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Non-Productive Time (NPT) Geomechanical Model for Borehole Stability Management in the Niger Delta Basin,

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Abstract

This research endeavors to develop a non-productive time (NPT) geomechanical model tailored for effective borehole stability management in the distinctive geological setting of the Niger Delta Basin. The model integrates analytic formulas rooted in advanced rock mechanics principles to address the challenges posed by complex sedimentary sequences, high overpressure, and salt tectonics prevalent in the region. Rock mechanical properties critical to wellbore stability, well design, fracking, sanding prediction and production planning were evaluated in 3 wells in an onshore field, western Niger Delta using 4-arm caliper, gamma ray, density and sonic logs, leak off tests and seismic data in an onshore field, Eastern Niger Delta. The stratigraphic units between 2000 and 3000 m depth investigated are the typical interlayered, normal to abnormal pressured shales and sandstones of the Agbada Formation. Wellbore breakouts were predominant in shales and weak shaly sandstones across the lithologic units.The vertical stress magnitude ranges from 23.08 - 25.57 MPa/km, minimum effective horizontal stress from 13.80 - 14.03 MPa/km, and maximum effective horizontal stress from 16.06 - 17.65 MPa/km inferring a normal fault stress regime. The minimum horizontal stress orientation varies from 015° - 033° forming the most stable azimuth for geosteering a directional well while the maximum horizontal stress orientation is N60°E - N123°E which is in agreement with the regional fault orientations in the Niger Delta. ENE – WSW, WNW – ESE and other maximum horizontal stress orientations suggest multiple sources of stress and in situ stress rotation across faults suggests wellbore instability. Structural evolution depicts NE – SW and NW-SE trending faults in the direction of the maximum horizontal stress. These data will be useful in the planning of well drilling in the field. Through the incorporation of adaptive algorithms, this model aims to reduce NPT events, optimize drilling operations, and enhance overall efficiency in the Niger Delta Basin.

I. Introduction

The Niger Delta is the delta of the Niger River sitting directly on the Gulf of Guinea on the Atlantic Ocean in Nigeria. It is located within nine coastal southern Nigerian states, which include: all six states from the South South geopolitical zone, one state (Ondo) from South West geopolitical zone and two states (Abia and Imo) from South East geopolitical zone.The Niger Delta basin occupies the Gulf of Guinea continental margin in equatorial West Africa, between latitudes 3° and 6° N and longitudes 5° and 8° E. It ranks among the world's most prolific petroleum-producing Tertiary deltas, comparable to the Alaska North Slope, the Mississippi, the Orionoco, and the Mahakam. The Niger Delta basin occupies the coastal and oceanward part of a much larger and older tectonic feature, the Benue trough. The Benue trough is a NE-SW folded rift basin that runs diagonally across Nigeria. It formed simultaneously with the opening of the Gulf of Guinea and the equatorial Atlantic in Aptian-Albian times, when the equatorial part of Africa and South America began to separate. Sediments of the coal-bearing Mamu and the tidally influenced Ajali formations accumulated during this epoch when the Nkporo cycle tended toward an overall regression with associated progradation. The influence of basement tectonics on the structural evolution of the Niger delta was largely limited to the movements along the equatorial Atlantic oceanic fracture zones that extend beneath the delta and determined the initial locus into which the proto-Niger built its delta.

The Niger delta basin stands as a significant hydrocarbon province, attracting intense exploration and drilling activities. However, the geological complexities of this region, including intricate sedimentary sequences and salt tectonics, often lead to borehole stability challenges, resulting in non-productive time (NPT) events. This research

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addresses these challenges by proposing a geomechanical model grounded in analytic formulas to predict and manage borehole stability effectively. The unique conditions of the Niger Delta Basin demand a specialized approach to drilling, making this model crucial for minimizing NPT and optimizing overall drilling operations.

Wellbore instability indicators includes breakout, collapse, undergauged hole, cavings at surface, excessive volume of cuttings and cavings, increased circulating pressures, unscheduled sidetracks, or even abandonment etc [7, 8, 9, 10, 11]. Designing and maintaining a stable wellbore requires acquisition of geomechanical properties data from drilling cores or from wireline logs[12, 13]. Using wireline logs for estimating geomechanical properties of rocks achieves satisfactory results because the logs are always run in the entire section of reservoir rocks. They give direct measurements of the petrophysical properties, and hence have become an ideal medium for obtaining geomechanical data [14]. Core samples of overburden formations where compressive shear failures occur, give better results but are never available for testing prior to commencement of drilling.

The high costs and complexity of wells both in terms of geometry, high-pore-pressure, low permeability, anisotropic and high stress regimes demandproactive pre-design geomechanical modeling of rock strength, deformation and stress for economic success of field developments. It is estimated that the minimum cost of instability of wells in the Niger Delta is 10% of the total cost per year, also the cost of non-productive time during drilling varies from a minimum of 60 days and sometimes up to 140 days with shales accounting for 90% of instability [16]. Poor understanding of a field’s geomechanics including the rock elastic properties, rock strength, in situ stress and wellbore stresses around the wellbore wall is a major contributory factor to poor well design and suboptimal production leading to collateral problems including severe wellbore collapse, lost circulation, blow outs, sidetracking and even well abandonment especially in directional and extended reach wells.

II. Geologic Setting

The study field is located in the onshore coastal swamp of the Niger Delta basin (Fig. 1). The tectonic evolution of the Niger Delta was controlled by Cretaceous fracture zones formed during the triple junction rifting and opening of the south Atlantic. The stratigraphic succession in the basin consists of three lithostratigraphic units . The oldest unit is the basal Akata Formation, Paleocene to Holocene in age and comprisingshales thought to be the source rock, was deposited under marine conditions. The Akata is overlain by the paralic sandstone/shale layers of the Agbada Formation which is the reservoir rock. Capping the sequence is the continental sand and sandstones of the Benin Formation which is the regional aquifer. These rock units are time transgressive, and they range in age from Tertiary to Recent [17]. Petroleum reservoirs in the Niger Delta are basically sandstone and unconsolidated sands in the Agbada Formation. The primary seal rocks are the interbedded shales within the Agbada Formation. Both structural and stratigraphic traps are common. The structural traps consist of growth faults and roll over anticlines which developed during synsedimentary deformation of the Agbada paralic sequence due to the instability of the under-compacted, over-pressured Akata shale [18, 19]. The interbedded shale within the Agbada Formation provides sealing units.

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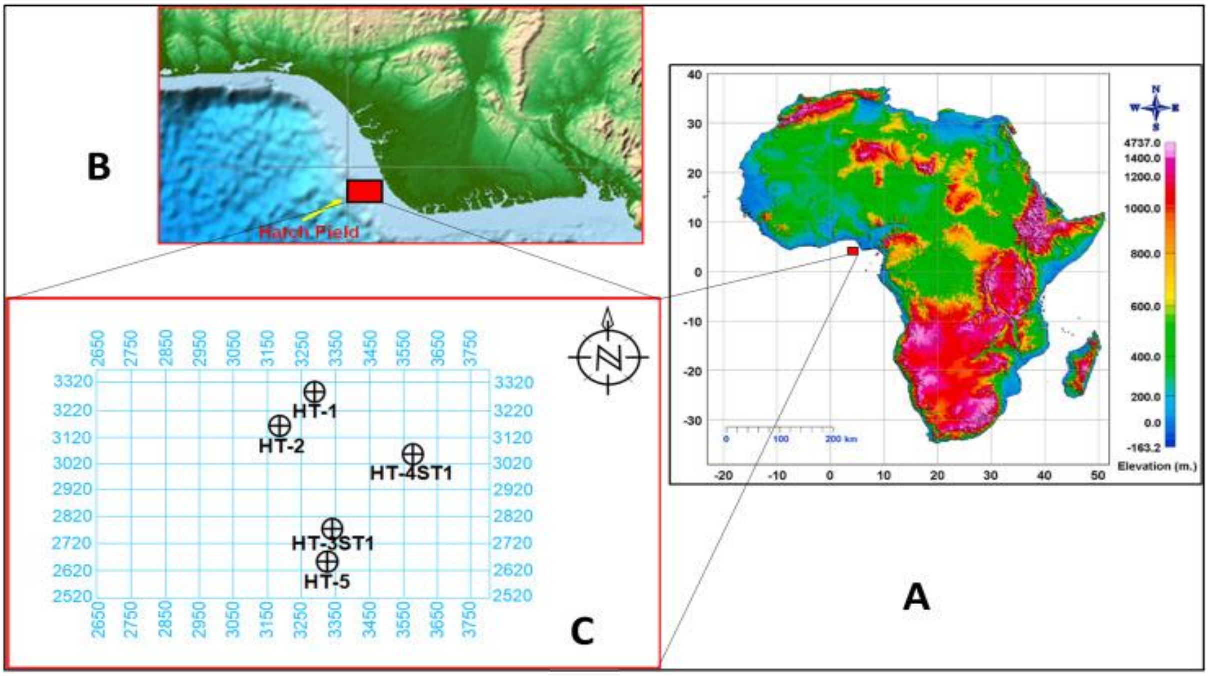

Figure 1: Reservior Map of Abgada farmation

III. Methods of Study

Data for this study included wireline logs (sonic, density, gamma ray, resistivity, and neutron porosity logs), 3D seismic data and Leak off tests (LOT) for 3 wells codenamed WABI 05, 010 and 011 for proprietary reasons. The wells lie in an east-west direction. These were available in well log American Standard Code for Information Interchange (ASCII) standard files formats. They were subjected to quality checks and converted to true vertical depth and thereafter loaded into the Schlumberger Petrel 2011 software to analyse and isolate the breakout zones. Stress induced wellbore failure zones known as breakouts were isolated from non-stress induced wellbore enlargements such as keyseats and washouts using 4-arm caliper and gamma ray log using the criteria for their identification in a well as outlined by[20, 21, 22]. Determination of rock mechanical properties including elastic and inelastic properties was carried out using density and sonic compressional (ΔTC) and shear (ΔTS) transit times as described in detail by [23, 6, 14]. The elastic properties included Poisson ratio (ν), elastic modulus (E) shear/rigidity modulus (G), bulk and matrix/grain moduli (Kb and Km), bulk and grain compressibility (Cb and Cr), and Biot's coefficient. The inelastic properties determined were fracture gradient and rock strength which include Uniaxial compressive strength, tensile and cohesive strengths, and frictional angle. Poisson's ratio and Young's Modulus (E), Shear Modulus (G), Bulk Modulus (Kb) and Matrix/Grain Bulk Modulus (Km) were obtained from the wireline logs using empirical relationships as described by [24, 25, 26]. Poisson's ratio and Young's modulus were determined from P- and S-wave velocity.

Where shear transit times data were not available like in well Wabi 05, interval transit time of the shear wave (ΔTS) was estimated and used to derive the shear wave velocity (Vs). This was achieved using the [27] relationships in equations (1), (2), and (3).

$$Vp = 304878\,\Delta Tc \quad (1)$$

$$Vs = 304878\,\Delta TS \quad (2)$$

$$Vs = (0.804 \times Vp) - 0.856 \quad (3)$$

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Poisson Ratio (ν)

Poisson ratio (ν) was computed from acoustic measurements including the slowness of the compressional wave (ΔTc) and shear wave (ΔTs) ratio using the [28] and [2] methods (equation 4) expressed as

ν = 0.5(Vp Vs) 2 – 1 (Vp Vs)2 – 1 (4)

Shear Modulus (G)

The shear modulus (G) which is the ratio of the shear stress to the shear strain was estimated from the[29]formula (equation 5)

G = aρb ΔTSν (5)

Where coefficient a = 13464, ρb= bulk density, ΔTs = shear sonic transit time.

Bulk Modulus (Kb)

The bulk modulus (Kb) was computed from the sonic and density logs using equation 6

Kb = aρb(1 ΔTC2 - 4 3ΔTS2) (6)

where ΔT denotes sonic transit times for compressional and shear waves.

Matrix/Grain Bulk Modulus (Km) This was determined from the empirical relationship in equation 7

Km = KS ρma/ (1/ΔTCma 2 - 4/3ΔTSma 2) (7)

Young's Modulus (E)

Young's modulus or modulus of elasticity was determined from shear modulus and Poisson's ratio as in equation (8). E = 2G (1+ ν) (8)

Bulk Compressibility (Cb) with porosity was determined by the relationship in equation 9

Cb = 1/Kb (9)

Rock Compressibility (Cr) zero porosity was obtained from equation 10 as

Cr = 1/(aρlog(1/ ΔTCma 2 – 4/3 ΔTSma 2) (10)

Biot Constants

Biot's poroelasticity describes the coupling between pore pressure and stress in rocks. When pore pressure changes and stresses are coupled, fluid diffusion plays an important role making stability time-dependent [30]Biot constant (α) was determined from the[31] method in terms of bulk and grain modulus using the expressions in equations 11 and in terms of compressibility (equation 12) as

α = 1-Kb/Km (11)

Where Kb and km are skeleton bulk and solid grain moduli respectively

α = 1-Cr /Cb (12)

Where Cr and Cb are grain and bulk compressibility respectively.

Unconfined Compressive Strength (UCS) Among the several empirical relationships proposed for application in sandstones, shales and carbonate rocks, the [32]relationship (equation 13) for fine grained, consolidated and unconsolidated sandstones with all porosity ranges suitable for the Niger Delta was adopted while [33] equation for shales was used for comparison of results as in equation 14.

UCS = 1200 exp(- 0.036ΔTc) (13)

UCS = 10(304.8/ΔTc – 1) (14)

where UCS = unconfined compressive strength, ΔTc = compressional wave transit time.

Shear Strength The initial shear strength (τi) and in situ rock's tensile strength (To) were determined using the empirical relationships by [34] in equation 15

τi = 0.026E/Cb x 106 {0.008Vsh + 0.0045(1-Vsh) (15)

where E = Elastic modulus,

Cb = bulk compressibility and Vsh = volume of shale and Insitu rock Tensile strength,

To = Co/12 (16)

where Co = cohesive strength = 5(Vp – 1)/0.5(Vp)

Determination of in situ stresses magnitudes and orientation Vertical stress (σv) was determined by integrating the density (ρb) of the materials from surface to the depth of interest as in equation 17

where $\sigma v = \int z\, \rho b(z)\, g dz$ (17)

The poroelastic equation which shows the relationship between vertical stress and minimum horizontal stress, Poisson's ratio and pore pressure (pw)was used together with leak off test to calculate the minimum horizontal stress (σH) according to equation 18

$$\sigma H = K (\sigma v - \alpha pw) + \alpha pw \quad (18)$$

Where α is Biot's coefficient and pw is mud pressure. Maximum horizontal stress (SHmax) was calculated using the [11] relationship in equation 19

$$SHmax = Shmin + tf*(SV- Shmin) \quad (19)$$

Where tf is tectonic factor.
The direction of SHmax was measured from the existing borehole breakout data. The orientation of maximum and minimum horizontal stresses was interpreted from wellbore breakouts and drilling induced tensile fractures using formation image logs and from breakout analysis using multi arm caliper logs as described by [35 and 22]Using the criteria proposed by [20] and [36]. Breakout data were ranked in accordance with the World Stress Map quality ranking system [22]. Breakout orientation data were analyzed statistically using equations by[37] and data ranked after the World Stress Map breakout quality ranking system described by [38]. Fracture gradient [39] distinguished between fracture gradient which is practically the minimum horizontal stress and the most likely fracture gradient duringdrilling as presented (equation 20)

$$PFP = 3\nu\, 2(1-\nu)\, (\sigma v - \alpha\, Pp) + \alpha Pp \quad (20)$$

where PFP = most likely fracture pressure gradient,

σv = vertical stress,
α = Biot's constant,
Pp = pore pressure gradient. Minimum mud weight

Wellbore stability analysis was carried out by determining the minimum and maximum mud weights required to prevent compressive shear failure and unwanted tensile fracturing. The minimum mud weight, the collapse pressure or shear failure gradient is the pressure required to drill safely below which shear failure will occur causing breakout and instability.

It is derived from the [29]formula in equation 7 based on Mohr-Coulomb criterion for critical wellbore pressure which is

$$Pc = \{1.5\ \sigma Hmax - 0.5\ \sigma hmin\ \alpha pp\ (1\text{-}2\upsilon/1\text{-}\ \upsilon) - 1.732\tau i\}/\ 1 - 0.5\alpha(1\text{-}2\upsilon/1\text{-}\ \upsilon) \quad (21)$$

where τi the initial shear strength
$$\tau i = 0.026E\ Cb\ x\ 106\ \{0.008Vsh + 0.0045(1\text{-}Vsh) \quad (22)$$

where E = Elastic modulus
Cb = bulk compressibility,
Vsh = volume of shale,
υ = Poisson ratio,
α = Biot's coefficient,
σHmax = maximum horizontal stress,
σhmin = minimum horizontal stress and pp = Pore pressure

IV. Results and Discussion

The application of the Non-Productive Time (NPT) Geomechanical Model in the Niger Delta Basin yielded promising results, demonstrating the model's effectiveness in predicting and managing borehole stability. The Agbada Formation whose stratigraphic succession consists of interbedded sandstones and shales. Thus, sandstone will fracture before shales in a hydraulic fracture stimulation process under the same fracture gradient while shales will form the barrier to fracture growth. Low rock strength accounts for the occurrence of wellbore failures in shales and weak shaly sandstones. Correlation of the properties across the field shows higher values of elastic, bulk and rigidity moduli in the east. Lateral decrease in the magnitude of the rigidity modulus from WABI 10 well on the eastern flank to WABI 11 well on the west implies a decrease in present day deformation eastward. There is a general decreasing trend in the modulus of rigidity, bulk and matrix moduli and an increase in elastic modulus of the rocks with depth. Compaction equilibrium during diagenesis under anoxic conditions depicted by normally pressured shale sourcebeds favoured hydrocarbon accumulation with the shale smears on the faults and caps on the sand tops providing the traps. The increase in rock compressibility with effective vertical stress and effective porosity and decrease in compressibility with depth and decrease in effective porosity with bulk compressibility further support equilibrium compaction. Increase in effective overburden stress due to sediment loading and fluids expulsion causes grain sliding in shear and compactional deformation with reduction in the bulk

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and grain compressibility and pore volume of the sediment with increasing depth. Grain to grain contact destroys the cement bonds and closes packing of individual grains by elastic distortions and strains. This mechanism is responsible for generation of over pressures since impermeable sediments such as shales saturated with an incompressible fluid will not deform elastically and when there is disequilibrium compaction, abnormal pore pressures will form as reported in most fields in the Niger Delta. The results are categorized based on key aspects of the model's performance:

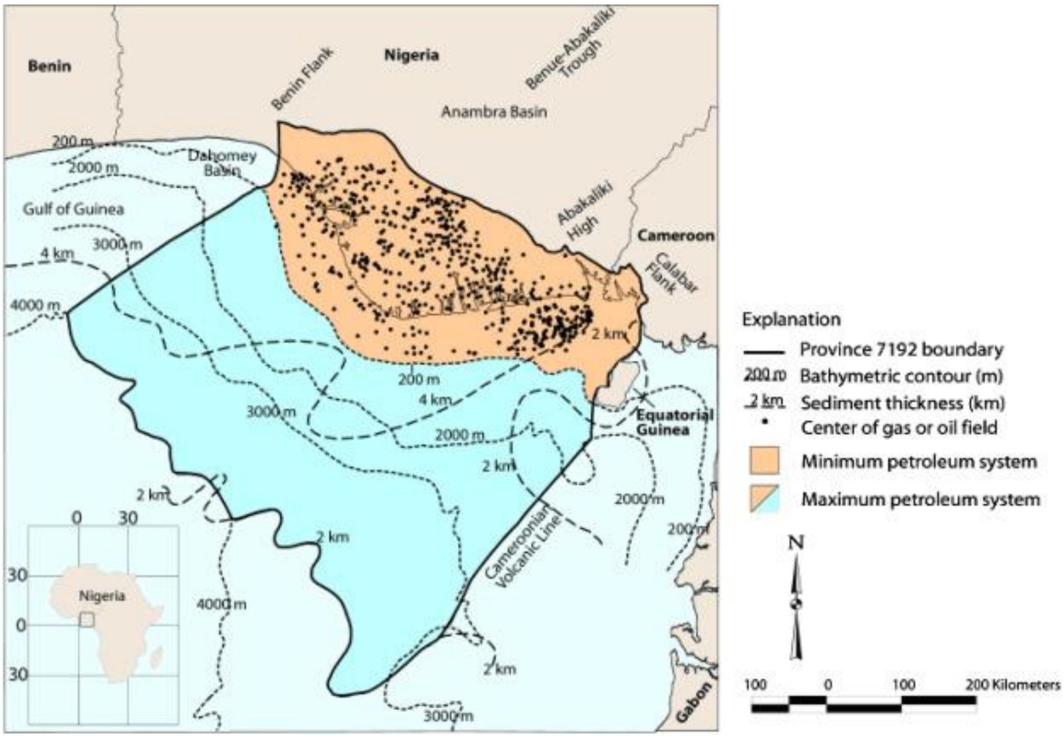

Figure 2:

Analytic Formulas Validation: The developed analytic formulas, rooted in advanced rock mechanics principles, were validated using well data from the Niger Delta Basin. The comparison between predicted and actual borehole stability conditions indicated a high degree of accuracy, affirming the reliability of the model in characterizing the mechanical behavior of sedimentary formations in the region.

In-Situ and wellbore Stress Analysis: The incorporation of analytic formulas for in-situ stress determination provided valuable insights into stress orientations and magnitudes within the borehole. . These vertical stress gradients indicate a variation across the field with magnitudes ranging from 23.08 MPa/km at 2km to 25.57 MPa/km at 4km in WABI 10, to 21.50 MPa/km at 2km to 22.63 MPa/km in WABI 11. There is a general increase in vertical stress with depth of burial due to increase in overburden loading. The magnitudes of the maximum and minimum horizontal stresses follow the trend of the vertical stress. Estimating the minimum horizontal stress in a well provides the lower limit of the fracturing pressure and puts a limit on the allowable injection pressure in a well. While the minimum horizontal stress varies from 14.03 MPa/km at 2km to 14.48 MPa/km at 4km true vertical depth s, the maximum horizontal stress ranges from 17.65 MPa/km at 2km to 16.06 MPa/km at 4km. The decrease in maximum horizontal stress magnitudes with depth of burial is due to variations in the bulk densities of the subcrustal rocks across the delta with a gradual increasing trend in easterly direction. Variations in crustal rock bulk density across the field could be caused by the deposition of siliciclastic materials derived from weathering of rocks in the hinterland during the rifting and uplift of the adjoining lower Benue Trough in the Late Jurassic to the Middle Cretaceous The model successfully identified zones prone to instability based on stress conditions, enabling proactive measures to be taken to prevent potential NPT events.

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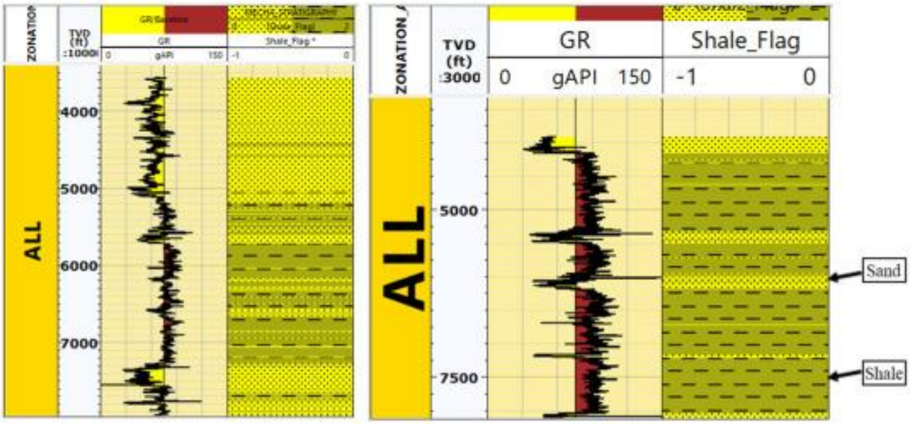

Figure 3:

Fluid-Induced Instabilities: Formulas addressing the effects of drilling fluids on rock properties demonstrated their significance in evaluating the impact of mud weight, viscosity, and filtration on borehole stability. Real-time adjustments to drilling fluid parameters guided by the model contributed to the prevention of fluid-induced instabilities, reducing the likelihood of NPT occurrences.

Adaptive Algorithms Performance: The implementation of adaptive algorithms proved crucial in maintaining the responsiveness of the model to changing subsurface conditions. Continuous updates based on real-time downhole data enhanced the accuracy of stability predictions, showcasing the model's adaptability and reliability in dynamic drilling environments.

V. Discussion:

Mud weight window for wellbore stability

Wellbore stability analysis involves determining the minimum mud weight (shear failure gradient) required for drilling without causing shear failure and the maximum mud weight required not to cause unintentional tensile fracturing. Maintaining a stable wellbore during drilling requires a mud weight window that is between the shear failure gradient and the fracture gradient. Normal overbalance drilling requires maintaining the mud density above the pore pressure and below the fracture gradient limit. Drilling at mud weights lower than the pore pressure may result in borehole splintering or washout and fracturing will occur if the mud weight is higher than the fracture gradient. Equally drilling at a mud weight lower than the shear failure gradient will cause shear failure. This therefore requires that a safe mud weight window be predicted for safe drilling [39]. The optimum mud weight is the average between the minimum and maximum mud weights. Fig. 9 shows predicted mud weight window for the wells for drilling without borehole collapse and unintentional fracturing of the formation based in isotropic formations. Mud weight window varies with depth across the field due to heterogeneity and anisotropies. A mud window range of 5.0 – 19.0ppg is predicted across the field. In some sections of the wells, the minimum mud weight exceeds the maximum mud weight. The drilling mud weight at such sections should be maintained at fracture gradient limit to avoid the risk of unintentionally fracturing the formation with attendant mud losses which is more dangerous than the breakout formation due to excessively low mud weights. Weak sections with very low shear strength may be strengthened to prevent collapse.

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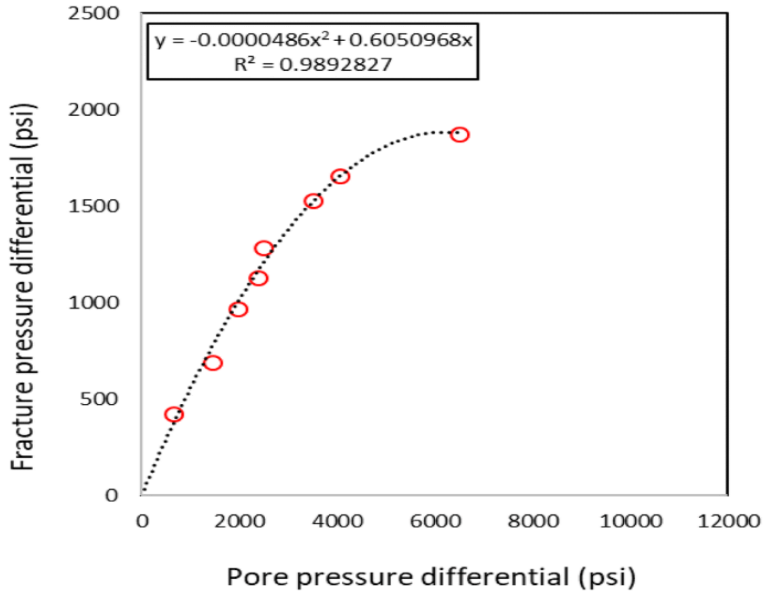

Figure4:

Drilling trajectory

Geosteering the optimum well path requires the most stable trajectory not to cause stress re-orientation, increase the wellbore hoop (tangential) stress and risk of wellbore instability. A vertical well will be most stable in isotropic formations. However, in anisotropic formations where a horizontal lateral section is required to intersect natural fractures and enhance the effective permeability and hence producibility, the minimum horizontal stress direction is recommended.In this study field, the direction of the minimum horizontal stress azimuth of approximately 024° is the most stable. This means that fractures will form and propagate in an orthogonal plane in a northwest- southeast direction. Drilling across the fault could cause anisotropies, reactivation, slip and rotation of the in situ stresses thereby causing instability. Under this condition, the well path will be more stable if drilled in the differential stress (σ1 – σ3) direction as suggested by [16]) rather than the minimum horizontal stress azimuth.

Overall Efficiency Improvement: The comprehensive nature of the NPT Geomechanical Model, integrating analytic formulas and adaptive algorithms, collectively contributes to an improvement in overall drilling efficiency. The reduction of NPT events not only minimizes operational costs but also enhances the safety and sustainability of drilling practices in the Niger Delta Basin.

In conclusion, the results and discussion affirm the effectiveness of the Non-Productive Time (NPT) Geomechanical Model for Borehole Stability Management in the Niger Delta Basin. Knowledge of in situ stress, mechanical properties of reservoir and cap rocks, pore pressure and fault system are key in designing stable and productive wells to optimize production and enhance recovery. In this study, the vertical stress increases vertically and laterally across the field due to variation in the density of subcrustal materials, while the moduli of rigidity, bulk and matrix volume, bulk and grain compressibility decreases with depth. Generally, there is an increase in elastic modulus of the rocks with depth due to increase in confining stress. Mud weight window varies between 5.0 to 19.0ppg with depth across the field due to heterogeneity and anisotropy. The direction of the minimum horizontal stress was approximately 024° azimuth in a general northeast-southwest implying that fractures will form and propagate in an orthogonal plane in a northwest- southeast direction. Results of the work may be used as a guide in drilling planning and production optimization. The model's ability to predict and mitigate stability issues, along with its adaptability to dynamic subsurface conditions, positions it as a valuable tool for optimizing drilling operations in this challenging geological setting.

Acknowledgements

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