

Predicting Subsurface Sand Fracture Stress in the Niger Delta's High-Pressure Environment: Insights from Oil-Well Drilling Experience

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Abstract: *A comprehensive understanding of fracture stress characteristics at greater depths is indispensable for drilling high-pressure deep exploration wells without operational complications. Pore pressure and fracture gradient are the two natural limits that most affect drilling costs and safety. The difference between the fracture gradient and pore pressure determines the safe drilling margin. Without accurately predicting pore and fracture pressures, serious wellbore challenges—including kicks, blowouts, lost circulation, and instability—pose a serious threat to drilling. Experience from the Deep well, part of the renewed HP campaign in the Niger Delta, indicates that field leak-off tests are best used at the well-planning stage, while the porosity-effective stress approach offers a viable alternative for real-time fracture-stress prediction in high-pressure reservoirs. Precise quantification of fracture stress is imperative for safe drilling and achieving the geological objective. Hard data from the Deep well support this assertion.*

Keywords: Fracture stress, pore pressure, effective stress ratio, leak-off test, seismic velocity, pressure cell, Niger Delta, Re-entry

1. Introduction

The S deep well was drilled to test the Deep gas prospect in the Eastern Swamp of the Niger Delta, below the prolific S oil and gas field (Figure 1). The Exploration Drilling Strategy was to re-drill an existing well to a deeper, previously unexplored depth and test the geological objective (Figure 2). The original well encountered a kick in 1971, and difficulty managing abnormal pressures led to premature termination; the kick fluid could not be identified. Pressure data suggest it was a water kick. The prospect was drilled by re-entering a well drilled in 1971, abandoning the completed intervals and sidetracking out of the old wellbore into the exploration section (Figure 3). The objective section was drilled with a 6" slimhole and evaluated with both LWD and wireline tools. The well encountered three target reservoirs, all water-wet.

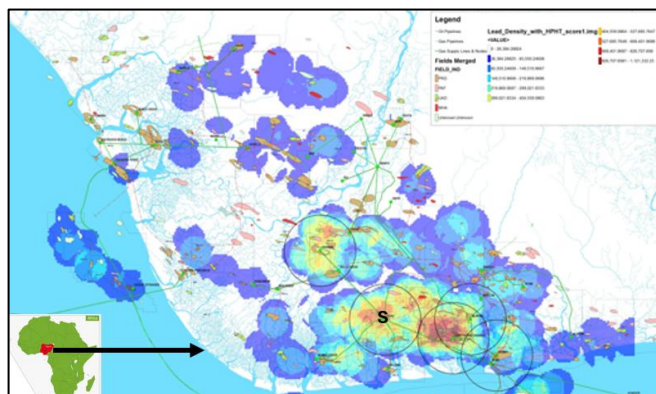


Figure 1: S Deep well in Niger Delta, West Africa

The well was successfully drilled to a total depth of 13,558 ft ah. This article describes the inadvertent leak-off test (LOT) and the drilling, which proceeded without issues, and discusses variations in fracture-pressure estimates from three established methodologies. It also suggests adopting real-time sand-strength prediction during drilling to evaluate the lower bound of the fracture gradient and, in turn, maintain a safe

handle on the drilling margin in a Deep HP exploration campaign.

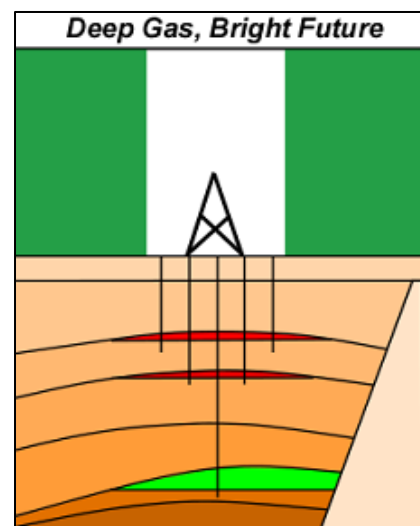


Figure 2: Deep gas prospect below the producing oilfield

At the outset, it was predicted to be a low-margin drilling exploration well, with a calibration point defined by a kick at the re-entry well bottom that prompted abandonment of deeper drilling. The Niger Delta legacy fracture-pressure data and cement-volume and height calculations for the kill plug in the S 13 well were used to define the worst-case fracture pressures in the kick sand. Specifically, we used 0.78 psi/ft as the sand strength and, given the 0.69 psi/ft to 0.754 psi/ft uncertainty range in pore pressures in the exploration section, expected a challenging drilling margin. However, drilling results eventually indicated that the fracture strength of the kick sand was underestimated, based on a rare, inadvertent measurement of sand strength obtained possibly for the first time in the Niger Delta overpressured regime.

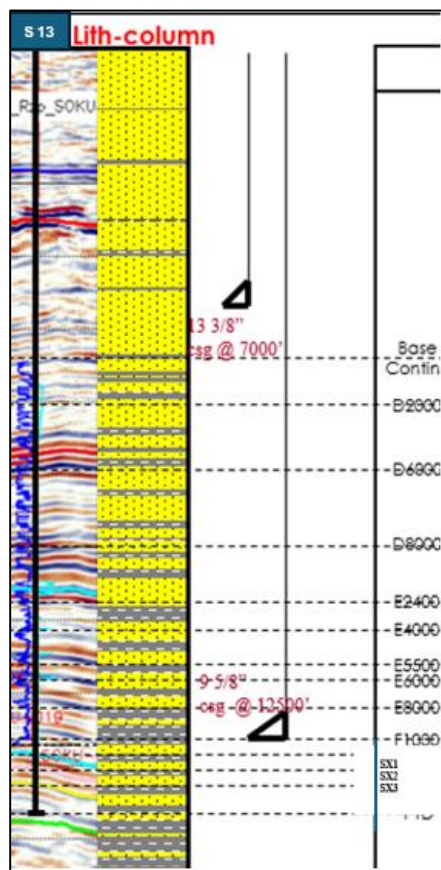


Figure 3: Re-entering an old S field well for Deep gas exploration

2. Pre-drill Pore Pressure Modelling

Pore pressure is the pressure exerted by fluids trapped within the pore space of rocks. Depending on the reservoir's geological history, compaction processes, fluid flow patterns, and tectonic activity, pore pressure may be classified as normal, overpressured, or underpressured¹ (Figure 4). The fracture gradient is the minimum pressure required to initiate or propagate fractures in the rock; this parameter depends on rock strength, in-situ stress conditions, and pore pressure. Both pore pressure and fracture gradient vary with depth and location within the reservoir.

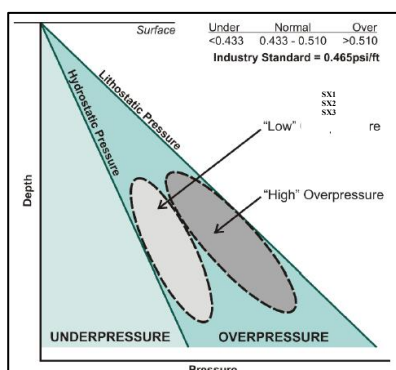


Figure 4: Pore pressure regimes¹

Pore pressure and fracture gradients strongly influence effective stress, which is calculated as the difference between total stress and pore pressure (Figure 5). Effective stress governs rock deformation and determines failure modes, including elastic, plastic, or brittle behaviour. Additionally,

pore pressure and fracture gradients define the safe mud-weight window for drilling and completion operations, the pressure range that prevents wellbore collapse or fracturing.

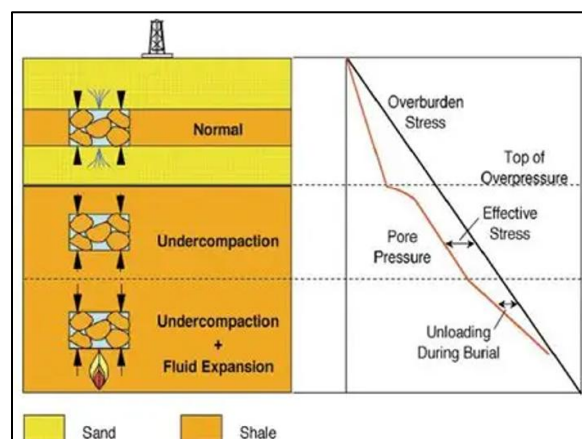


Figure 5: Effective stress concept²

Pore pressure and fracture gradients can be characterised using multiple methodological approaches. Common methods include empirical equations, such as Eaton's or Bowers' equations^{3,4}, which correlate pore pressure with well-log data or drilling parameters; and numerical simulations, such as finite element or finite difference models, which solve the equations of poroelasticity for complex geological formations and stress scenarios. Pore pressure and fracture gradients are neither static nor uniform throughout the reservoir. They can change over time and across space due to fluid production or injection, stress redistribution, or natural events such as fault reactivation or seismic events.

2.1 Model Calibration: the mainstay

Pore pressures were calibrated using drilling data, including kick and kill mud weights, and well tests. Fracture gradients were calibrated using formation integrity tests (FITs) and LOTs. Model calibration is essential for accurate, realistic pore- and fracture-pressure predictions.

2.2 Pore Pressure Calibration.

Where available, kick and kill MWs provide some of the most accurate indicators of pore pressure because they bracket the minimum (drilling MW when the kick occurred) and maximum (MW used to control the well) possible pore pressures. If only kick MWs are reported, they provide lower-bound estimates of pore pressure. If the shut-in drill pipe pressure (SIDPP) at the time of the initial influx is reported, it can be added to the MW to obtain a more reliable estimate of formation pressure. Well tests are among the most reliable measures of pore pressure.

2.3 Fracture Gradient Calibration

Unlike pore-pressure data, which can be adjusted to different depths under constant OP or constant VES based on sound theoretical arguments supported by field observations, the appropriate method for adjusting stress data is less clear. Possible models include a depth-based model that makes no adjustments other than accounting for KB elevation

differences when converting to pressure gradients. Alternatively, stratigraphic differences could be adjusted by holding S_V or VES constant. We adopted an approach that calculates the effective stress ratio (ESR) at the stress-measurement depth and applies it to the same stratigraphic position in the offset well.

An extensive analysis of key offset wells of the S field and PSDM seismic velocities was conducted to evaluate pore pressure at the Deep well location. We observed several pressure kicks in the deepest S Field penetrations and assessed each to calibrate the S Deep well pore-pressure model. Three independent methods were used to predict the pore pressure regime at S Deep: (a) velocity-to-pressure modelling, (b) basin modelling, and (c) pressure cell modelling.

3. Seismic velocity to Pore pressure modelling

3D PSDM seismic velocities and pre-stack velocity picks were used to develop a detailed velocity-depth function for the prospect (Figure 6). These velocities were inverted for pore pressure using a velocity-to-VES calibration, providing one end member of the pore pressure prediction.

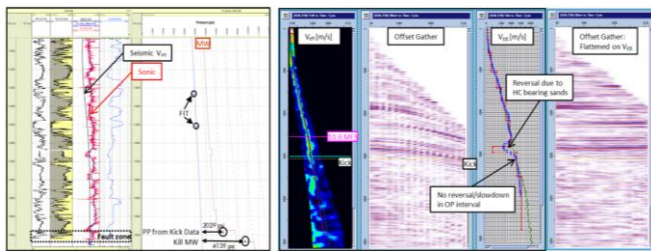


Figure 6: (Left) Log and pressure data at S (key calibration well). Sonic velocities in the overpressured interval are questionable because of fault crossing; no velocity reversal or slowdown occurs in the kick zone. (Right) Seismic velocities at S-4; the kick is not apparent.

The underlying principle of velocity-based PPP is that sediment compaction depends on rock properties and depositional history, while effective stress controls compaction and porosity loss (equations 1, 2).

$$\text{Equation 1: } \phi_z = \phi_0 e^{-c\sigma}$$

(where z is the depth, c is the compaction coefficient and σ is vertical effective stress)⁵

$$\text{Equation 2: } v_z = v_0 + a \cdot \sigma^b$$

(where a & b are constants, v_z is the measured velocity & v_0 is the mudline velocity)

Deviations from the normal compaction trend (porosity-derived) can be translated into changes in vertical effective stress (VES) and, subsequently, pore pressure by applying Terzaghi's principle⁶

(PP = OBS – VES), where OBS is overburden stress.

The Terzaghi principle⁶, established in 1943, states that overburden stress is distributed between the rock matrix and pore fluids. The matrix supports the vertical effective stress (VES), while the fluid component, termed pore pressure (PP),

is isotropic. In this study, we assumed that, in the structurally relaxed setting characteristic of the Niger Delta growth fault system, sediment mechanical compaction is predominantly governed by the matrix-supported weight of sediments—specifically, vertical effective stress. Terzaghi later formulated an equation to characterise the interrelationship among overburden stress, pore pressure, and vertical effective stress.

$$\text{OBP} = \text{VES} + \text{PP}$$

The model used to describe overpressures at S Deep, termed the 'Unloading Model'⁷, describes the relationship between velocity and a reduction in vertical effective stress (equation 3).

$$\text{Equation 3: } v_z = v_0 + a \cdot \{\sigma_{\max}(\sigma/\sigma_{\max})^{1/U}\}^b$$

(where a , b and U are constants) and $\sigma_{\max}$ is the maximum vertical effective stress

A VES-Vint calibration derived from Equation 3 was established utilising VES measurements obtained from two appropriately selected S field wells and sonic shale velocities (Figure 7). The drilled well data points presented below were derived from seismic velocity analysis. We then inverted the manually selected seismic velocities at S Deep (Figure 6) to estimate pressure using the aforementioned calibration; however, the velocity values did not match the pronounced overpressure conditions documented in the adjacent offset wells, as neither substantial velocity reductions nor velocity reversals were evident in the semblance data. Furthermore, seismic velocities at S Deep were inconsistent with the observed pressure gradients (Figure 6). This inconsistency was the inherent challenge that needed quantitative resolution to build a robust prediction.

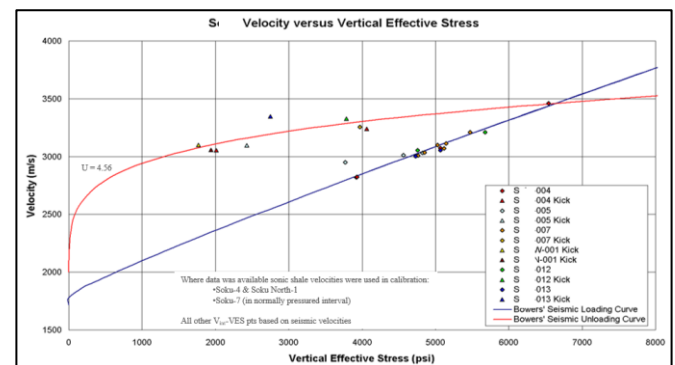


Figure 7: Velocity- VES plot of S field

4. Basin and Pressure Cell Modelling

A basin model was constructed that simulates subsidence and the resulting fluid flow and stress evolution in the S area; the results are consistent with those from pressure-cell modelling. Previous studies that used geology to constrain the overpressure system have largely limited pressure predictions to the concept of pressure cells. Pressure cells are volumes of sediments at approximately the same overpressure. They tend to be bound by structural elements (e.g., faults) or intervals of low-permeability sediments (shale, salt domes, etc.). Therefore, pressure cells can be distributed on a horizontal or vertical basis. In the former, pressure-cell boundaries tend to

be structural or rapid facies changes. In the latter, pressure cells are separated by tight facies distributions.

For the pressure cell models, individual formation layers exhibit constant overpressure (OP, difference between PP and hydrostatic pressure)⁸. The pressure cell model was constructed by assigning the same degree of overpressure/s (as penetrated in offset wells) to correlatable stratigraphic unit/s. Two degrees of overpressure were assigned to each stratigraphic unit, one describing the expected case, based on 'kick' mud weights – or mud weights used to control kick formations in a particular sand/cell/unit. The second, or maximum case, was based on the mud weights used to eventually 'kill' the influx of overpressure fluids in the wellbore (Figure 8).

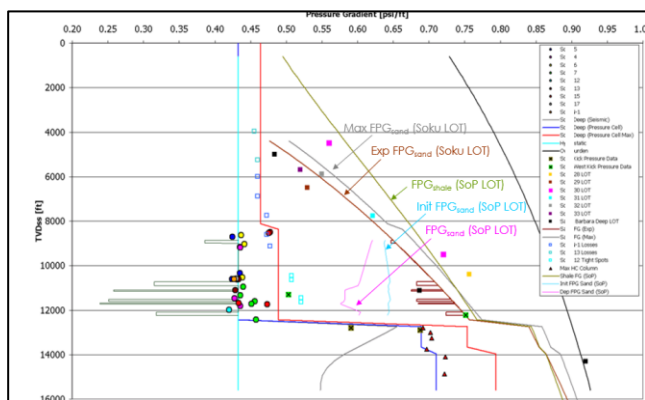


Figure 8: Pre-drill PP-FG prognosis of S Deep

The pressure cell model, validated by basin-model results, was the most reliable analysis method for S Deep PPP because seismic velocities did not accurately predict many of the field kicks observed. The top hole section of the S field has been under production for over three decades; seven reservoirs are now depleted as a consequence. The consequences of depletion were assessed on pore pressure and fracture pressure, and these findings were integrated into the comprehensive pre-drill PPP and well plan.

5. Pre-drill Fracture Gradient Models

The LOT establishes the pressure threshold at which formation losses beneath the casing shoe are anticipated to occur. A higher pressure tolerance in the wellbore allows drilling through elevated pore pressures without installing an additional casing string. When predicting formation fracture gradients, overburden load, rock Poisson's ratio, and pressure gradients vary with depth. Although developed specifically for the Gulf Coast, the Eaton method should be highly reliable in other areas, provided the variables reflect local conditions⁹.

Fracture pressures within depleted sand formations were projected utilising three methodologies:

- 1) The effective stress ratio relationship established from S Sand LOT data, and
- 2) Poisson's ratio values in sand and shale layers, derived from sonic measurements and the Regional Rock Properties trend analysis.
- 3) Salz's correlation using depleted press¹⁰

$$P_f = P_{f0} \cdot e^{C(P_p - P_{p0})}$$

Where P_f is the fracture propagation pressure, P_{f0} is the initial fracture pressure, P_p is the pore pressure, and P_{p0} is the initial pore pressure. Note that the relationship is not linear. C is the stress path coupling coefficient (Salz found $C \approx 0.36$), but it varies from basin to basin due to varying stress path coefficients.

Because LOTs were executed in a few shallow sand formations, it was deemed that the effective stress ratio was applicable for determining the original fracture pressure gradient of the shallow-depth sand layers. Leak-off tests performed in the S field can be analysed inversely to establish an effective or pseudo stress ratio. This derived effective stress ratio was subsequently employed to compute the fracture gradient (Figure 9). For tensile (hydraulic) fracturing, the fracture pressure is generally considered equal to the minimum principal total stress (S_h for normal or strike-slip stress regimes) and is calculated based on an effective stress ratio (ESR or K_0) of minimum effective horizontal stress to vertical effective stress⁸.

Salz's 1977 SPE paper⁹ showed that fracture propagation pressure decreases as pore pressure increases because pore pressure reduces the effective normal stress acting on the fracture walls.

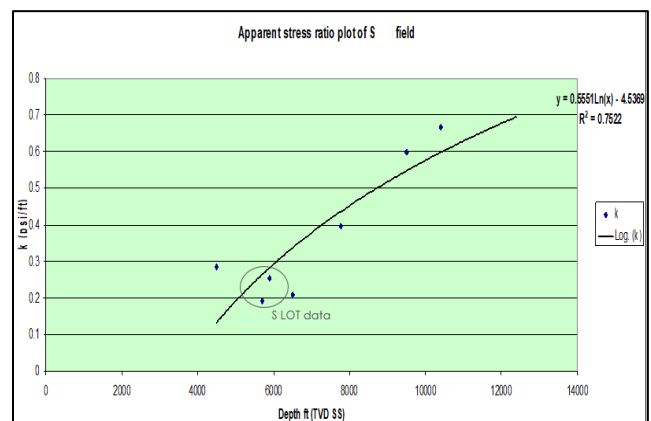


Figure 9: Effective stress ratio of sands of S Deep

A comparison of the two methods indicates that the fracture-gradient prediction from the effective-stress ratio derived from actual LOTs in sands is more consistent with field observations and appears reliable at the outset (Figure 10).

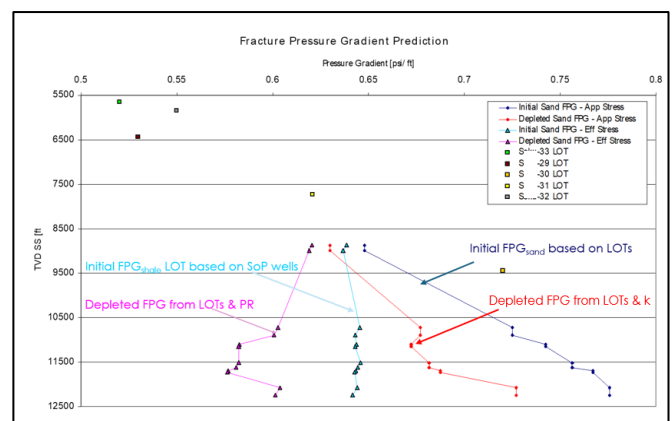


Figure 10: Pre-drill PP-FG plot of S Deep

6. Re-entry Operations

To drill the exploration section by re-entering the old well S 13, the perforations were to be permanently sealed, and well integrity had to be proved. The operational strategy was to seal the open perforations in the E2 and E4 sand formations before extending the wellbore toward the exploration targets. Each perforated section was then pressure-tested individually to identify the zone experiencing fluid loss. Cement was successfully retained in the E2 reservoir, allowing the mud weight to remain at 0.72 psi/ft. The E4 reservoir was identified as the loss zone, with fluid losses occurring when the mud weight exceeded 0.66 psi/ft. We recalculated the pre-drill formation fracture pressure for the depleted E4 formation from 0.246 psi/ft to 0.676 psi/ft. After identifying E4 as the loss zone, an additional cement plug was placed across the affected interval. However, after drilling out the plug and increasing the mud weight, fluid losses resumed at an equivalent mud weight of about 0.66 psi/ft. Because cementing could not seal the E4 perforations, sidetracking the wellbore by milling a window in the original S13 9 5/8" casing had to be implemented. Once the well integrity was secured, the well was ready for the deep exploration drilling.

7. Sidetracking

The deviated wellbore trajectory was engineered to maintain a secure azimuthal orientation throughout the Dodo shale formation and the underlying shale intervals beneath the E2 and E4 reservoirs. We calibrated the drilling fluid density to be high enough to mitigate the formation's documented shale-swelling characteristics while keeping it low enough to minimise the risk of additional fluid losses in the depleted zones. Subsequently, we deployed a directional bottomhole assembly equipped with gamma ray instrumentation, and drilling progressed to a total depth of 12,808 ftah without encountering fluid losses. Throughout this interval, the drilling fluid density remained constant at 0.52 pounds per square inch per foot, using synthetic oil-based mud supplemented with 4-5 pounds per barrel of G-Seal additive, which effectively prevented fluid losses into the depleted E2, E4, E55, E6, E8, and F1 reservoirs. The section total depth was established based on stratigraphic correlation with the original S 13 well, which had penetrated approximately 90 feet of shale beneath the F1040 reservoir, with 100 per cent shale cuttings returned to surface in the circulated returns (Figure 11). Casing subsequently landed at this depth.

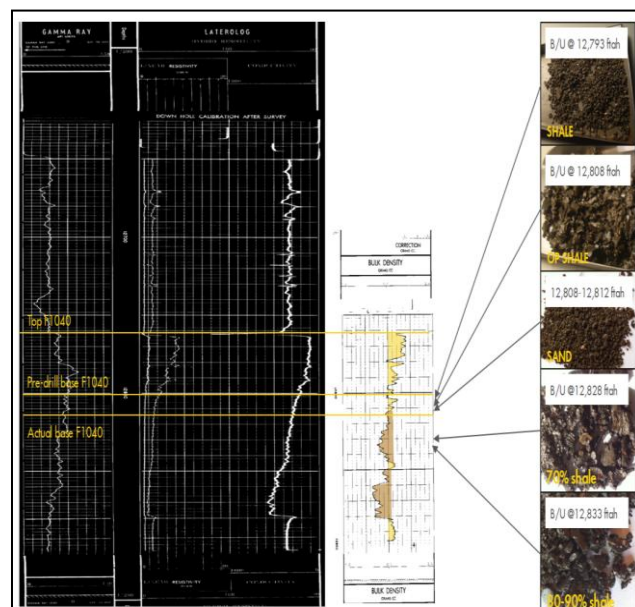


Figure 11: Basis: Casing seat setting at S Deep

8. Exploration Drilling

While drilling the rat hole with 0.74 psi/ft mud (ECD: 0.81 psi/ft), we observed sand in the cuttings; the BHA had no LWD. We proceeded with the LOT as planned, using a packer to isolate the casing and depleted zones behind it and reduce the risk of micro-annulus formation. After tripping into the hole to about two stands off bottom, we attempted to break circulation by starting the mud pumps. Standard procedure is to rotate the drill string before starting the pumps to break up any gels in the mud. However, with the packer on the string, we could not rotate it. As the pumps started, pressure surged suddenly, exerting an almost instantaneous shock pressure of 1.05 psi/ft on the formation. This fractured the formation, and fracture propagation continued for about 5 minutes until we shut down the pumps. As a result, we experienced losses. We controlled these losses by reducing the mud weight to 0.60 psi/ft, setting loss-circulation materials (LCM), and performing a cement squeeze.

It was decided to drill ahead to the base of the permeable unit before wellbore strengthening and conducting a further LOT. The base of the F1040 reservoir was found at 12,820 ftah—significantly deeper than prognosed based on the original S well (12,782 ftah). As drilling proceeded at S Deep Re-entry, the original S well's GR-RES response proved unreliable, and the density log matched the lithology from cuttings more accurately.

After confirming the F1040 base with cuttings, the well was treated with "Frac-Attack", a specialised proprietary severe-loss and wellbore-strengthening treatment. This was deployed via a hesitation squeeze method, achieving a final stable pressure of 0.88 psi/ft EMW. This provided sufficient formation strength to proceed with drilling and can be considered a pseudo-limit test for the casing shoe.

9. The Unintentional Leak-off Test

The 7" casing was landed at a depth of 12,803 ftah. A leak-off test was scheduled to begin after drilling 10 feet into the

fresh formation. During rat hole drilling operations using mud with a pressure gradient of 0.74 psi/ft (equivalent circulating density: 0.81 psi/ft), sand particles were identified in the drill cuttings, despite the bottomhole assembly lacking logging-while-drilling equipment. The planned leak-off test proceeded using a packer to isolate the casing and depleted zones in the annulus, minimising the risk of micro-annulus development. Following tripping operations to approximately 2 stands above the bottom, circulation was interrupted by initiating mud pump operations. Standard operational protocol requires rotating the drill string before pump activation to disperse gel formations in the mud system; however, the packer assembly on the string precluded this procedure. Upon pump initiation, pressure increased abruptly, generating an immediate shock pressure of 1.05 psi/ft against the formation. This pressure surge resulted in formation fracturing, with fracture advancement persisting for approximately five minutes until pump shutdown (Figure 9). Although unplanned, this leak-off test yielded significant lithological strength data seldom documented in the Niger Delta region, particularly proximate to the overpressured interval. We classified the occurrence as an Extended leak-off test, in which the pressurisation phase extends beyond the formation breakdown threshold. For the sandy stratum identified in S Deep, the measured values were derived assuming a depth of 12,818 feet above sea level.

These measured values provide a solid data point for planning future wells, particularly where formation strength in sands is critical. The pre-drill FG prediction for the F1030 sands (the last known sand in the field) was 0.819 psi/ft, compared with the 0.82 psi/ft observed during the LOT (Figure 12).

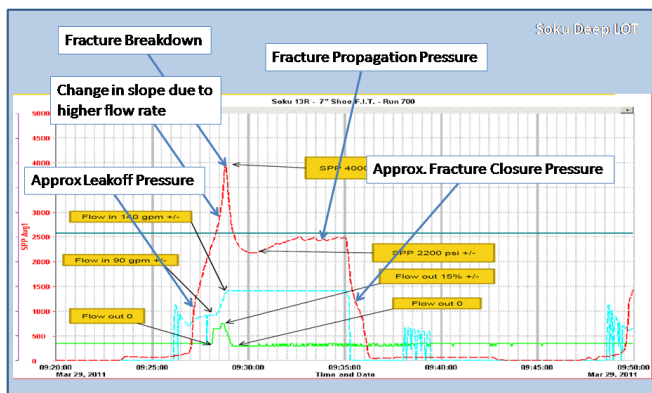


Figure 12: Standpipe pressure and Volumes vs time – attempting to break circulation prior to planned LOT at 7” casing shoe. Geomechanical properties observed during formation breakdown, S13 Re-drill.

These conditions caused significant mud losses, which the team managed effectively through lost circulation material (LCM), mud weight reduction, and cement interventions. The operational team deemed it prudent to continue drilling toward the base of the sandy formation, then attempt to reinforce wellbore integrity using the "Frac-Attack" severe loss mitigation protocol. The team administered the Frac-Attack treatment via a hesitation squeeze methodology, achieving a final stable pressure gradient of 0.88 psi/ft. This intervention increased wellbore strength by 0.06 psi/ft, exceeding the measured loss-of-pressure (LOP) threshold of 0.82 psi/ft.

10. 6” slim hole drilling

The 6-inch hole through the objective section was drilled with a static mud weight of 0.74-0.76 psi/ft and an equivalent circulating density of 0.83-0.85 psi/ft. These parameters were necessary because of the mud's viscosity and the elevated pump rates needed to maintain hole cleanliness. G-Seals were incorporated into the mud system at a concentration of 15 lb/bbl. Throughout this section, we observed no additional mud losses despite the elevated equivalent circulating density. This favourable outcome was attributed to two primary factors: the effective application of G-Seals, which establishes a stress-caging effect around the wellbore, and the formation demonstrating greater structural integrity than initially projected. The target reservoir sands designated SX1, SX2, and SX3 were intersected in close alignment with prognosis, with hydrocarbon shows documented in the SX1 and SX2 units. We used real-time, resistivity-based predictions during drilling. The objective section was drilled with a static mud weight of 0.74-0.76 psi/ft and an equivalent circulating density of 0.83-0.85 psi/ft, driven by the mud's viscosity and the high pump rates needed to maintain hole cleanliness. G-Seals were introduced to the mud system at 15 lb/bbl. No supplementary mud losses transpired during this section despite the elevated equivalent circulating density. This outcome was partially attributed to the effective utilisation of G-Seals, which generates a stress-caging effect around the wellbore. The actual structural capacity of the objective section's sand formation remains uncertain, partly because G-Seals establish a stress-caging effect around the wellbore. The real-time fracture gradient prediction in the target sands was 0.78 psi/ft, which is not true (Figure 13). The real-time pore pressure prediction, based on a constant, uncoupled Poisson's ratio, underpredicts fracture stress in overpressured sands because it assumes a constant Poisson's ratio of 0.27. If LWD includes a density tool, the real-time Poisson's ratio can be computed to provide a more realistic real-time fracture gradient.

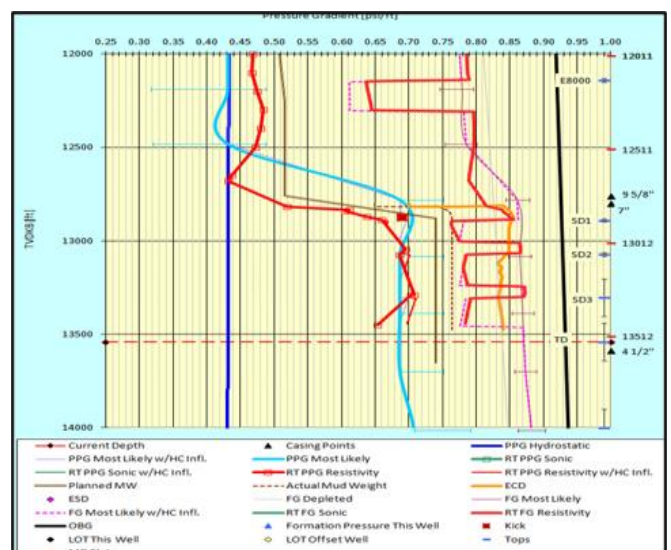


Figure 13: Real-time PP-FG plot of S Deep

11. Post-drill Fracture Pressure Analysis

The exploration phase successfully sustained equivalent circulating densities of up to 0.85 psi/ft without incurring

losses. The pre-drilling fracture pressure assessment for these formations was approximately 0.84-0.85 psi/ft, which aligned with the observed results. Conversely, historical Niger Delta data and the real-time fracture gradient estimate for these sands—derived using a constant, uncoupled Poisson's Ratio approach—indicated a fracture gradient of only 0.78 psi/ft within the target intervals. This estimate proved to be substantially underestimated: the measured leak-off pressure in a shallower formation (F1040) was 0.82 psi/ft. Conveying these reduced fracture-gradient projections to Well Engineering inadvertently created the impression of a constrained or negligible drilling safety margin, despite considerable operational margin for advancement. In retrospect, the pre-drilling fracture-gradient estimate was significantly more accurate than the real-time methods used.

The real-time formation gradient estimation methodology may be enhanced by incorporating pore-pressure-formation gradient stress coupling mechanisms into real-time operations, with corresponding adjustments to Poisson's Ratio parameters. The objective interval demonstrated equivalent circulating densities of up to 0.85 psi/ft without incurring losses. The pre-drilling fracture pressure for these sand formations, determined using the effective stress ratio method, was approximately 0.84-0.85 psi/ft, consistent with the observations above.

12. Alternative approach to Fracture stress prediction

When stress is relieved during unloading, sediments do not revert to their original state and recover only a small part of their original volume through elastic and inelastic processes. We used the effective-stress approach to predict pore pressure for pre-drill and real-time predictions. Both overburden and effective stress can be determined from petrophysical data. Effective stress has a lithology-dependent relationship to solidity, which is (1-porosity) during sediment loading and unloading¹⁰ (CD Ward et al., 1995). Assuming zero tensile strength, as it is only one-tenth of compressive strength, fracture stress in a normal faulting regime like in the Niger Delta can be estimated from porosity, vertical effective stress and pore pressure by

$$\text{FFG} = (1 - \text{porosity}) * \text{VES} + \text{pore pressure}$$

This approach incorporates horizontal stress considerations by using effective stress rather than depth to calculate the stress ratio derived from leak-off test data. It also accounts for reduced minimum horizontal stress in sandstone formations by using porosity measurements instead of Poisson's ratio. During the evaluation phase, we identified three primary target reservoirs, and comprehensive formation assessment confirmed that all three were water-wet (Figure 11). As shown in the figure, this approach estimates the fracture gradient in the target sands (Table 1).

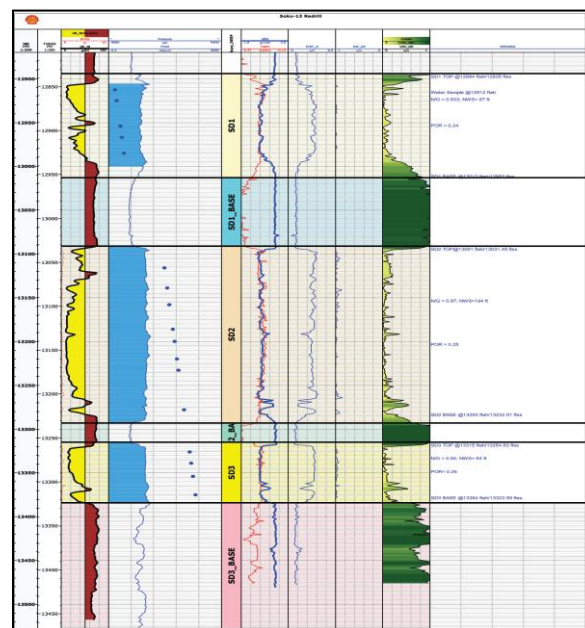


Figure 14: Petrophysical log of S Deep

Table 1: Fracture gradients of the target sands estimated through the Porosity-VES approach

Sand	Depth (TVDSS)	OBG (psi/ft)	Pore Pressure (psi/ft)	Porosity	VES (psi/ft)	Fracture stress (psi/ft)
SX1	12896	0.951	0.699	0.26	0.252	0.8858
SX2	13099	0.952	0.702	0.25	0.25	0.8895
SX3	13309	0.954	0.709	0.23	0.245	0.8976
E4000	11104	0.93	0.24	0.3	0.69	0.723

Additionally, we examined the unintended fracturing at a depth of 12818 ftah. The formation exhibited a sustainable pressure gradient of 0.81 psi/ft during drilling. Assuming hydrostatic formation pressure for the F1040 sand formation yielded calculated fracture stress gradients of 0.85 psi/ft and 0.82 psi/ft for the high and low scenarios, respectively, based on porosity measurements of 20% and 25%. The formation could not withstand an equivalent circulating density of 0.85 psi/ft without implementing a stress-caging frac-attack treatment. The hydrostatic pressure assumption was supported by the fact that the upper, more substantial section of the F1040 formation was drilled at a mud gradient of 0.52 psi/ft without any observable signs of instability.

12.1 Inference from re-entry intervention of the production section

During the workover at a mud weight of 0.66 psi/ft, we experienced severe mud losses into the E4 reservoir, suggesting formation breakdown. The pre-drill fracture gradient estimate for E4 sand was 0.676 psi/ft deduced from sand LOTs. This differs from the VES-derived fracture gradient, as fracturing in the previous two attempts to seal off the perforations may have created preferred pathways. Hence, if the reservoir stress path alters the fracture gradient, this method needs further testing. Pore pressure measurement could also be a variable, as it was taken more than a year ago. During the workover at a mud weight of 0.66 psi/ft, we experienced severe mud losses into the E4 reservoir, suggesting formation breakdown. The pre-drill fracture gradient estimate for E4 sand was 0.676 psi/ft, deduced from

sand LOTs. This differs from the VES-derived fracture gradient, as fracturing in the previous two attempts to seal off the perforations may have created preferred pathways. Hence, if the reservoir stress path alters the fracture gradient, this method needs further testing. Pore pressure measurement could also be a little different, as it was taken more than a year ago.

13. Post-drill analysis

Post-drill analysis completes the cycle initiated by the pre-drill process and enables evaluation of the actual uncertainty margins associated with pressure forecasts in regions where calibration data were previously limited or unavailable. In this instance, kick-derived data enabled robust calibration. Furthermore, the post-drill analysis incorporates insights from earlier drilling operations into the development strategy for subsequent wells, ensuring that challenging stratigraphic intervals, atypical lithological characteristics, and other unfavourable drilling circumstances are thoroughly examined and understood to reduce the likelihood of complications from these conditions. Analysis of pre-drill estimates against real-time pore pressure forecasts derived from resistivity data shows the wellbore encountered pore pressures consistent with expectations, later validated by RCI measurements. However, these pressures exceeded the predicted fracture gradient, providing a larger drilling safety margin than originally anticipated. The causes for the underprediction of the fracture gradient were investigated.

13.1 Comparison of stress ratios

The effective stress ratio relates effective horizontal stress to effective vertical stress. Figure 15 presents the effective stress ratio (ESR) computed from dipole sonic (V_p and V_s), gamma ray, and actual LOTs. ESR varies significantly, which critically affects fracture gradient prediction. The effective stress ratio forecast of an altered fracture gradient due to production-induced depletion was confirmed in the E4 sand formation during a cement squeeze operation. When the fracture gradient calculated for the exploration deep section is compared with observed well performance, the effective horizontal stress remained approximately 400 to 540 psi below the fracture pressure of the permeable formations encountered in the wellbore. The fracture gradient variance between these two methods is 0.07 psi/ft. The well exhibited an equivalent circulating density of 0.85 psi/ft and maintained stability with no mud losses recorded. Consequently, underestimating the fracture gradient from sonic measurements reduces the drilling safety margin. This reduction then affects mud-weight planning for well design.

In the S Deep well, fracture gradient estimates under both normally pressured and overpressured conditions systematically underestimate when calculated using Poisson's ratio from sonic measurements. Workover activities revealed that fracture gradient predictions based on sonic-derived Poisson's ratio values were substantially inadequate in the depleted E4 sand formations, whereas predictions from field leak-off test (LOT) data were accurate. The underestimation of fracture gradient from sonic-based methods consequently reduces the calculated drilling margin. Nevertheless, the field LOT-based prediction methodology was confirmed to be

reliable in the normally pressured interval and demonstrated reasonable validity in the pressured interval as well.

13.2 Validity based on the well results

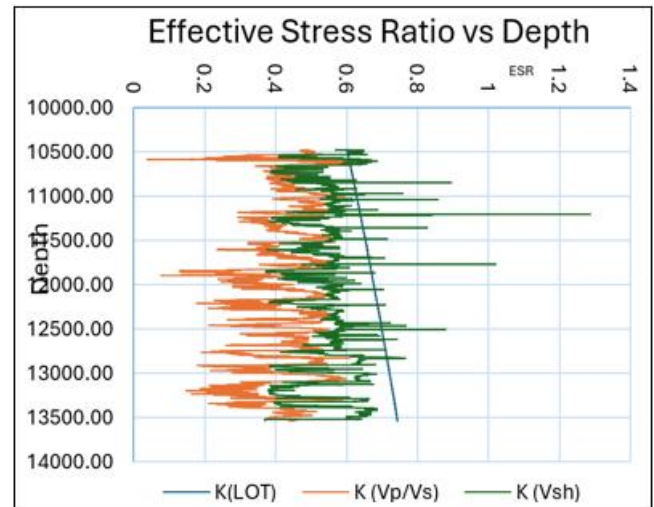


Figure 15: Effective stress ratio determined by three methods

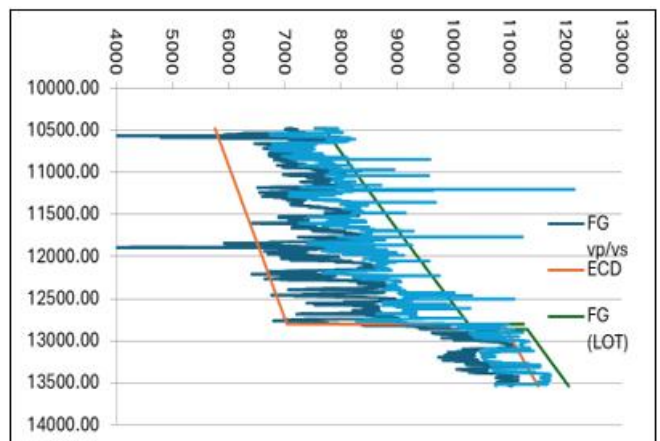


Figure 16: Comparison of Fracture gradients from LOT, GR and Sonic with ECD

The distinction becomes apparent when the stress ratios derived from the three methods are plotted against depth (Figure 16). The stress ratio calculated from LOT measurements increases consistently with depth. This occurs because leak-off occurs in an inelastic medium rather than an elastic one. When well performance data on equivalent circulating density is juxtaposed with corresponding fracture gradient values and plotted against depth, a clear pattern emerges both sonic-based and gamma-based methodologies substantially underestimate the fracture gradient, thereby contradicting or minimising the fracture gradient estimates, in marked contrast to those values obtained from LOT test analysis (Figure 16).

The fracture gradient estimated using sonic-derived Poisson's ratio was lower than the gradient indicated by the actual well results. In contrast, the fracture gradient estimated from field LOT interpretation is supported by the well events/behaviour. Poisson's ratio is an elastic constant defined as the ratio of lateral unit strain to longitudinal strain in a body subjected to longitudinal stress within its elastic limit.

14. Explanation for the variations in ESR

Comparing the ESR values derived by the three methods shows that the well LOT-based ESR yields similar, but not identical, stress-coupling values. The LOT-derived ESR values are higher and better justify the well data than the other two derivatives. Lahn et al. (2018) report the same. LOT data better capture the poroelasticity component and coupling than lithological and sonic-derived Poisson's ratio, especially in a Tertiary Basin with an extensional setting.

The sonic-derived Poisson's ratio assumes the rock to be isotropic. It assumes the formation has not undergone any lateral deformation since sedimentation and that it deformed elastically during compaction. This ignores the stages of tectonic history during which the stresses might have changed. Deformation in shales is plastic, while in sands and silts it is more or less elastic but not fully recoverable. Rocks are seismically elastic and geologically plastic. This means that rocks, subject to overburden stress for millions of years, do not return to their initial state after the stress is removed. Hence, it is natural to expect that, in a rock in situ subject to overburden stress for millions of years, a higher horizontal stress develops than would result from instantaneous vertical loading and unloading. Thus, given the definition of Poisson's ratio, the sonic-derived and actual leak-off test derivations naturally differ.

During such a calibration procedure, fracture-stress estimates often differ from LOT data, and these discrepancies become more pronounced at greater depths when sonic log-derived Poisson's ratio measurements are used (E. Kozlov et al¹², 2005). Holbrook¹³ (2000) showed that the stress ratio concept applies only under fully recoverable, linear-elastic conditions and may introduce inaccuracies when applied alongside actual Poisson's ratios from dipole sonic logs or core samples. Consequently, we establish a pseudo or effective stress ratio/Poisson's ratio for fracture-pressure prediction derived from field LOT data rather than the genuine elastic constant. The calculated values for ' K_0 ' appear implausible; however, they match the leak-off tests while ignoring location-specific variations in overburden and pore pressure. The underlying premise is that "lower-bound" leak-off tests furnish an estimation of the in-situ horizontal stress. Poisson's ratio represents a critical formation property that influences fracture-pressure determination.

14.1 Realisation

It may not be appropriate to use the elastic property, Poisson's ratio, to calculate fracture gradient for an inelastic compaction process. This assumption is consistent with sediment's irrecoverable porosity decreasing during burial, and the stresses estimated this way are more consistent with leak-off-test data. This may be because of the overpressured environment and the magnitude of the pressures. Poisson's ratio is a mineralogical constant within an elastic, but not a plastic, mechanical system. The relationship between Poisson's ratio and fracture pressure is a complex correspondence between distinctly different mechanical systems. That correspondence lies entirely within the realm of physical mechanics. The elastic and plastic stress/strain coefficients are necessarily different. Poisson's ratio and

fracture pressure are in two separate mechanical systems. Fracture pressure depends strongly on porosity, while Poisson's ratio is independent of porosity. It is the elastic and plastic mechanical systems that are linked as described above, not individual parameters in either system. Hence, it will be inappropriate to rely on Poisson's ratio from Sonic and gamma measurements. The effective stress ratio, linked to actual field tests, therefore replicates the physical breakdown of formation in the plastic realm, and care should be taken to discard FITs in the elastic regime. One advantage of this approach over the simplistic lower-bound LOT trend analysis is that the derived fracture pressure does depend on changes in pore pressure.

15. Recommended Method for Effective Stress Ratio Analysis

The guidance for pre-drill fracture pressure estimation in an extensional stress regime is to use models that either apply a constant fraction of vertical stress or empirically estimate the effective stress ratio from LOT data. The effective stress ratio derived from actual LOTs is strongly recommended for estimating the fracture gradient. If LOT data are unavailable for the field in question, determine the stress ratio from adjoining fields and regional datasets rather than relying on sonic- and gamma-ray-based stress ratios, which may provide a lower bound for the fracture pressure gradient. This aligns well with FITs, which are recorded within the elastic limit of rocks. In an HP campaign with coupled FG, sonic- and gamma-ray-based methods can inadvertently reduce the drilling margin and, in turn, reduce hydrocarbon retention capacity, especially at the boundary between elastic and anelastic environments. But in an HP campaign such as the one in S Deep, the solidity and VES approach could be appropriate for determining the lower bound of fracture pressure in real time, which is critical to drilling the well.

16. Conclusions

Drilling experience shows that fracture stress prediction based on Poisson's ratio estimates from both sonic and gamma ray tends to underpredict. Assessment of in situ Poisson's ratio derived from leak-off tests and corresponding fluid pressure measurements in the Niger Delta, a Tertiary basin, shows that in situ Poisson's ratio decreases more slowly than alternative Poisson's ratio determination methods suggest. In situ Poisson's ratio measurements show that stress-ratio calibration based on conventional Poisson's ratio approaches is unsuitable and may significantly underestimate fracture pressure. The LOT-based effective stress ratio used to estimate fracture stress more closely matches the actual well results and is recommended for future well planning in the Niger Delta. When estimating fracture gradients in sands, consideration should always be given to stress coupling between PP-FG and its effective stress ratio. Failure to take this step leads to a severe underestimation of formation strength. The drilling margin estimates can be optimised; otherwise, they will be termed a low drilling margin if the fracture pressure gradient is underestimated in overpressured sands, affecting well design and, in turn, the exploration depth that can be reached.

Real-time pore pressure prediction based on a constant, uncoupled Poisson's ratio underpredicts fracture stress in overpressured sands because it assumes a constant Poisson's ratio of 0.27. With an LWD Density tool in the drilling assembly, one can evaluate porosity and, in turn, fracture stress while drilling. In the absence of field LOT, it is appropriate to use regional LOT to estimate the effective stress ratio and relate it to the fracture pressure gradient. Where available, measured FITs can be used to calibrate estimates from Gamma ray and sonic velocity, both of which are within elastic limits. This provides a lower bound and can be used for hydrostatic environments, but not for overpressures.

Nomenclature

HP = high pressure
LWD = logging while drilling
LOT = leak-off test
FIT = formation integrity test
ECD = equivalent circulating density
MW = mud weight
VES = vertical effective stress
KB = kelly bushing
 S_v = overburden stress gradient
ESR = effective stress ratio
OP = overpressure
PSDM = post-stack depth migration
PP = pore pressure
OP = overpressure
OBP = overburden pressure
OBS = overburden stress
SIDPP = shut-in drill pipe pressure
PPP = pore pressure prediction
ftah = feet along hole
PPP = pore pressure prediction
Ko = effective stress ratio
Sh = minimum horizontal stress
PP-FG = pore pressure gradient, fracture gradient
ECD = equivalent circulating density
BHA = bottom hole assembly
EMW = equivalent mud weight
LCM = lost circulation material
GR = gamma ray
RES = resistivity
LOP = leak-off pressure
FFG = formation fracture gradient
RCI = reservoir characterization instrument

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Author Profile



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