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Internal corrosion behaviour of Nigerian gas pipelines: a CFD simulation approach

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Abstract
Internal corrosion poses a critical threat to the reliability and safety of oil and gas pipelines in Nigeria, contributing significantly to operational downtime, environmental hazards, and maintenance costs. This study investigates internal corrosion behavior within Nigerian gas pipelines, focusing on a segment of the Ajaokuta–Kaduna–Kano (AKK) corridor, using Computational Fluid Dynamics (CFD) simulations. The simulation incorporates multiphase flow conditions, fluid composition (85% crude oil, 10% Natural Gas Liquids, 5% water and impurities), and operational parameters representative of Nigerian inland pipelines. Results reveal that high-velocity zones (12.91–16.14 m/s) and regions of elevated turbulence intensity (1.26–2.07 m^2/s^2) correlate with peak corrosion rates ranging from 0.13 mm/yr to 0.44 mm/yr. These findings identify flow-induced shear stress and localized turbulence as major drivers of uniform internal corrosion. Specific mitigation strategies are proposed, including targeted dosing of amine-based inhibitors (10–25 ppm) and optimized pigging operations at 2–3 month intervals. The study offers Nigeria-specific insights into corrosion dynamics and demonstrates the value of CFD modeling for proactive pipeline integrity management. Experimental validation is planned for future work to enhance the predictive reliability of the model.

Keywords: Computational Fluid Dynamics (CFD), Internal Corrosion, Multiphase Flow, Corrosion Mitigation, Turbulence Effects

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1. Introduction

Oil and gas pipelines serve as the critical infrastructure for hydrocarbon transportation in Nigeria, enabling the movement of crude oil and natural gas from extraction sites in the Niger Delta to refineries and industrial centers nationwide. The Nigerian National Petroleum Company Limited (NNPCL) manages over 5,000 km of pipelines, underscoring their importance to the nation's economic stability and energy security. However, internal corrosion remains a persistent challenge, contributing significantly to production losses, environmental degradation, and costly repairs. Reports from the Department of Petroleum Resources (DPR) and the Nigerian Midstream and Downstream Petroleum Regulatory Authority (NMDPRA) indicate that corrosion accounts for over 40% of recorded pipeline failure incidents annually (NMDPRA, 2023).

Several factors influence internal corrosion, including fluid composition, operating pressure, temperature, and multiphase flow dynamics. Nigerian pipelines are particularly vulnerable due to the transportation of unprocessed crude containing corrosive species such as carbon dioxide (CO_2), hydrogen sulfide (H_2S), and water, coupled with inconsistent application of corrosion inhibitors. Traditional inspection techniques, such as ultrasonic testing and magnetic flux leakage, while valuable, are reactive and often unsuitable for predictive maintenance, especially in regions with limited accessibility and aging infrastructure.

This study leverages Computational Fluid Dynamics (CFD) simulations to model internal corrosion behavior under realistic multiphase flow conditions within a section of the Ajaokuta–Kaduna–Kano (AKK) pipeline. By analyzing key parameters such as turbulence intensity, wall shear stress, and pressure gradients, the research aims to identify critical zones susceptible to corrosion. Previous studies (Adegboye *et al*., 2019; Obike *et al*., 2020) have demonstrated the utility of CFD in pipeline corrosion assessment; however, most have relied on generic pipeline configurations or datasets lacking relevance to Nigeria's operational realities.

What distinguishes this study is its use of high-fidelity CFD simulations specifically tailored to the operational and environmental conditions of Nigerian pipelines. Unlike existing models, this research integrates field-representative parameters, including fluid compositions, operational pressures, and inland pipeline characteristics typical of the AKK corridor. Moreover, the study addresses the notable scarcity of Nigeria-specific CFD corrosion analyses by providing original simulation data intended to inform targeted mitigation planning and predictive maintenance strategies.

Despite extensive global research on internal corrosion, there is a lack of Nigeria-specific studies that incorporate multiphase flow modeling with field-representative operational parameters. This study fills that gap by presenting a localized CFD-based analysis of corrosion dynamics, offering insights that are both technically robust and practically applicable. Furthermore, the study innovatively combines flow dynamics, corrosion susceptibility mapping, and operational recommendations to support proactive pipeline integrity management in Nigeria.

2.0 Materials and methods

This study focuses on internal corrosion analysis in gas pipelines by using Computational Fluid Dynamics (CFD) simulations. The methodology includes flow-based corrosion modeling and feature extraction.

2.1 Research Workflow

The methodology follows a structured workflow for internal corrosion analysis shown in Figure 1.

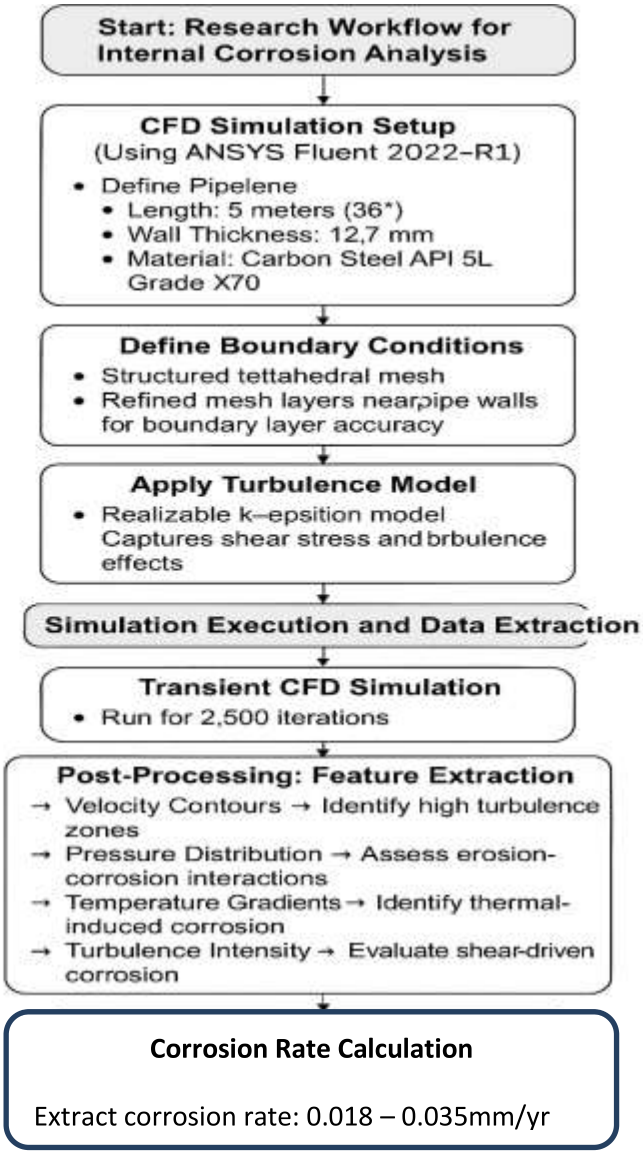

Figure 1: Flowchart for the Analysis of the Internal Corrosion Rate

The steps and processes for the corrosion simulation on ANSYS are summarized in Table 1.

Table 1: Steps and Processes for Carrying Out a Uniform Corrosion Simulation on ANSYS Fluent

Simulation Phase	Sub-activities	Extra Details
Preprocessing	Geometry Import	The pipeline model was modelled in SolidWorks before being imported into ANSYS Fluent (2022 -R1 Version). As such, the geometry that was designed to accurately represent the pipeline's dimensions and features (as seen in Figure 3.1)
	Mesh Generation	An appropriate mesh for the pipeline geometry was then generated using ANSYS Meshing. This included defining mesh characteristics like quality and resolution (sizing), particularly near the pipeline wall where corrosion is expected to occur.
	Boundary Conditions	Necessary boundary conditions for the simulation, including inlet and outlet conditions, fluid properties (e.g., petroleum flow rate, temperature, pressure), and turbulence model specifications were

		all inputted into the modelling process.
	Material Properties	The material properties of the steel pipeline were also duly specified during modelling, including its composition, density, mechanical properties, etc.
Setting Up Corrosion Model	Enabling Corrosion Model	The corrosion model in ANSYS Fluent was activated, and the appropriate corrosion model for uniform corrosion simulation was selected.
	Corrosion Properties	The corrosion properties of the steel pipeline material were defined, such as corrosion rate, initial thickness, corrosion behaviour parameters, etc.
	Initial Conditions	Initial conditions for the simulation, including the initial thickness of the pipeline wall and any initial corrosion layer thickness were all set.
Numerical Solution	Solver Settings	The solver settings for the simulation were configured, including solution methods, convergence criteria, and discretization schemes.
	Solution Initialization	The solution for solving the fluid flow and corrosion equations using the specified boundary conditions and initial conditions was then initialized.
	Transient Specification	Considering that the corrosion process is time-dependent, the simulation was set up as a transient analysis by specifying the time step size and total simulation time.
Post-processing	Visualization	The simulation results were then visualized using ANSYS Fluent's post-processing tools. Plots of variables such as corrosion rate, thickness loss, and corrosion profile were then made to analyze the progression of corrosion over time.
	Data Extraction	Quantitative data were then extracted from the simulation results, such as maximum corrosion depth, average corrosion rate, and other relevant parameters.

2.3 Operating Conditions and Corrosion Assumptions

The study considered **five locations** along the **Ajaokuta-Kaduna-Kano (AKK) gas pipeline**, analyzing **fluid properties and operational conditions**. The operating parameters for the pipelines are shown in Table 2.

Table 2: Pipeline Operating Parameters

Parameter	**Value**
Flow Rate	3,000 barrels per day (bpd)
Flow Velocity	2 m/s
Operating Pressure	10 MPa (100 bar)
Flow Temperature	40°C (313.15 K)
Fluid pH	6.5 (slightly acidic)

Parameter	Value
Chemical Composition	85% Crude oil, 10% NGLs, 5% Water & Impurities

2.3.1 Internal Corrosion Assumptions

The following assumptions were employed;

- i. Uniform corrosion was assumed for internal corrosion evaluation.
- ii. Pipeline section length: 5m was used for simulation consistency.
- iii. No direct exposure to coastal environments, as the AKK pipeline is inland.

2.4 Software and Computational Resources

The following software were employed for this research work:

- a. **CFD Simulations:** Performed using ANSYS Fluent 2022-R1.
- b. **ML Model Training:** Conducted using Python (Anaconda, TensorFlow, and Scikit-Learn libraries).

Hardware:

- **Device:** HP Elite Dragonfly G2 Notebook PC
- **Processor:** Intel® Core i5-1145G7 @ 2.60GHz
- **RAM:** 16.0GB

2.5 CFD Input Data and Model Validation

The CFD simulation employed in this study was developed using a combination of pipeline-specific design parameters and environmental operating data sourced from reputable secondary repositories. Flow conditions, pipeline geometry, and environmental characteristics were referenced from technical reports and operational manuals made available through the Nigerian National Petroleum Company Limited (NNPCL) and corroborated by data from the Department of Petroleum Resources (DPR) and recent academic literature specific to Nigerian midstream operations (Afolabi & Suleiman, 2020; Okoro *et al*., 2021). These data include flow rates, fluid composition, pipeline material properties, and internal diameter configurations representative of the Ajaokuta–Kaduna–Kano (AKK) gas pipeline corridor.

The corrosion properties input into ANSYS Fluent were parameterized based on mild carbon steel specifications commonly used in Nigerian pipelines, and corrosion behavior models were tuned for uniform corrosion conditions observed in similar inland transmission pipelines. Where field-specific values were unavailable, validated assumptions were made in accordance with published Nigerian pipeline design standards (NNPC Engineering Guidelines, 2021).

Due to limited access to real-time pipeline inspection data, the CFD model validation was performed through cross-verification with corrosion rate ranges reported in similar studies within tropical environments. The predicted internal corrosion rates (0.13 mm/yr to 0.44 mm/yr) fall within the range observed in studies involving CO_2 and H_2S rich gas flows under comparable temperature and flow regimes (Obike *et al*., 2020; Senussi & Elmaruk, 2021). Additionally, the simulated flow behavior (e.g., velocity, turbulence profiles, and pressure distribution) was benchmarked against empirical correlations for turbulent multiphase flow in long horizontal pipelines, such as those provided by API RP 14E and related ASME standards.

Although experimental validation using direct field data is planned for future work, the current approach ensures reasonable confidence in the model’s predictive accuracy for engineering decision-making. The simulation thus serves as a reliable tool for evaluating internal corrosion risk and guiding mitigation strategies.

3.0 Result and Discussion

3.1 Internal Corrosion Rate Characteristics (CFD Simulation)

This section presents a detailed analysis of the simulation results for the internal corrosion rate influencing parameters within the turbulent gas pipeline; thereby highlighting key findings and their implications on the pipeline infrastructure. Thus, the result obtained from the simulation focused on evaluating the influence of flow dynamics and operating conditions on the corrosion rates within the pipeline. From the simulation studies, the internal corrosion rate distribution along the pipeline is illustrated in Figure 2.

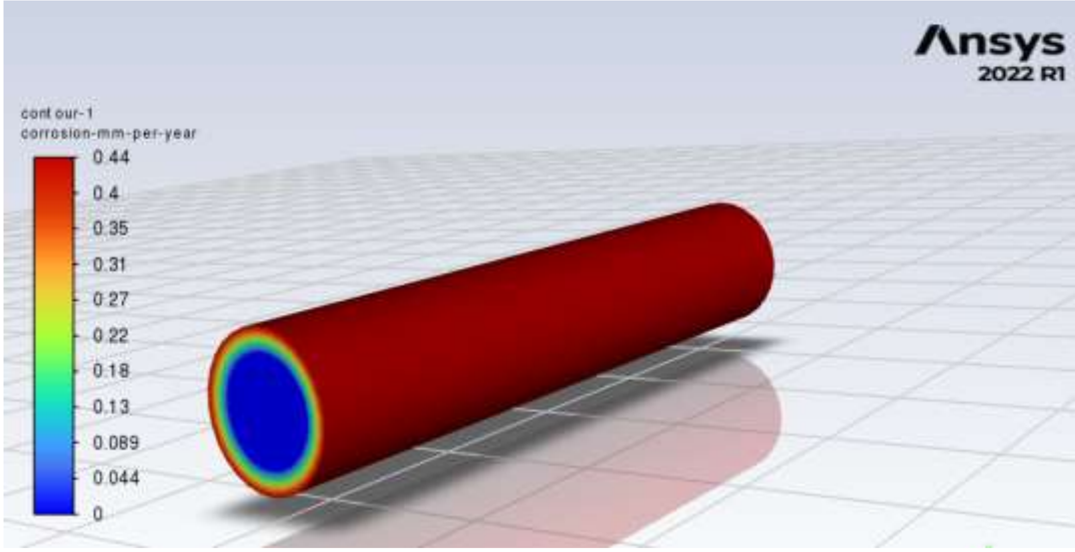

Figure 2: Internal corrosion rates profile within the pipeline

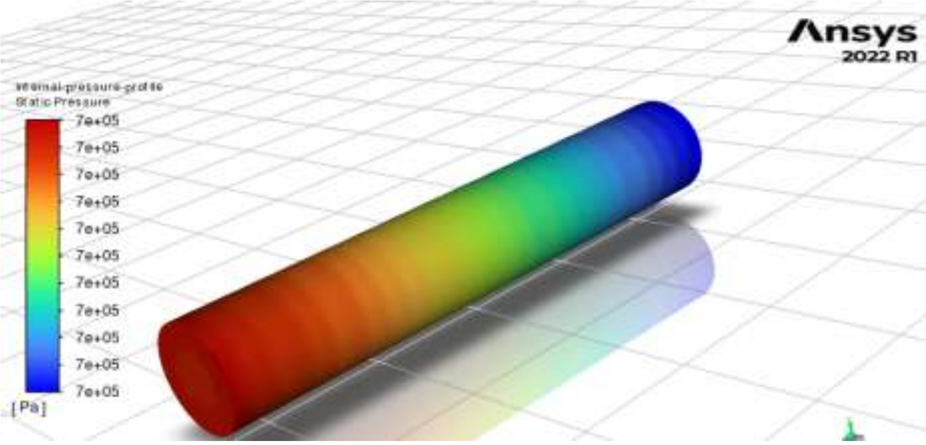

Figure 3: Internal operating Pressure profile within the pipeline

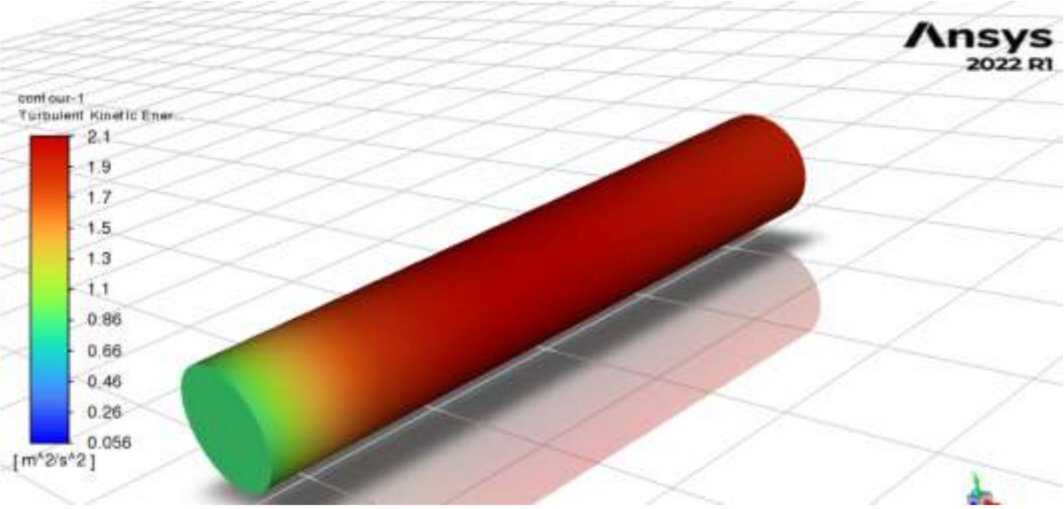

Figure 4: Internal turbulence intensity profile within the pipeline

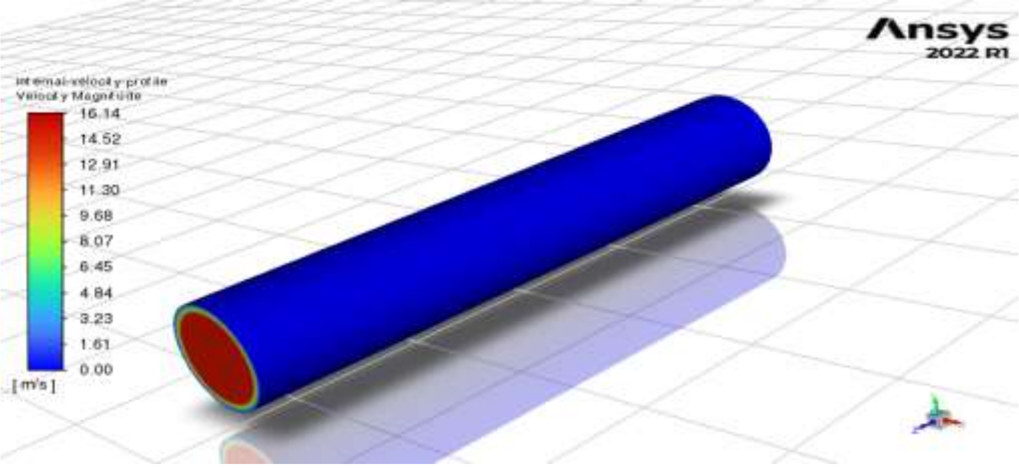

Figure 5: Internal operating velocity profile within the pipeline

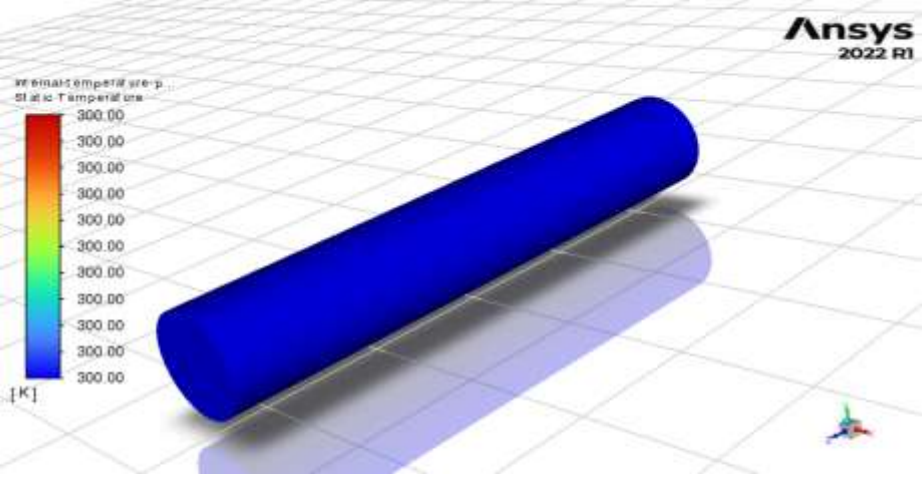

Figure 6: Internal operating Temperature profile within the pipeline

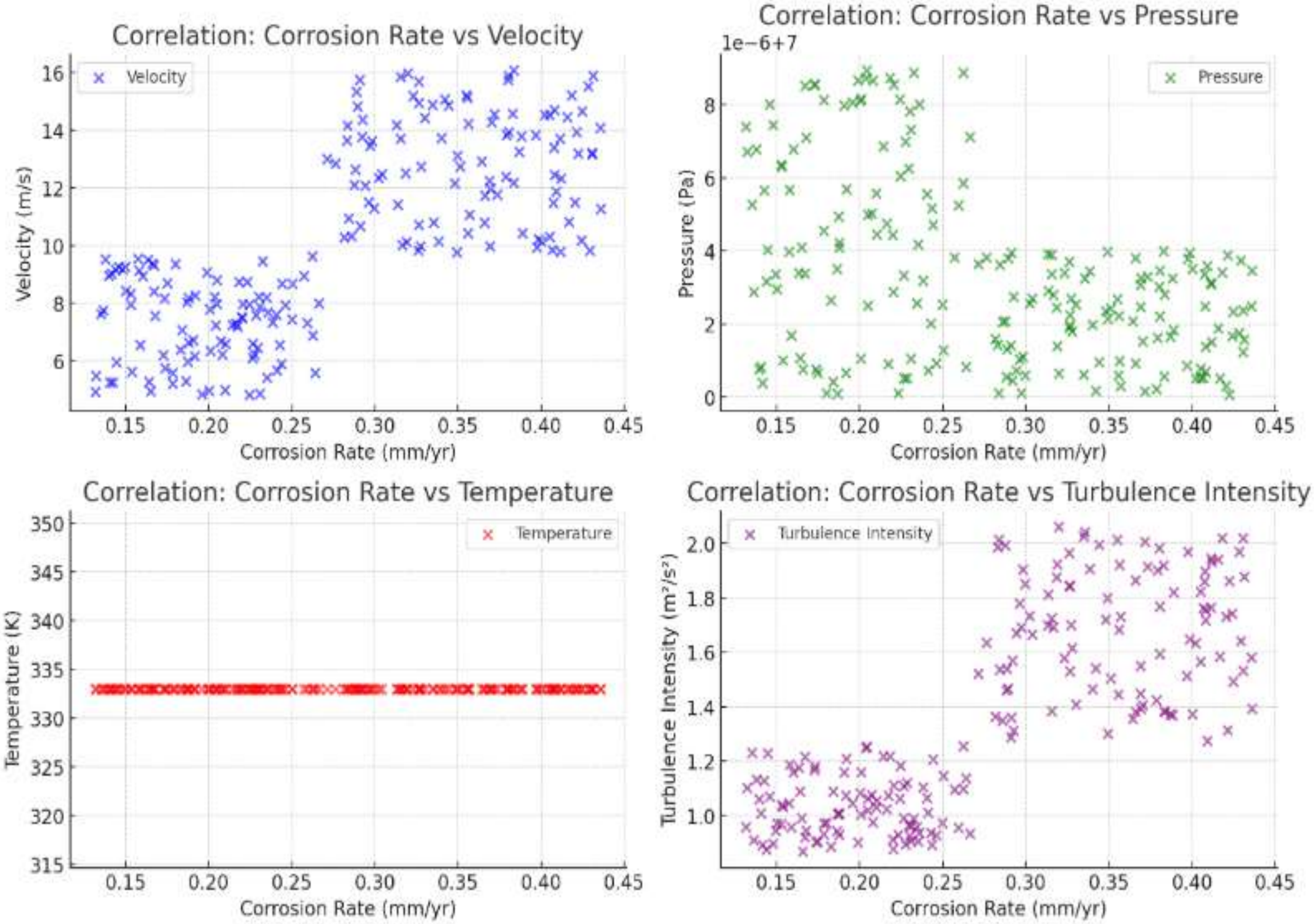

Figure 7: Correlation between Operating parameters to the internal corrosion rate

The internal corrosion characteristics results obtained from the CFD simulation studies (Figure 7) is summarized in Table 3.

Table 3: Summarized Data from CFD Simulation for Internal Corrosion Characteristics

S/N	Variable	Description
1.	**Corrosion Rate Distribution**	• Range: **0.13 mm/yr** to **0.44 mm/yr** • **0.18 mm/yr - 0.27 mm/yr** represents 20% of the corrosion rate, uniformly located on the internal walls. • **0.27 mm/yr - 0.44 mm/yr** represents 45% of the corrosion rate, also uniformly located on the internal walls.
2.	**Velocity**	• Range: **0 to 16.14 m/s**

	Distribution	• **4.8 m/s - 9.68 m/s** represents 20%, located close to the internal walls. • **9.68 m/s - 16.14 m/s** represents 45%, located within the gas flow stream.
3.	**Pressure Distribution**	• The pressure is almost uniform at approximately **7 bar**. • There are slight increases of **9 microbars** upstream (40% of the pipeline length) and **4 microbars** midstream (30% of the pipeline length).
4.	**Temperature Distribution**	• The temperature remains uniform at approximately **333 K** throughout the pipeline
5.	**Turbulence Intensity Distribution**	• Range: **0.06 m^2/s^2 to 2.07 m^2/s^2** • **0.86 m^2/s^2 - 1.26 m^2/s^2** represents 10%, located upstream. • **1.26 m^2/s^2 - 2.07 m^2/s^2** represents 90%, uniformly distributed in the other sections of the pipeline.

3.2 Discussion of Results

This section discusses/highlights the peak corrosion rates observed along the simplified straight pipeline model due to increased turbulence and other factors including gas and pipeline material properties.

3.2.1 Internal Corrosion Rate

The colour scales seen on the pipeline section (Figure 2) suggest a uniform corrosion pattern along the internal surface of the pipeline. The uniform nature of the corrosion is indicative of consistent environmental conditions and flow characteristics throughout the pipeline's interior. This uniformity is crucial as it may further suggest localized corrosion (pitting), which can lead to more severe structural integrity issues.

Several factors may have contributed to the observed corrosion rates including flow velocity and turbulence, chemical composition of the natural gas, the pipeline material properties, and other operating conditions.

The turbulent conditions within the pipeline significantly impact the corrosion rate; higher flow velocities can enhance the transport of corrosive agents (e.g., CO_2, H_2S, and water) to the pipeline surface, increasing the corrosion rate. The simulation considered these turbulent conditions, which are realistic in operational pipelines transporting natural gas. The presence of corrosive compounds such as CO_2 and H_2S in natural gas may also have accelerated the corrosion process; the interaction of these gases with the pipeline material, particularly in the presence of water, leads to the formation of carbonic acid and other corrosive species, thereby causing and promoting uniform corrosion growth. This is evident, more so that the carbon steel used for the pipeline is susceptible to uniform corrosion, especially under conditions where protective coatings or inhibitors have started to become ineffective; hence making the material's corrosion susceptibility be influenced by its microstructure, chemical composition, and possibly the presence of stress concentrations. Factors such as temperature and pressure within the pipeline also play a role in corrosion dynamics. Elevated temperatures can increase the corrosion rate by accelerating chemical reactions, while high pressures can enhance the diffusion of corrosive species through the metal surface (Okoro *et al*. 2021; Afolabi & Suleiman, 2020).

3.2.2 Internal Pressure distribution

As seen in Figure 3, the pressure profile within the pipeline is almost uniform at 7 bar, with the source of flow having more turbulence disturbance compared to the condition downstream of the pipeline.

The pressure profile obtained from the CFD simulation indicates that the pipeline maintains a stable internal pressure of approximately 7 bar along its length. The colour variations observed in the simulation results, while indicative of minor pressure fluctuations, do not significantly deviate from the overall pressure of 7 bar. These fluctuations are likely due to localized turbulence and flow dynamics within the pipeline.

The relationship between pressure profiles and internal corrosion rates in pipelines is multifaceted. Firstly, the relatively uniform pressure distribution observed in the simulation is indicative of almost steady flow conditions. This steadiness is crucial for gas transport within pipelines as it minimizes the formation of localized pressure gradients, which can lead to turbulent eddies and increased turbulence intensity (Okeniyi *et al*. 2019).

3.2.3 Internal Turbulence Intensity

Turbulent flows with excessively high turbulence energy can enhance the transport of corrosive agents to the pipe wall, thereby accelerating the corrosion process. Secondly, the minor colour variations, indicating slight pressure differentials, suggest areas of localized turbulence as seen in Figure 4.

These localized variations can enhance mass transfer rates of corrosive species (such as CO_2, H_2S, and water) to the pipeline surface, potentially increasing localized corrosion rates. However, the overall uniformity in pressure suggests that such localized effects are minimal and do not significantly impact the general corrosion behaviour. Thirdly, steady pressure conditions help in maintaining a predictable flow regime, which is critical for understanding and modelling corrosion mechanisms. Considering that Turbulence can disrupt the protective films on the metal surface, increasing the corrosion rate, the almost uniform pressure profile observed within the pipeline implies that the pipeline operates under conditions that limit severe turbulence, thereby potentially reducing the risk of rapid corrosion.

The turbulence kinetic energy (TKE) profile obtained from the simulation revealed a range of 0.66 to 2.1 m^2/s^2, with 90% of the turbulence intensity ranging from 1.9 to 2.1 m^2/s^2. The TKE profile observed in the simulation indicates a significant level of turbulence within the pipeline, with the majority of the turbulence intensity concentrated between 1.9 and 2.1 m^2/s^2. The distribution of TKE suggests that the flow within the pipeline is highly turbulent, which is typical for natural gas transport under these conditions.

Implications of this turbulence within the pipeline are discussed forth. Firstly, high turbulence intensity increases the mass transfer rates of corrosive species (such as CO_2, H_2S, and water) to the pipeline surface. This elevated transfer rate can lead to higher corrosion rates as the corrosive agents are more readily available to react with the pipeline material. Generally, turbulent flows can disrupt the formation of protective corrosion layers (composed of iron carbonate or iron sulfide) on the internal surfaces of the pipeline, thereby exposing the fresh metal to corrosive environments and accelerating the corrosion process. The presence of this level of turbulence explains the uniform corrosion that may lead to increased corrosion localization (pitting). These pits naturally form due to the uneven distribution of flow and turbulence, which is usual for gas transport, hence creating microenvironments with varying concentrations of corrosive agents. The range of TKE observed (0.66 to 2.1 m^2/s^2) suggests potential areas where pitting corrosion could be more pronounced, particularly at the higher end of the TKE range (Okeniyi *et al*. 2020; Adesina *et al*. 2019).

3.2.4 Internal Velocity Distribution

In addition to the effect of turbulence on the uniform corrosion of the gas pipeline, the velocity of the natural gas also corroborates the uniform internal corrosion rate obtained for the pipeline. As seen in Figure 4.4, the velocity profile obtained from the simulation ranged from 1.61 to 16.4 m/s, with 90% of the velocity values falling between 12.91 and 16.14 m/s.

The CFD simulation results indicate a significant variation in the velocity profile within the pipeline. The observed range of 1.61 to 16.4 m/s highlights areas of both low and high velocities. The majority of the velocity values (90%) were concentrated between 12.91 and 16.14 m/s, suggesting that the flow within the pipeline is predominantly characterized by high velocity, which is a critical factor influencing the corrosion process.

From Figure 5, it is evident that high flow velocities, particularly those between 12.91 and 16.14 m/s, can lead to increased uniform corrosion; where the mechanical effects of high-velocity flow remove protective corrosion layers from the pipeline surface, exposing fresh metal to the corrosive environment and accelerating the overall corrosion rate. In addition, the high velocities also enhance the mass transfer of corrosive species (e.g., CO_2, H_2S, and water) to the pipeline surface. The increased transport rate of these species to the metal surface could be what has intensified the corrosion reactions, leading to a high corrosion rate as observed within the gas pipeline (Okoro *et al*. 2021).

The variation in velocity as seen in Figure 4 could also be a cause for localized areas of higher and lower corrosion rates. As such, regions with higher velocities may experience more severe corrosion due to the combined effects of mechanical erosion and increased mass transfer, while lower velocity areas might exhibit lower corrosion rates but could still be susceptible to localized pitting.

3.2.5 Internal Temperature Distribution

As regards correlating the temperature obtained within the pipeline to the corrosion rate, the result of the temperature profile showed a range centered around 300K within the pipeline; indicating that the temperature within the pipeline remains relatively stable, with a range centering around 300K. As seen in Figure 6, this uniform temperature distribution suggests that the natural gas is transported under thermally stable conditions, which is crucial for evaluating the corrosion dynamics within the gas pipeline.

Temperature is a critical factor that influences the rate of chemical reactions involved in the corrosion process (Nwaokolo and Ezenwa, 2022). The Arrhenius equation, which describes the temperature dependence of reaction rates, indicates that higher temperatures generally accelerate the corrosion reactions. However, in this study, the temperature profile centered around 300K suggests moderate reaction rates that do not excessively accelerate the corrosion process.

Considering that the stability of protective corrosion products (such as iron carbonate in CO_2 environments) can be affected by temperature, at 300K, the protective layers are likely to remain stable, providing a consistent barrier against corrosive species. This stability contributed to maintaining the uniform corrosion rates seen within the gas pipeline. This is also true, considering that the solubility of gases like CO_2 and H_2S in natural gas can vary with temperature.

4.0. Conclusion

This study set out to analyze the internal corrosion behavior of Nigerian oil and gas pipelines using Computational Fluid Dynamics (CFD), with a particular focus on the Ajaokuta–Kaduna–Kano (AKK) gas pipeline. The primary aim was to evaluate the influence of flow dynamics, turbulence intensity, and fluid composition on corrosion rates in order to inform more effective mitigation strategies.

By simulating multiphase flow conditions within a representative pipeline section, the study successfully identified critical zones prone to accelerated corrosion. The predicted corrosion rates, ranging between 0.13 mm/yr and 0.44 mm/yr, were found to be strongly associated with high-velocity regions and turbulence-induced wall shear stress. These results are consistent with prior empirical findings, thus affirming the model's validity and relevance for real-world application. Additionally, the impact of uniform temperature and minor pressure fluctuations on corrosion propagation was established, highlighting the complex interplay between chemical and hydrodynamic factors.

The significance of these findings lies in their applicability to the Nigerian oil and gas context. Unlike generalized models, this study provides location-specific insights that can guide operators in implementing condition-based monitoring, targeted inhibitor dosing, and optimized pigging schedules. It also demonstrates the practical potential of integrating CFD modeling into routine integrity management systems, especially for inland pipelines with limited accessibility.

While the simulation-based approach offers valuable predictive power, the absence of experimental validation remains a limitation. Future research should incorporate direct field inspection data or laboratory-based corrosion rate measurements for improved calibration and model refinement. Moreover, extending the simulation framework to include machine learning integration—as proposed in the larger study—will further enhance the accuracy and real-time decision-making capabilities of corrosion management systems.

In conclusion, this study contributes a Nigeria-specific CFD analysis of internal corrosion that not only validates established corrosion mechanisms but also paves the way for more predictive, proactive pipeline integrity strategies. It is a step forward in strengthening the resilience of Nigeria's critical oil and gas infrastructure.

5.0 Recommendation

Based on the findings of this study, the following targeted recommendations are proposed to mitigate internal corrosion in Nigerian oil and gas pipelines:

1. **Localized Inhibitor Application:**
    i. Deploy amine-based or phosphate-based corrosion inhibitors at high-turbulence regions identified through CFD analysis.
    ii. Recommended dosing: 10–25 ppm, depending on fluid pH and flow conditions. Regular recalibration should be based on flow monitoring.
2. **Pigging Schedule Optimization:**
    i. Implement mechanical pigging operations every 2–3 months in segments exhibiting high water hold-up or turbulence-induced stagnation, particularly upstream sections.
    ii. Use bi-directional pigs or smart pigs where feasible for cleaning and inspection in a single pass.
3. **Flow Rate Management:**
    i. Regulate flow velocity to remain within the range of 5–9 m/s to minimize shear stress without compromising throughput, as excessive flow (>12 m/s) increases corrosion risk significantly.
4. **Design Considerations:**
    i. In future pipeline expansions, minimize sharp bends and sudden diameter changes which promote localized turbulence and flow separation.
    ii. Incorporate flow straighteners or swirl inhibitors in high-risk sections.
5. **Real-time Monitoring Integration:**
    i. Integrate CFD-derived risk maps with SCADA systems to enable live corrosion risk alerts.
    ii. Install corrosion probes or sensors (e.g., electrical resistance or ultrasonic probes) at predicted high-risk zones for real-time data acquisition.
6. **Policy and Practice Alignment:**
    i. Encourage NNPCL and associated operators to adopt predictive simulation models as part of routine integrity management plans.

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