Technical Evaluation of Formation Damage Remediation in Niger Delta Clastic Reservoirs

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Abstract

Formation damage continues to pose a significant challenge in hydrocarbon extraction, substantially hindering the productivity of reservoirs by diminishing the inherent permeability of the rock formations. This issue, which arises during drilling, production, or workover activities, results in subpar recovery efficiencies and considerable financial repercussions. The present investigation undertook a thorough technical assessment of formation damage and its remedial approaches for a well situated in the Niger Delta. In this study, pressure transient analyses were conducted on the buildup tests of Well P, both prior to and following acidization treatment.The PTA of Well P before acidizing revealed a positive skin value of +6.11 and a permeability of 3.15 mD, confirming the presence of considerable formation damage in the vicinity of the wellbore. To counteract this damage, a matrix acidizing treatment was executed, aimed at dissolving materials obstructing the pores and reinstating permeability. Post-treatment analysis indicated a skin factor of -0.658 and an improved permeability of 11.9 mD, signifying successful well stimulation and enhanced inflow performance. This research highlights the effectiveness of acidizing as a remedial measure in the clastic reservoirs of the Niger Delta, while also stressing the importance of combining technical diagnostics with economic assessments to enhance production efficiency and maximize asset value.

Introduction

Formation damage, a pivotal concept within the petroleum industry, pertains to the detrimental interplay between drilling activities and the productive formation. Such interplay results in a diminishment of permeability in the vicinity of the wellbore, thereby ultimately diminishing the productivity of the well. This phenomenon represents a widespread challenge encountered throughout the processes of well-drilling, completion, production, and workover within the petroleum sector.

Bennion (2002) posits that formation damage refers to any process that degrades the inherent productivity of an oil or gas reservoir or the injectivity of a water or gas injection well. This study adopts the Niger Delta as a case in point. Klungtvedt and Saasen (2022) indicate that during drilling activities, interaction with drilling fluids can impair the formation's capacity for production or fluid flow. Dake (1978) describes the incursion of foreign fluids into the reservoir rock as creating a zone of diminished permeability within the wellbore, termed the "skin." It is important to note that formation damage is not exclusively a consequence of drilling or completion activities; rather, it arises from a multitude of intricate reservoir processes (Clifford 2019).

In the development process, when the formation interacts with external fluids, physical and chemical reactions may occur if these fluids are incompatible with the reservoir fluids or mineral properties. These reactions can significantly impact the formation's productivity. The Niger Delta formation consists mainly of sandstone. As

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reported, the porosity of sandstone formations ranges from 10% to 35% due to the loose packing of individual sand or mineral grains. Raza et al. (2015) have shown that the permeability of sandstone reservoirs typically ranges between 0.4 md and 60 md. However, Fatt (1953) demonstrated that the application of overburden pressure decreases the permeability and porosity of sandstone reservoirs. Consequently, the Niger Delta region is characterized by relatively good porosity and permeability properties.

Formation damage can be triggered by various factors and can occur at any stage of a well's life. These factors affect the permeability of reservoir rocks, thereby reducing the natural productivity of the reservoir. To effectively evaluate formation damage, it is essential to investigate its root causes. This investigation is crucial for making informed decisions regarding the remedial actions to be taken on the well. Factors contributing to formation damage include erosion, chemical weathering, fluid injection, and overburden pressure.

The technical evaluation of formation damage demands a multidisciplinary approach due to its complexity. Engineers can employ different strategies to address the problem of a damaged formation. A professional and in-depth understanding of formation damage is required to analyze data and solve problems accurately and comprehensively.

Formation damage can result in substantial costs for remediation and deferred production (Oseh et al. 2015). Economic evaluation involves conducting a cost-benefit analysis of the financial impact. This includes assessing the lost revenue due to the reduced production rate caused by formation damage and the revenue generated from hydrocarbon production in the reservoir. Once formation damage occurs, the reservoir generally cannot return to its original state. The phenomenon where substances that enter the porous media do not easily exit is known as the reverse funnel effect (Porter 1989).

Well testing is an effective method for determining whether a formation is damaged. By analyzing transient well-test data, the skin factor can be obtained (Renpu 2011). Pressure transient analysis, which involves the analysis of pressure and flow data sets, extracts information from pressure and rate data measured in a producing well (Alain 2018). Well testing can directly assess the degree of damage by matching a model (either analytical or numerical) of the well and reservoir to the data (Zarrouk and McLean 2019). Pressure transient analysis is one of the most valuable tools for evaluating formation damage (Denson et al. 2015). Well testing is primarily conducted to obtain information on the formation's permeability and skin factor, which helps in assessing well conditions and estimating reservoir parameters.

Methodology

The methodology employed in this study is well testing, a fundamental technique in petroleum engineering that involves measuring flow rates and pressure changes during production or injection tests. Among the various types of well-testing methods, this research focuses specifically on the pressure buildup well test.

A pressure buildup test entails the measurement and analysis of bottom-hole pressure data after a producing well is shut in. In this study, pressure transient analysis was performed using KAPPA Saphir^{TM} (developed by KAPPA Engineering), a reservoir modeling software, to characterize reservoir parameters, including permeability and skin factor. The data required for the analysis is stored in a spreadsheet, typically in Microsoft Excel format. This spreadsheet contains detailed information such as the pressure and time data collected during the test, along with other essential parameters necessary for a comprehensive analysis. Additionally, it includes the flow-rate data of the well and the pressures recorded with respect to time before the well was shut in. The process of loading data into the Kappa Saphir^{TM} software for pressure transient analysis involves two key aspects: loading flow-rate data and loading pressure data.

Loading Flow-rate Data. For the flow-rate data, which is measured in standard barrels per day (STB/D), it is sourced from a spreadsheet, usually in Microsoft Excel format. Once the software is set up with the correct data types and units, the "free" option is chosen in the format region. After specifying the appropriate time format for the flow-rate data, it is imported into the Kappa Saphir software. Once loaded, the flow-rate data is presented in a history plot, enabling a visual representation of how the flow rate changes over time.

Loading Pressure Data. Regarding the pressure data, it is also retrieved from an Excel spreadsheet. The data is organized in a two-column layout, with the first column showing time in hours and the second column presenting pressure in pounds per square inch absolute (psia). In the software, the relevant field is selected, and the correct data types and units are specified. The appropriate time format for the pressure data is then chosen. After importing the pressure data, a history plot is generated, plotting the pressure change against time. This plot helps in observing the pressure behavior during the test.

After successfully importing the data into the software, several plots are generated, including the history plot, the Horner plot, and the log-log plot. These plots are invaluable for extracting the required reservoir parameters, such as permeability and skin factor. The permeability value provides insights into the state of the permeable spaces within the reservoir, while the skin factor serves as an indicator of well damage. A skin factor of zero indicates no damage, a negative value suggests well stimulation, and a positive value implies formation damage. By analyzing these values, it is possible to quantify the extent of damage inflicted on the formation.

Results And Discussions

Pressure Transient Analysis on Well P. The reservoir rock, fluid, and wellbore parameters for Well P (**Table 1**) provide foundational insights into the reservoir's physical characteristics and fluid behavior, critical for interpreting pressure transient analysis. The reservoir thickness (h=200 ft) and porosity (φ=0.30) define a volumetrically significant formation with substantial hydrocarbon storage potential, given the high porosity—indicating 30% of the rock volume is pore space. This porosity, combined with the oil viscosity (μ = 0.8 cp), suggests favorable fluid mobility, as low viscosity reduces resistance to flow through the reservoir. The total compressibility ($C_t=3\times10^{-6}$ psi^{-1}) reflects minimal fluid and rock compression under pressure, which influences pressure propagation during transient tests. The oil formation volume factor (B_o=1.136 rb/stb) quantifies the expansion of oil from reservoir to surface conditions, aiding in converting subsurface volumes to stock-tank barrels for production calculations.

Additionally, the wellbore radius (r_i=0.345 ft) directly impacts near-wellbore flow dynamics and skin effect calculations, which are essential for evaluating formation damage or stimulation efficiency. Together, these parameters underpin the reservoir's storage capacity ($\varphi\cdot h$), fluid mobility (μ), and transient pressure response (governed by compressibility and viscosity), forming the basis for modeling well performance and optimizing acidizing interventions to enhance productivity.

Table 1—Parameters used for pressure transient analysis.

Reservoir rock parameters for well P	
Reservoir thickness (h)	200ft
Reservoir porosity (ϕ)	0.30
The PVT Parameters for well P	
Oil viscosity (μ)	0.8cp
Total compressibility of fluid (C_t)	$3E^{-6}ps^{-1}$
Oil formation volume factor (B_o)	1.136rb/stb
The wellbore parameters	
Wellbore radius (r_w)	0.345ft

The chosen interpretation models for pressure transient analysis (PTA) of Well P (**Table 2**) reflect a streamlined, conventional approach tailored to the well's characteristics. The standard model was selected, indicating reliance on established methodologies for vertical wells in a homogeneous reservoir with finite boundaries, simplifying the analysis by assuming uniform reservoir properties and a defined spatial extent. The single-phase oil flow assumption aligns with the reservoir's fluid phase, allowing straightforward interpretation of pressure responses without complexities from multiphase interactions. A single flow rate during testing further reduces variables, enabling consistent analysis of transient data under steady production conditions. The assumption of constant wellbore storage and skin implies stable near-wellbore dynamics during the test, which simplifies early-time pressure data interpretation but may overlook transient changes in formation damage or stimulation effects over longer durations. Together, these choices prioritize analytical simplicity and clarity, ideal for assessing baseline reservoir performance and evaluating acidizing impacts. However, homogeneity and finite boundary assumptions may limit the model's ability to capture reservoir heterogeneities or long-term boundary effects, underscoring the need for complementary analyses if complex behaviors emerge post-acidizing.

Table 2—Interpretation model for PTA of well P before and after acidizing.

Interpretation models	**Chosen interpretation models**
Model option	Standard model
Well type	Vertical
Reservoir	Homogenous
Boundary	Finite
Fluid phase	Oil
Fluid flow rate	Single flowrate
Wellbore storage and skin	Constant

Table A within the Appendix furnishes the detailed pressure buildup test data acquired from Well P prior to the acidization procedure. The pressure buildup tests conducted on Well P prior to and after acidization (**Table 3**) elucidate significant operational and performance disparities.Before acidizing, the test spanned 57 hours (July 11-14, 2022) with a liquid rate of 1,000 STB/d at shut-in, reflecting a prolonged period likely required to assess pressure recovery in a damaged well with restricted flow. Post-acidizing, the test duration shortened dramatically to 10 hours (October 22, 2022) under a higher liquid rate of 1,100 STB/d, signaling improved near-wellbore permeability and faster pressure stabilization due to reduced formation damage. The zero-rate shut-in during both tests ensured accurate measurement of reservoir pressure response, while the use of a single gauge-maintained data consistency. The shorter test duration post-acidizing underscores the treatment's success in mitigating skin effects, enabling quicker reservoir evaluation and aligning with the increased production rate—a direct indicator of enhanced well productivity. These results highlight the acidizing intervention's effectiveness in optimizing both operational efficiency and reservoir performance.

Table 3—History listings of the pressure buildup test before and after acidizing

	Before acidizing	After acidizing
Name of well	Well P	Well P
Name of test	Buildup test	Buildup test
Start date of buildup test	07/11/2022	10/22/2022
End date of buildup test	07/14/2022	10/22/2022
Time at start date of buildup test	03:00:17	12:00:00
Liquid rate at start time (STB/d)	1000	1100
Liquid rate at shut-in time	0	0
Duration of buildup test	57.0277	10.00
No of gauges used for the test	Single gauge	Single gauge

PTA Result Analysis on Well P Before Acidizing. Figure 1 presents a historical plot of pressure (measured in psia) and liquid rate (in STB/d) against time (in hours) prior to acidizing. This plot effectively depicts two key aspects: the relationship between pressure and time, as well as the flowrate of the test over time.

When examining the flow-rate plot, a distinct pattern emerges. During the initial flowing period, which lasts approximately 75 hours, there is a noticeable decline in pressure. This pressure decline is a characteristic phenomenon associated with the production of crude oil from the reservoir. As the oil is being extracted, the reservoir pressure gradually drops, which is a natural consequence of the reduction in the fluid volume within the reservoir.

After the 75-hour flowing period, the well is shut in. Subsequently, a pressure build - up occurs over a period of 57 hours, which is the duration of the shut-in period. This process of pressure build - up after shutting in the well is the basis for what is known as a pressure buildup test. This test is crucial in petroleum engineering as it provides valuable insights into the reservoir's properties, such as permeability and the presence of boundaries.

In summary, the figure offers a clear visual representation of the reservoir's behavior during the production phase (pressure decline) and the subsequent shut - in phase (pressure build - up), highlighting the key stages of a pressure buildup test before acidizing the well.

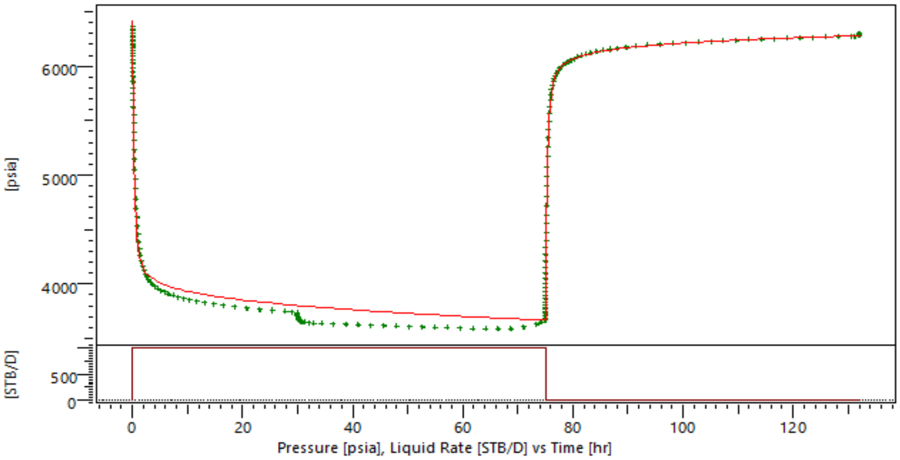

Figure 1—The history plot of pressure (psia), liquid rate (STB/d) vs time (hrs) before acidizing.

Figure 2 illustrates a Horner plot delineating the correlation between bottom-hole pressure (expressed in psia) and the logarithmic function of (tp+dt)/dt. The alignment of the data points on this plot with the derivative curve is a critical indicator. This congruence substantiates the robustness of the model, offering a firm basis for conducting thorough and dependable analyses. Consequently, we can exhibit a high degree of confidence in the precision of the outcomes yielded by this model.

The Horner plot serves a fundamental purpose in facilitating the computation of critical reservoir parameters. Through the examination of the curve's slope on the plot, engineers can precisely ascertain the permeability of the reservoir. Permeability, a crucial attribute, characterizes the ease with which fluids traverse the rock formation and is imperative for comprehending reservoir productivity. Furthermore, the plot allows for the determination of the skin factor, which quantifies the extent of damage or improvement in the vicinity of the wellbore, exerting a substantial influence on well performance.

Furthermore, the Horner plot constitutes a valuable instrument for the identification of various flow regimes encountered during well testing. These flow regimes, encompassing the early transient, transient, late transient, and pseudo-steady-state periods, each exhibit unique characteristics indicative of the fluid flow behavior within the reservoir. The recognition of these flow regimes is imperative for reservoir engineers, as it facilitates the optimization of well production strategies, the prediction of reservoir performance, and the making of informed decisions pertaining to reservoir management.

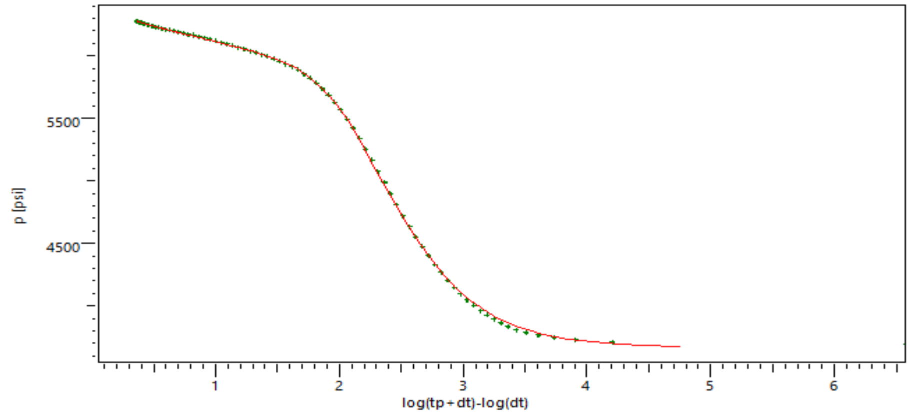

Figure 2—Horner plot of bottomhole pressure vs log (tp+dt/dt) before acidizing.

Figure 3 illustrates a logarithmic scale graph depicting the correlation between differential pressure, pressure derivatives, and time (measured in hours). The curve positioned at the top of the graph signifies the pressure derivative (dp) plotted against time, whereas the curve located at the bottom corresponds to an additional pressure derivative (dp’) also plotted against time.

Within the domain of petroleum engineering, the log-log plot is of paramount importance in ascertaining the wellbore storage constant (C). The concept of wellbore storage, which pertains to the retention and subsequent release of fluids within the wellbore under transient flow conditions, is fundamental. Through the examination of the curve characteristics on this log-log plot, engineers can precisely determine the value of C, a critical factor for comprehending well behavior and forecasting reservoir performance.

Additionally, the vertical divergence between the two curves on the logarithmic scale plot has substantial implications for the skin factor. The skin factor is a quantifiable parameter that characterizes alterations in the vicinity of the wellbore resulting from factors such as formation damage or stimulation. A more pronounced vertical divergence between the two curves signifies a greater value of the skin factor. This correlation enables engineers to evaluate the extent of near-wellbore damage or improvement, which subsequently affects well productivity and the efficacy of reservoir management strategies. Thus, the log-log plot depicted in Figure 3 offers significant insights into wellbore storage and conditions in the vicinity of the wellbore, facilitating more precise reservoir characterization and optimization of well performance.

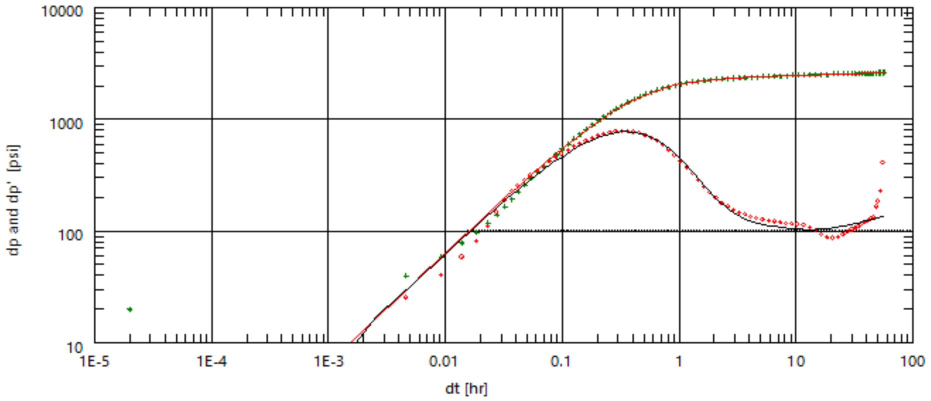

Figure 3—Log-Log plot of differential pressure (dp) and pressure derivative (dp') vs Dt (hrs) before acidizing.

The results from the pressure transient analysis before acidizing reveal critical insights into the well's performance and reservoir characteristics (**Table 4**). The total skin factor of 6.11 indicates significant near-wellbore formation damage, which directly contributes to a pressure drop (ΔP) of 1,243.59 psi due to restricted flow efficiency. This damage underscores the necessity of acidizing to mitigate productivity losses. The reservoir's low permeability (3.15 md) and moderate permeability-thickness product (kh= 631 md·ft) suggest a thick but tight formation (~200 ft net pay), inherently limiting fluid flow despite the high initial reservoir pressure of 6,417.58 psia, which signals strong reservoir potential if damage is alleviated. The drainage radius of 214 ft and tested volume of 7.05 MMB further define the accessible reservoir volume, emphasizing the scale of recoverable resources. Combined, these parameters highlight a reservoir constrained by both natural tightness and induced damage, positioning acidizing as a critical intervention to enhance connectivity, reduce skin, and unlock the well's productivity aligned with the reservoir's high-pressure potential.

Table 4—Results of pressure transient analysis before acidizing.

Model Parameters	Values	Units
TMatch	31.7	$[hr]^{-1}$
PMatch	0.00492	$[psia]^{-1}$
C	0.00734	bbl/psi
Total skin	6.11	
kh	631	md×ft
pi	6417.58	psia
Wellbore parameters (tested well)		
C	0.00734	bbl/psi
Skin (s)	6.11	
Reservoir and boundary parameters		
Initial reservoir pressure	6417.58	psia
Permeability thickness product (k*h)	631	md×ft
Permeability (k)	3.15	md
Derived and secondary parameters		
Drainage radius (re)	214	ft
Tested volume	7.0514	MMB
Delta P (Total skin)	1243.59	psi

PTA Result Analysis on Well P After Acidizing. **Figure 5** depicts a dual-axis graph illustrating the relationship between bottom-hole pressure (in psia) and liquid flow rate (in STB/d) over time (in hours) during a well test. The analysis of the pressure transient reveals a 14-hour shut-in phase, wherein the well was sealed, resulting in a distinctive pressure buildup curve—a defining feature of a pressure buildup (PBU) test. The evaluation of near-wellbore conditions, reservoir permeability, and skin effects is critically dependent on this test, which analyzes the pressure recovery response subsequent to the cessation of production. The flow rate axis corroborates the shut-in event (0 STB/d) and offers context for the production rate prior to shut-in. The pressure buildup observed over a 14-hour period equips engineers with the means to ascertain crucial reservoir parameters, including formation transmissibility and initial reservoir pressure, which are indispensable for the optimization of subsequent interventions such as acidizing. This analysis highlights the pivotal role of the PBU test in diagnosing well performance and in guiding strategies for reservoir management.

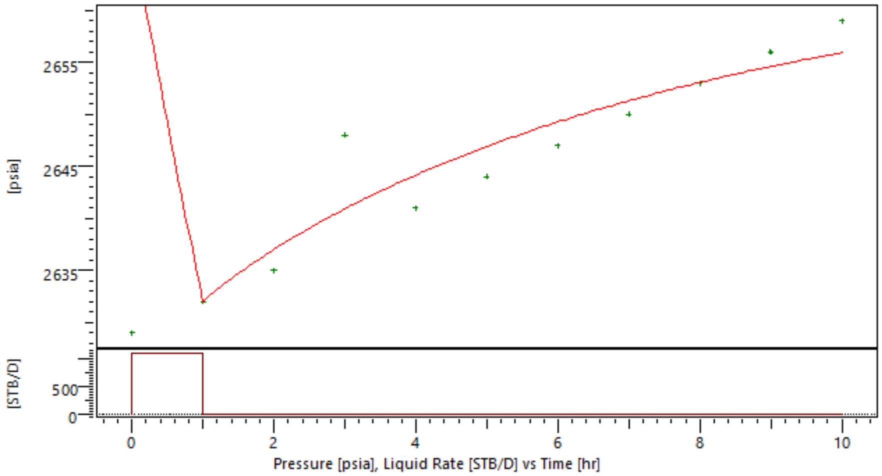

Figure 5—The history plot of pressure, liquid rate vs time after acidizing.

Figure 6, which depicts a Horner plot, is evident that the data points correspond well with the derivative curve, indicating that the model is robust and suitable for our analysis. This facilitates the derivation of reliable results. The plot is instrumental in determining parameters such as permeability from its slope and the skin factor. Furthermore, the Horner plot enables the identification of various flow regimes pertinent to well testing, encompassing the early transient, transient, late transient, and pseudo-steady state periods.

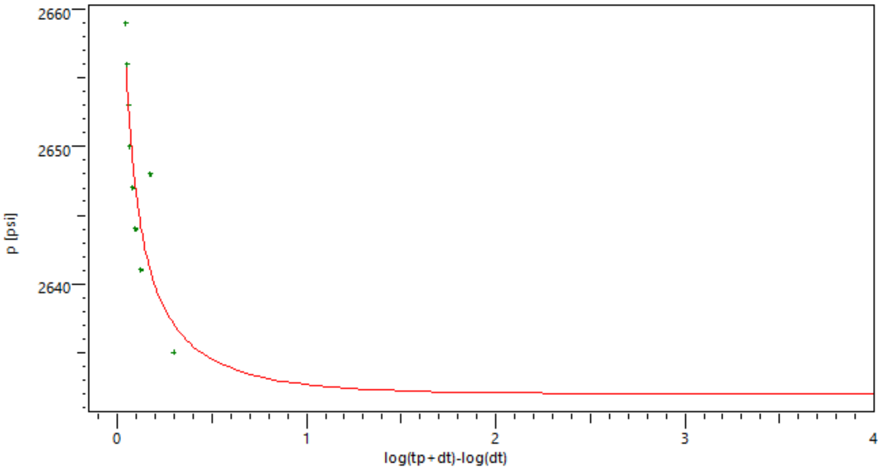

Figure 6—Semilog plot of bottomhole pressure vs. log (tp+dt/dt) after acidizing.

Figure 7 illustrates the differential pressure and pressure derivative as a function of time in hours. The upper curve corresponds to the pressure derivative (dp) plotted against time (hrs), whereas the lower curve represents the pressure derivative (dp') as a function of time (hrs). The log-log plot facilitates the calculation of the well bore storage constant (C). Additionally, it is understood that the vertical separation between the two plots is indicative of the skin factor, with a greater separation corresponding to a higher value of the skin factor.

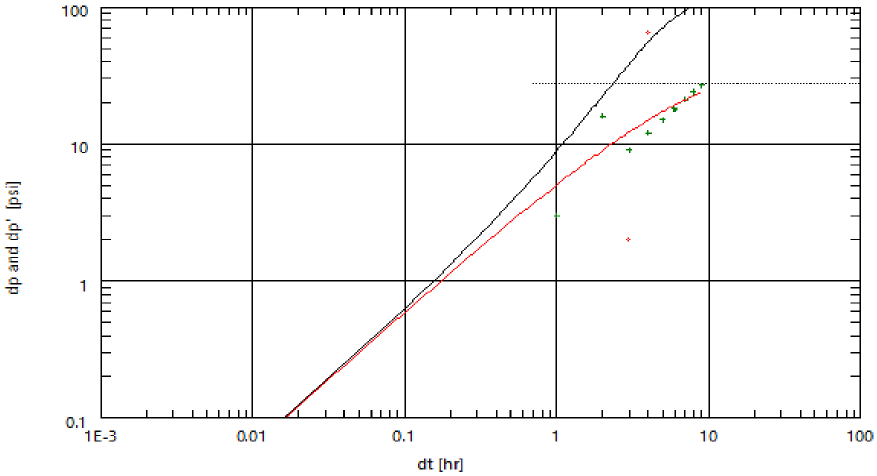

Figure 7—Log-log plot of differential pressure and pressure derivative vs. dt after acidizing.

Table 5 provides a detailed analysis of the permeability results following the acidification treatment of Well P. The data presented in this table indicates that the permeability of the well has been measured to be 11.9 millidarcies (md). This value represents the ease with which fluids can flow through the rock formations surrounding the wellbore. Additionally, the initial reservoir pressure was recorded at an impressive 2667.83 pounds per square inch absolute (psia), reflecting the high energy status of the reservoir before any production activities commenced.

Furthermore, the skin factor, a dimensionless parameter used to evaluate the condition of the wellbore and the near-wellbore formation, was calculated to be -0.658. A negative skin factor suggests that the acidification treatment has been successful in improving the permeability around the wellbore by removing or reducing damage caused by drilling muds, scales, or other factors that might have impeded fluid flow. This indicates an overall improvement in the well's performance due to the treatment.

Lastly, the wellbore storage coefficient was estimated to be 1.23 barrels per psi (bbl/psi). This coefficient quantifies the volume of fluid that the wellbore can store per unit of pressure change and is crucial for understanding the well's response to pressure changes during production or injection operations. A lower value of this coefficient implies that the wellbore is more efficient in transmitting reservoir pressure changes to the formation, which is generally a favorable characteristic for well performance.

Table 5—Results of pressure transient analysis from Saphir after acidizing.

Model Parameters	Values	Units
TMatch	0.71	$[hr]^{-1}$
PMatch	0.0181	$[psia]^{-1}$
C	1.23	bbl/psi
Total skin	-0.658	
kh	2390	md×ft
p_i	2667.83	psia
Wellbore parameters (tested well)		
C	1.23	bbl/psi
Skin (s)	-0.658	
Reservoir and boundary parameters		
Initial reservoir pressure	2667.83	psia
Permeability thickness product (kh)	2390	md×ft
Permeability (k)	11.9	md
Derived and secondary parameters		
Drainage radius (re)	214	ft
Tested volume	7.0514	MMB

PTA Result Comparison. Table 6 provides a detailed summary and comparison of three crucial parameters—permeability, skin factor, and wellbore storage coefficient—derived from the Pressure Transient Analysis (PTA) conducted on Well P both before and after the acidizing treatment. The data presented in this table clearly illustrate that the acidizing process has significantly improved the fluid flow characteristics in the vicinity of the wellbore. Specifically, there is a notable enhancement in permeability, which indicates a greater ease of fluid movement through the reservoir rock. Additionally, the skin factor, which is a measure of the near-wellbore damage or improvement, has decreased substantially, suggesting that the acidizing treatment has effectively reduced any damage and improved the well's productivity. Furthermore, the wellbore storage coefficient, which reflects the ability of the wellbore to store fluids, has also been positively impacted by the treatment. Overall, these findings unequivocally demonstrate that the acidizing treatment has successfully enhanced the production capacity of Well P by improving the fluid flow conditions near the wellbore.

Table 6—Results of reservoir and wellbore parameters from Saphir before and after acidizing Well P.

Parameters	Before acidizing	After acidizing	Units
Permeability (k)	3.15	11.9	md
Skin factor (s)	6.11	-0.658	-
Wellbore storage coefficient (C)	0.00734	1.23	bbl/psi

Conclusion

Formation damage has been identified as the blockage of the permeable spaces of a reservoir. Technical evaluation has given room to professionally analyze a Niger Delta well from this project having a deep knowledge of what formation damage is and the properties of a Niger Delta formation which gave guide in validation of the results obtained during the analysis. The skin factor obtained before acidizing the well and Permeability value proved that the well was damaged. From the results obtained after acidizing the well, it has shown that acidization is one of the effective remedial actions that can be carried out on a sandstone formation to improve permeability and productivity of a well.

Conflicting Interests

The author(s) declare that they have no conflicting interests.

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Appendix

Table A—Field data obtained from Well P before acidizing.

Δt (hrs)	Pws (psia)	tp+Δt/Δt	Q (STB/D)
0	6363.499		1000
0.00462	6342.726	16452.21212	1000
0.00924	6322.22	8226.606061	1000
0.01386	6301.943	5484.737374	1000
0.01848	6281.922	4113.80303	1000
0.0231	6262.127	3291.242424	1000
0.02772	6242.543	2742.868687	1000
0.03234	6223.182	2351.17316	1000
0.03696	6204.043	2057.401515	1000
0.04158	6185.135	1828.912458	1000
0.046654	6164.6	1630.128704	1000
0.052346	6141.827	1452.962465	1000
0.058733	6116.618	1295.062921	1000
0.0659	6088.786	1154.334789	1000
0.073941	6058.109	1028.910712	1000
0.082963	6024.368	917.1263887	1000
0.093086	5987.331	817.4985023	1000
0.104444	5946.758	728.7050554	1000
0.117188	5902.442	649.567816	1000
0.131488	5854.136	579.0366735	1000
0.147531	5801.723	516.175728	1000
0.165533	5745.04	460.1508488	1000
1.044442	4453.707	73.77050568	1000
1.171884	4383.539	65.85678143	1000
1.314875	4319.707	58.80366731	1000
89.75314	6175.142	1.846818277	1000
91.5533	6184.132	1.830167817	1000

93.5731	6192.292	1.812248359	1000
95.83937	6199.78	1.793041564	1000
98.14937	6206.715	1.774376888	1000
100.4594	6213.18	1.756570578	1000
102.7694	6219.24	1.739564751	1000
105.0794	6224.957	1.723306615	1000
107.3894	6230.368	1.707747921	1000
109.6994	6235.504	1.692844483	1000
112.0094	6240.396	1.678555761	1000
114.3194	6245.07	1.66484449	1000
116.6294	6249.548	1.651676358	1000
118.9394	6253.84	1.639019721	1000
121.2494	6257.961	1.626845344	1000
123.5594	6261.924	1.615126177	1000
125.8694	6265.742	1.60383716	1000
128.1794	6269.428	1.592955035	1000
130.4894	6272.985	1.582458194	1000
131.2447	6276.422	1.579106128	1000
132.0000	6279.745	1.575792424	1000
132.0046	6282.961	1.575772272	1000
132.0092	6286.076	1.575752122	1000
132.0139	6289.097	1.575731972	1000
132.0185	6292.03	1.575711825	1000
132.0231	6294.876	1.575691678	1000
132.0277	6297.639	1.575671533	1000
132.0323	6300.324	1.57565139	1000