Int. j. adv. multidisc. res. stud. 2025; 5(1):502-512

Received: 04-12-2024
Accepted: 14-01-2025

International Journal of Advanced Multidisciplinary Research and Studies

ISSN: 2583-049X

Contribution to the Comparative Analysis of Tubing Performance by the Hagedorn-Brown Method and the Beggs-brill Method at the Mibale-01 Well

[1] Hubertine Kasogo Maila, [2] Déo Mumbungu Noel, [3] Rachidi Opuluku Rachidi, [4] Cesar Tambashie Okitafumba, [5] Dirk Akili Bihivu, [6] Patrick Efoto Bokungu, [7] Precieux Kanu Kande

[1] Department of Oil Management and Economy Exploration and Production, Faculty of Oil, Gas and Renewable Energies, University of Kinshasa, Kinshasa, D.R. Congo

[2, 3, 4, 5, 6, 7] Department of Exploration and Production, Faculty of Oil, Gas and Renewable Energies, University of Kinshasa, Kinshasa, D.R. Congo

[3] DRC Geological And Mining Center, D.R. Congo

DOI: https://doi.org/10.62225/2583049X.2025.5.1.3683

Corresponding Author: **Hubertine Kasogo Maila**

Abstract

The proposed study aims to evaluate and compare the effectiveness of two methods commonly used in the petroleum industry to analyze casing performance: the Hagedorn-Brown and Beggs-Brill methods. More specifically, this analysis will focus on the MIBALE-01 well. This study is part of a process of continuous improvement of industrial practices in the field of oil production. It will not only optimize the performance of the MIBALE-01 well, but also provide valuable knowledge for the entire industry.

Keywords: Comparative Analysis, Tubing Performance, Hagedorn-brown Method, The Beggs-Brill Method

1. Introduction

Multiphase flows in oil wells are complex phenomena influenced by many parameters, such as fluid composition, temperature, pressure, and geometric casing characteristics. To characterize these flows and estimate the pressure drops, various correlations have been developed. Among the most used are those of Hagedorn-Brown and Beggs-Brill. This study aims to evaluate the relevance of these two methods in the specific case of the MIBALE-01 well, with a view to improving performance prediction and optimizing production.

Optimizing oil well production is a major challenge for oil companies. A proper estimation of casing pressure drops is essential for making informed operating decisions. The Hagedorn-Brown and Beggs-Brill methods are two commonly used tools for this purpose. This study aims to determine, through the analysis of the MIBALE-01 well, which method offers the best accuracy and allows to obtain more reliable results for the optimization of production. After the discovery of an oil deposit, work is then carried out to calculate the reserves in place. Many other studies are also carried out, such as pumping tests and especially nodal analysis which gives the flow rate compatible between what the reservoir rock indicated by the IPR curve can produce and what the buying customers want. The operating engineer would then have to choose the tubing capable of bringing the said flow to the surface under effective and efficient conditions.

In reality, there are many empirical and analytical mathematical models based on different assumptions according to modelers. Two families of hypotheses exist. One family considers the fluids flowing in the tubing (oil, water, and gas) to form a homogeneous mixture whose physical properties (viscosity, density, surface tension, etc.) are constantly changing as the mixture travels from the bottom of the well to the surface. As we will see in the second chapter, the most cited model in this family is that of Poettman and Carpenter. The second family bases its models on the heterogeneity of the mixture and the permanent change in the properties of the fluids throughout the tubing. Two models are the most cited; they are the one from Beggs and Brill and the one from Hagedorn-Brown. These models are widely used because of their basic assumption that the heterogeneity of the mixing of flowing fluids in the tubing seems more realistic.

This work focuses on the analysis of the performance of the tubing operated by the Mibale 01 well by comparing the two empirical mathematical models of Beggs-Brill and that of Hagedorn-Brown and to see which of these two models can be used to satisfy the desired demand of the production of this well to bring to the surface the flow rate that the company would impose on itself.

The use of the Hagedorn and Brown correlation would be applied to determine the different variations of pressure from the bottom to the wellhead in the Mibale_01 well for our study;
The Beggs and Brill correlation could be applied to estimate the flows that can rise from the bottom to the tubing surface in the Mibale_01 well in the context of our work.

Objectives

- To compare the performance of the Hagedorn-Brown and Beggs-Brill methods in the evaluation of pressure drops and pressure profile in the casing of the MIBALE-01 well.
- Identify the most suitable method for the characterization of multiphase flows in this specific well.
- Contribute to the optimization of the production of the MIBALE-01 well by proposing accurate mathematical models to simulate multiphase flows in the casing of the MIBALE-01 well using Hagedorn-Brown and Beggs-Brall correlations.

To analyze the performance of the tubing operated by the Mibale 01 well by comparing the two empirical Beggs-Brill and Hagedorn-Brown mathematical models and to see which of these two models can be used to meet the desired demand from the production of this well to bring the flow rate that the company would impose on the surface.
Evaluate the tubing performance, make a choice among the different empirical correlations of the performance analysis as well as draw the different TPR curves that explain the behavior of pressure and flow in the well.

2. Methods and Materials

- A comparative method, this allowed us to compare the performance of tubings from the Hagedorn-Brown model and the Beggs-Brill model;
- An analytical method, which allowed us to examine the different data available to us in order to draw conclusions between the two models.
- The documentation technique has allowed us to enrich our different solutions thanks to the consultation in several books, scientific publications, the internet as well as the notes of the courses related to our work. As well as additional data collected at the company PERENCO REP.

We used approaches with software such as:

- HagedornBrownCorrelation.xls.
- Microsoft Excel software.

3. Mibale Field Overview

The Mibale field is located in the "Offshore Concession" of the Congo Rep. Dem. This field is located approximately 3 to 5 km offshore and 3 to 7 km southeast of the DRC's offshore border with Cabinda (Angola) and extending over an area of approximately 11 km2, is a high-relief anticline structure formed on the overturned block of major NW-SE-trending growth fault system. A salt ridge underlies the Pinda along the northwest-se orientation of the structure.
This model as shown is derived from the cartographic model of the Mibale field made from the Argis software.

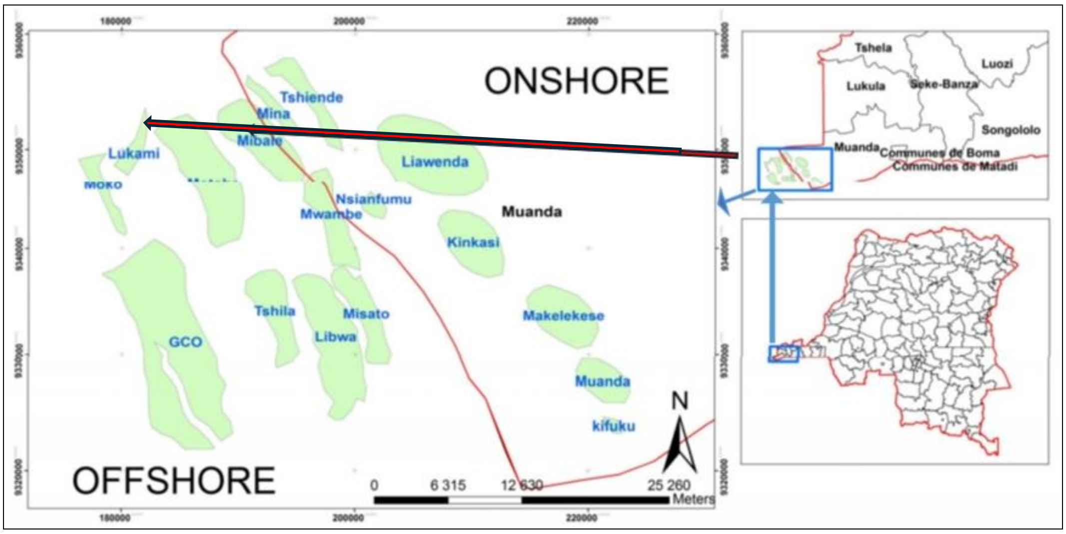

Fig 1: Location of the Mibale field (Argis software)

4. The Hydraulic Properties of Flowing Fluids

To understand the volumetric behavior of flowing fluids as a function of the pressure that changes during the process of ascent in the tubing, it is essential to have an in-depth knowledge of the hydraulic properties of flowing fluids that directly influence the behavior of fluids under different pressures [1, 2, 3, 4, 5].

The Performance of Tubing

The analysis of the effectiveness of a wellbore under the aegis of a production tubing will focus on the evaluation of the pressure loss between the downhole and the wellhead. This is why the knowledge of this pressure loss and its causes makes it possible to design the well equipment so that it best provides the desired production under the best economic and other conditions. The oil obtained from the surface is facilitated by the tubing channel, casing and annular space. But production through tubing is the most used because it allows to strengthen production by facelift, i.e. the injection of fluids into the annular space. Thus, in this chapter we will deal with the analysis of TPR (tubing productivity relationship), sometimes called VLR (vertical lift relationship) with these mathematical approaches [6, 7, 8, 9].

The study of TPR and pressures will be more based on both monophasic and polyphasic flow. Thus, in this chapter, the emphasis will be placed more on the multiphase flow in the oil well since the models retained for the analysis are those of Hagedorn and Brown and Beggs and Brill. We will briefly outline these two correlations that will allow us to analyze the effectiveness of tubing [6, 8, 10].

5. Correlations Methods on the Performance Study

Multiphase flow in pipes is the process of simultaneous flow of two or more phases. In oil or gas production wells, the multiphase flow is typically oil, gas, and water. Estimating pressure drop in vertical wells is very important for cost-effective well completion design, production optimization, and surface facility optimization. However, due to the complexity of multiphase flow, several approaches have been used to understand and analyze multiphase flow.

The oil and gas industry needs a general method for predicting and evaluating multiphase flow in vertical pipes [11, 12, 13, 14]. Multiphase flow correlations are used to determine the pressure drop in pipes. Although many correlations and models have been proposed to calculate the pressure drop in a vertical well, the effectiveness of these proposed models remains controversial.

Many correlations and equations have been proposed in the literature for multiphase flow in vertical, inclined, and horizontal wells. Early methods treated the multiphase flow problem as the flow of a homogeneous mixture of liquid and gas.

This approach completely ignores the well-known observation that the gas phase, due to its lower density, exceeds the liquid phase, resulting in "slippage" between phases.

Sliding increases the flow density of the mixture compared to the homogeneous flow of the two phases at equal speeds. Due to the poor physical model adopted, the accuracy of the calculations was low for these early correlations. Another reason for this is the complexity of multiphase flow in vertical pipes. Where water and oil can have almost equal speed, gas has a much greater speed. As a result, the difference in speed will definitely affect the pressure drop.

Many methods have been proposed to estimate the pressure drop in vertical wells producing a mixture of oil and gas. The study by [15, 16, 17, 18, 19] concluded that none of the traditional multiphase flow correlations work well across the range of conditions encountered in oil and gas fields. In addition, most of the vertical pressure drop calculation models have been developed for average petroleum fluids and that is why special conditions such as: Emulsions, non-Newtonian flow behavior, excessive limescale or wax deposits on the tube wall, etc. Can cause serious problems. In such cases, the forecasts could therefore be doubtful [20, 21, 22].

The main objective of this study is to evaluate the current empirical correlations, mechanistic model and artificial neural networks for the estimation of pressure drop in multiphase flow in vertical wells by comparing the most common methods in this field.

The parameters affecting the pressure drop are very important for the calculation of pressure. They will therefore also be taken into account in the evaluation.

Application of Tubing Performance

In the previous chapter, we talked about the different types of methods for analyzing tubing performance in reservoirs as well as the hydraulic properties of hydrocarbons by detailing the key elements of tubing performance, which we will use to obtain results based on existing models.

In addition, we have developed different formulas that allow us to determine the different properties of the effluents we need to use them when studying the performance of tubing.

Thus, with regard to the tubing performance analysis during production in the upper Pinda reservoir of the Mibale field in the coastal basin, we will apply the theory of performance analysis while respecting the hydraulic properties of hydrocarbons according to the Hagedorn-Brown model and the Beggs-Brill model seen in the previous chapter, to analyze the performance of each of this model and conclude with an interpretation.

6. Presentation of the Mibale-01 Well PVT Data

This determination takes into account the PVT parameters as well as the fluid properties of the upper Pinda reservoir of the Mibale field. These parameters are presented in Table 1 below:

Table 1: PVT data from the Mibale-01 well [23]

Parameters	Values	Units
Wellhead pressure	100	Psia
Tubing head temperature	100	F
Inner diameter of the tubing	3,813	In
Tubing Depth	5095	Ft
Temperature at the bottom of the well	170 F	F

Liquid flow rate produced	2500	stb/D
Production GLR	133.5418	
Water viscosity	1,002	Cp
Gas viscosity	0,01	Cp
The water volume formation factor	1,2	
GOR	130	scf/stb
Tubing Length	5095	Ft
Absolute roughness	0,0006	In
Gas viscosity	0,01	
Gas density	0,65	
Water density	1	
Oil density	35	API
Water Cut	72	%

Data Analysis

The tubing performance analysis is based on the evaluation of the pressure loss from the bottom and at the well head.
This curve is drawn using several pairs of points between the flow rates and pressures at the bottom of the tubing.
 Analysis of tubing performance according to the Beggs and Brill correlation method:
We recall that when the fluid flows from the place of high pressure to the place of low pressure, the resulting loss of pressure is due to three simultaneous actions:

- The effect of friction;
- The variation of potential energy;
- The variation of kinetic energy.

If the flow is horizontal, the variation in the potential energy of position is zero; If the flow takes place in a pipe with a constant cross-sectional area, the variation in kinetic energy is also zero.
But for lack of presentation, we will just present the detailed calculations for a single point by referring to the initial flow rate of QO = 700 Stb/stb and the others will be presented in the form of tables.
This correlation requires the subdivision of the tubing into several segments for a precision approach. But for didactic problems we will subdivide our tubing into 4 segments.
To do this, we will divide the tubing into 4 segments for didactic reasons, so 1273.75 ft each (these segments are too long for a correct solution because we cannot accept that the average density over a length of the tubing of 1273.75 ft is really representative given the continuous variation of pressure and temperature along the tubing on which it depends).
• Determination of the Froude number
The Froude number is calculated as follows:

$$N_{FR} = \frac{v_m^2}{gd} \tag{1}$$

where

$$v_{sL} = \frac{Q_L}{\frac{\pi}{4}D^2} \tag{2}$$

And the formula v_sL must be expressed in ft/s; As well as:

$$v_{sG} = \frac{(Q_g - Q_o R_s)}{\frac{\pi}{4}D^2 E} \tag{3}$$

Bo, Bw and Bg are used in these equations to convert the flows harvested under standard conditions to the flows in the tubing.
Replacing the PVT data in the equations for determining the Froude number, we find the results summarized in Table 2.

Table 2: Parameters related to the calculation of the Froude number

d_o	R_s	B_o	Q_G	Q_L	v_{sg}	v_o	v_m	$v_m{}^2$
0.849	14.2535	1.0200	9100	2500	1.7697	2.086	3.8557	14.866

Hence the Froude number is equal to 1.4577
• The proportion of fluid entering the pipe (CL)
In accordance with the equation below, CL is obtained as follows*:*

$$C_L = \frac{Q_L}{Q_L + Q_{g\times B_g}} \tag{4}$$

With

$$B_g = 0.0054 \times \frac{zT}{p} \quad (5)$$

z is the gas compressibility factor, or deflection factor, which is obtained by calculating the parameters below:

$$z = A + \frac{1-A}{e^B} + Cp_{pr}^D$$

$$A = 1{,}39(T_r - 0{,}92)^{0{,}5} - 0{,}36T_r - 0{,}1$$
$$B = (0{,}62 - 0{,}23T_r)p_r + \left(\frac{0{,}066}{T_r - 0{,}86} - 0{,}037\right)p_r^2 + \frac{0{,}32p_r^6}{10^E}$$
$$C = 0{,}132 - 0{,}32\log(T_r)$$
$$D = 10^F$$
$$E = 9(T_r - 1)$$
$$F = 0{,}3106 - 0{,}49T_r + 0{,}1825T_r^2)$$
$$p_{pc} = 709{,}604 - 58{,}718d_g$$
$$T_{pc} = 170{,}491 + 307{,}344d_g$$
$$p_{pr} = \frac{p}{p_{pc}}$$
$$T_{pr} = \frac{T}{T_{pc}}$$

And so we find the value of Z according to this formula below

Ainsi les r

The results of the parameters for the calculation of the proportion of fluid entering the pipe are summarized in the following Tables (3) and (4):

Table 3: Parameters used for the calculation of CL

A	B	C	D	E	F
0,4254	0,0442	0,0745	0,9704	4,6118	-0,0130

Table 4: Parameters used for the calculation of CL

T_{pc}	p_{pc}	T_{pr}	p_{pr}	Z	B_g
370.2646	671.4373	1.5124	0.1568	0.9874	0.0265

By replacing the parameters with their values as represented in the table above in this formula $C_L = \frac{Q_L}{Q_L + Q_g \times B_g}$ (4), We find 0.00414469 as the value of the proportion of the liquid at the inlet in the pipe. We have just calculated the Froude number (Frm) and the proportion of the liquid at the inlet in the pipe (CL), so we still have to find the parameters (L1; L2; L3; L4), to determine the type of flow that would exist if the pipe were horizontal. Hence we replace the corresponding values:

Table 5: Parameters that determine the type of flow for a horizontal pipe

L_1	L_2	L_3	L_4
258,1685	0,0048	0,2642	45,4502

We notice that:

CL is less than 0.001 and NFR is less than L1, we are in the segregation regime.

3.3.1.c Determination of Holdup Fluid

The holdup liquid refers to the share of liquid in the mixture. It is calculated as follows:

$$E_L(0) = a\,\frac{C_L^b}{{N_{Fr}}^c} \quad (6)$$

Or a, b and c are constants given in Table (2.2) according to the flow regime.

For the segregation regime a= 0.98; b=0.4846 and c= 0.0868

Hence EL (0) is 0.0664440856

This value corresponds to the flow in a horizontal pipe, and we work in vertical wells. Hence we need to calculate the correction factor for the tilt of liquid holdup () to have a value that will reflect reality.

So to determine the tilt correction factor of the holdup liquid, we will find these two parameters:

$$\psi = 1 + \beta\,[\sin(1.8\theta)_{-0.333}sin^3(1.8\theta)] \quad (7)$$

$$\beta = (1 - E_L(0)\ln(dE_L^e {N_{vl}}^f {N_{Fr}}^g) \quad (8)$$

Table 6: The parameters that calculate the correction factor for holdup liquid

ρG	ρo	ρW	ρL
1,8714	52,1230	62,4219	59,5382

holdup Thus we can find NLV and calculate the correction factor of the tilt of the holdup liquid Is dimensionless number due to the flow of liquids of which:

(**β**)

$$N_{Lv} = v_{sl}\left(\frac{\rho_L}{g\sigma_L}\right)^{0,25}$$

σ_L : Is the interracial tension ($\sigma_L = (30)$)

ρ L The density of liquid given by $\rho_L = \rho_o \times (1 - water\ cut) + (water\ cut \times \rho_w)$ (8)

Table 7: Parameters used to find EL

β	σ_L	φ	NLV
1.1028	30	1.2273	4.7983

Thus we can find the EL (φ) by the product of EL and φ gives 0.0815422. Once the actual liquid hold-up is calculated, it will be necessary to calculate the density of the mixture (ρm). This density of the mixture, in turn, will be used to calculate the pressure variation due to the hydrostatic pressure of the vertical component of the pipe of the pipe:

$$\Delta p_{HH} = \frac{\rho_m}{144} L * \sin(\theta)$$

Ainsi : $\rho_m = \rho_L E_{L(\psi)} + \rho_g\left(1 - E_{L(\psi)}\right)$ (9)

Table 8: Parameters for Finding the Density of the Mixture

EL(Θ)	EG	ρNS	ρ_m (lbm/cf)
0,7562	0,2437	31,4006	45,4812

Au bout du premier segment L = 1273,75ft

Table 9: Parameters for calculating the variation in hydrostatic pressure

L (ft)	ρ_g (lbm/cf)	ρ_m (lbm/cf)
1273.75	**7.5338**	**45.4812**

$\Delta p_{HH} = \frac{\rho_m}{144} L * \sin(\theta)$ = 201.1520 psi

And then, we find the two-phase flow resistance factor
Let us find the density of the mixture when there is no phase slippage, which is calculated by the following formula:

$$\rho_{NS} = \rho_L C_L + \rho_G C_G = \rho_L C_L + \rho_G(1 - C_L) \quad (10)$$

Which is equal to 0.6833lbm/ft3
Then we find "s" by the following formula:

$\frac{f_{tp}}{f_{NS}} = e^s$ cfr table 10:

Table 10: Parameters for the calculation of the frictional pressure gradient

S	μ_{NS} (cp)	R_e (scf/stb)	f_F	f_{tp}
0.26654	0.6838	83514,11	0.00566	0,007391

And so the variation of the pressure due to friction at the end of the first segment is calculated by:

$$\Delta p_f = \frac{2 f_{tp} \rho_{NS} V_m^2 L}{144 g_c D} \quad (11)$$

Where from Δp_f = 3.37544 psi

The change in total pressure along the tubing will be the sum of the hydrostatic pressure loss and the frictional pressure loss. Therefore:

$$\Delta P = \Delta P_{HH} + \Delta P_f \quad (12)$$

: $\Delta P = \Delta P_{HH} + \Delta P_f = 204.5374$ psi

The change in total pressure along the tubing will be the sum of the hydrostatic pressure loss and the frictional pressure loss.

P= $\Delta p + 100$ = 304.5374 psi

Thus we proceeded to find the value of the pressure by referring to a segment taken as a reference of the iteration on this, the sequence of values is given in the table below;

Table 11.a: General summaries of calculation results on Microsoft Excel

Depth	L (ft)	ϴ	Δz	Bottom temperature(F)	Head temperature(F)	Head pressure (psi)	dt/dx
0	0	90	0	170	100	100	0,0105
1273,75	1273,75	90	1273,7496	170	100	100	0,0105
2547,5	1273,75	90	1273,7496	170	100	100	0,0105
3821,25	1273,75	90	1273,7496	170	100	100	0,0105
5095	1273,75	90	1273,7496	170	100	100	0,0105

Table 11b: General summaries of calculation results on Microsoft Excel

Deepth (F)	Pressure (psi)	Tension interfacial	Qgas	Qoil	Qw	Qliquid (bbl/d)	GOR
100	105,3	30	91000	700	1800	2500	130
113,4078	586,071	30	91000	700	1800	2500	130
126,8157	1147,637	30	91000	700	1800	2500	130
140,2236	1712,214	30	91000	700	1800	2500	130
153,6315	2269,389	30	91000	700	1800	2500	130

Table 11.c: General summaries of calculation results on Microsoft Excel

GLR	WC	API	Dg	do	dw	Diameter(in)	Rs
133,5418	0,72	35	0,65	0,8498	1	0,317	14,2535
133,5418	0,72	35	0,65	0,8498	1	0,317	108,9760
133,5418	0,72	35	0,65	0,8498	1	0,317	236,6791
133,5418	0,72	35	0,65	0,8498	1	0,317	370,4255
133,5418	0,72	35	0,65	0,8498	1	0,317	502,7045

Table 11.d: General summaries of the calculation results on the Microsoft Excel software

Bo	Tpc	Ppc	Tpr	Ppr	A	B	C
1,0200	370,2646	671,4373	1,5124	0,1568	0,4254	0,0442	0,0745
1,0608	370,2646	671,4373	1,6026	0,8728	0,4715	0,2589	0,0664
1,1186	370,2646	671,4373	1,6388	1,7092	0,4885	0,5549	0,0633
1,1834	370,2646	671,4373	1,6750	2,5500	0,5048	0,8846	0,0603
1,2511	370,2646	671,4373	1,7112	3,3798	0,5204	1,2283	0,0573

Table 11.e: General summaries of calculation results on Microsoft Excel

D	E	F	Z	Bg	Bw	ρgaz	Poil
0,9704	4,6118	-0,0130	0,9874	0,0265	1,01	1,8714	52,1230
0,9863	5,4239	-0,0059	0,9375	0,0051	1,01	9,6737	50,8065
0,9947	5,7498	-0,0022	0,8901	0,0027	1,01	17,8421	49,0892
1,0043	6,0757	0,0018	0,8636	0,0019	1,01	24,8118	47,3278
1,0151	6,4016	0,0065	0,8582	0,0016	1,01	30,2074	45,6504

Table 11.f: General summaries of the calculation results on the Microsoft Excel software

Peau	Pl	µgaz	µh	µW	µL	Vsg	Vsh
62,4219	59,5382	0,02	2,13	1	1,3164	1,7697	2,0860
62,4219	59,1696	0,02	2,13	1	1,3164	0,0621	2,1095

62,4219	58,6888	0,02	2,13	1	1,3164	-0,1710	2,1428
62,4219	58,1956	0,02	2,13	1	1,3164	-0,2772	2,1802
62,4219	57,7259	0,02	2,13	1	1,3164	-0,3530	2,2193

Table 11.g: General summaries of the calculation results on the Microsoft Excel software

Vsm	Frm	CL	Cg	L1	L2	L3	L4
3,8558	1,4578	0,5120	0,4879	258,1685	0,0048	0,2642	45,4502
2,1717	0,4624	0,8458	0,1541	300,4170	0,0013	0,1275	1,5451
1,9718	0,3812	0,9113	0,0886	307,2623	0,0011	0,1144	0,9346
1,9029	0,3551	0,9356	0,0643	309,7166	0,0010	0,1101	0,7826
1,8662	0,3415	0,9474	0,0525	310,8880	0,0010	0,1081	0,7194

Table 11 h: General summaries of the calculation results on the Microsoft Excel software

EL(0) segregation	EL(0) Intermiting	EL(0) Distributed	A	b	EL(0) Transition	Nvl
0,6857	0,5867	0,5883	-4,6020	5,6020	0,1314	4,7983
0,9661	0,7829	0,9677	-2,6559	3,6559	0,2963	4,8448
1,0186	0,8175	1,0434	-2,3557	3,3557	0,3438	4,9114
1,0381	0,8301	1,0717	-2,2464	3,2464	0,3630	4,9865
1,0479	0,8363	1,0858	-2,1790	3,1790	0,3750	5,0656

Table 11. i: General summaries of the calculation results on the Microsoft Excel software

ßsegregation	ßIntermiting	ßDistributed	B(Ө)	EL(Ө)	EG	ρNS	Pm
1,4412	0,1056	0	1,1028	0,7562	0,2437	31,4006	45,4812
0,4548	0,0389	0	1,1038	1,0664	-0,0664	51,5382	62,4598
0,2685	0,0222	0	1,1052	1,1258	-0,1258	55,0670	63,8307
0,1993	0,0157	0	1,1068	1,1490	-0,1490	56,0476	63,1723
0,1666	0,0125	0	1,1085	1,1617	-0,1617	56,2792	62,1770

Table 11. j: General summaries of the calculation results on the Microsoft Excel software

	µNS	µm	E	Re	K	FNS	Y
	0,6838	1,0003	0,001	83514,11	13,2900	0,0056	0,8953
53,970	1,1165	1,4025	0,001	47285,67	12,8339	0,0060	0,7436
63,1453	1,2014	1,4795	0,001	42629,58	12,7389	0,0061	0,7189
63,501	1,2329	1,5096	0,001	40803,17	12,6978	0,0062	0,7086
62,674	1,2482	1,5260	0,001	39689,93	12,6715	0,0062	0,7019

Table 11. k: General summaries of the calculation results on the Microsoft Excel software

S	ftp	∆PHH	∆Pf	∆P	P
0,2665	0,0073	0	0	0	105,3
0,2764	0,0080	477,3958	3,3754	480,7713	586,0713
0,2756	0,0081	558,5507	3,0149	561,5657	1147,6371
0,2751	0,0081	561,7017	2,8754	564,5771	1712,2142
0,2748	0,0081	554,3878	2,7876	557,1754	**2269,3897**
		2257,3362	12,05352	2269,3897	

Referring to the procedure that facilitates the drawing of the TPR curve, we will use the flow and downhole pressure values of the Mib-01 well. The couples formed from its values will make basis points for tracing the curve. We have just given the details on the calculation procedure when 700 Stb/D, so we just have the iterations for the other bitrates. We will not be able to provide us with all the details in this work, which is certain and that the table above gives a perspective of how we proceeded for the iterations.

Table 12: The variation of flow rates as a function of the pressure at the bottom of the well in the case of Mib-01

Qo (stb)/D	pfw (psi)
2	3673,52
5	3449,76
10	3270,22
50	2839,07
100	2657,16
300	2401,97
700	2269,38
1000	2247,18
1400	2256,67
1800	2291,09
2100	2327,54

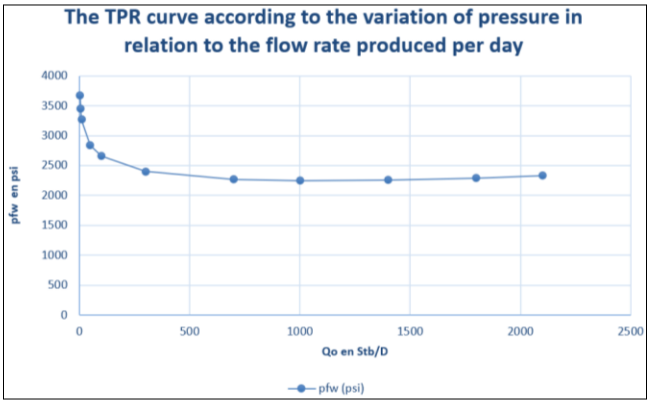

Fig 2: The TPR curve of the Mibale-01 well by the correlation of beggs and brill

3.3.2 Tubing Performance Analysis According to the Hagedorn and Brown Method
To perform a quick calculation on small (Δz), the Hagedorn-Brown model was codified in a software program that could be used on Excel called HagedornBrownCorrelation.xls. This is what we are going to use to achieve the right result.
By entering the data into this software, we arrive at the following results, the first graph of which gives the variation of the pressure in MPa and the second gives it in psi:

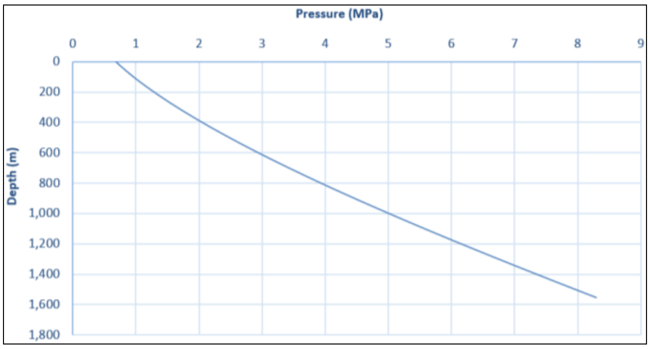

Fig 3: The curve drawn by the HagedornBrownCorrelation.xls software of the Mibale-01 well whose pressure is expressed in Mpa

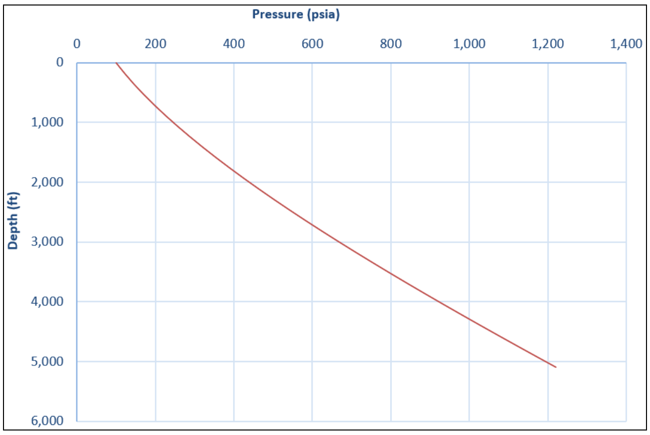

Fig 4: The curve obtained by the Hagedorn-Browncorrelation.Xls software of the Mibale-01 well the pressure in psi

Interpretations of the Results
The object of this work was to make a comparative study of the tubing performance using the mathematical methods of Beggs and Brill and that of Hagedorn and Brown.
The results of these analyses can be interpreted as follows:
During the analysis of the tubing performance by the Beggs and Brill correlation, we found that when the oil flow increases at the surface the flow regime in the tubing so much to change from segregation to the regime distributed in the following order:
(i) From 2 stb to 500 stb: the regime is segregated
(ii) From 500 stb to 600 stb: transitional regime
(iii) 600 to 700 STB: intermittent and
(iv) Above 700stb the scheme becomes distributed.

With the Qo we found the pressure at the bottom of the well to be 1827.104psi. Since the wellhead pressure was set at 100 psi, the difference gives us a pressure of 1727.104 psi as the pressure lost to raise a flow of 700stb.

After data processing by the HagedornBrownCorrelation.xls software we found that the pressure at the bottom of the well to give a value of 1219.5095psi therefore the pressure loss to row a flow rate of 700stb will be 1119.5095stb.

These two correlation models were manipulated to calculate the pressure drop in the Mibale-01 well casing. The correlation of Hagedorn and Brown, gave us a pressure loss from the bottom to the wellhead of 1119.5095 psi. But this loss does not take into account the inclination of the well.

For the Beggs and Brill correlation, gave a pressure loss of 1727.104psi in relation to the well data taking into account the angle of inclination.

But we can clearly see that the Hagedorn and Brown correlation neglects the angle tilt so its value does not really reflect reality, on the other hand the Beggs and Brill correlation takes into account all the parameter that can influence the pressure loss in the tubing so its value is close to the truth.

7. Conclusion

The subject of our thesis was to make a comparative analysis of the tubing performance by the hagedorn-brown method and the beggs-brill method applied to the mibale-01 well.

In the first chapter, we presented our study area by giving some geological aspects of the land and its history. In the second chapter we discussed the theories of tubing performance and we hammered more on the correlation of Beggs and Brill and that of Hagedorn and Brown.

And in the last chapter we performed the performance tu tubing by the two correlations mentioned in chapter two.

After these analyses, we arrived at the following results:

Beggs and Brill correlation with a Qo of 700stb.

The correlation of Beggs and Brill to give a pressure at the bottom of the well of 1827.104psi but the pressure at the wellhead was set at 100psi. So the pressure loss is 1727.104psi.

Hagedorn and Brown correlation with a Qo of 700stb.

This correlation gave a bottom of the well pressure of 1219.5095psi and we obtained a pressure loss of 11219.509psi.

Based on the above, we find that the Hagedorn and Brown correlation gave a value of the pressure loss minus the Beggs and Brall value.

But the HagedornBrownCorrelation.xls software cuts the tubing into several segments to have a density value close to reality, on the other hand with Beggs and Brill we have to cut the tubing with only 4 segments to find the density.

Hence the correlation of Hagedorn and Brown is less precise than that of Beggs and Brill since the latter takes into account the angle of inclination and all the parameters involved in the analysis of the pressure loss in the tubing.

8. References

1. Dake LP. Fundamentals of Reservoir Engineering. Ce livre est un ouvrage de référence pour l'ingénierie des réservoirs et couvre les aspects fondamentaux de la production de pétrole et de gaz, y compris la modélisation du flux multiphasique.
2. Admed T. Petroleum Production Engineering: Ce livre traite des aspects techniques de la production de pétrole, y compris les méthodes d'estimation de la production et les techniques de récupération des réserves.
3. Economides MJ. Multiphase Flow in Wells. Par Economides, M.J., *et al*. Ce livre est spécialisé sur les écoulements multiphasiques dans les puits de pétrole et de gaz, avec des sections dédiées aux méthodes de prédiction de la performance du tubing.
4. Mohaghegh S, Ameri S. Artificial Neural Network As A Valuable Tool For Petroleum Engineers. West Virginia University. U.S.A. Telex: SPE 29220, 1995.
5. Mohammadpoor M, Shahbazi K, Torabi F, Qazfini A. A new methodology for prediction of bottomhole flowing pressure in vertical multiphase flow in Iranian oil fields using artificial neural networks (ANNs), 2010.
6. Professeur KASONGO-NUMBI K. [Cours d'hydrogéologie des gisements pétroliers] université de Kinshasa (UNIKIN), 2021.
7. A New Method for Estimating Two-Phase Flow in Vertical and Inclined Wells par Beggs, H.D. et Brill, J.P. Article fondateur qui a présenté la méthode de Beggs-Brill pour la prédiction du flux multiphasique dans les puits, 1973.
8. par Hagedorn AR, Brown KE. Prediction of Pressure Gradients in Vertical Wells Producing Oil and Gas. Article qui présente la méthode de Hagedorn-Brown pour la prédiction du flux multiphasique, 1965.
9. par Aziz K, *et al*. Comparison of Multiphase Flow Correlation Models for Predicting Well Performance. Article comparant différentes méthodes de prédiction du flux multiphasique, y compris celles de Beggs-Brill et de Hagedorn-Brown, 2007.
10. Professeur KAMPATA Dona. [cours des techniques production]. Université de Kinshasa (UNIKIN), 2019.
11. Sukubo IA, Igboanugo AC. Improved analytical model for predicting field production performance in vertical multiphase flow in pipes using MATLAB; A case study. The Nigeria annual international conference and exibition, 30 July - 3 August 2011. Abuja, Nigeria, 2011.
12. Ayoub MA. Development and Testing of Universal Pressure Drop Model in Pipelines Using Abductive and Artificial Neural Networks. Bandar Seri Iskander, Perak: Phd Thesis, Universiti Teknologi Petronas, 2011.
13. Beggs HD, Brill JP. A Study in Two-Phase Flow in Inclined Pipes. Journal Chierici, G. L., Ciucci, G. M., & Sclocchi, G. (1974). Two-Phase Vertical Flow in Oil WellsPrediction of Pressure drop. Journal of Petroleum Technology, August 1974, 927-938, May, 1973.
14. Dun R, Ros NC. Vertical Flow of Gas and Liquid Mixtures in Wells. Proc., Sixth World Pet. Con- gress, Frankfort (J nne 19-26, 1963) Section II, Paper 22-PD6., (pp. 451-465).of Petroleum Technology, 607-17., AIME 255, 1963.

15. Abdul-Majeed GH, Al-Mashat AM. A mechanistic model for vertical and inclined two phase slug flow. Journal of Petroleum Science and Engineeringn, 2000, 59-67
16. Al-Attar HH, Mohamed MY, AMin ME. A Modified Version of the Aziz *et al*. Multiphase Flow correlation Imporoves Ressure drop Calculation in High-Rate Oil wells. EAGE annula conference and exhibition, 4-7 June 2012. Copenhagen, Denemark, 2012.
17. Ansari AM, Sylvester ND, Sarica C, Shoham O, Brill JP. A Comperhensive Mechanistic Model for Upward Two-Phase Flow in Wellbore. SPE Production and Facilities, May, 1994, 143-152.
18. Takacs G. Consideration on the Selection of an Optimum Vertical Multiphase Pressure drop Prediction Model for oil Wells. SPE Production and Operation Symposium, 24-27 March 2001. Oklahoma, 2001.
19. Trick MD. Comparision of Correlations For Predicting Wellbore Pressure Losses in Gas-Condensate and Gas-Water Wells. The Petroleum Society's Canadian International Petroleum Conference. Calgari, Alberta: Neotechnology Consultants Ltd, 2003.
20. Xiao JJ, Shoham O, Brill JP. A Comperhensive Mechanistic Model for TwoPhase Flow in Pipelines. 65th Anuual technical Conference and Exibition of the Society of Petroleum Engineering, September 23-26 (pp. 167-180). New Orleans, LA: University of Tulsa, 1990.
21. Zafareh F, Hill AD, Podio AL. Flow Regimes in Vertical and Inclined Oil/Water Flow In Pipes. 63rd Annual technical conference and exibition of the society of petroleum engineers, October 2-5. Huoston, TX: U. of Texas, 1988.
22. Ivakhnenko AG. Group Method of Data Handling a Rival of the Method of Stochastic Approximation. Soviet Automatic Control. 1966; 13:43-71.
23. Rapport PERENCO. [Mibale upper pinda study offshore RDC], 2018.