Sand Production Prediction of a Reservoir in Niger Delta Using Empirical Relationships of Rock Mechanical Parameters from Wireline Logs

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Abstract:- Sand production in the Niger Delta oil region is one of the most difficult challenges encountered during the many stages of field development planning, resulting in expensive drilling, production costs, and damage to oil installations. This geomechanical problem is expected because the Niger Delta Province is dominantly a loosed sandstone terrain, and the sand grains are highly friable. The study centres on employing empirical relationships of rock mechanical parameters from wireline logs to predict the vulnerability of lithologic formations to sand production in a reservoir in the Niger Delta. The reservoir five sandstone units were first recognized by using wireline logs (Gamma ray and self-potential logs), and the fluids were differentiated using resistivity, porosity, and density logs. The identified hydrocarbon prospecting sands were correlated throughout the five (5) wells. Gamma ray, resistivity and porosity logs were used for the correlation. Shear and compressive wave from the sonic log were then used to derive the rock mechanical parameters (Poisson ratio (v), Young modulus (E), shear/rigidity modulus (G), bulk and matrix/grain moduli (Kb and Km), bulk and grain compressibility (Cb and Cr), Unconfined compression strength (UCS) and Critical flow rate pressure (CFRP). Four Prediction of Sand Production indicators (Formation sanding indicator method, Schlumberger formation sanding indicator, Bulk Elastic Modulus Ratio and Composite Modulus Estimation) derived from the rock mechanical parameters were used to adequately analyse sanding. The analysed reservoir exhibits sandstone units with lower value of Poisson ratio, Bulk modulus, Young's modulus, Shear modulus and Unconfined compression strength of 2.3GPa, 0.26, 11.2GPa, 7.93GPa, and 16.73MPa, respectively. The formation shale exhibited higher values of Poisson ratio, indicative of its ductile nature that is resulting mostly from its clay content; the Bulk modulus, Young's modulus, Shear modulus, and Unconfined compression strength exhibited high values (8.23 MPa,0.37,17.08 MPa, 25.02 MPa, 66.22 MPa respectively) while porosity and compressibility showed decreased values (0.07, 0.08 Mpa^{-1} respectively), leading to enhanced stiffness due to elevated moduli, hence less prone to deformation than the loosed sandstone units. The results of the four (4) Prediction of Sand Production models indicate a high risk of sanding during production of the investigated reservoir. A Critical flow rate pressure (CFRP) of 18.30 MPa is predicted to mitigate against sanding in the wells if the critical flow rate during production stays below 18.30 MPa. Thus, this research application of empirical relationships derived from rock mechanical parameters and wireline logs in predicting sand production can effectively aid informed investment decisions, risk assessment and performance optimization in Niger Delta reservoirs.

Keyword:- *Sand Production, Geomechanical Parameters, Wireline Logs, Niger Delta, Unconfined Compression Strength*

I. INTRODUCTION

In the upstream petroleum sector, the potential of sand reservoir failure and the resulting sand production is an unfortunate reality. The knowledge that sand reservoirs hold more than 75% of the world's hydrocarbon reserves and that sand production is concentrated in these reservoirs (particularly in Trinidad, the Gulf of Mexico, Egypt, Venezuela, Malaysia, Indonesia, Canada, tar sands), makes sand reservoir life cycle very challenging. One of the most difficult problems in the many phases of field development planning, such as wellbore stability during drilling, production, and IOR/EOR stages, is sand production. The quantity of sanding and reservoir fluids may range from negligible levels, measured in grammes per cubic metre, resulting in minimal challenges, to significant volumes over a short time, which can cause reduced productivity and injectivity, obstruction of perforations or production liners, wellbore instability, failure of sand control completions, collapse of sections in horizontal wells within loosed formations, erosion of pipelines and surface facilities, environmental effects and additional cost of remedial and clean-up operations. (Willson *et al*., 2002)

Sand production in oil and gas wells occurs when fluid flow attains a specific threshold that depends on variables such as reservoir rock consistency, stress condition, and the kind of completion implemented around the well. Operational conditions, reservoir pressure depletion, strength-weakening effect of water, drilling operations, and cyclic effects of shut-in and start-up may eventually trigger sandstone degradation around the perforations and boreholes. Sand particle separation can also be caused by the high-pressure gradient caused by fluid flow. Additionally, fluid movement is responsible for transporting and producing cohesionless sand particles or disconnected sand clumps into the borehole. It is a complicated phenomenon that is determined by a number of factors, including the stress distribution around the wellbore, the composition of the reservoir's rock and fluids, and the method of completion. As a result, integrating all of the components and processes in numerical models is challenging, and the models have significant limitations. However, knowing the sand production processes, as well as the ability to forecast and mitigate sand production rates, is critical. It is vital to forecast the potential amount and particle size distribution of sand, as well as the frequency with which sand is produced and transported down the wellbore to the topside facilities. Management of sand production demands an in-depth knowledge of "if the formation will fail, when the formation will fail and how much sand will be produced from such failure" (Oyeneyin, 2009).

Sand prediction, control, and management include a broad range of publications aimed at explaining the essential variables contributing to sand production generating models for forecasting sand production potential, and developing different methods for sand prevention, management, and control. Important sand control techniques are often used throughout the oilfield's life cycle, particularly in the Niger Delta's hydrocarbon fields, which are distinctly characterised by loosed sand formations, increased sand production rates, corrosive and abrasive fluids, as well as high temperatures and pressures. The unique geology of the Niger Delta needs careful selection of sand management techniques. Expandable Sand Screens, Inflow Control Devices (ICDs), perforated liners, gravel packing and sand screens are often used for the effectiveness they provide in managing sand production. However, the choice of approach ultimately relies on unique well factors, requirements for production and sand production forecasting findings.

The primary objective of most of the articles is to identify when and how sand control decision-making should be implemented throughout the life cycle of a field. The approaches that are generally discussed for predicting the starting point of sanding is empirically applying elastic parameters and wireline logs, geomechanically laboratory testing method, numerical method and analytical method (Qui et al., 2006). However, the important step to successful sand production solutions remains hidden in getting reservoir geo-mechanical properties and evaluating the rock (lithological) strength of the formation (Osaki et al., 2019). Studies have demonstrated that it is vital for the rock strength to be appropriately evaluated in determining the sand potential of a particular formation. There is strong evidence that a good correlation exists between the inherent strength of the rock and its elastic constants (Eyinla and Oladunjoye, 2014; Osaki et al., 2018; Agoha et al., 2021).

Chang (25) has provided several empirical relationships for UCS that can be used in different types of rocks. The research highlighted the importance of local calibration before any relationship is applied. Sulaimon and Teng (2020) investigated the application of Bulk Elastic Modulus ratio for predicting possible sanding and concluded that the method could be integrated with a geomechanical model for improved prediction. Empirical methods have the benefit of being closely connected to field data and can utilise readily identifiable properties to give routine and normally obtainable method for evaluating sanding risk on a well-by-well basis.

Chang et al. (2006) put together over thirty (30) totally different empirical relations for evaluating rock strength and analysed those correlations for a large data set taken from different locations. Most of the empirical correlations performed averagely for the larger data set, but they performed well for the smaller local data sets from which they were gathered.

Zhang et al., (2000) validated that the mechanical strength of a formation is highly significant information necessary for calculating sand production and understanding the type of and control methods to apply. Their approach proposes a means of assessing rock strength such that the limits on core testing may be eliminated. Tri-axial and hydrostatic tests were carried out to generate the failure envelope. The findings of their investigations demonstrated that a single normalized failure envelope could be applied for determining sandstone formations making it easier to generate the failure envelope from the knowledge of critical pressure.

According to Tiab (2004), clastic formations with low porosity exhibited considerable rock strength, and porosity may be used as a qualitative indicator of rock strength to forecast when sanding will begin. According to his theory, sand production should be expected if the product of shear and bulk modulus falls below the benchmark value of 8E11 psi^2, where the bulk modulus, Kb, and the shear modulus, G, are precisely determined by the evaluation of acoustic and density logs.

A new approach for estimating the rate of sand production was developed by Willson et al. (2002) using the non-dimensionalized loading factor (LF) concepts, the Reynolds number (Re), and the water production boost factor. By considering the impact of water production, they were able to derive an empirical equation between the loading factor, Reynolds number, and the rate of sand production. They recommend using SPR = f (LF, Re, water-cut) as the definition of the sand production rate.

Udebhulu and Ogbe (2015) established a mechanistic model for forecasting sand production by combining the static sanding criterion with the dynamic condition for fluidization of the sand generated. The model included the idea of dimensionless quantities connected with sanding the quantities evaluated included the loading factor (LF), Reynolds number Re, water-cut W and gas-liquid ratio GLR.

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Azizi and Memarian (2006), reported a correlation for calculating geomechanical properties of reservoir rocks utilising logs and porosity information based on the data set acquired from three wells in Iran and derived from various formations.

A number of empirical, numerical, and analytical sanding prediction models have been developed in the literature that typically require a large number of rock mechanics input parameters that are rarely available in field practice and require extensive computations (such as finite element models), which are impractical when making quick decisions about sand control, particularly in the Niger Delta basin, which is mostly composed of loosed sandstone terrain, the sand grains are friable, indicating that sand production will be expected when hydrocarbon reserves are developed in such terrain. This study centres on employing empirical relationships of geomechanical and petrophysical parameters to predict sand production in an offshore depobelt reservoir of the Niger Delta basin. The application of geomechanics and petrophysical parameters for predicting sand production is critical in reservoir management, well stability, well intervention and maintenance, drilling program, completion design plan, perforation strategy.

II. GEOLOGY OF THE STUDY AREA

The Niger Delta remains the most well-studied area of Nigeria's continental margin because of its abundant hydrocarbon resources, and the focus of this research is on the basin's offshore terrain (Fig 1), which is located in the Gulf of Guinea (Klett et al., 1997). It is located between longitudes 4_220E and 5_150E, and latitudes 5_240N and 6_000N. The Tertiary Niger Delta covers 75,000 km2 and is composed of a regressive clastic succession with a maximum thickness of 12,000 m (Orife & Avbovbo, 1982). The Tertiary part of the Niger Delta is geologically separated into three distinct Formations, with sand-shale ratios used to define each major prograding depositional facies. Sand thickness decreases with depth, whereas shale thickness increases (Short and Stauble 1967; Doust and Omatsola 1990; Kulke 1995; Agbasi et al., 2021). The Benin Formation sits on top of the paralic Agbada Formation, which is on top of the prodelta Marine Akata Formation (Agbasi et al., 2021). The Tertiary Niger Delta (Akata-Agbada) petroleum system has been recognized (Kulke, 1995; Ekweozor and Daukoru, 1994; Osaki et al., 2021), and hydrocarbon accumulations in the investigated basin are distinguished by roll-over anticlinal structures (Agbasi et al., 2021).

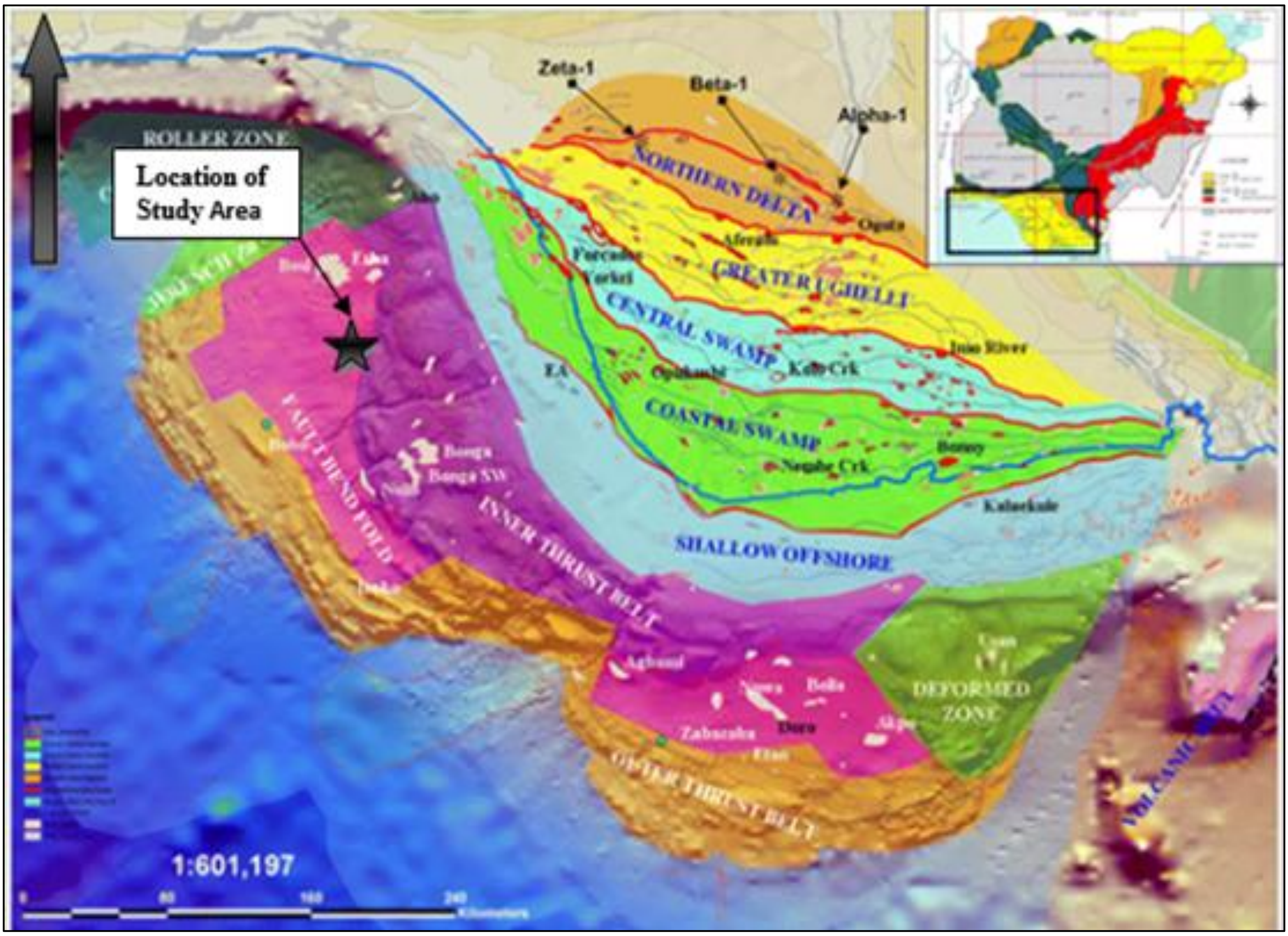

Fig 1: Index Map of the Niger Delta Showing Province Outline Bounding Structural Features and Location of the Study Area (Source Whiteman, 1982).

III. MATERIALS AND METHODS

The data for this research were collected from the Nigerian National Petroleum Corporation (NNPC) with the approval of the Department of Petroleum Resources (DPR). This research utilised data from five wells in an oilfield and the wells are OXL1, OXL2, OXL3, OXL4, and OXL5. Schlumberger TechlogTM and Petrel software, as well as Microsoft Excel, were used to determine the formation susceptibility and sand production potential in the selected reservoirs.

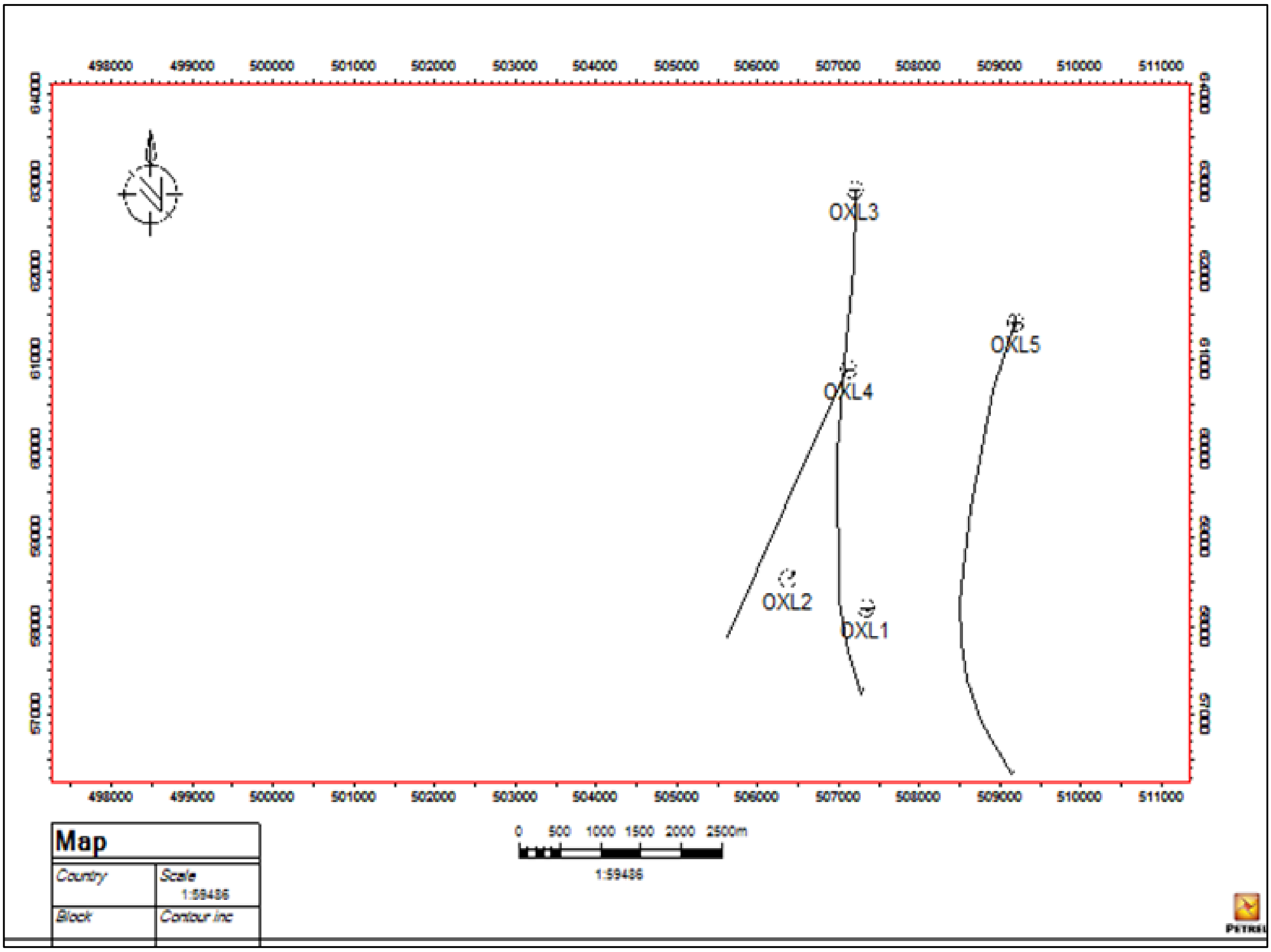

Fig 2: Base Map of the Studied Area Showing Location of the Five Wells. (OXL1, OXL2, OXL3, OXL4 & OXL5)

A. *Quality Checks of Wireline Logs*

Firstly, pre-processing was done so that the wireline logs could be applied to calculate the reservoir geo-mechanical parameters. Splicing, normalizing, and despiking which are examples of primary processing were successfully carried out. The wireline logs were adjusted for normality to eliminate any variances in the various log response signatures that have nothing to do with a direct result of reservoir geological parameters, allowing for the accurate computation of appropriate range and thresholds for shale-sand contents and porosity. At the moment of entry, data was additionally examined using the Petrel software to determine whether it fell within the dataset's minimum and maximum ranges. Since the GR and Sonic logs are vital, their availability and consistency were determined for each of the five wells.

B. *Data Analysis of Wireline Logs*

The sandstone units were recognized using lithology logs (Gamma ray and self-potential logs), and the fluids were differentiated using resistivity, porosity, and density logs. The identified hydrocarbon prospecting sands were correlated throughout the five (5) wells. Gamma ray, resistivity and porosity logs were used for the correlation (Fig.3). The reservoir geomechanical parameters were derived by calculating the petrophysical relationships from the wireline logs.

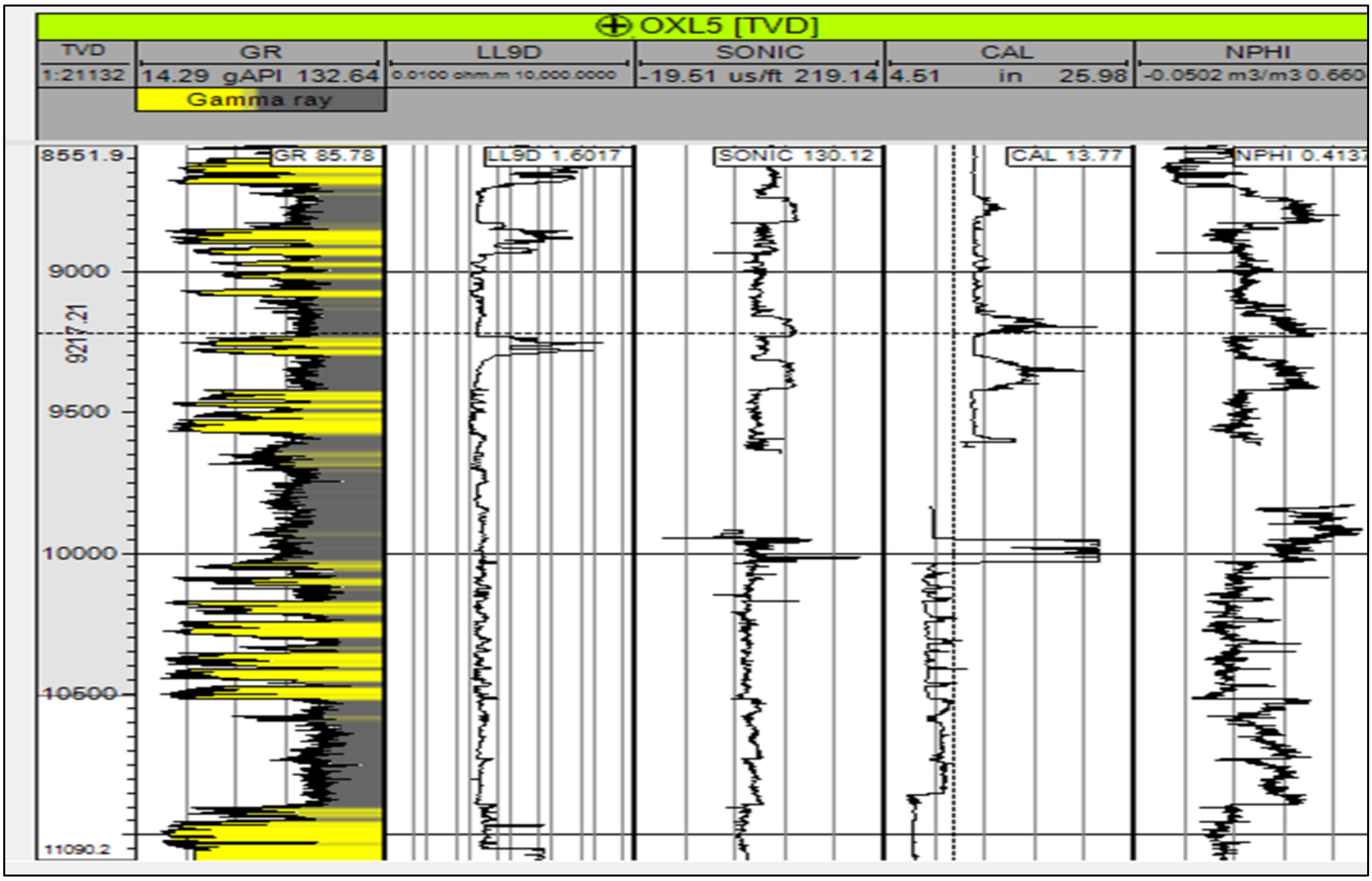

Fig 3: OXL5 Well of the Oil Field Showing Delineated Sand Bodies (Area of Interest) in Yellow Colour using Gamma Ray, Resistivity, Calliper and Neutron Porosity Logs.

C. *Estimation of Reservoir Geomechanical Properties*

The reservoir mechanical properties were determined using log data from resistivity, neutrons, acoustics, and density. The geomechanical properties include the poisson ratio, young modulus (E), shear/rigidity modulus (G), bulk and matrix/grain moduli (Kb and Km), bulk and grain compressibility (Cb and Cr), Unconfined compression strength (UCS), and Critical flow rate pressure (CFRP).

D. *Estimation of Poisson Ratio (v)*

The log derived Poisson ratio was determined from acoustic measures such as the sonic log, which is typically expressed in terms of slowness, the reciprocal of velocity called interval transit times (ΔT) in units of microseconds per foot. To calculate the Poisson ratio, Jones et al. (1992) and Moos (2006) use the slowness of the compressional wave (ΔT2) and the slowness of the shear wave (AL) ratio.

$$\boldsymbol{v} = 0.5({}^{V_p}\!/_{V_s})^2 - 1/({}^{V_p}\!/_{V_s})^2 - 1 \quad (1)$$

The theoretical maximum value of v is 0.5

E. *Shear Modulus (G)*

The shear modulus is defined as the ratio of shear stress to shear stress for a homogeneous, isotopic, and elastic rock, as indicated by equation (3.2) (Schlumberger 1989).

$$G = {}^{ap_b}\!/_{\Delta Ts\ v} \quad (2)$$

Where coefficient a = 13464, p= bulk density in g/cni3, AT5 = Shear sonic transit time in. The unit of G is 10_6 psi or MPa.

The bulk modulus (K_b) is a static modulus but an equivalent dynamic modulus can be computed from the sonic and density logs. The relationship is given in below:

$$(K_b) = ap_b\left(1/\Delta Tc^2 - \frac{4}{3\Delta Tsma^2}\right) \quad (3)$$

Where coefficient a =13464, p_b = bulk density in g/cm^3, ΔT= sonic transit times in us/ft. The unit of K_b is 10_6 psi or MPa.

F. *Matrix/Grain Bulk Modulus (K_m)*

$$K_m = KS_{Pma} / (1/\Delta Tcma^2 - \frac{4}{3\Delta Tsma^2}) \quad (4)$$

Where KS is constant and = 1000 for metric units and 13400 for English units.

G. Young Modulus (E)

Young modulus or modulus of elasticity was determined from the relationship between Young modulus, Shear modulus and Poisson ratio.

$$E = 2G(1+v) \quad (5)$$

Where
G = shear modulus and v =Poisson ratio. E is in psi or MPa.

H. Bulk Compressibility (C_b,) with Porosity

$$C_b=1/K_b \quad (6)$$

Where K_b = Bulk modulus

I. Unconfined Compression Strength (UCS)

$$UCS = 1200exp^{(-0.036\Delta Tc)} \quad (7)$$

$$UCS = 10(304.8/\Delta Tc - 1) \quad (8)$$

Where:
UCS =Unconfined compression strength.
ΔTc =compressional wave transit time.

J. Critical Flow Rate Pressure

$$CDP= 1-(v * UCS*\sigma h) \quad (9)$$

Where
v= Poisson ratio.
UCS= Unconfined compression strength (MPa)
σh = Minimum Horizontal Stress (MPa)

K. Estimation of Sand Production Prediction methods

The estimation is focused on building advanced and precise predictive modelling techniques; hence the following methods have been generated from mechanical properties logs, acoustic and density logging data to clinically predict and evaluate sand production across the reservoir.

L. Bulk Elastic Modulus Ratio.

Tixier et al. (1975) found an empirical relationship between the Bulk Elastic Modulus ratio and sand production. The empirical correlation suggests that a threshold for sanding exists around G/Cb= 0.8 ×1012 psi^2, where G is shear modulus and Cb is bulk compressibility. Values less than 0.8 ×1012 psi^2 indicate a high probability of sanding. Although this method predicts whether a well will generate sand, the stated G/Cb ratio cannot be used to calculate a total sand-free rate. Ehsan and Ebrahim (2015) used the G/Cb ratio to estimate sand production. They investigated free-water-producing wells in Iran's Kaki and Bushgan offshore oil fields and the result showed that all G/Cb values ranged from 1.37×1012 to 3.30×1012 psi^2.This demonstrated that there was no sanding in the reservoir because it was above the predicted cutoff.

M. Formation Sanding Indicator Method (B) (Zhinjun,2008 and Zhang Qi, 2000).

This method is particularly useful when reservoir sand is weakly consolidated; because core samples are difficult to collect, operators frequently rely on logging data to forecast reservoir sanding.

$$B= E/(3(1-2v)) +4/3\times(E/(2(1+v)) \quad (10)$$

Where B is the Formation sanding indicator (MPa), E is the elasticity modulus, and v is Poisson's ratio. When the Formation sanding indicator B is high, it shows that the rock elastic modulus is large, implying that the rock is of high strength and stable. Reservoir sanding occurs when B < 2.0× 104Mpa, according to previous experience. Bianlong et al. (2013) produced a sand prediction index of 0.73× 104 Mpa, indicating that sanding was inevitable.

N. Schlumberger Formation Sanding Indicator Method (S/I) (Zhinjun,2008)

The Schlumberger sand index approach is used to evaluate rock strength more precisely. The Schlumberger sanding index SR is calculated by multiplying bulk modulus (K) by shear elastic modulus (G). Sand production is expected when the formation index is less than 1.24×1012 psi^2, necessitating sand control measures. Bianlong et al. (2013) used the Schlumberger Formation sanding indicator and discovered a value of lower than 1.24×1012 psi^2, indicating that sand production is certain.

O. Composite Modulus Estimation

This method predicts sanding using acoustic and density logging data.

$$E_c = \frac{9.94\times10^8 \rho_r}{\Delta t_c^2} \quad (11)$$

Where Ec is the rock elastic combined modulus (MPa), ρr is the formation rock volume density (g/cm^3), and Δtc is the rock wave acoustic time (μs/m). Most logging data, rock parameters, and sand production investigation indicate that formations with Ec >2.608×104 may not have sand influx.

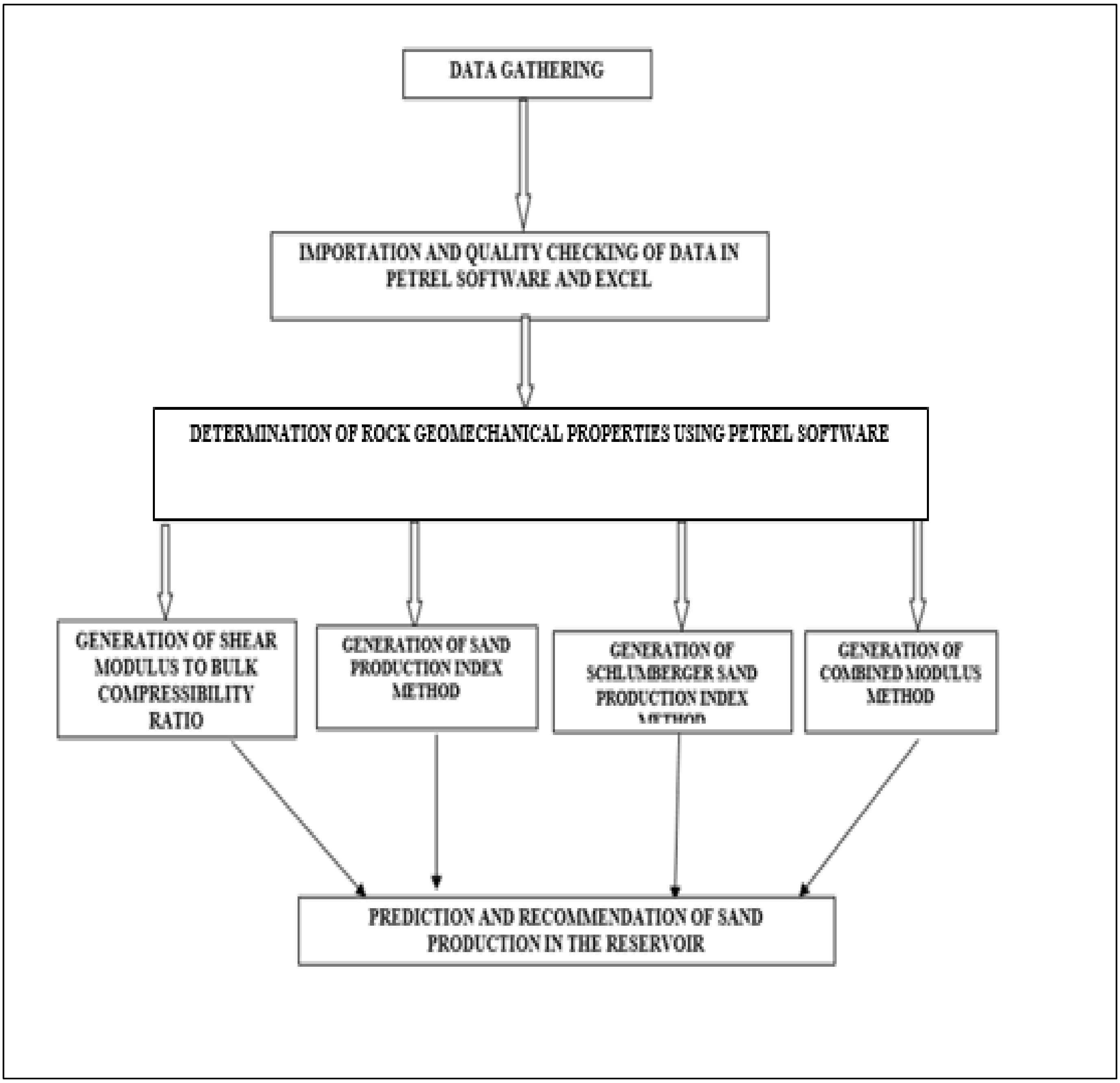

Fig 4: Workflow Chart of Prediction of Sand Production Analysis

IV. RESULT AND DISCUSSION

A. Reservoir Mapping

The first phase in the reservoir mapping process was done by delineation of Wells OXL1, OXL2, OXL3, OXL4, and OXL5 on a well correlation panel at a depth of 9000–9900 meters in the NNW direction. The area of interest is confirmed to be within the Agbada formation of the Niger delta (Doust and Omatsola, 1990) as depicted in Fig. 5 by the lithological and stratigraphic study of the reservoir using GR log, which reveals that the geological units are primarily sand and shale with an increasing trend of high sand/shale ratio. The study is located at a depth of 9000m to 9800m across the five wells. Differential subsidence variation from compaction of sediments and the presence of growth faults, as indicated in the Niger delta (Weber and Daukoru, 1975), strongly control the lateral variation in reservoir thickness, which tends to be thickest at OXL5. The correlation showed five strata of sand unit in the reservoir, namely horizon A, B, C, D, E, and F across five wells with thicknesses of approximately 89m, 98m, 106m, 100m, and 135m respectively.

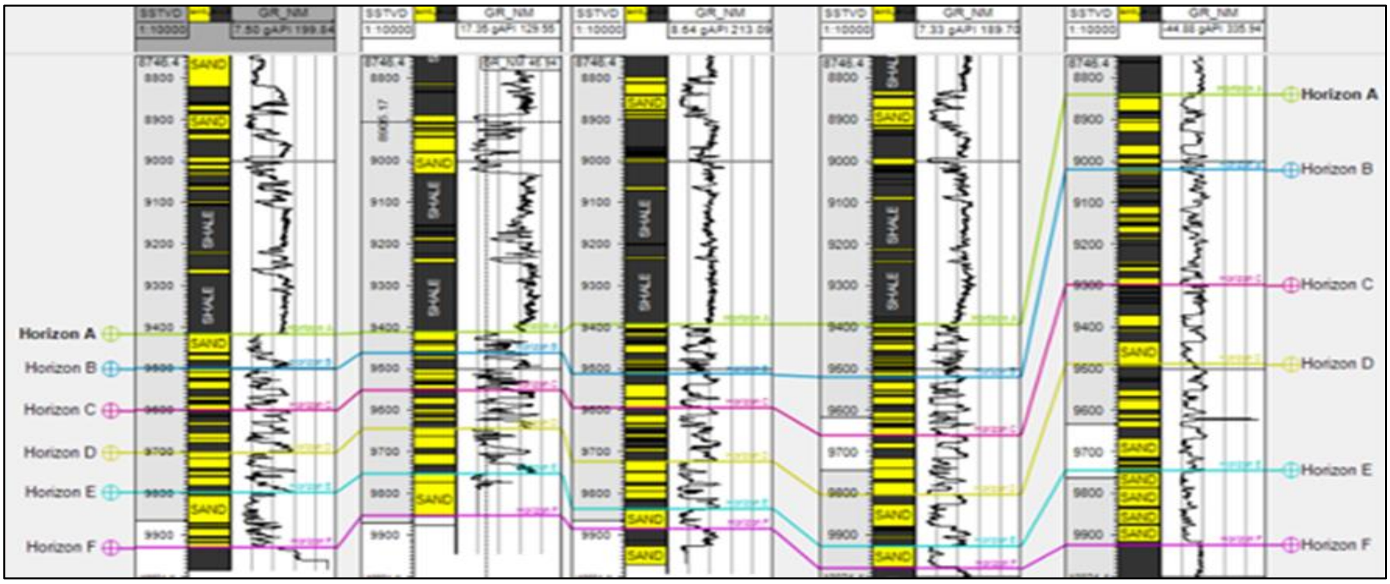

Fig 5: Wireline logs from OXL1, 2, 3,4 &5 Presenting the Studied Reservoir's Delineated Horizon using Gamma Ray (GR) Log

The competency of the studied reservoir in terms of sanding was predicted using sand prediction indices and logs derived from the relationship of elastic properties. The elastic moduli are utilized in this work to determine the sand prediction parameters, these included the Schlumberger Formation sanding indicator (Zhij, 2008 and Zhang, 2000), the Composite Modulus Estimation, the Bulk Elastic Modulus ratio (Tixier et al., 1975), and the Formation sanding indicator (Zhij, 2008 and Zhang, 2000). With the objective to help determine the type of sand control method to use during the production operation phase (Bellarby, 2009).

B. Determination of Geomechanical Parameters

To evaluate the variances between the sand and shale of the studied reservoir, the shear modulus, bulk modulus, Young's modulus, bulk compressibility, Poisson ratio and unconfined compression strength of the five sandstone units interbedded with shale have been calculated for each well. To generate and analyse mechanical property logs, these parameters were obtained by inputting the empirical relationships into a Microsoft Excel program, which was subsequently imported into the Schlumberger Petrel software 2023 edition. All the wells had the elastic parameters correlated, as can be seen in one of the wells (OXL5) in Fig. 6 below.

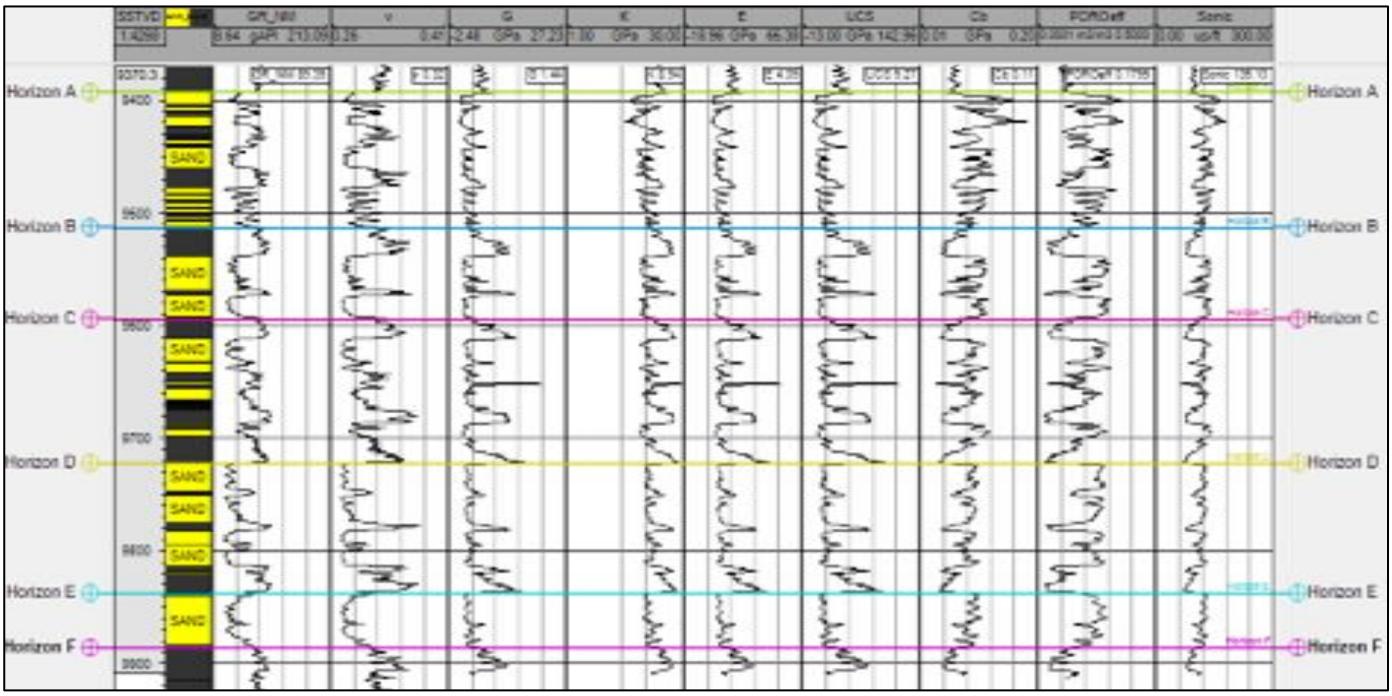

Fig 6: Geomechanical Properties Logs Showing Lithology, Poisson Ratio (V), Bulk Modulus (Kb), Shear Modulus (G), Young Modulus (E), Bulk Compressibility (Cb), Effective Porosity, Compression Velocity (Vp), Unconfined Compression Strength (UCS) of the OXL5.

Table 1 and Figure 5 show the petrophysical parameters and elastic characteristics that were determined by empirical relations to describe the sandstone and shale of the different lithological units of the reservoir under investigation. The properties of the sand and the shale differ significantly, according to the results for all wells. The average sand parameters in Table 1 indicate that the sand is more brittle and has a higher potential for tensile failure due to its lower value of Poisson ratio (0.26), Bulk modulus, Shear modulus, Young modulus and Unconfined compression strength (11.2 MPa, 7.93 MPa, 2.3 MPa and 16.73 MPa respectively), as well as its higher compressibility and porosity (0.12 Mpa-1, 0.23). However, shale has higher rock strength, Poisson ratio, Young, Bulk, and Shear modulus (0.37, 8.23 MPa, 17.08 MPa, 25.02 MPa, and 63.22 MPa, respectively). Because of its clay content, it has a lower porosity and compressibility (0.08 Mpa^{-1}, 0.07), making it more ductile with increased rigidity than the loosed sandstone. Since reservoir rock strength influences rock elastic moduli, a reservoir rock strength increases with its elastic moduli (Chang et al., 2006).

With a maximum mean value of 63.22 MPa for the rock strength as shown in Table1, the shale can withstand a force of compression without shattering or failing entirely. It indicates that shale requires a greater vertical stress or pressure (16.73MPa) to undergo deformation than sand. In a hydraulic fracture process, the sandstone of the investigated reservoir will fracture before the shale under the same fracture gradient, while the shale will form seal rocks to the fault zone, because these qualities also make the shale fracture stimulation barriers. When a series of sandstone with high porosity is divided by impermeable shales, this is one of the main reasons for hydrocarbon reservoir compartmentalization of (Ortoleva, 1994). Additionally, the results indicate that shale has very low porosity while sand has significant porosity, which makes shale stiffer and denser. Since pores are among the weakest and brittle features of rocks, an increase in porosity resulted to a failure in the elastic moduli and rock strength of units.

Table 1: Showing Average of Elastic Parameters, Porosity and for Sand (sst) and Shale (Sh) Units of the Five Well of the Studied Reservoir

WELL	LITHOLOGY	GR API	Poro Eff	V	G Mpa	Kb Mpa	E Mpa	Cb Mpa-1	UCS Mpa
OXL 1	Sst	46.57	0.26	0.27	2.23	10.24	7.84	0.20	8.75
	Sh	104.29	0.08	0.37	11.42	18.44	18.32	0.07	57.30
OXL 2	Sst	41.76	0.23	0.28	1.75	9.28	4.94	0.14	11.61
	Sh	95.66	0.07	0.34	7.90	18.07	19.02	0.07	35.04
OXL 3	Sst	42.46	0.31	0.24	1.63	8.61	5.29	0.21	13.57
	Sh	98.30	0.07	0.31	7.95	18.32	20.28	0.07	44.12
OXL 4	Sst	38.07	0.25	0.26	1.92	9.72	9.72	0.21	16.77
	Sh	92.71	0.08	0.35	8.71	17.62	23.78	0.16	63.57
OXL 5	Sst	37.05	0.26	0.27	3.88	13.14	9.57	0.17	28.72
	Sh	110.06	0.06	0.35	7.98	17.75	23.75	0.07	75.44
RESERVOIR SANDSTONE AVERAGE		42.17	0.23	0.26	2.3	11.20	7.93	0.12	16.73
RESERVOIR SHALE AVERAGE		103.05	0.07	0.37	8.23	17.08	25.01	0.08	63.22

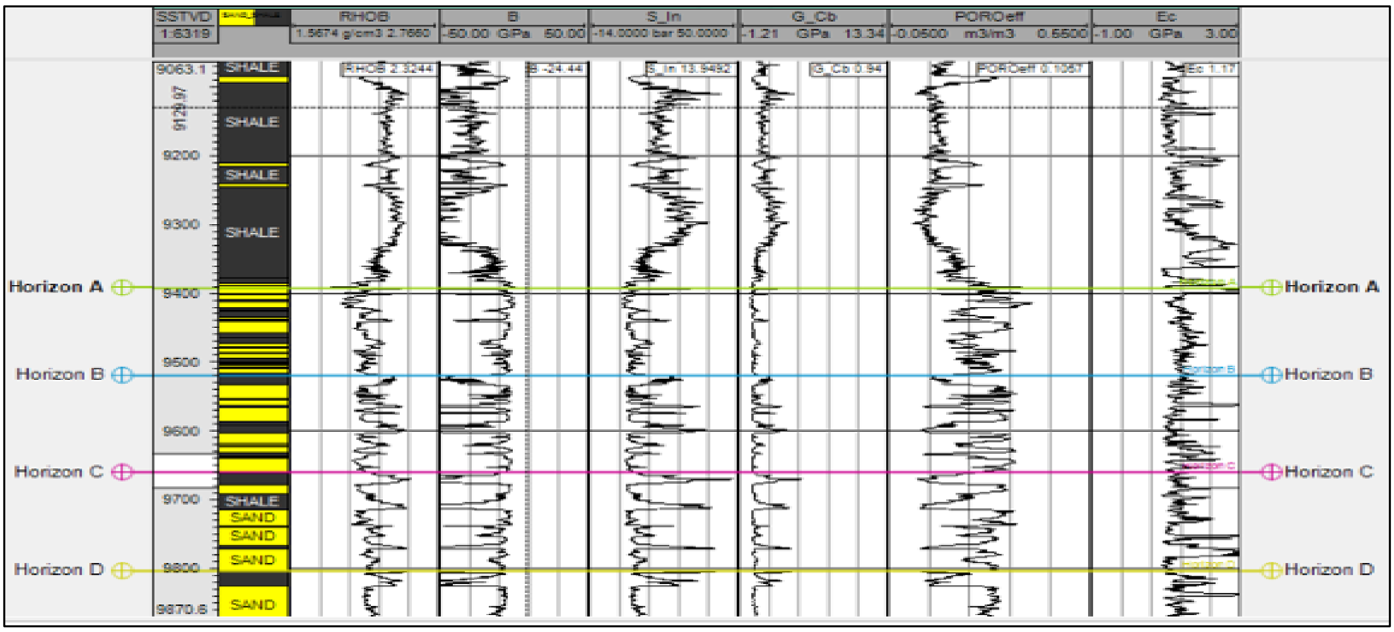

Fig 7: Correlation of Prediction of Sand Production Logs (Schlumberger Formation Sanding Indicator (S/I), Formation Sanding Indicator Method (B), Bulk Elastic Modulus Ratio (G/Cb), Composite Modulus Estimation (Ec) with Effective Porosity of OXL3)

C. Prediction of Sand Production and Critical Flow Rate Pressure

The Critical flow rate pressure and sanding parameter predictions for the investigated reservoir were produced using the generated geomechanical parameters. Elastic moduli and rock strength are examples of rock mechanical parameters that are necessary for a successful mechanical evaluation of rocks (Farquhar et al., 1994). As shown in Fig. 7 and Table 2, the prediction was performed using the logs generated by the rock mechanical parameters to model four predictive methods for sand production: the Schlumberger formation sanding indicator, the sand production index, the ratio of shear modulus to bulk compressibility, and the Composite Modulus Estimation.

Table 2: Breakdown of Prediction of Sand Production Methods for the Investigated Field and Critical Flow Rate Pressure (CFRP).

WELL	G/Cb 10^{12} psi^2	B 10^6 psi^2.	S/I 10^{12} psi^2	Ec 10^6 psi^2.	CDP MPa
OXL 2A	0.53	1.04	1.33	2.90	24.27
OXL 2	0.90	1.08	1.13	2.32	16.76
OXL 2	1.04	1.43	1.32	2.27	17.12
OXL 4	0.72	1.22	1.06	2.07	14.48
OXL 5	0.65	1.23	0.83	1.88	13.61
PREDICTION OF SAND PRODUCTION INDEX AVERAGE	0.68	1.17	1.15	2.70	18.30

D. Bulk Elastic Modulus Ratio (G/Cb)

The analysis predicted sanding in five wells of the reservoir of interest. The G/Cb value ranged from 0.53×1012 psi2 to 1.04 ×1012 psi2, with an average of 0.68×1012 psi2. Tiab and Donaldson (2004) established an empirical relationship indicating a threshold for sanding at G/Cb= 0.8×1012 psi2, while values less than 0.8×1012 psi2 indicate a high probability of sanding.

E. Formation Sanding Indicator (B) Method

Table 2 shows that the values range from 1.43×106 psi2 to 1.04×106 psi2, with an average of 1.17×106 psi2. When the Formation sanding indicator (B) increases, it suggests the rock elastic modulus is high, implying that the rock is stiffer and has better stability. When B is less than 2.0×106 psi2, the reservoir will yield high reservoir sand during production (Bianlong et al., 2013).

F. Schlumberger Formation Sanding Indicator Method (S/I)

Table 2 shows values ranging from 0.83×1012 to 1.33×1012 psi2, with an average of 1.15×1012 psi2.According to Bianlong et al. (2013), if a formation with Schlumberger Formation sanding indicator that is less than 1.24×1012 psi2, it is likely to generate much sand and may require sand management.

G. Elastic Combined Modulus (Ec)

This method predicts sanding using acoustic transit time and density logging data. The values ranged from 1.88×106 psi2 to 2.90×106 psi2, with a general average of 2.70×106 psi2.Bianlong et al. (2013) identified that when Ec exceeds 2.608×106 psi2, formation may require sand control.

H. Critical Flow Rate Pressure

Critical flow rate pressure (CFRP) of the wells, which can lower the rate of sanding, was also measured; the average was 18.30 MPa, with values ranging from 13.61 MPa to 24.27 MPa. The production of reservoir fluids usually results in the creation of pressure differential and frictional drag forces that can be combined to surpass the compressive strength of the formation. However, if the critical flow rate of production remains below 18.30 MPa, the pressure differential and frictional drag forces are not enough to surpass the compressive strength of the rock to produce sand. Bianlong et al. (2013) state that the reservoir can be kept relatively free from sanding when the Critical flow rate pressure (CFRP) is half that of the reservoir's Unconfined compression strength (UCS). When the Critical flow rate pressure (CFRP) is half the reservoir unconfined compression strength (UCS), the reservoir can be kept relatively safe from sand production, according to Bianlong et al. (2013).

V. CONCLUSION

To predict sand production in a Niger Delta reservoir, this study effectively demonstrated the application of empirical relationships derived from rock mechanical parameters and wireline logs. To predict the sanding parameters and the critical flow rate pressure of the reservoir under study, a thorough predictive analysis was made possible by the integration of these mechanical parameters (Shear modulus, Young's modulus, Bulk modulus, compressibility, Poisson ratio) and Unconfined compression strength (UCS) from wireline logs.

Having a dominantly loosed sandstone and indurated shale formation, the analyzed reservoir exhibits reservoir sandstone units with lower value of Poisson ratio, Young's modulus, Bulk modulus, Shear modulus and Unconfined compression strength of 0.26, 2.3GPa, 11.2GPa, 7.93GPa, and 16.73MPa, respectively. The formation shale exhibited higher values of Poisson ratio, indicative of its ductile nature that is resulting mostly from its clay content; the Bulk modulus, Young's modulus, Shear modulus, and Unconfined compression strength exhibited high values (8.23 MPa,0.37,17.08 MPa, 25.02 MPa, 66.22 MPa respectively); and lower compressibility and porosity as (0.08 Mpa-1, 0.07 respectively), making it stiffer (due to high moduli), more resistant to overburden stress, and less compressible than the loosed sand. These characteristics make the shale a fracture stimulating baffle; hence, in a hydraulic fracturing process under the same fracture gradient, the sandstone of the studied reservoir would fracture first, whereas the shale will easily form a seal rock to the fault zones. It also induces compartmentalization of hydrocarbon reservoir, with sands with high porosity separated by tight shales (Ortoleva, 1994).

The sand production index, Schlumberger formation sanding indicator, the Bulk Elastic Modulus ratio, and the Composite Modulus Estimation suggest that the investigated reservoir will experience significant sanding during production, according to the results of the mechanical property evaluation that was applied to the Prediction of sand production analysis (Zang, 2000 & Zhang, et al., 2011). In this reservoir, if the production flow rate is kept below the critical level of 18.30 MPa, it will undoubtedly prevent sand production in the wells. Conversely, if the drawdown pressure is higher than the calculated Critical flow rate pressure of the wells, the formation will fail and produce sand at levels that are inappropriate. This is because the wellbores are subjected to frictional drag forces and pressure differentials that are greater than the formation rock compressive strength, which results in the production of sand. Critical flow rate pressure is a good indicator for potential formation sand production.

This study provides a valuable framework for predicting sand production in Niger Delta reservoirs using empirical relationships from rock mechanical parameters and wireline logs. It contributes to improving the understanding of geomechanical controls on sand production in Niger Delta reservoirs, which supports the ongoing efforts to optimize hydrocarbon recovery, ensure wellbore stability, and reduce operational costs in the region.

I recommendation that further research should focus on integrating additional data types (e.g., seismic, core) to refine predictive models, application of advanced machine learning techniques (e.g., deep learning) may improve model accuracy and collaboration between industry and academia is essential for validating and implementing these predictive models in field operations.

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