Communication in Physical Sciences, 2026, 13(2): 267-280

Hydraulic Modelling and Compression Design for High-Pressure Natural Gas Transmission: A Case Study of the Calabar–Ajaokuta Gas Pipeline System

Musa M. Mbusube, Dahiru D. Muhammed, Saidu Abdullahi and Abdulaziz Bel

Received: 14 November 2025/Accepted: 10 February 2026 /Published: 20 February 2026

https://dx.doi.org/10.4314/cps.v13i2.7

Abstract: *Natural gas is one of the most critical components of the global energy mix and plays a central role in the ongoing energy transition It is regarded as one of the cleanest and most versatile fossil fuels due to its lower carbon emissions compared to coal and oil. Global natural gas consumption is projected to increase steadily, particularly in developing economies where industrialization and power generation demand are expanding.Nigeria's economy relies heavily on oil revenue, which has historically limited diversification into gas-based industrial development, including petrochemical and fertilizer production. For Nigeria, possessing abundant reserves of natural gas with most of it wastefully flared off, channelling this gas to supply energy to these industries becomes inevitable. The current demand capacity of CAPS that proposed to be 2000 MMSCFD has been found to be insufficient for the future demand capacity. Process simulation using PIPESIM software package showed that the required capacity could not be achieved without the use of compressors along the pipeline. This study presents a detailed hydraulic and steady-state process simulation analysis using PIPESIM software to evaluate the suitability of 48-inch and 565-inch pipeline diameters for delivering 2000 MMSCFD and 3200 MMSCFD under specified pressure constraints. Applying the hydraulic and steady state process simulations enable the compression requirements, pressure and velocity profiles to be evaluated. Two operational scenarios representing current (2000 MMSCFD) and projected future (3200 MMSCFD) demand capacities were evaluated. Results indicate that one compressor station is required to deliver 2000 MMSCFD, while four compressor stations are necessary to sustain 3200 MMSCFD at the minimum arrival pressure of 68 barg. The findings provide a technical basis for optimal pipeline sizing, compressor configuration, and long-term gas transmission reliability within Nigeria's expanding energy infrastructure.*

Keywords: *Natural Gas Transmission, Hydraulic Modelling, Pipeline Design, Compressor Station Optimization, PIPESIM Simulation.*

Musa M. Mbusube
Department of Geology, Heriot-Watt, University, United Kingdom
Email: mbusube49@gmail.com

Dahiru D. Muhammed
Department of Geology, University of Maiduguri, Maiduguri, Nigeria
Email: dahirudmuhammed@gmail.com

Saidu Abdullahi*
Department of Geology, Federal University Gusau, Zamfara State, Nigeria
Email: saiduabdullahi@fugusau.edu.ng
https://orcid.org/0009-0008-9707-9021

Abdulaziz Bello
Department of Geology, Federal University Gusau, Zamfara State, Nigeria
Email: abello@fugusau.edu.ng

1.0 Introduction

The global consumption of natural gas is expected to increase dramatically over the coming decades. Natural gas is increasingly viewed as an important transition fuel globally because it produces fewer carbon emissions than coal and oil. According to the International Energy Agency, global natural gas use is expected to keep rising, especially in developing countries where demand for power generation and industrial gas use is growing. Currently pipelines are used in transporting natural gas to the markets as LNG. Pipelines are economically attractive and is more convenient to use in the onshore as a means of transporting materials for natural gas (Economides, Sun, & Subero, 2006). High-pressure pipelines are more efficient than LNG shipping because they provide continuous gas flow, have lower long-term operating costs, and integrate easily with domestic distribution networks. Pipeline hydraulics must be designed to meet required flow rates and delivery pressures while keeping both capital and operating costs as low as possible (Bjørlykke, 2010; Guo *et al*., 2021). Several studies have addressed hydraulic modelling of high-pressure gas transmission systems, emphasising the importance of diameter optimization, compressor station placement, and pressure sustainability over long distances (Economides *et al*., 2006; Guo *et al*., 2021). However, most existing works focus on generic modelling frameworks or established transmission systems in developed economies. Limited integrated studies exist that evaluate both diameter selection and compression strategy simultaneously under projected capacity expansion scenarios in emerging gas markets such as Nigeria.

The Calabar-Ajaokuta Gas Pipeline (CAP) system is a 395-kilometre (km) pipeline spanning from Calabar in Cross River to Ajaokuta in Kogi State of Nigeria (NNPC Ltd., 2020). The pipeline was designed to link the new power stations and would serve as a backbone for gas supply to other gas-based industries, including petrochemicals and fertilizer plants across the country. This pipeline will also connect to form the South-North pipeline, transporting gas to the eastern, middle belt and northern regions of Nigeria. It is also planned that the pipeline will form part of Trans-Sahara Gas Pipeline that will supply gas to Europe from Nigeria through Niger and Algeria (NNPC Ltd., 2022). This pipeline project is part of the Nigerian Government's plan to boost power generation from 4,000MW to 40,000MW. The system is expected to have a delivery capacity of 2000 MMSCFD. The CAP has regional significance because it is planned to integrate into the proposed Trans-Sahara Gas Pipeline (TSGP), a multinational infrastructure project aimed at transporting Nigerian natural gas to Europe through Niger and Algeria. This broader regional linkage underscores the technical and economic importance of ensuring adequate capacity, pressure sustainability, and system reliability in the CAP design.

The proposed capacity of (CAP) Gas Pipeline system was 2000 MMSCFD with a minimum arrival pressure of 68barg. In its quest to increase the carrying capacity of the system, NGC commissioned a conceptual study to assess the possibility of boosting the capacity to 3200 MMSCFD. During the course of the engineering design, pipes with the size of 48" and 56" were selected, but the process simulation using PIPESIM package software showed that the arrival pressure at Ajaokuta would be 61barg for 2000 MMSCFD and 8barg for 3200 MMSCFD, falling short of the expected 68barg. Despite preliminary simulations indicating pressure shortfalls at increased throughput, there remains insufficient integrated evaluation of the trade-offs between pipeline diameter enlargement and compressor installation in achieving sustainable delivery pressures for both current and future demand scenarios. This gap necessitates a comprehensive hydraulic assessment to inform optimal engineering decisions. Thus, the proposed 2000 MMSCFD and 3200 MMSCFD capacities cannot be achieved unless compression facilities are installed. With this new challenge, it has been proposed to install one compressor for the delivery of 2000 MMSCFD and four (4) compressors for 3200 MMSCFD, which would give the required minimum delivery pressure of 68barg. This review to generate engineering inputs in order to select between the 48" and 56" pipes, pipe tonnage and compressor spacing requirement for the pipe while meeting the delivery pressure of 68barg.

This study aims to conduct a detailed hydraulic modelling and compression design assessment of the Calabar–Ajaokuta Gas Pipeline system in order to determine the optimal pipeline diameter, compressor requirements, and spacing necessary to reliably deliver 2000 MMSCFD and 3200 MMSCFD at a minimum arrival pressure of 68 barg.

This study is critical for identifying the most technically efficient and economically viable pipeline configuration for the CAP project. It compares 48-inch and 5-inch pipeline options, estimates material requirements and associated capital implications, determines optimal compressor station number and spacing, and evaluates system reliability under both current and projected gas flow conditions. The evaluation provides a technical foundation for informed decision-making on pipeline sizing, hydraulic performance, and compression strategy to support Nigeria's long-term gas transmission infrastructure development.

The remainder of this paper is structured as follows: Section 2 presents the methodology and modelling assumptions adopted for the hydraulic simulations. Section 3 discusses the results of the pressure and velocity analyses under both demand scenarios. Section 4 presents conclusions and engineering recommendations.

2.0 Materials and Methods

2.1 Gas Properties and Design Assumptions

The methodology adopted for the hydraulic modelling of the Calabar–Ajaokuta Gas Pipeline (CAP) is summarized in Fig. 1. The workflow outlines the sequential stages of pipeline sizing, hydraulic simulation, compressor station selection, and system performance evaluation, leading to final design optimization.

The input data used for the hydraulic modelling and simulation were sourced from the Nigerian National Petroleum Corporation (NNPC). These include the natural gas composition and the pipeline design and operating parameters required for the PIPESIM simulations, as presented in Tables 1 and 2, respectively.

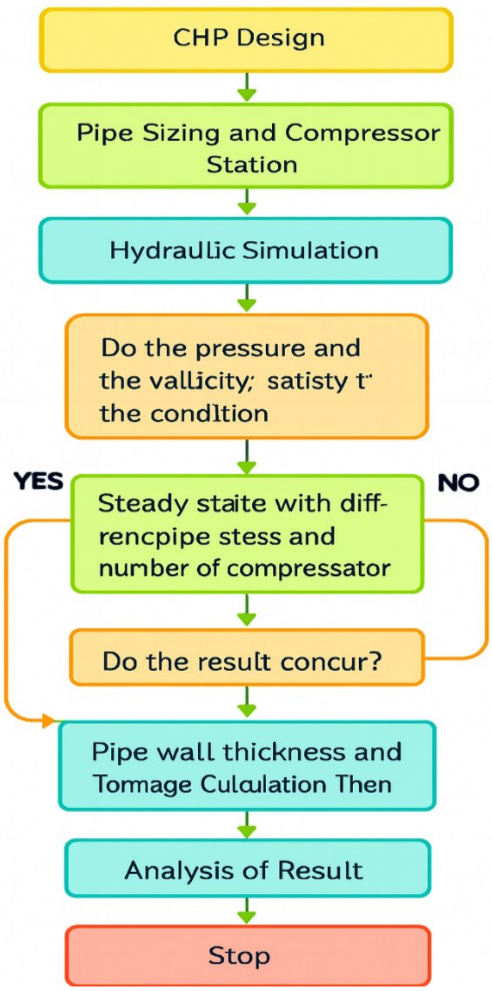

Fig. 1: Workflow diagram illustrating the methodology for pipeline sizing, hydraulic simulation, and compressor configuration

Table 1: Natural Gas Composition Used in the Hydraulic Simulation

Component	Chemical Formula	Mole Fraction
Nitrogen	N_2	0.016
Methane	CH_4	93.126
Carbon dioxide	CO_2	1.512
Ethane	C_2H_6	5.021
Propane	C_3H_8	0.034
i-Butane	C_4H_{10}	0.014
n-Butane	C_4H_{10}	0.022
i-Pentane	C_5H_{12}	0.004
n-Pentane	C_5H_{12}	0.010
Hexane+	C_6^+	0.020
Oxygen	O_2	0.010

Table 2: Pipeline Design and Operating Parameters

Parameter	Design Value
Inlet Pressure	80 barg
Minimum Delivery Pressure	68 barg
Pipeline Capacity	2000 MMSCFD and 3200 MMSCFD
Pipeline Length	395 km
Gas Temperature	25 °C
Pipeline Diameters Considered	48 in and 56 in
Pipeline Material	API 5L X65 Carbon Steel

he methodological framework adopted for the hydraulic modelling of the Calabar–Ajaokuta Gas Pipeline (CAP) system is illustrated in **Fig. 1**. The workflow summarizes the sequential st ages of pipeline sizing, hydraulic simulation, compressor configuration, and system performance evaluation used to determine the optimal pipeline design.

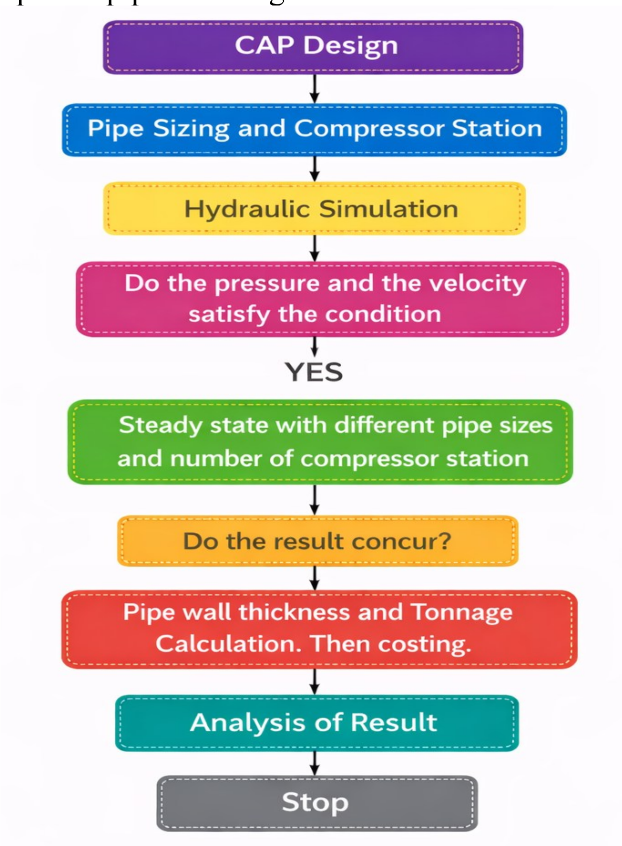

Fig. 2: A workflow diagram for the hydraulic modelling and design optimization of the Calabar–Ajaokuta Pipeline (CAP) system

The gas pipeline operating pressure is 80barg and the expected delivery pressure of the gas is 68barg. The inlet gas temperature was specified as 25°C The pipeline was evaluated under two throughput scenarios of 2000 MMSCFD and 3200 MMSCFD for both 48-inch and 56-inch diameters to assess hydraulic performance under current and projected demand conditions. The length of the pipeline is approximately 395 kilometres from source to delivery location. The pipeline material selected for this study is carbon steel grade API 5L X65, commonly used in high-pressure gas transmission systems due to its high strength and fracture resistance. These sizes are 48" and 58" respectively. Hydraulic simulations were conducted using steady-state flow assumptions. The pressure drop along the pipeline was estimated using the general gas flow equation derived from the Darcy–Weisbach formulation and modified for compressible gas flow. Friction factors were determined based on the Colebrook–White correlation, accounting for internal pipe roughness. Gas compressibility factors (Z-factor) were calculated within PIPESIM using the appropriate equation of state embedded in the software.

Compressor station requirements were determined based on maintaining the minimum delivery pressure of 68 barg at Ajaokuta under both throughput scenarios. Compressor spacing was optimized by iteratively adjusting station locations within the simulation model until pressure constraints were satisfied without exceeding allowable velocity limits or mechanical design constraints.

The combination of validated input data, steady-state hydraulic modelling, and iterative compressor optimization provides a robust framework for evaluating pipeline diameter selection and compression strategy for the CAP system under both present and future demand scenarios.

3.0 Results and Discussion

3.1 Results

This section presents the results obtained from hydraulic and steady-state simulations performed using PIPESIM software. The results are analyzed in relation to the pipeline design constraints and operational requirements discussed in the preceding sections. Pressure and velocity profiles are presented graphically to facilitate technical interpretation and comparison between pipeline diameters and flow scenarios.

3.1.1 PIPESIM Simulation

Simulations were conducted for two throughput scenarios: 2000 MMSCFD representing current demand and 3200 MMSCFD representing projected future demand. Each scenario was evaluated for both 48-inch and 56-inch pipeline diameters. Initial hydraulic simulations were performed under free-flow (non-compressed) conditions to determine whether the required minimum delivery pressure of 68 barg could be achieved without intermediate compression. Where pressure constraints were violated, steady-state simulations incorporating compressor stations were subsequently performed. A Hydraulic simulation was first carried out for each of the two cases to predict the required inlet pressure under free flow condition in order to achieve a pressure of 68barg at the delivery point. The results obtained necessitated the need for steady state simulation to be carried out under fully compressional conditions.

3.1.2 Basis for the scenarios

The first scenario represents the current demand capacity of 2000 MMSCFD, aligned with domestic transmission requirements and potential integration with regional export infrastructure. The second scenario represents the projected future demand capacity of 3200 MMSCFD, reflecting expanded utilization within Nigeria's growing power generation and industrial sectors. These two scenarios provide a comparative basis for evaluating pipeline performance under incremental load expansion.

3.1.3 Hydraulic simulation

Hydraulic simulations were conducted for 48-inch and 56-inch pipeline diameters assuming an outlet delivery pressure of 68 barg and negligible elevation effects for gas flow capacities of 2000 MMSCFD and 3200 MMSCFD, respectively

For the current demand scenario of a gas flow capacity of 2000 MMSCFD, the results obtained from the hydraulic simulation are tabulated in Tables 3 and 4, respectively.

Table 3: Hydraulic Simulation results using 56" pipe @ 2000 MMSCFD

Pipe Length (km)	Gas Velocity (m/s)	Gas Pressure (barg)	Gas Pressure (bar abs)
0.00	5.32	71.03	72.04
20	5.40	69.92	70.93
40	5.48	68.83	69.84
55	5.55	68.00	69.02

Table 4: Hydraulic simulation results using 48" pipe @ 2000 MMSCFD

Pipe Length (km)	Gas Velocity (m/s)	Gas Pressure (barg)	Gas Pressure (bar abs)
0.00	4.91	101	102.02
40	5.07	97.60	98.61
80	5.24	94.11	95.12
120	5.43	90.79	91.80
160	5.66	87.04	88.05
200	5.93	83.11	84.12
240	6.24	78.99	79.91
280	6.58	75.02	76.03
320	7.03	70.42	71.43
340	7.29	68.00	69.02

The hydraulic simulation results for 2000 MMSCFD indicate that under free-flow conditions, the required inlet pressure for the 48-inch pipeline reaches 101 barg, exceeding the allowable operating inlet pressure of 80 barg. This demonstrates that the required delivery pressure of 68 barg cannot be achieved without compression. Therefore, installation of at least one compressor station is necessary to satisfy operational constraints. Therefore, the need to install a compressor station at a certain pipeline length is necessary. The pressure profile of hydraulic simulation at 2000 MMSCFD is shown in Fig. 3.

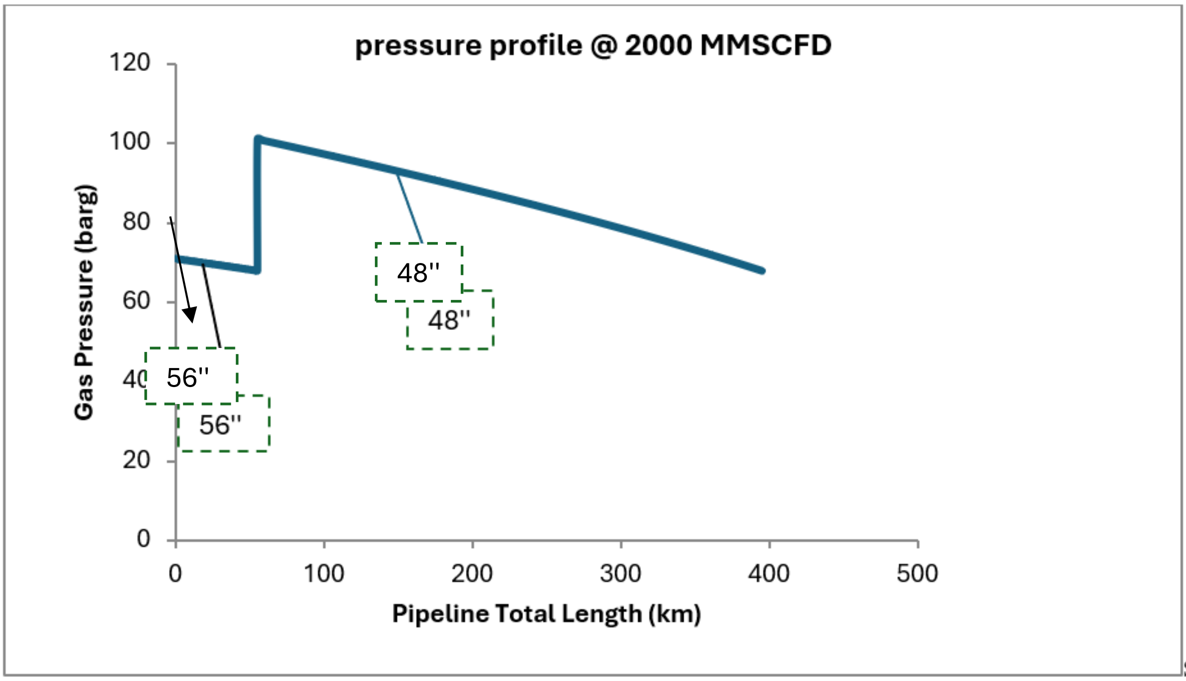

Fig. 3: Pressure profile of hydraulic simulation using 48'' and 56'' pipe sizes

For the future demand scenario of a gas flow capacity of 3200 MMSCFD, the results obtained from the hydraulic simulation are tabulated in Tables 5 and 6, respectively.

Table 5: Hydraulic Simulation results using 56'' pipe @ 3200 MMSCFD

Pipe Length (km)	Gas Velocity (m/s)	Gas Pressure (barg)	Gas Pressure (bar abs)
0.00	7.96	75.40	76.41
20	8.24	72.75	73.76
40	8.54	70.07	71.08
55	8.79	68.00	69.02

For the 3200 MMSCFD scenario, the required inlet pressure under free-flow conditions increases to approximately 135 barg for the 48-inch pipeline (Fig. 10), significantly exceeding both the operating inlet pressure of 80 barg and the maximum allowable pipeline pressure. This confirms that multiple compressor stations are required to maintain the minimum delivery pressure of 68 barg under future demand conditions. Therefore, the need to install compressor stations at certain pipeline length is imperative. the pressure profile of hydraulic simulation at 3200 MMSCFD is shown in Fig. 4.

Table 6: Hydraulic Simulation results using 48'' @ 3200 MMSCFD

Pipe Length (km)	Gas Velocity (m/s)	Gas Pressure (barg)	Gas Pressure (bar abs)
0.00	5.75	134.72	135.73
40	5.98	128.39	129.40
80	6.26	121.80	122.81
120	6.56	115.47	116.48
160	6.95	108.20	109.21
200	7.44	100.46	101.47
240	8.08	92.11	93.12
280	8.86	83.77	84.78
320	10.07	73.63	74.64
340	10.90	67.99	69.00

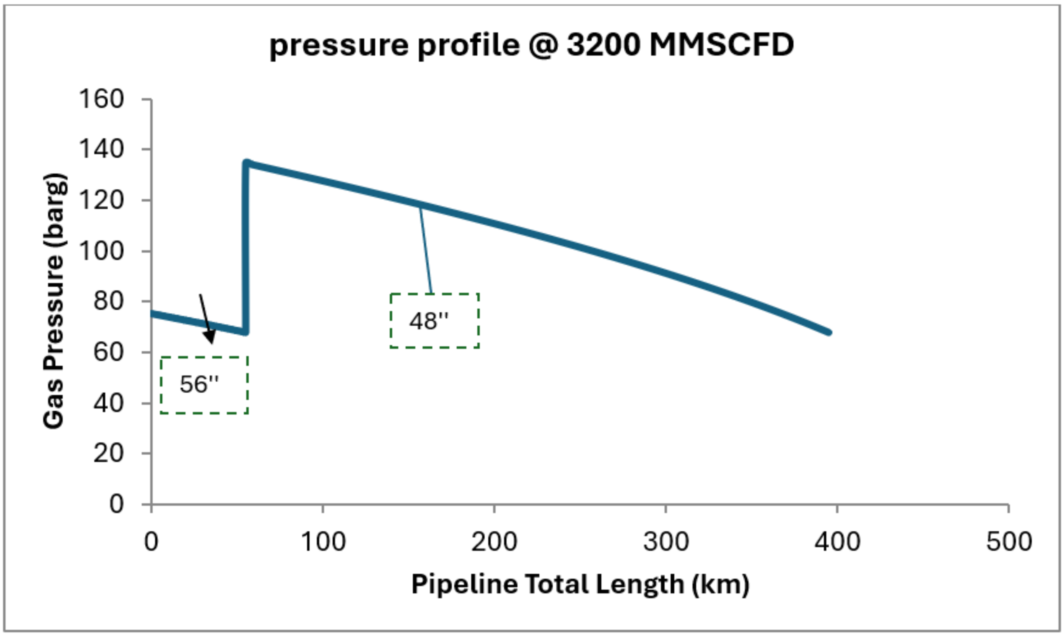

Fig. 3: Pressure profile of hydraulic simulation using 48'' and 56'' pipe sizes

3.1.4 Steady state simulation

Steady-state simulations incorporating compressor stations were conducted for both 2000 MMSCFD and 3200 MMSCFD scenarios using 48-inch and 56-inch pipeline diameters. The maximum allowable compressor discharge pressure was limited to 80 barg in accordance with the pipeline design pressure constraint. The maximum compressor discharge pressure allowed is 80barg. This is due to the maximum allowable pipeline pressure of the system. The pipeline is designed with a compressor stationed at a certain distance to boost the pressure and, at the same time, reduce the gas velocity, hence preventing erosion of the pipe wall. Compressor stations were positioned at locations where gas velocity approached operational limits, ensuring that the erosional velocity threshold of 20 m/s was not exceeded.

Current Demand Scenario

Running the simulation with an inlet pressure of 80barg. For a gas flow capacity of 2000 MMSCFD, the results obtained from the steady state simulation are tabulated in Table 7. Table 7 shows that one compressor was operated with a discharge pressure of 77.3barg. The delivery pressure of 68barg was achieved.

Fig. 4. and 5 show the pressure and velocity profile of the steady state simulation at 2000 MMSCFD. As shown in these figures, only one compressor will be required to deliver 2000 MMSCFD of natural gas over a distance of 395 km with an inlet pressure of 80barg. The final delivery pressure was maintained above the required minimum of 68 barg.

Table 7: Steady state simulation results using 48'' and 56'' @ 2000 MMSCFD and 80barg

Pipe Length (km)	Gas Velocity (m/s)	Gas Pressure (barg)	Gas Pressure (bar abs)
0.00	0.46	80	81.02
40	0.46	78.07	79.08
80	6.85	74.63	75.64
120	7.31	69.85	70.86
160	7.88	64.72	65.73
200	8.63	59.14	60.15
240	9.55	53.52	54.53
280	11.00	46.60	47.61

320	13.40	38.43	39.44
361	18.50	27.91	28.92
	1st Compression Stage P = 77.3		
361	6.63	77.3	78.31
395	6.96	73.00	74.02

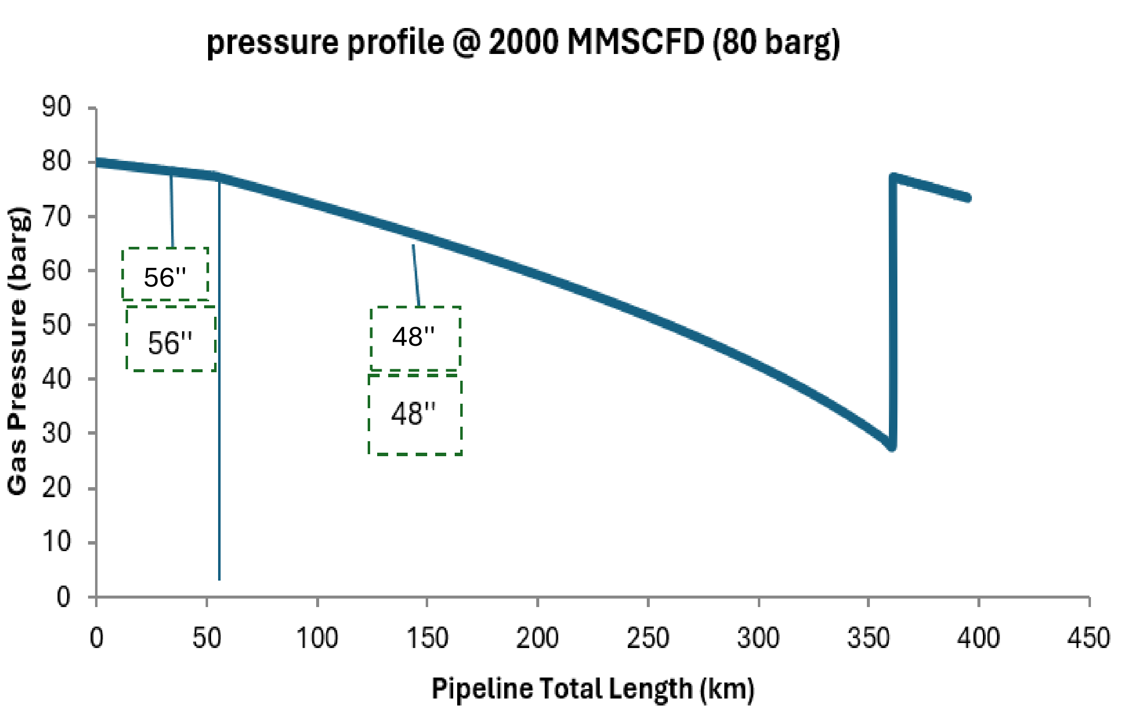

Fig. 4: Pressure profile of steady state simulation using 48'' and 56'' pipe sizes

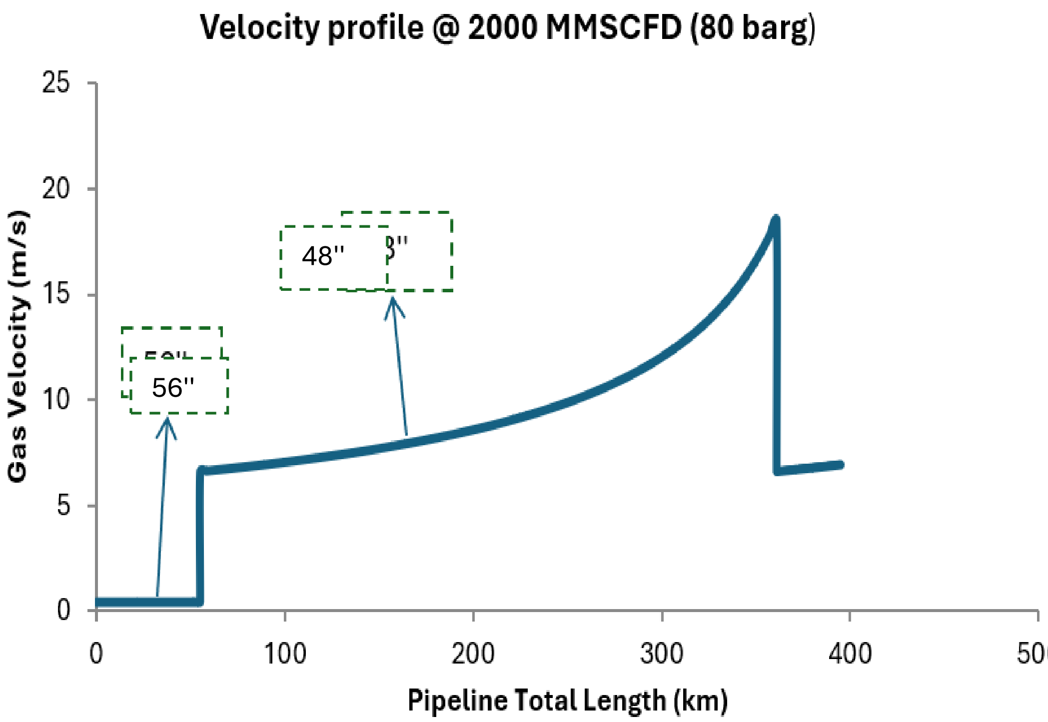

Fig. 5: Velocity profile of steady state simulation using 48'' and 56'' pipe sizes

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Running the simulation with an inlet pressure of 80barg. For a gas flow capacity of 3200 MMSCFD, the results obtained from the steady state simulation are tabulated in Table 8.

Table 8: Steady state simulation results using 48" and 56" @ 3200 MMSCFD and 80barg

Pipe Length (km)	Gas Velocity (m/s)	Gas Pressure (barg)	Gas Pressure (bar abs)
0.00	7.45	80	81.02
20	7.67	77.52	78.53
40	7.92	75.03	76.04
60	11.58	71.14	72.15
80	12.48	65.76	66.77
100	14.24	57.40	58.42
120	16.11	50.62	51.63
136	19.03	42.79	43.81
1st Compression P = 73.2			
136	11.27	73.2	74.22
160	12.45	65.94	66.95
180	13.92	58.76	59.77
200	16.12	50.62	51.63
216	18.71	43.53	45.54
2nd Compression p =73.2			
216	11.27	73.2	74.22
240	12.56	65.73	66.38
260	13.98	58.53	59.54
280	15.83	50.79	51.80
296	**18.73**	**43.47**	**45.54**
3rd Compression p = 73.2			
296	11.31	73.2	74.22
320	12.62	66.54	66.38
340	14.01	59.97	60.98
360	16.07	51.98	52.99
374	18.89	45.81	46.82
4th Compression p = 73.2			
374	12.21	73.2	74.22
395	12.30	67.00	68.02

Table 8 shows that four compressors were operated with a discharge pressure of 73.2barg. The expected delivery pressure of 68barg was attained. The pressure and velocity profile of steady state simulation at 3200 MMSCFD are shown in Fig. 6 and 7, respectively. It can be clearly seen in these Fig.s that four compressors were required to deliver 3200 MMSCFD of natural gas over a distance of 395 km with an inlet pressure of 80barg. The delivery pressure of the gas was shown to be 68.02 barg, and the arrival velocity was shown to be 12.30 m/s. From Fig. 6 and 7 it can be seen that four (4) compressors were required to deliver 3200 MMSCFD of natural gas over a distance of 395 km with an inlet pressure of 80barg. The compressors were operated with a discharge pressure of 73.2barg. The delivery pressure of the gas was shown to be 68.02barg.

3.2 Discussion

3.2.1 Hydraulic and steady state simulations

Hydraulic simulation runs were conducted using PIPESIM software package over a gas pipeline length of 395 km and diameters of 48" and 56" respectively. The hydraulic simulation runs were carried out considering two different flow capacities and with an expected delivery pressure of 68barg for both flows.

Using 48" and 56" pipe sizes for a gas flow rate of 2000 MMSCFD, which was the current demand scenario and the future demand

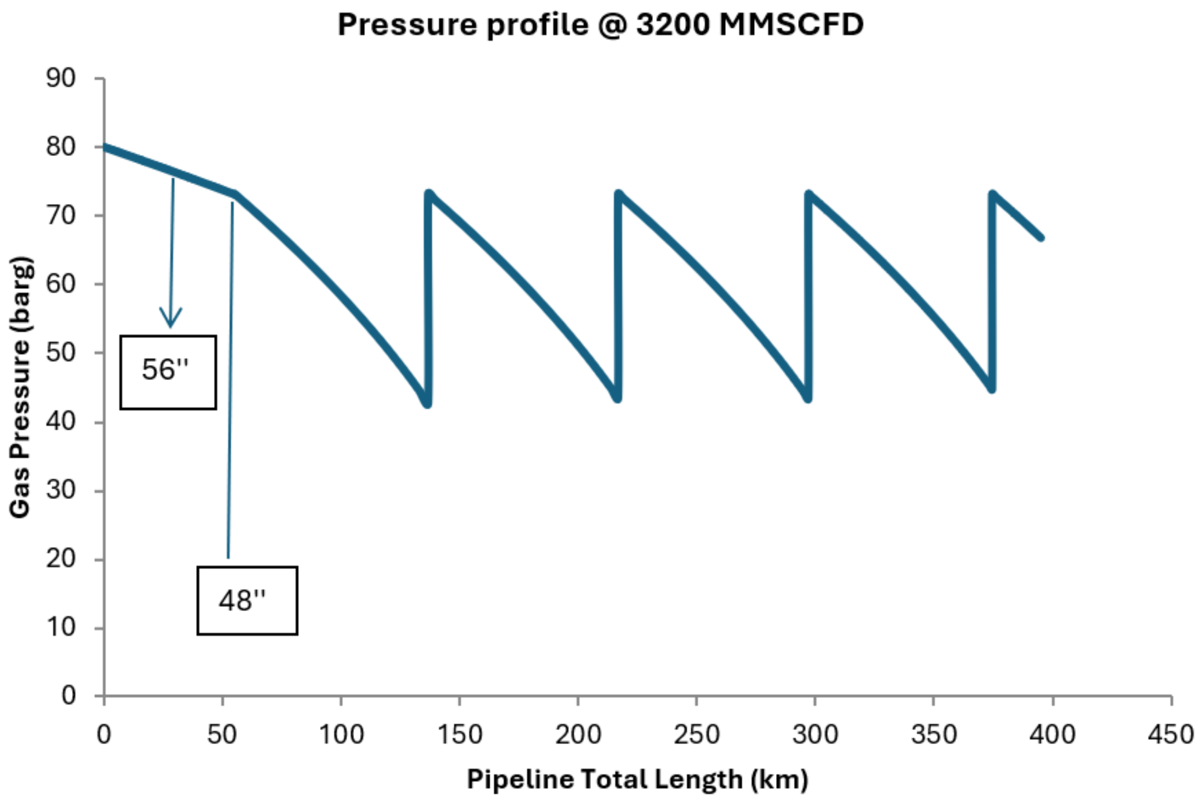

Fig. 6: pressure profile of steady state simulation using 48'' and 56'' pipe sizes

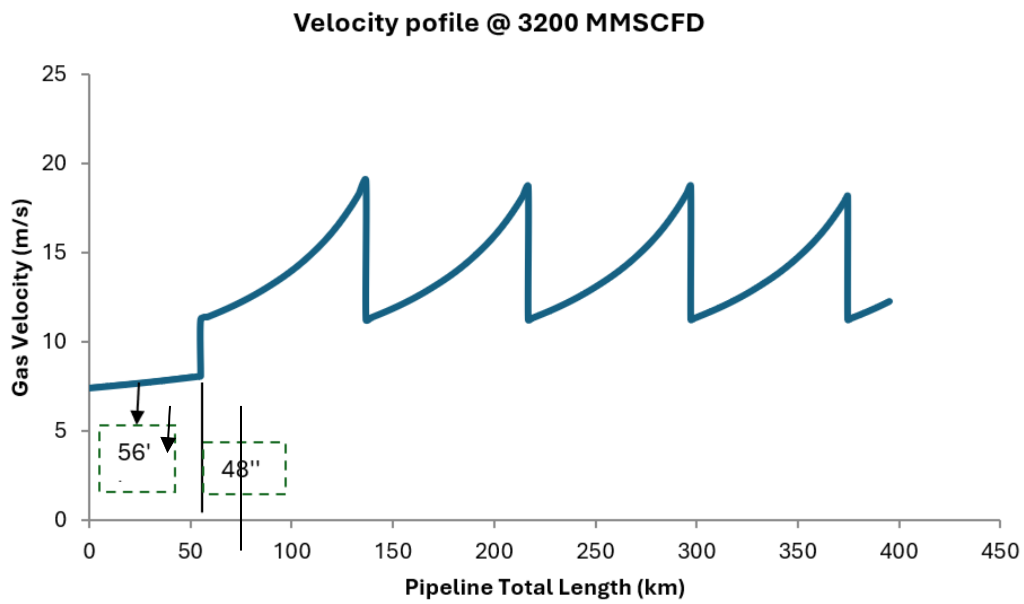

Fig. 7: Velocity profile of steady state simulation using 48'' and 56'' pipe sizes

scenario of 3200 MMSCFD the simulation result showed that the required inlet pressure in the second segments of the pipelines under free flow conditions for current and future demand scenarios would be 101barg and 134barg respectively, which are found to be greater than the operating inlet pressure of 80barg, at the same time it is greater than the maximum design pressure which is given as 100barg. Looking at the velocity profile, the arrival velocity at Ajaokuta for 2000 and 3200 MMSCFD were found to be 7.29 and 10.90 respectively. This shows that the velocity is in erosional limits of 20m/s.

For steady state simulation, also PIPESIM software package were used to run the simulation over a gas pipeline length of 395 km and diameter of 48" and 56". Two different flows of 2000 and 3200 MMSCFD were considered in running the simulation with an expected delivery pressure of 68barg for both current and future demand scenarios. Simulating with the operating inlet pressure of 80barg, the results showed that one (1) compressor is required to deliver the current demand of 2000 MMSCFD of natural gas with and expected delivery pressure of 68barg. While for the future demand gas flow capacity of 3200 MMSCFD with an inlet pressure of 80barg, the results showed that four (4) compressors were required to deliver the future demand of 3200 MMSCFD of natural gas with an expected delivery pressure of pressure of 68barg over a pipeline length of 395 km. Looking at the velocity profile for the current and future demands of 2000 and 3200 MMSCFD respectively, the terminal velocity at Ajaokuta were found to be 6.96 m/s for the current demand and 12.30 m/s for the future demand. This shows that the velocity were in the operational limits of 20 m/s. The pressure and velocity profile against the pipeline total length are shown in (Figs. 8 through Fig. 11) respectively.

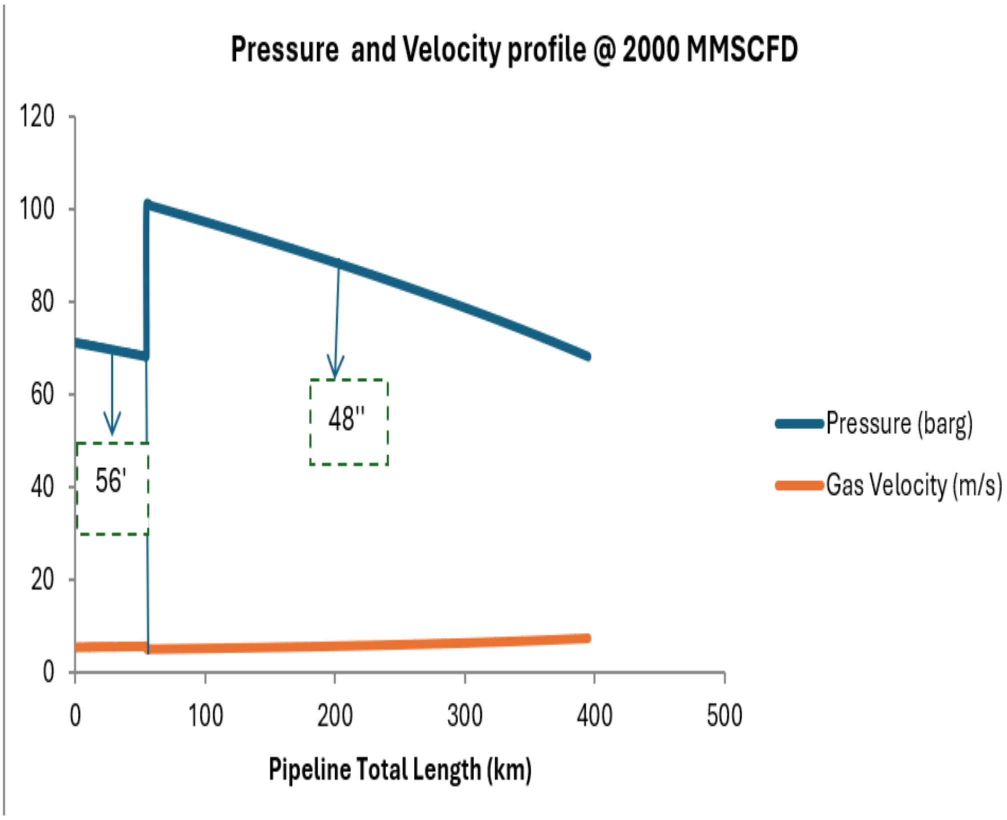

Fig. 8: Hydraulic simulation profile of Pressure and Velocity against Total Length

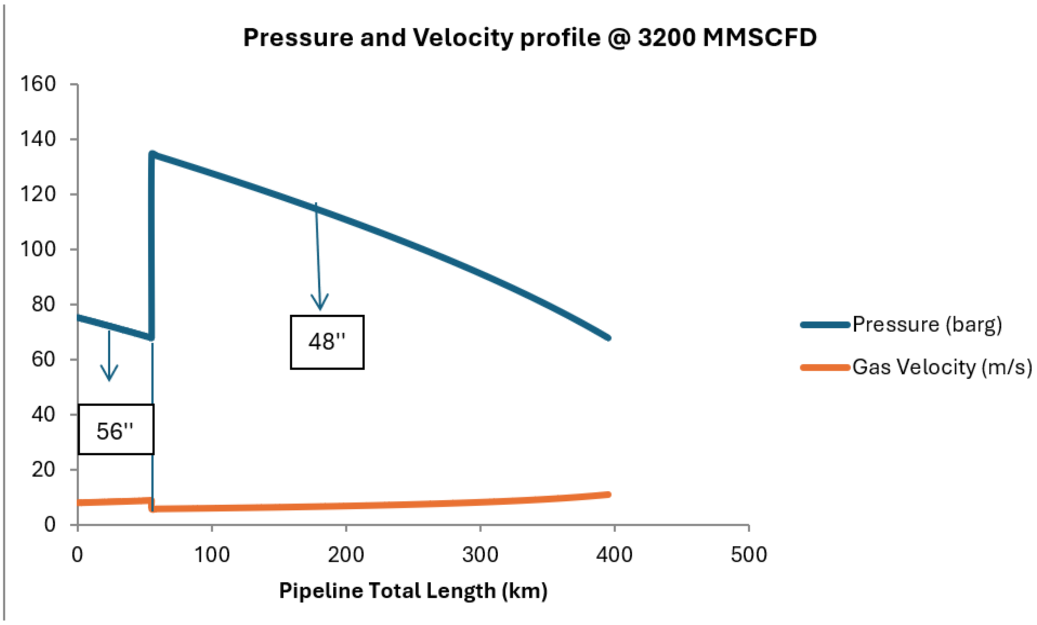

Fig. 9: Hydraulic simulation profile of Pressure and Velocity against Total Length

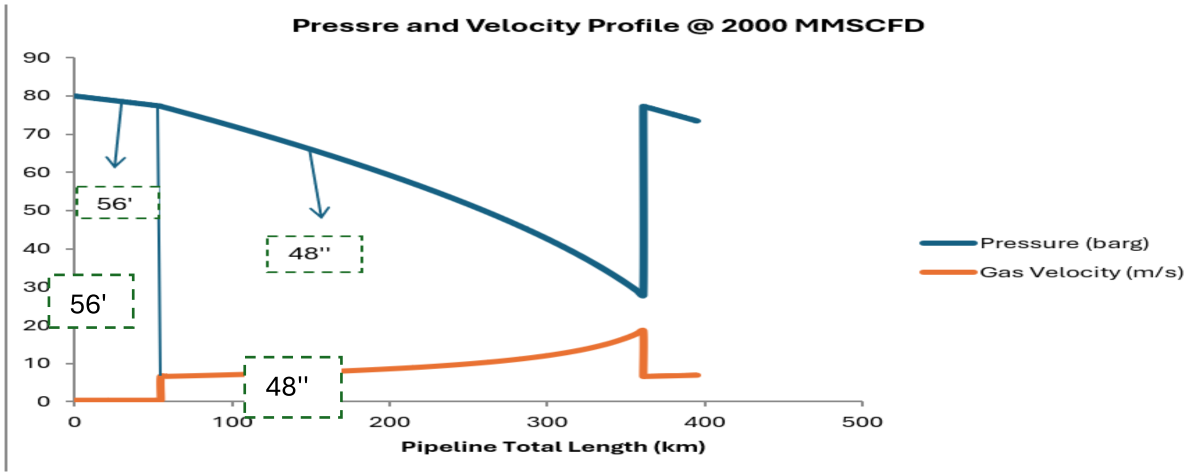

Fig. 10: Steady state simulation profile of pressure and velocity against total Length

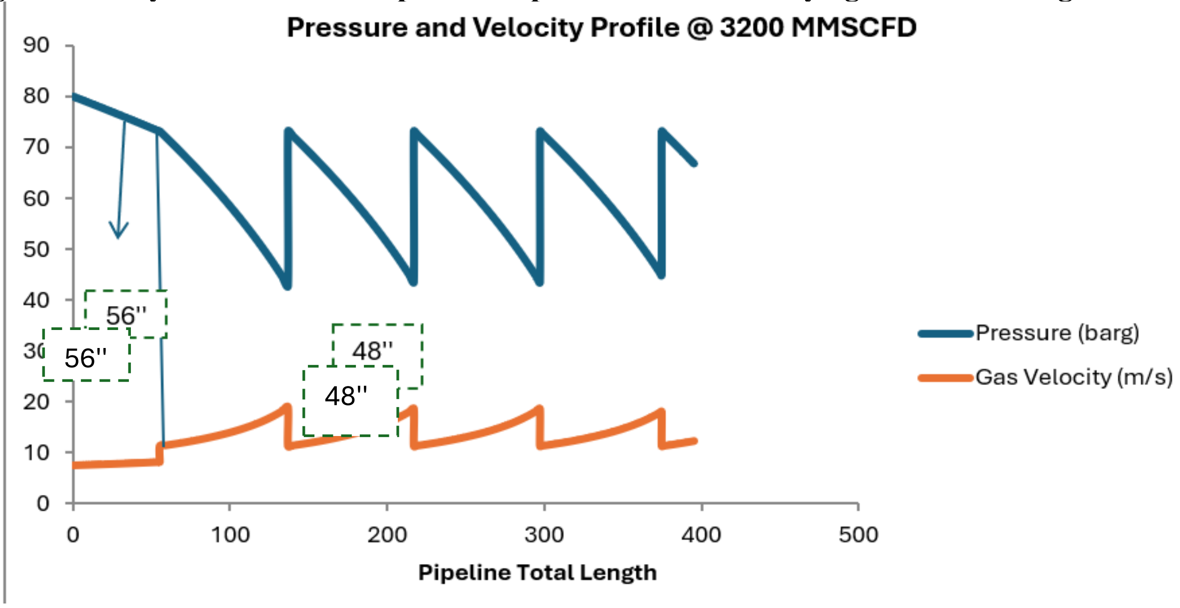

Fig. 11: Steady state simulation profile of pressure and velocity against Total Length

5.0 Conclusions

A comprehensive hydraulic and steady-state simulation analysis was conducted for the 395 km Calabar–Ajaokuta Gas Pipeline system to evaluate its performance under current (2000 MMSCFD) and projected future (3200 MMSCFD) demand scenarios. The results demonstrate that under free-flow conditions, the required minimum delivery pressure of 68 barg cannot be achieved within the allowable inlet pressure constraint of 80 barg for either demand case. Hydraulic limitations therefore necessitate the incorporation of compressor stations to sustain operational performance.

Steady-state simulations indicate that one compressor station is sufficient to deliver 2000 MMSCFD, whereas four compressor stations are required to maintain 3200 MMSCFD over the 395 km transmission distance. Gas velocities in both scenarios remained below the erosional threshold of 20 m/s, confirming operational safety within acceptable limits.

These findings provide a technical basis for optimizing pipeline diameter selection and compressor configuration, thereby supporting cost-effective and reliable long-term gas transmission infrastructure development in Nigeria.

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Declaration

Consent for publication

Not Applicable

Availability of data and materials

The publisher has the right to make the data public

Conflict of Interest

The authors declared no conflict of interest

Ethical Considerations

Not applicable

Competing interest

The authors report no conflict or competing interest

Funding

The author declared no source of funding

Authors' Contributions

Musa M. Mbusube conceptualized the study, conducted the hydraulic modelling and PIPESIM simulations, and prepared the initial manuscript draft. Dahiru D. Muhammed contributed to the study design, data interpretation, and technical review. Saidu Abdullahi supervised the research, validated the methodology, and edited the manuscript. Abdulaziz Bello assisted in literature review, data analysis, and manuscript revision. All authors reviewed and approved the final manuscript.