobi et al., 2018; Olalere, 2019).

$$S = \rho b \times D \text{ x } g \tag{9}$$

Where;

S = overburden pressure.

ρ_b = average formation bulk density.

D = vertical thickness of the overlying sediments,

From the density log the overburden Pressure was generated using, cumulative summation of the sediment weight, for each depth interval, at constant sea water density of 1.025g/cm using Equation (3.5),

$$S = \rho_b \frac{Z}{g} \tag{10}$$

where S= Overburden stress ($kgcm^{-2}$); g = acceleration due to gravity (cms^{-2}); ρ_b = formation average bulk density (gcm^{-3}); Z = vertical thickness of the overlying sediments (metres).

The effect of overburden pressure on porosity and permeability are observed when the overburden pressure exceeds the fluid pressure in the pore space, the formation is compacted. The porosity, permeability, and compressibility are reduced. To illustrate the effect of net overburden pressure, consider an unconsolidated sandstone. At low net overburden pressures, the formation is loosely packed, and there is a lot of space for sand grains to realign under pressure. In general, the pore throats are relatively large. Hence, the compressibility, porosity, and permeability are high. As the net overburden pressure increases, the sand grains are forced into close contact, and there is less space for realignment. Hence, the porosity and compressibility decrease. The compaction of the sand grains also reduces the size of the pore throats. Therefore, the permeability is also reduced.

3.3 Interpretation of Abnormal Compaction

Wireline log data from selected reservoir wells were used in this study, including gamma ray, sonic, density, and resistivity logs. These logs were widely use for Compaction trend modeling from petrophysical parameters of reservoir Wells in the Central Depobelt, Niger Delta. Shale intervals were identified using the gamma ray log, as shale responses provide more reliable indicators of compaction behavior compared to sandstone intervals (Eaton, 1975; and Hart et. al., 1995; Han et. al.,2004; Mirghaed et. al., 2024). Departures from the modeled normal compaction trend were interpreted as indicators of undercompaction and possible overpressure development. Such deviations are commonly associated with rapid sedimentation and restricted fluid expulsion in the Niger Delta Basin (Onyishi, et al., 2022; Boboye et. al., 2013, kii et al., 2024).

Table 1: Data Availability for Petrophysical Evaluation

Field Name	**Z**	**Z**	**Z**	**Z**	**Z**	**Z**	**Z**	**Z**
Well Name	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**H**
Surface Coordinates	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢
RTE	🔴	🔴	🔴	🔴	🔴	🔴	🔴	🔴
Deviation Survey	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢
Log Suite	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢
Care/SCAL Data	🔴	🔴	🔴	🔴	🔴	🔴	🔴	🔴
Composite log	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢
Pressure Data	🔴	🔴	🔴	🔴	🔴	🔴	🔴	🔴
Well Tops	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢
Data Availa bility	🟩			**Data Nonavailability**		🟥		

4.0 Results and Discussion

The average estimated depth range and gross thickness across Wells A – H is shown in Table. 2, while the petrophysical parameters estimated across these Wells are shown in Table 3. The compaction trend delineation obtained from petrophysical parameters cross-plotted against depth for Sonic transit time (D_t), Compressional velocity (V_p), Density(ρ), Porosity (ϕ), and Overburden stress (σ_{stress}) for wells A-D and E-H are shown in Figs. 3 - 4, 5 - 6, 7 - 8, 9 - 10, and 11 – 12 respectively. Average estimated sonic transit time (D_t) results for Well A – H are 117.93us/ft, 108.74us/ft, 105.60us/ft, 98.54us/ft, 104.29us/ft, 104.70us/ft, 105.97us/ft, and 87.64us/ft, respectively with the highest value of 117.93 us/ft in Well A and H the lowest with 87.64us/f; while the estimated average compressional velocities (V_p) are 264.82m/s, 2881.57m/s, 2928.37m/s, 3132.63m/s, 3000.46m/s, 3001.15m/s, 2980.33m/s, and 3549.58m/s, respectively with Well H the highest with 3549.58m/s and Well A the lowest with 264.82m/s. Average density across Wells(A – H) are 2.22gcc, 2.27gcc, 2.28gcc, 2.32gcc, 2.29gcc, 2.29gcc, 2.28gcc and 2.52gcc respectively with the average value of 2.52gcc in Well H and 2.21gcc the lowest in Well A. Average estimated porosity value are 0.38, 0.33, 0.31, 0.26, 0.30, 0.30, 0.31, and 0.20, respectively. The highest average porosity value was observed in Well A with 0.38, while the lowest was observed in Well H with 0.20. Average overburden stress across Wells (A – H) are 0.96psi/ft, 0.98psi/ft, 0.99psi/ft, 1.01psi/ft, 0.99psi/ft, 0.99psi/ft, 0.99psi/ft, and 1.09psi/ft respectively. Well H was observed to have the highest value with 1.09psi/ft, while the lowest was observed in Well A with 0.96psi/ft. However, Figs. 11 and 12 shows that a direct and linear relationship exists across all Wells (A – H) as observed in the presentation of the compaction trend delineation. The overburden - depth profile, and correlational regression equations and the correlations coefficient for all the Wells (A-G) apart from Well – H which appeared differently, where shown as; y = 24.731x – 3355 and R^2 = 0.9956, y = 0.04x + 153.98 and R^2 = 0.994, y=0.0403x + 155.98 and R^2 = 0.09912, y = 0.0406x + 126.89 and R^2 = 0.9815, y = 0.0395x + 241.53 and R2 = 0.9954, y = 0.0385x + 289.45 and R^2 = 0.9925, y= 0.0393 x + 240.98 and R^2 = 0.9939, respectively.

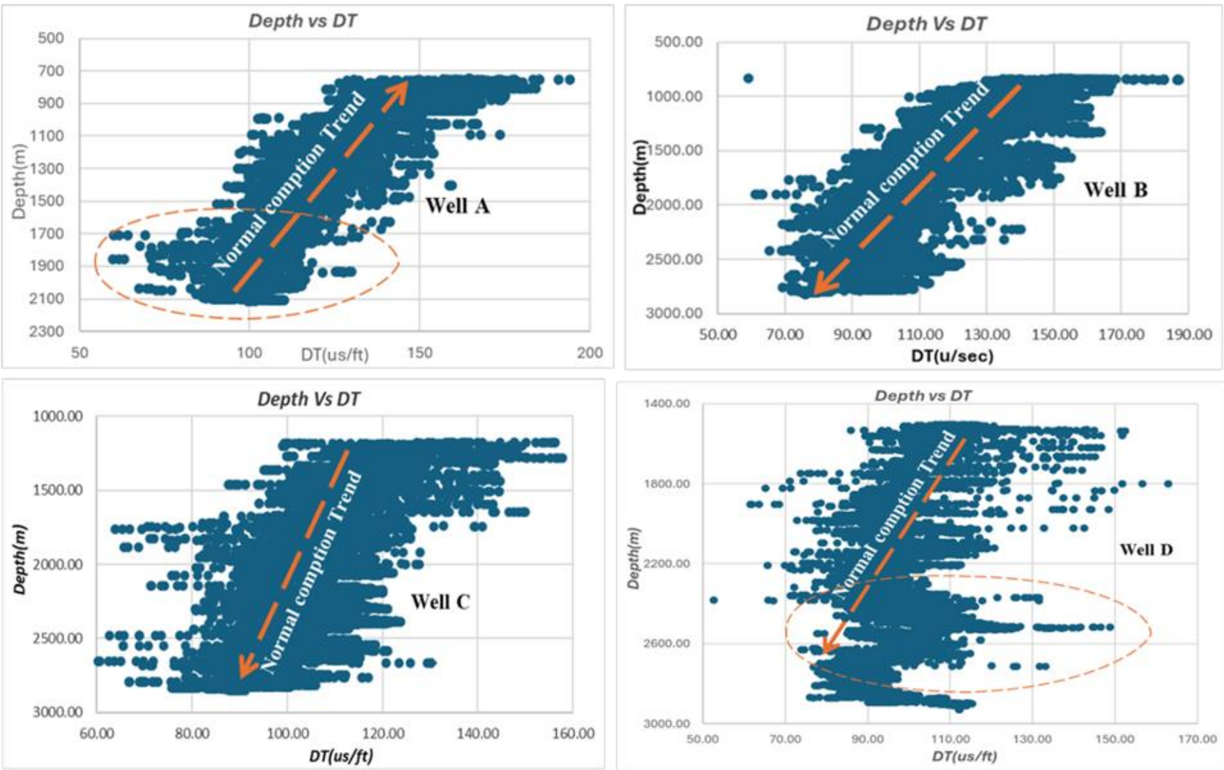
Table 2: Data Distribution of Well logs intervals within study area

S/N	Field	Well	No.	Depth Range(m)	Gross Chickness(m)
1	Z	A	1	750.11 – 2115.01	1364.90
2	Z	B	1	836.22 – 2817.88	1981.66
3	Z	C	1	1178.05 - 2850.64	1672.59
4	Z	D	1	1502.66 –2929.74	1427.08
5	Z	E	1	1363.98 –4141.93	2777.95
6	Z	F	1	1328.78 – 944.42	2615.64
7	Z	G	1	1101.09 – 244.95	3143.86
8	Z	H	1	3961.18 –4365.04	403.86

Table 3: Estimated Petrophysical parameters for Well A – H

Well Description								
Well	Depth (m)	Statistic	DT (µs/ft)	Vp (m/s)	ρ (g/cc)	Φ (frac)	σv (psi)	σv (psi/ft)
WELL A	750.11–2115.01	Average	117.93	2647.82	2.2189	0.3838	4567.24	0.96
		Max	194.26	5086.68	2.6180	0.8538	7366.78	1.14
		Min	59.96	1570.07	1.9514	0.0269	2099.56	0.85
WELL B	836.37–2817.88	Average	108.74	2881.57	2.27	0.33	5953.61	0.98
		Max	187.13	4984.68	2.60	0.81	9940.91	1.13
		Min	61.19	1629.93	1.97	0.03	2370.70	0.85
WELL C	1178.05–	Average	105.60	2928.37	2.28	0.31	6561.61	0.99

	2850.03	Max	161.11	5106.84	2.62	0.65	10130.48	1.14
		Min	59.72	1893.08	2.04	0.03	3458.62	0.89
WELL D	1502.66–2929.74	Average	98.54	3132.63	2.32	0.26	7321.95	1.01
		Max	175.70	7625.00	2.90	0.74	10080.59	1.26
		Min	40.00	1735.91	2.00	-0.10	4530.60	0.87
WELL E	1363.98–4141.93	Average	104.29	3000.46	2.29	0.30	9056.56	0.99
		Max	248.28	5119.88	2.62	1.19	14488.06	1.14
		Min	59.57	1228.45	1.84	0.02	3581.18	0.80
WELL F	1328.78–3944.42	Average	104.70	3001.15	2.29	0.30	8678.47	0.99
		Max	203.16	5605.07	2.68	0.91	14135.54	1.16
		Min	54.41	1501.31	1.93	-0.01	3836.94	0.84
WELL G	1101.09–4244.95	Average	105.97	2980.33	2.28	0.31	8811.30	0.99
		Max	181.72	7611.98	2.90	0.78	15828.82	1.26
		Min	40.07	1678.37	1.98	-0.10	3302.66	0.86
WELL H	3961.182–4365.042	Average	87.64	3549.58	2.52	0.20	14894.64	1.09
		Max	112.20	4600.30	2.68	0.35	16574.34	1.16
		Min	66.30	2718.36	2.34	0.07	13559.00	1.02



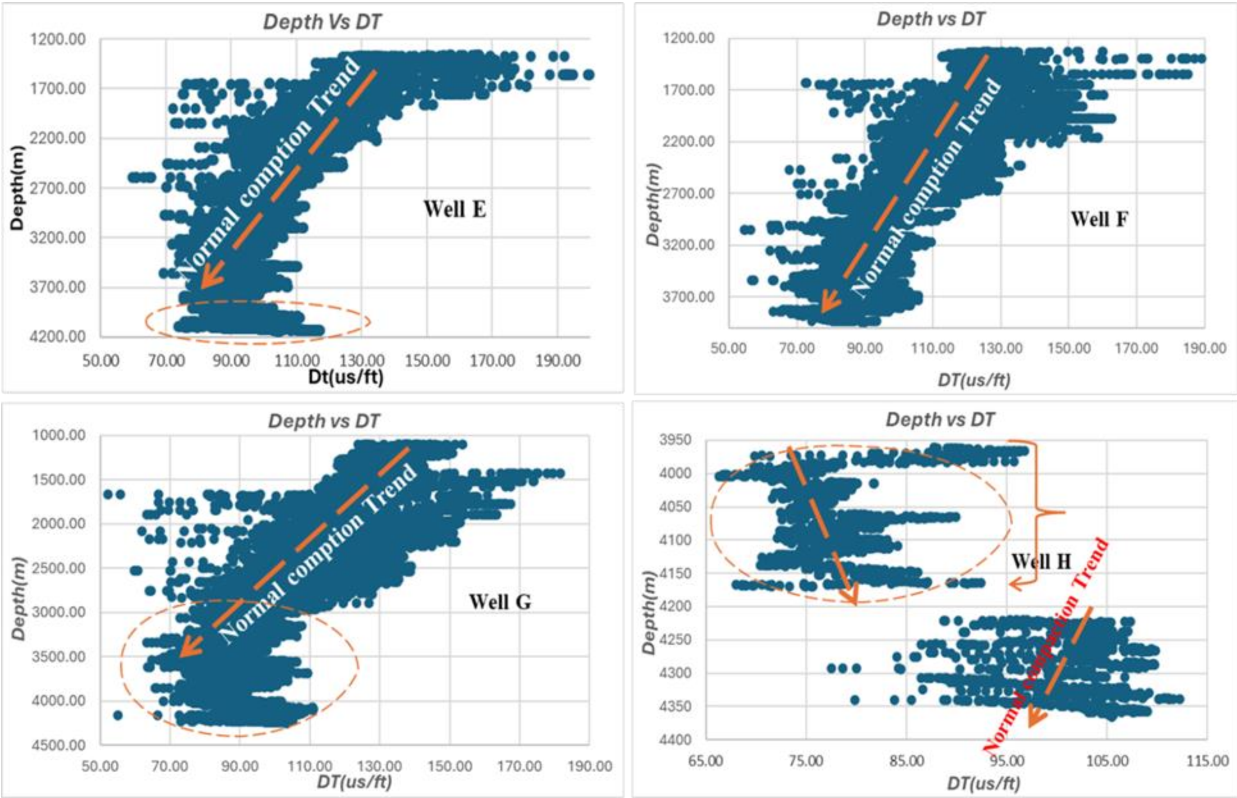


Fig. 4: Effect of Dt - Depth relation across Well E - H

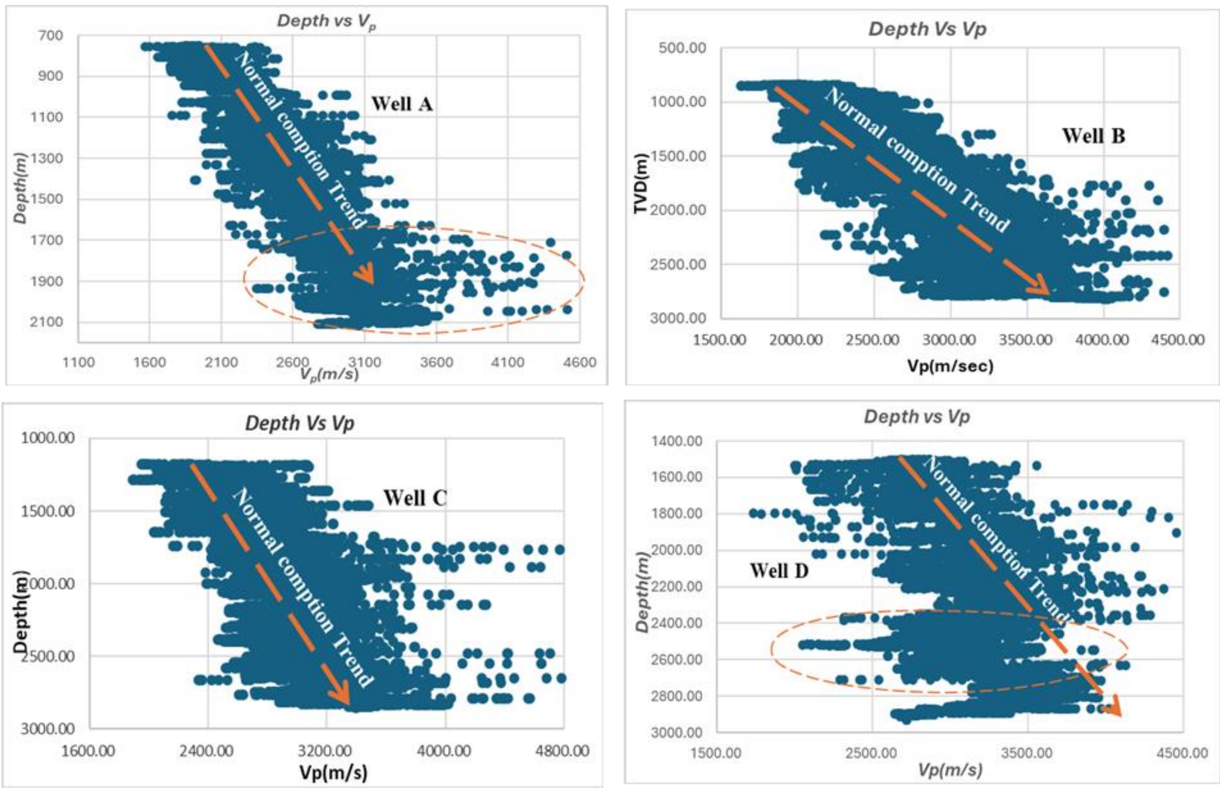


Fig. 5: Vp-Depth relation across Well A-D

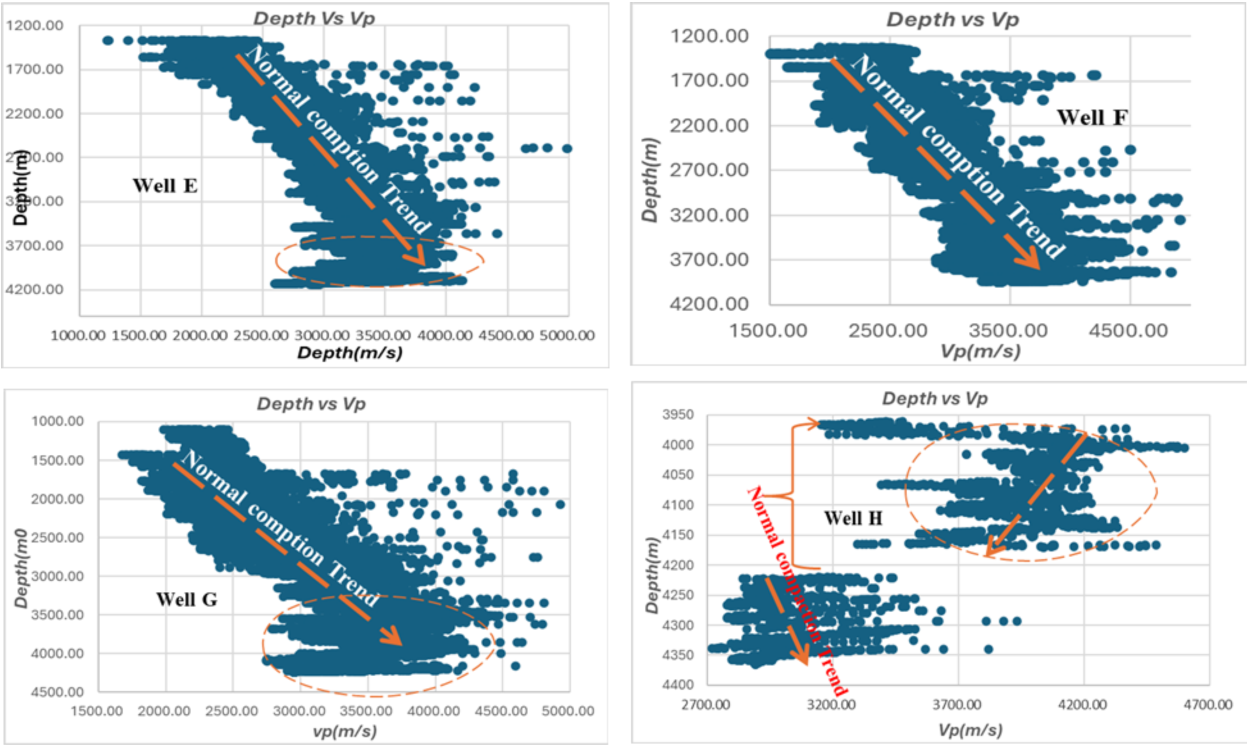


Fig. 6: Vp-Depth relation across Wells E - H

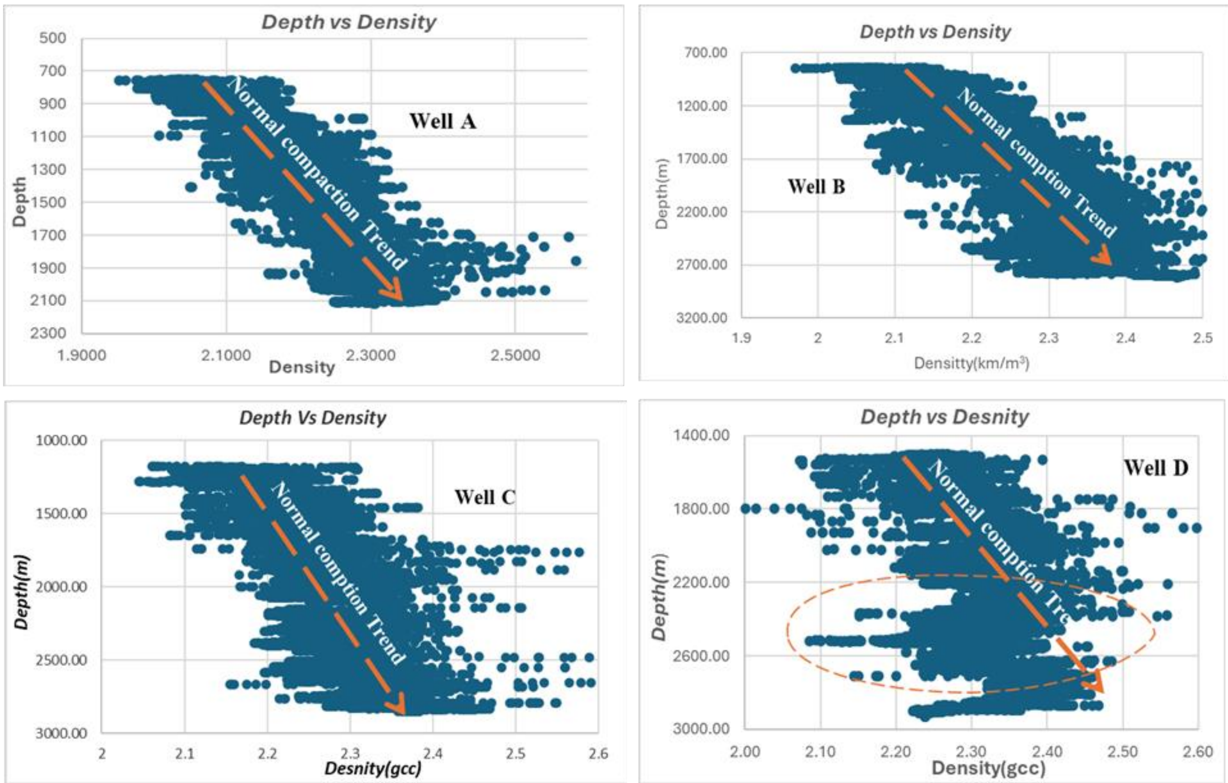


Fig. 7: Effect of Density-Depth relation across Well A - D

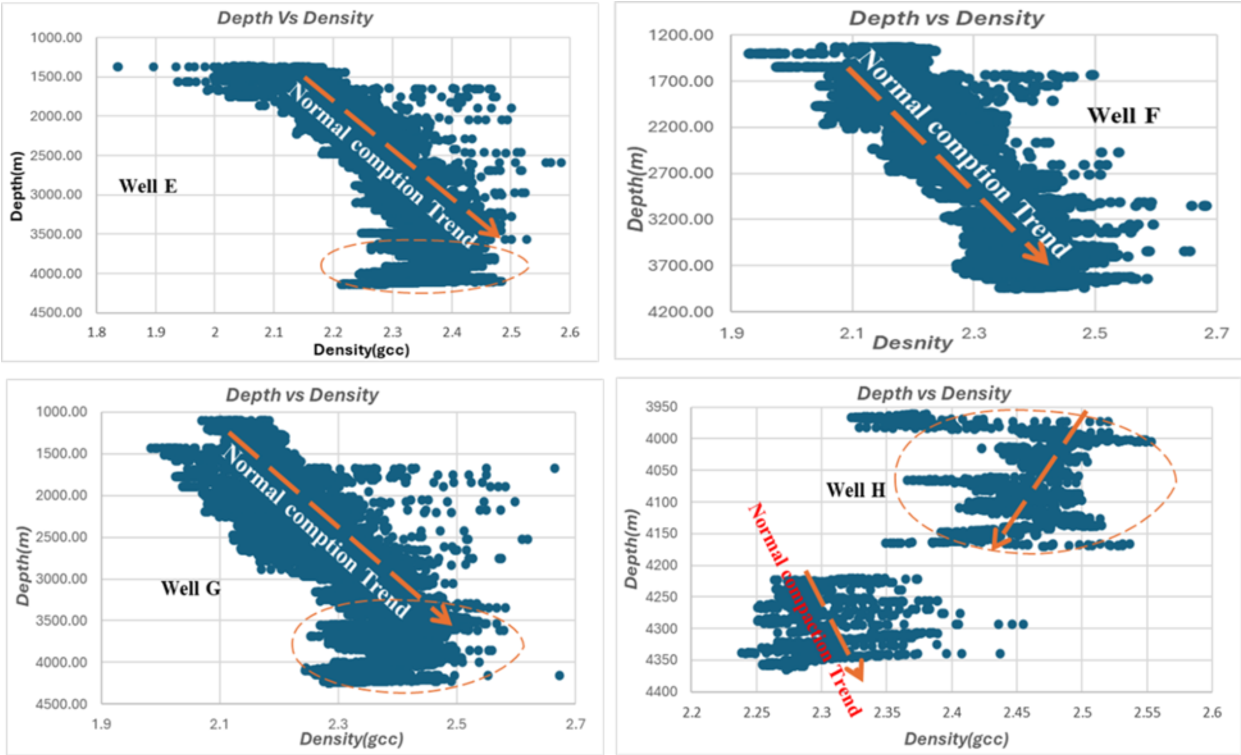


Fig. 8: Density-Depth relation across Well E – H

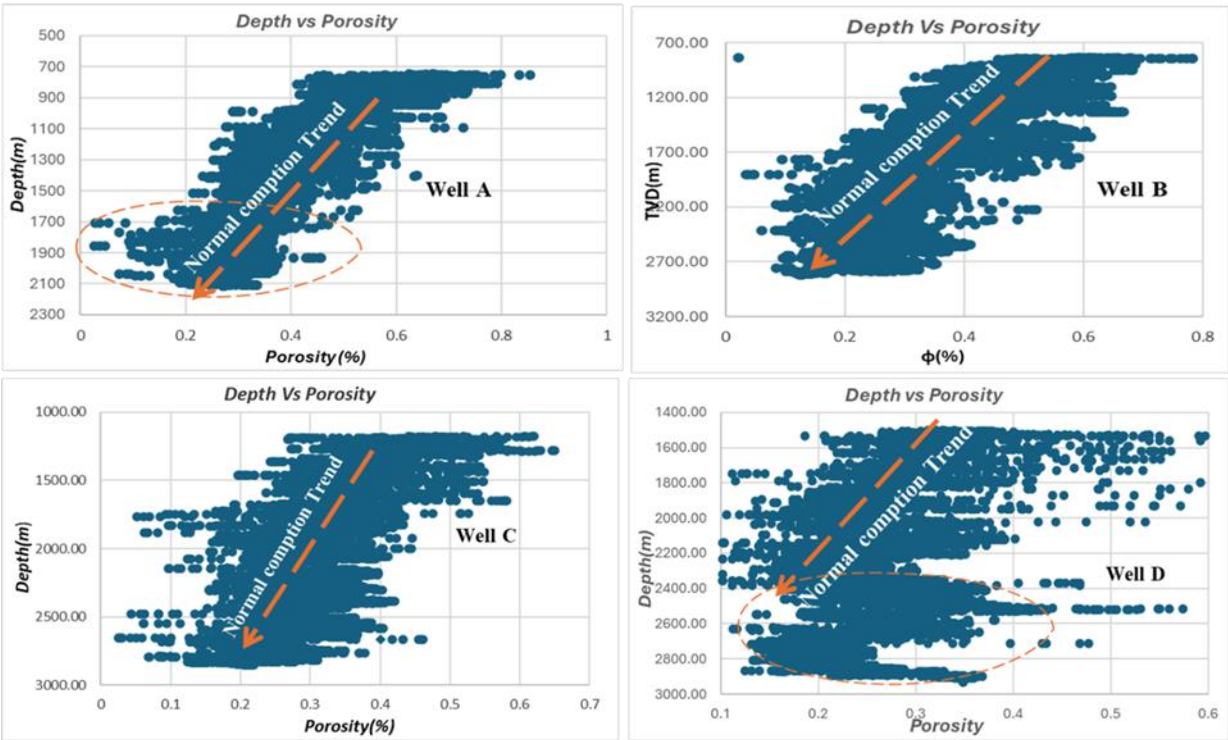


Fig. 9: Porosity-Depth relation across Well A – D

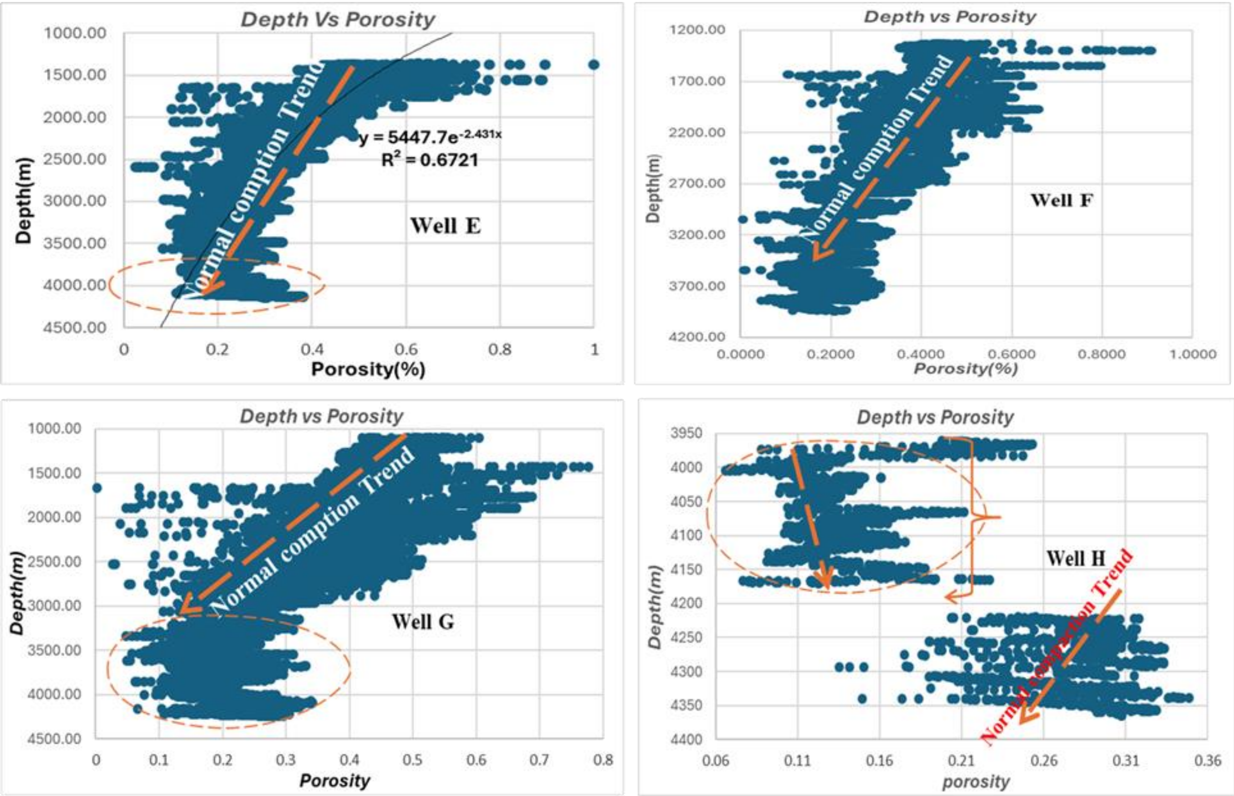


Fig. 10: Porosity-Depth relation across Well E - H

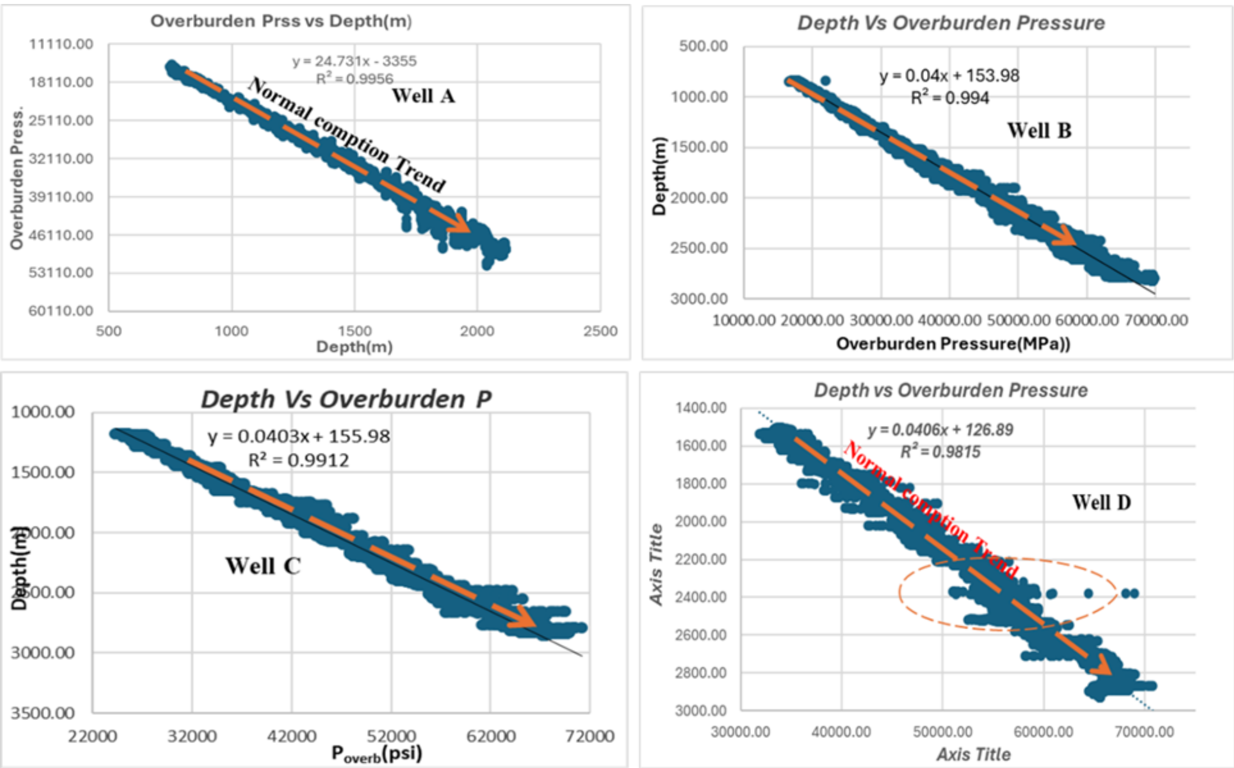


Fig. 11: Depth-Overburden relation across Well A – D

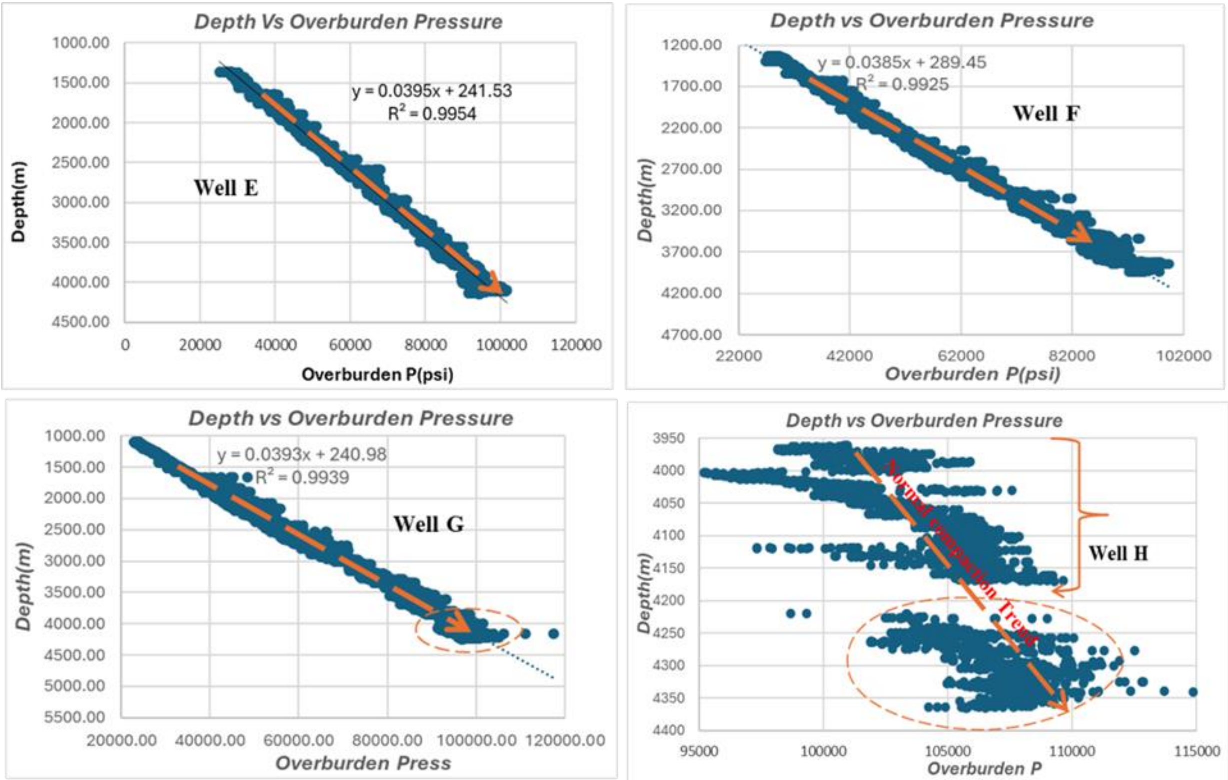


Fig. 12: Depth-Overburden relation across Well E - H

From the results delineated for Wells A – H (Figs. 3 and 4), the sonic interval transit time decreases with dept as compaction of rock increases with increase in density and velocity with depth. Where values of Δt increased, it directly corresponds to higher porosity values (slower travel), and as depth increases, overburden pressure causes rocks to become denser and less porous, resulting in lower sonic transit times (higher velocities).

However, the delineated results from all the Wells (A – H), showed a trending compaction pattern in the study area with observably normal compactions trend (NCT), implying geomaterials being more compacted (denser) and less porous with loading, except where high porous and less dense zones were experienced, that could initiate the reverse case of the trend, which possibly suggests the presence of abnormal pressure as observed from other complimentary profiles within the study area. In Well A, compaction reversals were visibly observed between 1950 – 2040m, and 2100 – 2100 – 2140m, Well B between 2420 – 2800m, Well C between 1700 – 2190m, 2290 – 2750m, and 2790 – 2990m, Well D between 2000 – 2200m, 2300 – 2700m, and 2800 – 2950m, Well E between 2800 – 4150m, Well F between 1900 2150m, 2450 – 2800m, 2850 – 3300m, 3100 -3300, 3400 – 3500m, 3500 – 3800m, and 3900 – 4000m, Well G intermittently between 3000 – 4300m, and Well H showed complete reversal between 3950 – 4170m and discontinuity between 4170 – 4220m showed a compaction that appeared normal. These compaction reversals across the Wells (A – H) suggest that the area is undercompacted and overpressured and hence post significant risk to any exploratory drilling campaign except adequate and combined primary, secondary and tertiary well control measures are put in place to control the geoharzard. The undercompaction of sediments could be attributed to high sediment influx, which affects Sonic transit time - Compressional velocity– Density – Porosity – Overburden stress - Depth relations as the rock deviates from the normal compaction trend. The findings highlight the effectiveness of compaction trend modeling as a practical tool for subsurface evaluation and provide useful insights for drilling optimization and reservoir management within the Central Depobelt of Niger Delta of Nigeria.

CONCLUSION

In most explored intervals within the Central Depobelt of Niger Delta, undercompaction due to high sedimentation rate happens to be more rapid than fluid expansion rate, are now the dominant primary overpressure mechanism, and based on subsurface investigation, like Well logs survey for downhole measurement has revealed that, shallow sandstone reservoirs are found to have sub-hydrostatic pore pressure, while the lower reservoir unit is presently at hydrostatic pressure regime (Agbasi et al. 2020). Therefore, with drilling activities now focused into deeper reservoirs, secondary overpressure mechanisms become increasingly important which necessitates a proper understanding of these mechanisms and modified approach to prediction techniques. This study has demonstrated that compaction trend modeling using wireline log data is an effective approach for evaluating subsurface pressure conditions in reservoir wells of the Central Depobelt, Niger Delta. The results indicated that deviations from normal compaction trends occur at greater depths, suggesting the influence of undercompaction and potential overpressure development. The integration of petrophysical parameters for rock characterization is crucial for compaction evaluation and formation geopressure delineation. This approach is critical for optimizing well completion, improving wellbore stability, designing hydraulic fracturing, and managing reservoir compaction, fluid production efficiently and overpressure prediction. A proper understanding of the Porosity, Permeability, density, Compressional (Vp) and Shear (Vs) velocities, Sonic transit time(Δt), and overburden stress and their relationships across various depths were estimated for compaction evaluation and overpressure prediction. The computed data for this petrophysical estimations in Table 2 and delineated results across Well A – H, in Fig. 3 -12, for compaction characterization and geopressured delineation showed that, the study area is well compacted with normal compaction trend (NCT) within good depth ranges, but deviated trend from certain depth intervals which estimated undercompaction and suggested overpressured establishment, caused by compaction disequilibrium and other natural phenomena. These findings are consistent with earlier geological and basin studies in the Niger Delta (Doust & Omatsola, 1990).

CONFLICT OF INTEREST

The authors declare that there was no conflict of interests while executing this study.

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