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OPTIMIZATION OF MIB-02 WELL BY CONVERTING THE ACTIVATION MODE USING PROSPER SOFTWARE

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ABSTRACT

Mibale oil field considered a mature oil field, located offshore in the coastal basin of the DR Congo and discovered in 1973, has seen an evolution in its production since it began operation in 1976, starting from an initial rate of 10,000 BOPD with 3 producing wells to the current production of 5,905 BOPD from 14 wells. In 2021, the field had 393 MMstb of oil reserves in the reservoir. A thorough study of the production system was carried out, focusing on the five best producing wells, including well MIB-02. Despite traversing layers of the reservoir with high oil potential, the well is underperforming with a respective flow rate of 351 BOPD and a 60% WOR using an electric submersible pump. Following this low production, various studies were conducted, including the study on converting the activation method by proceeding with nodal analysis technique.

The use of nodal analysis proved crucial in identifying the shortcomings of the production system, combining field history with analysis of production, well test, pressure, and completion data. The IPM Prosper software enabled a thorough analysis, revealing that MIB-02 had a production potential greater than its current performance.

This performance was revealed after evaluation and interpretation of IPR, VLP curves and sensitivities of variables such as water cut and pressure at the first node. After interpreting these curves, the MIB-02 well had the production capacity of 4100.62 BOPD and 12463.9 BWPD. By converting the submersible electric pump activation mode to gas-lift and exploring various scenarios, production was improved with an oil flow rate of 1244.9 BOPD, water flow of 2539 BWPD, to a gas flow of 0.37346 MMscf/day and 67.1% water cut.

Despite these improvements, excessive water production remains a challenge while also highlighting the complexity of the production system and the limitations of the analysis technique. Therefore, further studies can be envisaged by modeling and simulating the reservoir, considering well interventions and quantifying the remaining reserves today. This more comprehensive approach will enable a clearer vision and help decide the best optimization strategies for the Mibale field production system.

***Keywords*:** mature oil field, activation mode, nodal analysis, oil well, performance

INTRODUCTION

Optimization was developed during World War II by the Armed Forces in the field of applied mathematical research to be used in various fields of research [1]. Optimization, a complex technique that involves several variables to find an optimal solution, has helped solve production problems that were previously insoluble [8]. Therefore, production optimization encompasses the various measurement, analysis, modeling, priority and execution actions aimed at improving the productivity of a field: reservoirs, wells and surface [28]. It is essential to ensure that developed reserves are recovered while maximizing profits [14, 25].

Various options offered by optimization are derived from two general methods, known as exact and approximate methods. Both techniques are based on very different principles that apply to the production of hydrocarbons. Each individual studies and uses the field of research according to their own approaches [24, 9]. However, with regard to the optimization of the production system, this limitation may be due to the complexity of the reservoir (reservoir geology, fluid characteristics, pressure and temperature), geological uncertainty (accuracy of the optimisation results), variations in the tank condition (need for regular re-evaluation of optimization), operating constraints (financial costs, etc.), environmental impacts, etc. [18].

In this regard, our optimization study suggests a detailed analysis of the MIB-02 well, focusing on the technical and operational aspects of its production. The objective of the evaluation is to deepen our understanding of the performance of the well, to identify any difficulties (loss of pressure (load loss), leaks or other technical problems) that limit its production, and to propose appropriate optimization solutions to improve its production and efficiency. There are many methods and techniques for evaluating a production system, such as production test, pressure analysis, well diagrams, fluid analysis, tank modeling, and production monitoring. The choice of method depends on the objectives set and the specific characteristics of the well [5].

Apart from these approaches, nodal analysis is used for the study of various fluid production problems in the well. It appears to be the most effective method, as it allows to quickly identify the problem in a production system and to propose the most optimal solution, taking into account several variables [28]. This technique divides the journey of the fluid from the reservoir to the surface into two parts that meet at a point known as "node". The flow in the reservoir before the node is therefore known as the inflow, while that after the node is referred to as the outflow in the well [26].

Once the problem quickly detected by the nodal analysis technique is solved in the well but whose results are still unsatisfactory to expectations, it is envisaged to undertake further studies to deepen knowledge of the oil field production system using conventional methods of improved oil recovery (IOR). It should be noted that the IOR encompasses the use of technological advances throughout the lifetime of an oil field and includes improved reservoir management, cost reduction initiatives and advanced methods, often referred to as Enhanced Oil Recovery (EOR) or tertiary recovery, such as thermal injection, microbial injection, chemical injections, and gas injecting, among others. The chosen EOR techniques are based on the physico-chemical properties of the fluids produced and the petrophysical characteristics of the reservoir [4, 6]. Since nodal analysis complements the IOR methods by providing a broader analysis of the performance of the low-performance production system, this implies that nodal analyses are not associated at a specific time in the production optimization process. It can be used at various stages of the process. Since optimization in hydrocarbon production systems is difficult to solve, computer simulation software is used to provide data on well behavior in static and dynamic conditions [23, 15]. In this respect, IPM Prosper is the ideal software for performing extremely accurate simulations of well production systems.

Problem statement

Since there are few new discoveries of hydrocarbons and there is a projected shortage of supply by 2025, it is crucial to invest in this area as soon as possible and to maximize the recovery of already discovered hydrocarbons using suitable techniques [14]. The different recovery techniques vary depending on the reservoir characteristics, pressure of reservoir or well, volume and temperature of the fluids, the activation method of well, etc.

The upper Pinda formation, considered as the productive reservoir of the Mibale field, contains good-quality oil but with a pressure too low to lift it to the surface through production wells. Given this low pressure, after one year of production, gas-lift activation was implemented to improve production. Unfortunately, after one year, this activation method became ineffective, and the decision made by the operating company was to assist the reservoir by injecting water. However, due to corrosion issues with some water treatment equipment, the injection was halted in 2005, with an unsuccessful attempt to resume it in 2008 [22].

In-depth studies conducted in 2007, 2010 and 2016 in the Mibale field led to the development of the field and the conversion of some wells' activation method to submersible electric pumps. However, the results were not as satisfactory as the company's expectations [22, 17]. This prompted a new line of thinking, which involved reviewing all the studies conducted in this field and identifying the shortcomings in order to propose appropriate solutions to the company for extracting a significant portion of the remaining 393 million stock tank barrels (MMstb) of oil in the upper Pinda reservoir.

Based on the above, we are interested in understanding the production system using nodal analysis approach in order to propose optimal solutions for increasing production in the Mibale field. This understanding raises the formulation of the following research questions:

- What is causing the low production yield of certain wells producing hydrocarbons from the upper Pinda reservoir in the Mibale field?
- Are the current gas-lift and submersible electric pump (ESP) activation methods used for oil production in the Mibale field still compatible with the economic and technical operating conditions of the associated well?
- Do the petrophysical properties of the productive reservoir, upper Pinda, have a significant impact on the low oil production in this field?

- Is it necessary to convert the activation mode of MIB-02 well based on the current knowledge in this field?

The scientific contribution regarding the study on the evaluation and optimization of the hydrocarbon production system in the Mibale field lies in understanding how to quickly identify performance issues in an oil field production system through the collection and analysis of production data using nodal analysis technique and IPM Prosper software. The limitation of this technique will help uncover the major factors contributing to the low production of the field as a whole and the individual well in particular.

Specific Objectives

The specific objectives set in this study are as follows:

- Analyze and assess the production history of oil wells drilled in the Mibale field in order to identify strengths and weaknesses;
- Analyze the petrophysical properties of the upper Pinda reservoir and the parameters of the MIB-02 well that crossed it;
- Develop IPR (Inflow Performance Relationship) and VLP (Vertical Lift Performance) curves and determine parameters related to the production of currently well in order and ESP activated well to optimize;
- Propose reconditioning works by converting the activation mode of MIB-02 well.

MATERIALS AND METHODS

For the realization of this study, we followed a methodological approach comprising two main phases:

Data collection

Apart from documentary research, the following data were collected to the objectives set:

- Production fluid data from 2010 to 2021;
- Completion data (Casing depth, tubing depth, pump depth, inner and outer diameter, inclination, sediment level in the well, packer depth, ...);
- Reservoir pressure data (Gauge and perforation depth, gauge and perforation pressure, fluid gradient, pressure-depth relationship, limit depth for gauge pressure measurement, perforation pressure at the top of the reservoir, gauge temperature by depth...);
- Well testing data (Produced fluid rates, sediment rates, pressure and temperature at the wellhead, casing pressure, injected fluid rates, fluid production ratios, ...);
- Fluid and reservoir properties in initial and current conditions (Reservoir fluid viscosity, dissolved gas ratio, bubble pressure, reservoir pressure, reservoir permeability, oil and gas volumetric factor, ...);
- Reserve evaluation and simulation data of the upper Pinda reservoir in the Mibale field.

Data processing and interpretation of results

Field data was processed for presentation in the form of tables, various graphs and maps. To do this, the following computer tools or software are used:

- Excel for the establishment of fluid production curves and mathematical or statistical calculations;
- Arcgis for the development of the study area map;
- Integrated Production Modelling - Production System Performance "IPM Prosper": to evaluate and optimize the Mibale field production system based on the analysis of the MIB-02 producer well.

The meaning of the results obtained from these treatments is the subject of the interpretation section. The following diagram (Figure 1) summarizes the phases of our methodological approach:

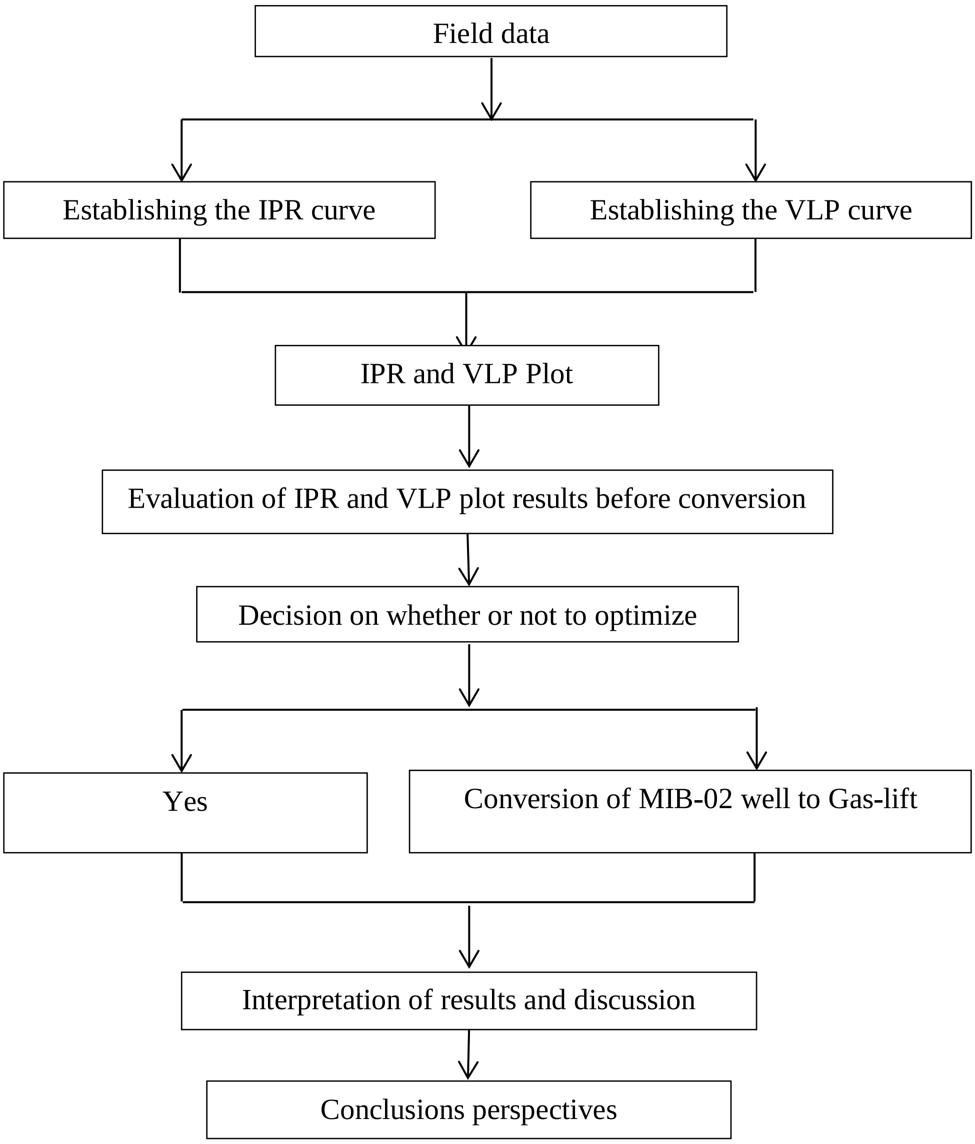


***Figure 1**. Methodological approach*

OVERVIEW OF THE MIBALE FIELD

The Congolese Offshore has 9 oil fields with 65 wells of which 21 wells belong to the Mibale field. Of these 21 wells, we have 14 producers, 6 injectors and 1 appreciation well, which is equivalent to 32.3% of the total oil fields. As of today, the field is producing an average of 5905.54 barrels of oil per day (BOPD) with a water-oil ratio (WOR) of over 60% (September 2021 average). Starting from the average official production of 25,000 BOPD for this company, we observe that this field contributes to the extent of 23.6%. Therefore, we can conclude that this field represents the largest offshore oilfield. It is worth noting that the Mibale field was discovered in 1973 by the oil company CHEVRON with the Mibale 1X well in the Upper Pinda formation, which is part of a fault-related structure with three branches. With three wells, MIB-01, MIB-02, and MIB-03, this field was put into production in 1976 [22, 17].

A good quality oil (32° API) has been discovered in a multi-layer complex in the upper part of the Albien-age Pinda formation, also known as the Upper Pinda reservoir. The Upper Pinda in the Mibale field is a reservoir with high permeability intervals, sand-rich layers, and dolomitic layers. It is divided into eight layers (LP or UP) ranging from the transition layer to L7 (UP-7). The upper transition layer is often described as poor-quality limestone and clays, while the underlying UP-1 layer consists of relatively low-quality limestone and less developed carbonate sands [27].

Location of the Mibale field

The Mibale field is located in the coastal basin of the Democratic Republic of Congo, 5 km wide and 3 to 7 km southeast of the DRC's offshore border with Cabinda (Angola), and covers an area of around 11 km^2 (Figure 2).

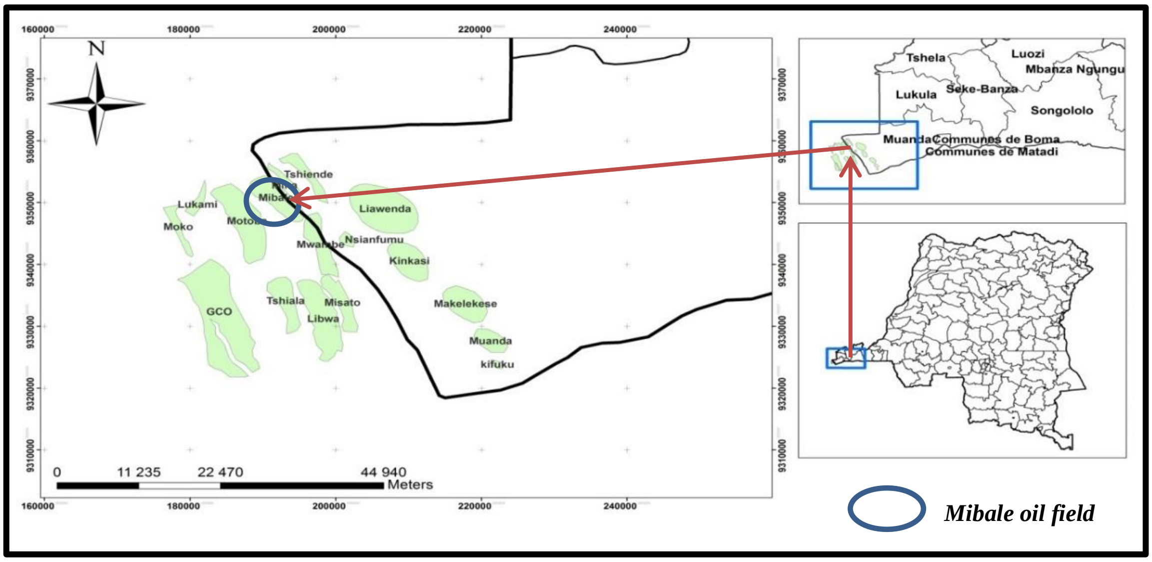


Figure 2. *Location of Mibale field*

Reserves of Mibale field

The studies conducted in 2016 provided the STOIIP (Stock Tank Oil Initially in Place) of the different layers of the Upper Pinda reservoir, as summarized in Table 1 below, comparing them with the geological STOIIP values from 2006. L1 layer (34%), L2 layer (22%) and L4 layer (25%) are the main STOIIP. The L1 and L2 carbonate layer STOIIPs account for 56% of the Pinda field STOIIP as a whole. The difference with the geological model lies mainly in the way water saturation is used relative to depth, a relationship that introduces a large area of transition. Table 2 shows the layers of the reservoir with the wells crossing them.

Table 1. *Mibale field STOIIP by layer (MMstb)*

Layer	*Mibale Field*	
	Geological model (2006)	***Geological model (2016)***
L1	97	132.3
L2	107	86.9
L3	74	46.9
L4	163	99
L5	13	7.7
L6	20	10.5
L7	22	9.7
STOIIP Total (MMstb)	**496**	**393**

Table 2. *The layers of the reservoir with the wells crossing them*

Layer	***Producing wells***	***Injector wells***
L1	MIB-01-02-03-05-09ST-10-11-14-15-16-17-18	MIB-06-08-13ST
L2	MIB-01-02-03-05-09ST-10-11-14-15-16-17-18	MIB-06-13ST
L3	MIB-01-02-03	MIB-06
L4	MIB-02-05-09ST-14ST-10-11-15-16-18	MIB-07-08-12
L5	MIB-05-09ST-14ST-17	MIB-07-08-12
L6	MIB-09ST	MIB-07-08-12
L7		MIB-12

By observing tables 1 and 2, we note that well MIB-02 produces from L1, L2, L3 and L4 with estimated remaining reserves of 365.1 MMstb so this well passes through the layers of the reservoir containing 92% of the oil reserves of the Mibale field.

Production of Mibale field

The evolution of annual production in the Mibale field from 2010 to 2021 is illustrated in Figure 3. In 2010, the production was good, but in 2015, it was too low, as a result of the shutdown, refueling and excessive production of water and gas from certain producing wells. This decline in production prompted the company in 2016 to deepen its knowledge of the Mibale field by conducting studies on the static and dynamic tank model in order to assess the remaining oil volume in place and identify potential locations for new drilling.

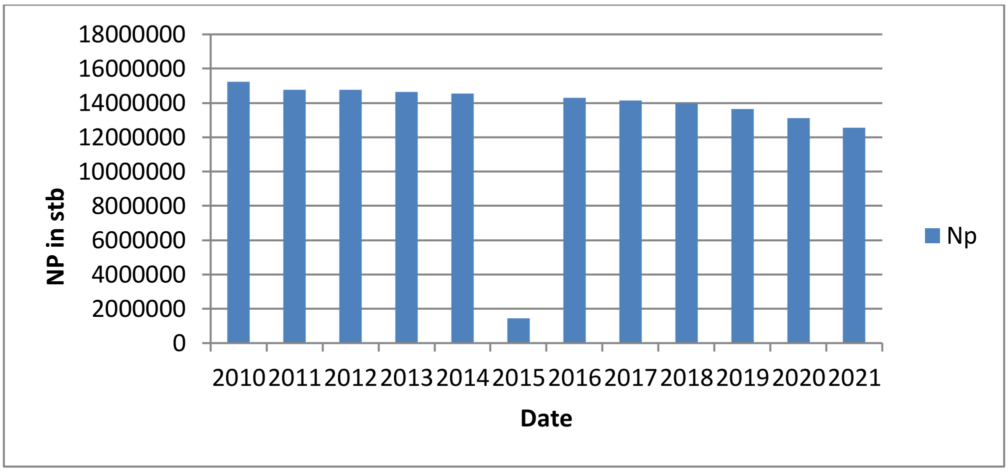


Figure 3. *Butt diagram showing the evolution of oil production in the Mibale field from 2010-2021*

For MIB-02 well

In October 1973, the well was drilled into the L5 layer at a TD of 6400 ftMD. Work began in layers L1 to L4. A workover was carried out in September 1980 to isolate the L4 zone from the flooding of heavy waters. In June 2007, oil production totaled 19 MMstb. Production was approximately 352 BOPD in 2021 with a 60% WOR (Fig. 4).

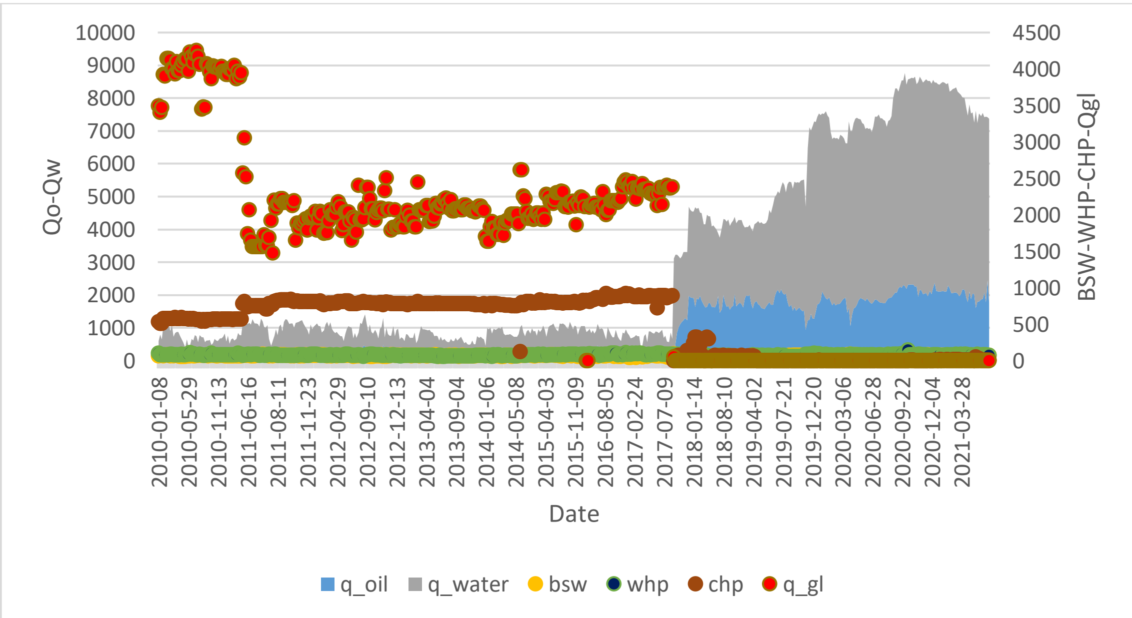


Figure 4. *Evolution of the production of the MIB-02 well (August 2010- September 2021)*

INFORMATION AND DATA ESSENTIAL FOR OPTIMIZING MIB-02 WELL

Reservoir and fluid parameters for the Mibale field

Table 3 shows the reservoir and fluid properties of the Mibale field, in which all wells drain oil to surface. Completion data for the MIB-02 well are presented in table 4.

Table 3. *Reservoir and fluid parameters for the Mibale field* [17, 21]

Parameter	Value
Bubble point pressure (Pb) @Tr	1336 psia
Drainage area	100 acres
Gas specific gravity (γ_g)	0.865
Impurities (N2, CO2, H2S)	0
Initial gas formation volume factor (Bgi)	0.002 rcf/scf
Initial oil formation volume factor (Boi)	1.13 rb/stb
Oil gravity (°API) (γ_o)	32
Oil viscosity @Pb	1.1 cP
Overall heat transfer coefficient	8 btn/hr/F
Porosity (Ø)	18%
Recovery factor (RF)	32.58%
Reservoir permeability (k)	50 mD
Reservoir Pressure (Pr)	2600 psia
Reservoir temperature (Tr)	167°F
Solution GOR (Rs)	300 scf/stb
Surface temperature	60°F
Top node pressure	500psig
Water salinity	0 ppm
Wellbore radius	0.354 ft

Table 4. *Completion data for the MIB-02 well on the Mibale field* [22, 27]

Well type	Producing well
Trajectory	Deviated
Tubing	Inside Diameter : 3.958 inches ; Outside Diameter : 4.5 inches ; Depth : 5608.4feet
Liner	Inside Diameter : 7 inches Depth : 5821feet
Water cut	67.1 %

Well Head & X-Mas Tree			
Items	Manuf.	Details	Flange
X-Mas tree	FMC	FMC X-mas tree 4-1/16 5K, Pneumatic actuator	4 1/16 5K
THA	FMC	FMC type A-3-EC, HD FLANGE, Shoulder type	4 1/16 5K x 11" 5K
THS	FMC	FMC Assy tbg head, C-29	11" 5K x 13 5/8" 3K
CHS			
-	-	-	-

Additionnal info	
PUW	44 Tons
SOW	xxx
TOL	
TOS	5968 ft
PBTD	5981 ft
TD	6400 ft

Casing data					
Size	Weigth	Grade	Thread	Top depth	Btm depth
36"	-	-	-	Surface	191 ft
20"	-	-	-	Surface	600 ft
13 3/8"	-	-	-	Surface	3980 ft
9 5/8"	-	-	-	Surface	6400 ft

Additional Info *	
1	Splice @5505ft; @2349ft ; @49,69ft
2	5 clamps MLE; 21 bandits; 117 x-cplg
3	Tubing hanger (FMC PN 2000012976)
4	21/04/2020: light WO performed to replace defa
	Penetrator and surface connector
5	
6	
7	

Perforation					
N°	zone	comments	status	Interval (ft)	Date perf.
1	UP 1		Activé	5645-5670	juin-11
2	UP 1		Activé	5690-5718	juil-11
3	UP 1	reperfs juin 2011	Activé	5718-5782	juil-76
4	UP 1		Activé	5784-5802	juil-76
5	UP 1/2		Activé	5805-5841	juil-76
6	UP 2/3		Activé	5848-5868	juil-76
7		reperfs juin 2011			
8		reperfs juin 2011			
9	UP 3	reperfs juin 2011	Activé	5993-6011	juil-76
10	UP 4		Plugged	6031-6049	oct-73
11	UP 4		Plugged	6062-6085	oct-73
12	UP 4		Plugged	6095-6192	
13	UP 4		Plugged	6151-6192	
14	UP 4		Plugged	6199-6352	

Factors Contributing to Pressure Losses in the Tubing

We noticed at point II.2 that the oil reserves are still significant in the field and also, the under-examined MIB-02 well passes through layers of the reservoir containing more than 92% of oil Reserves of this field. Thus, we will try to understand the causes of load losses that lead to the low output of the MIB-02 well. There are many factors that can contribute to the reduction of pressure in an oil well production system including [16, 11]:

1. Pipe friction: Pressure decreases can be caused by the friction between petroleum fluids and the pipe walls. They vary with the viscosity of the fluid, the internal diameter of the pipes, and the length of the pipes, and can increase if the pipes are too rough;
2. Narrows and obstructions: Narrows, bends or obstructions in production lines can lead to head losses. These losses are mainly caused by sudden changes in cross-section, which increase turbulence and fluid friction;
3. Clogging: Clogging of the well can lead to significant head losses. Solid particles, such as sands, clays or drilling cuttings, can settle in the well and obstruct fluid flow. This creates additional resistance to fluid flow and increases head losses;
4. Presence of water: If water is present in the well, it can cause high head losses. Water has a higher density than oil or gas, which increases the pressure required to move fluids through the well;
5. Cementing problems: Poor well cementing can lead to head losses. If the cement is not properly applied, or if there are leaks in the cementing, this can create undesirable flow paths for fluids, resulting in additional head losses;

6. Well activation mode restrictions: Limitations on the activation mode can be implemented in certain cases to control and pump the flow of trapped liquid in the well. This can be achieved through gas injection, valves, chokes, or other flow control devices. However, significant pressure losses can occur if these restrictions are too severe.

WELL BEFORE ACTIVATION MODE CONVERSION

Overview of MIB-02 well design

Figure 5 shows the first trajectory of the MIB-02 well drilled in 1973.

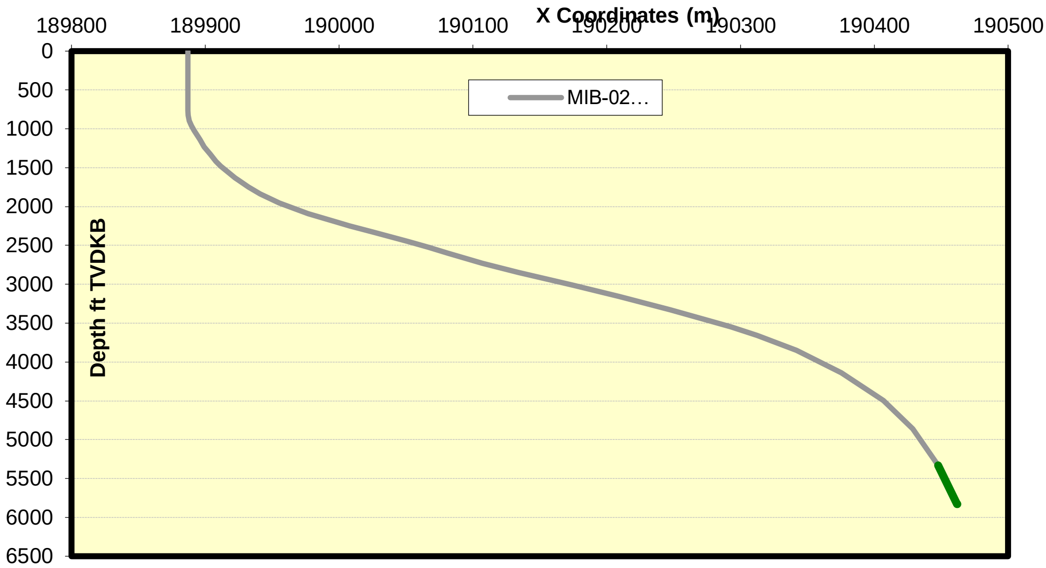


Figure 5. *MIB-02 well trajectory and perforation depths*

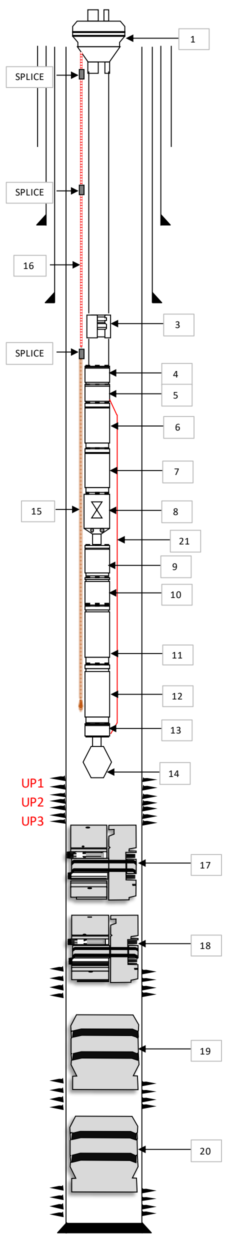
Except for the problem of excessive water production, in September 1980, a workover was carried out to isolate the L4 area from the flooding of heavy waters but unfortunately, this had created mechanical and technics problems in the well, the ideal solution of which was to make the well deviate to the vertical well.

Figure 6 illustrates the downhole equipment with depth accuracy vertically.

Well evaluation before activation mode conversion

To assess the well's productivity, the IPR and VLP curves must be analyzed to determine the well's production capacity and operating point. To establish these curves, certain correlation choices must be made:

- Rs correlation ;
- correlation on flow law;
- head loss correlation.



	Description (w/ SN &P/N)	ID	OD	Length	Top depth	Btm depth
		in	in	ft	ft	ft
1	**TH 4-1/2'' eue 8rd box Top & bttm, A/F BIW penetrator, 4'' H-BPV, w/seal sleeve**			0,77	29,20	
	3x Pup Joint 4 1/2" EUE pin x pin 9,2# L80, 10ft	3,95			29,97	
	175x Tubing 4 1/2" 9,2# EUE L80	3,95			59,93	
	Pup Joint 4 1/2" 9,2# EUE 10ft L80	3,95			5489,89	
2	**Landing Nipple 3,75 'R' profile, 4 1/2 EUE Top&Bttm**				5499,74	
	Pup Joint 4 1/2" 9,2# EUE 5ft L80				5500,95	
	Tubing 4 1/2" 9,2# EUE L80				5505,97	
3	**X-Over 4 1/2'' EUE box x 3 1/2'' EUE pin**				5536,30	
4	**DSCHG B/O PMP 513 3.5X8EUE 416SS (C50557)**			**0,55**	5537,08	
5	**HEAD S/A 513/538PX PRESS PORT (C308660)**			**0,75**	5537,63	
6	**PMP 538PMXSXD 059 FLEX80 H6 FER STD_PN (C326713)**			**18,93**	5538,38	
7	**PMP 538PMXSXD 054 FLEX80 HS FER AOR (105121358)**			**17,42**	5557,31	
8	**GASSEP 538GSHVEVX H6 FER STD_PNT (C322271)**			**3,25**	5574,77	5578,02
9	**SEAL GSB3DB XUT HL 1.125 H6 PFSA AB/AB (C317561)**			**6,89**	5578,02	
10	**SEAL GSB3DB XLT 1.125 H6 AB/AB CL5 HL (C317560)**			**6,89**	5584,91	
11	**MTR 562XPUX 350/1725/125/60Hz (105100418)**			**22,70**	5591,80	
12	**MTR 562XPLX 350/1725/125/60Hz (105100419)**			**22,47**	5613,52	
13	**WELLLFT, H 150 5K PSI 450 6B 22 CR 65 MY (H307790022)**			**1,83**	5635,99	
14	**GDE BULLNOSE 7 1/2" 9 5/8" CASING (CUKC1961700)**			**1,31**	5637,82	5639,13
15	CENTRILINK 20 110 4PLHT 76373 400°F (C78713-110)					
16	ESP Power Cable #2 AWG CELR Round					
17	Sump packer				5981,00	
18	Packer fish (after WO with Seawork in 2011)				5997,00	
19	Cement retainer (plugged in September 1980)				6092,00	
20	Cement retainer (plugged in January 1977)				6205,00	

Figure 6. *Downhole equipment configuration and illustration of perforation's depth for MIB-02 well*

Choice of gas solubility correlation (Rs)

To establish the IPR curve, we need to choose the dissolved GOR correlation. By replacing the fluid property values from Table 3 in mathematical equations (1), (2), (3), (4) and (5), we estimate the gas solubility (Rs) at bubble point pressure and compare this with the experimental value in terms of the absolute average error (AAE). The Rs's correlations expressed as mathematical equations are given as follows [12, 20]:

a. **Standing's (1981) correlation** is expressed in the following mathematical form:

$$R_s = c\left[\left(\frac{P}{18.2} + 1.4\right)10^x\right]^{1.2048} \quad (1)$$

$$x = (0.0125\,\gamma_o) - 0.00091(\mathrm{T} - 460)$$

b. **Vasquez-Beggs correlation** is given in the following form:

$$R_s = C_1 \gamma_{gc} P^{C_2} e^{\left[C_3 \cdot \frac{°API}{T+460}\right]} \quad (2)$$

with coefficient values C_1, C_2 and C_3.

c. **Glaso correlation** is proposed according to this relation:

$$R_s = \gamma_g \left[\frac{API^{0.989}}{(T-460)^{0.172}} \cdot P_b^*\right]^{1.2255} \quad (3)$$

where $P_b^* = 10^x$ and $x = 2.8869 - [14.1811 - 3.3093 logP]^{0.5}$

d. **Marhoun's correlation** proposed the following equation:

$$R_s = \left[a\gamma_g^b \gamma_o^c T^d P\right]^e \quad (4)$$

The coefficient values *a*, *b*, *c*, *d* and *e* are: *a*= 184.843208; *b*=1.8778480; *c*= -3.1437; *d*= -1.32657 and *e*=1.398441.

e. **Petrosky-Farshad correlation** is given by the following expression:

$$R_s = \left[\left(\frac{P}{112{,}727} + 12.34\right)\gamma_g^{0.8439} \cdot 10^x\right]^{1.73184} \quad (5)$$

$$X = 7.916 \cdot (10^{-4}) \cdot (API)^{1.541} - 4.561 \cdot (10^{-5})(T-460)^{1.3911}$$

The following formula makes it possible to find the absolute average error (AAE):

$$AAE = \left|\frac{Vr - Vm}{Vr}\right| x100 \text{ as a percentage} \quad (6)$$

with *Vr*: Real Value (Field Data) and *Vm*: Measured Value (correlation values).

This allows us to summarize the Rs correlation values found with AAE (Table 5).

We note that the value of GOR dissolved in oil (Rs) calculated by the Glaso correlation is a little close to that of the Mibale Field determined by PVT analyses with a deviation or AAE of 13.12%, which allows us to choose this correlation as the one applicable in the optimization of this well. Referring to table 3, the value of Rs is 300 scf/stb and using the Glaso correlation, Rs is 339.37 scf / stb with 13.12 deviation factor

***Table 5.** Summary of Rs calculation using empirical correlations*

Correlation	***R_s (scf/STB)***	***AAE(%)***
Standing	645.5	115
Vasquez-Beggs	589.7	96.6
Glaso	339.37	13.12
Marhoun	435.51	45.1
Petrosky-Farshad	599.4	99.8

Choice of flow law correlations

Several correlations on the flow law in the reservoir have been established with their mathematical expressions [30, 27, 8]. These are the correlations of:

- Darcy's method or law;
- Vogel's method;
- IP method;
- Fetkovich method;
- Johns, Blout and Glaze method.

Given the available data and the characteristics of the Mibale field reservoir, Darcy's law correlation was used to establish the IPR curve. The mathematical expression of Darcy's law is as follows:

$$Q_o = \frac{0.0078.k.h(P_r - P_{wf})}{\mu_o B_o \ln(\frac{r_e}{r_w})} \quad (7)$$

Choice of upward two-phase flow correlation

Several correlations on the law of flow in the reservoir have been established with their mathematical expressions. Beggs and Brill summarized the correlations of the law of flow into three main categories, each of which varies in complexity and technique. These are the following categories [5, 7]:

Category A: No slip effect or flow regime is considered - Poettmann & Carpenter, Fancher & Brown;

Category B: Slip effect is considered, no flow regime is considered - Hagedorn & Brown, Gray, Petroleum experts, Olgas;

Category C: Both slip effect and flow regime are considered - Beggs & Brill, Orkiszewski, Duns & Ros.

However, no single correlation was found to be the best over the others for all flow conditions. Individual well tests and experience can be used to obtain the correlation that best suits the characteristics of each well [2, 3].

RESULTS

Correlation Selection

Regarding pressure loss correlations, after inputting values for the wellhead pressure, water cut, oil or liquid production rate, GOR, and tubing depth of well MIB-02 into the Prosper software, the software calculates correlation parameters by determining the deviation factor for each correlation. The obtained values are presented numerically (Table 6) and graphically (Figure 7). Based on the different values of load losses of category C, it is noted that the Orkiszewski correlation has a deviation factor of 229.421 which is smaller than the others so it is the one that is best suited for the tubing of this well.

Table 6. *Correlations's parameters*

Correlation	Parameter 1	Parameter 2	Standard Deviation
Duns and Ros Modified	0.81836	0.34722	324.404
Hagedorn Brown	0.2	16.1803	202.504
Fancher Brown	0.2	16.1499	202.375
Mukerjee Brill	0.552	0.2	256.629
Beggs and Brill	0.2	7.74632	229.568
Petroleum Experts	0.2	11.9059	207.977
Orkiszewski	0.2	11.1377	229.421
Petroleum Experts 2	0.2	11.348	202.038
Duns and Ros Original	0.2	10.1803	224.507
Petroleum Experts 3	0.2	11.4785	201.33
GRE (modified by PE)	0.91653	0.26114	323.314
Petroleum Experts 4	0.2	13.2216	158.682
Hydro-3P	1	1	
Petroleum Experts 5	1	1	
OLGAS 2P	1	1	
OLGAS 3P	1	1	
OLGAS3P EXT	1	1	

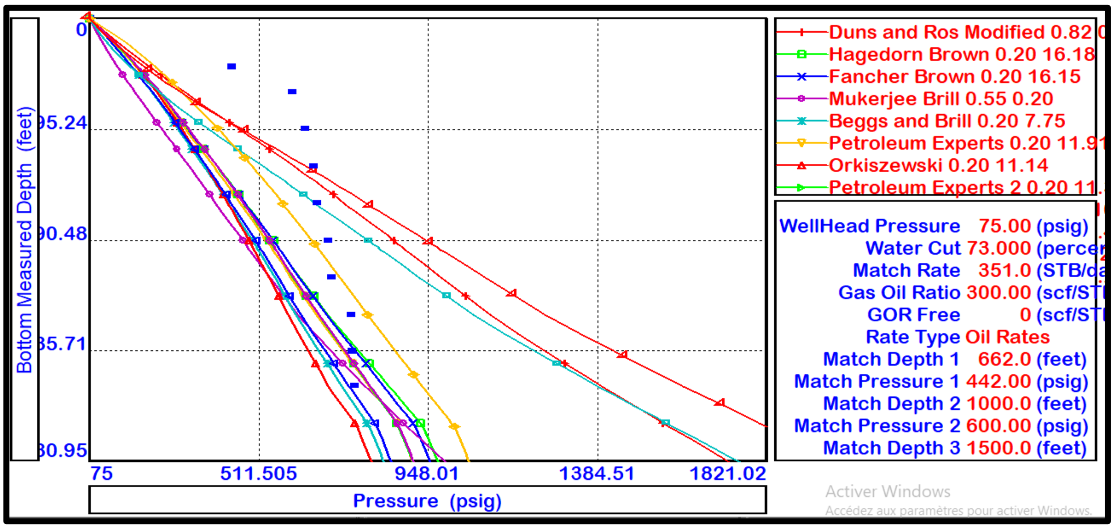


Figure 7. *Pressure gradient curves and depth for different upward two-phase flow correlations. The blue rhomboid points in the graph represents the OLGAS 2P correlation.*

Establishing the IPR and VLP curves

After selecting the flow law (Darcy) and the pressure loss correlation (Orkiszewski), we establish Inflow Performance Relationship (IPR) curves to determine the production capacity and Vertical Lift Performance (VLP) curve to understand the pressure losses in the well (Figure 8). We observe that the well still has the capacity to produce at a rate of

16,564.52 liquid flow, including 4100.62 BOPD and 12,463.9 BWPD. We would like to remind you that the last production capacity of the well was 351 barrels of oil per day (BOPD) with as ESP pump activation mode. The calculations were likely automatically performed in the software taking into account the predefined data in table 3 (reservoir characteristics, fluid properties, pressure and temperature conditions, BSW, etc (Figure 8). The situation in figure 8 is for the naturally flowing system.

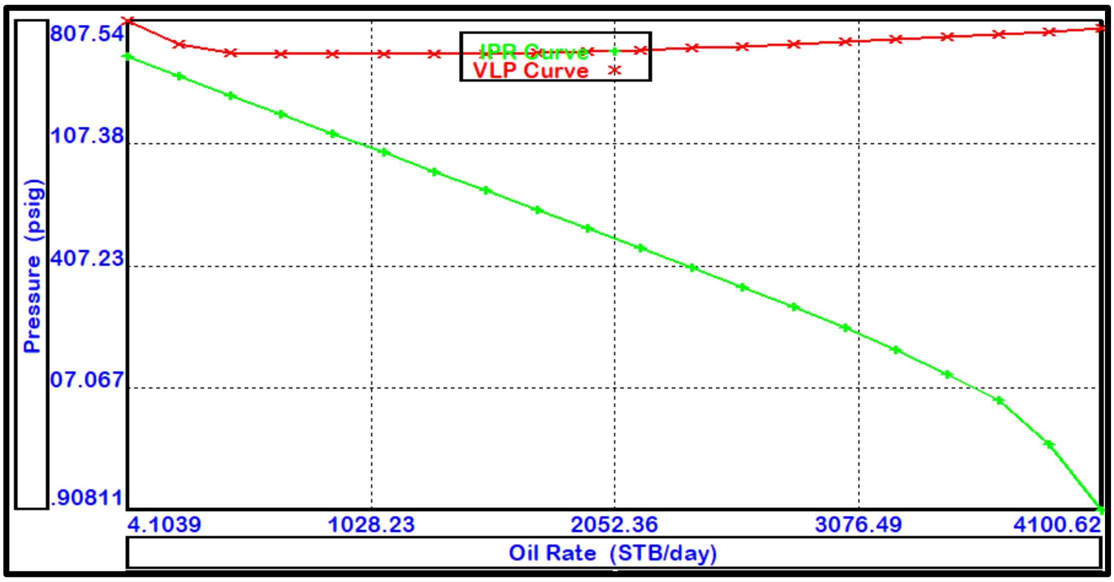


Figure 8. *IPR and VLP curves before converting MIB-02 well activation mode*

Because the relationship between pressure drop and flow rate is nonlinear for most elements of the production system, p-q graphs are usually curved. In particular, for wells that produce a mixture of gas and liquids (as do most oil wells), this may lead to a situation in which the graphs intersect at two or many points. At a first glance we could therefore conclude that such a well could produce at two different flow rates. In reality, however, wells will always produce at only one of these flow rates. The reason is that only one of the operating points is stable, whereas the other one is unstable. To understand why an operating point can be unstable, we need to consider the dynamics of the system. Nodal analysis, however, usually considers only the steady-state relationship between pressure drop and flow rate [15].

Analysis of variation of variables such as GOR, WOR, GLR, gas injection flow rate, injection depth, pressure in the tubing, pressure at the head of the well are tailored to specific applications to allow for a clear understanding of the variable's value that can lead to the optimal solution, providing us with multiple operating points of the well, of which only one will be considered as the realistic point. Therefore, any modification of these parameters such that injection depth, lift gas injection rate, specific gravity of the injecting gas will impact the VLP curve. Thus, we can define:

- stable points are flow conditions where production is constant and the system operates predictably. In a VLP-IPR chart, stable points are often found in areas where curves meet and where the production rate is supported by sufficient pressure.

- instable points are situations where the system may be exposed to variations or disruptions in production. Some points may be at crossings where the curves are abrupt or changing, which can cause instability in the production system.

In the case of MIB-02 well, the key variables that can influence production modification are the first node pressure, injection depth, water cut, gas-lift injection rate, and GOR. Figure 9 shows the intersection points between the IPR (green) and VLP (red) curves from several scenarios of gas injection flow variation between 0 and 5 MMscf and the water cut from 0 to 67.1%. This allowed to identify trends and relationships between these parameters if the well could produce how stable.

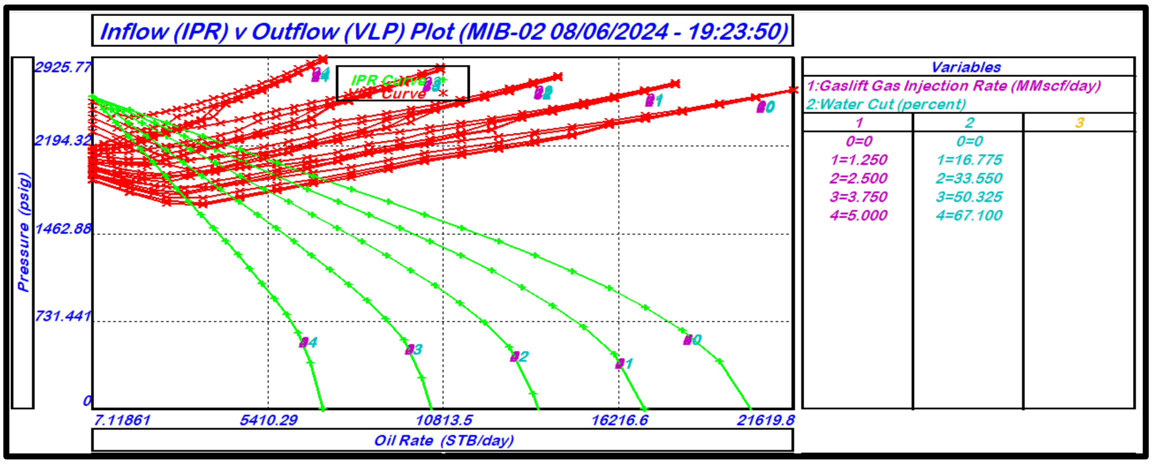


Figure 9. *Analysis of sensitivity curves of variables such as gas-lift injection flow and injection depth in the MIB-02 well*

We take the example of a scoreboard among many others with the different scenarios. As an illustration, table 7 shows the results obtained from the scenario such as the gas injection flow rate is 3.750 MMscf and the water cut at 50.325%.

GAS-LIFT OPTIMIZATION FOR MIB-02 WELL

Gas-Lift Well Design

The sensitivities explored above aimed to develop an overall gas-lift design system for the well. Thus, the sensitivities of the injected Gas-Lift Ratio (GLR), injection depth, and gas injection rate for gas-lift were tested to uncover the effect of variation on the oil production rate and bottomhole flowing pressure (node pressure of the solution).

When designing a gas-lift in Prosper, the following information must be entered for the well simulation [10]:

- Optimal production and gas-lift injection rates;
- Inject gas as deep as possible;
- Maximum depth and number of unloading valves.

Table 7. *Results obtained from the scenario such as the gas injection flow rate is 3.750 MMscf and the water cut at 50.350%*

Liquid Rate	4582.3	(STB/day)
Oil Rate	2276.3	(STB/day)
Water Rate	2306.1	(STB/day)
Gas Rate	0.68288	(MMscf/day)
Injection Depth	1129.5	(feet)
Solution Node Pressure	2161.08	(psig)
dP Total Skin	0	(psi)
dP Perforation	0	(psi)
dP Damage	0	(psi)
dP Completion	0	(psi)
Completion Skin	0	
dP Sand Control	0	(psi)
Sand Control Skin	0	
Total Skin	0	
Water Cut	50.325	(percent)
Wellhead Liquid Density	56.993	(lb/ft3)
Wellhead Gas Density	1.596	(lb/ft3)
Wellhead Liquid Viscosity	2.0482	(centipoise)
Wellhead Gas Viscosity	0.012614	(centipoise)
Wellhead Superficial Liquid Velocity	3.606	(ft/sec)
Wellhead Superficial Gas Velocity	16.958	(ft/sec)
Wellhead Z Factor	0.94318	
Wellhead Interfacial Tension	15.3118	(dyne/cm)
Wellhead Pressure	500.00	(psig)
First Node Liquid Density	56.993	(lb/ft3)
First Node Gas Density	1.596	(lb/ft3)
First Node Liquid Viscosity	2.0482	(centipoise)
First Node Gas Viscosity	0.012614	(centipoise)
First Node Superficial Liquid Velocity	3.606	(ft/sec)
First Node Superficial Gas Velocity	16.958	(ft/sec)
First Node Z Factor	0.94318	
First Node Interfacial Tension	15.3118	(dyne/cm)
First Node Pressure	500.00	(psig)

Taking into account completion data, production ratio, well testing, and reservoir fluid properties, we have the following design (Table 8).

Gas-Lift Valve Placement

The determination of the number of valves for a gas-lift well depends on several factors, including the required gas-lift flow rate, bottom hole pressure, gas composition used, gas-lift system characteristics, etc. There is no single formula to calculate the number of valves as it depends on the specific configuration of the gas-lift system [29, 30].

Table 8. *MIB-02 gas-lift well design interface*

Valve Type	Casing Sensitive	
Design Rate Method	Entered By User	
Check Rate Conformance With IPR	Yes	
Dome Pressure Correction Above 1200psig	Yes	
Tubing Correlation	Petroleum Experts 2	
Pipe Correlation	Beggs and Brill	
Use IPR For Unloading	Yes	
Orifice Sizing Method	Calculated dP @ Orifice	
Valve Manufacturer	Valve1	
Valve Type	R-20	
Valve Specification	Monel	
Maximum Gas Available	5.000	*(MMscf/day)*
Maximum Gas During Unloading	5.000	*(MMscf/day)*
Flowing Top Node Pressure	500.00	*(psig)*
Unloading Top Node Pressure	500.00	*(psig)*
Operating Injection Pressure	1000.00	*(psig)*
Kick-Off Injection Pressure	1000.00	*(psig)*
Desired dP Across Valve	250.00	*(psi)*
Maximum Depth Of Injection	5500.0	*(feet)*
Water Cut	67.100	*(percent)*
Minimum Spacing	250.0	*(feet)*
Static Gradient Of Load Fluid	0.7	*(psi/ft)*
Minimum Transfer dP	25.00	*(percent)*
Maximum Port Size	32	*(64ths inch)*
Safety For Closure Of Last Unloading Valve	0	*(psi)*

Therefore, sensitivity analysis was conducted for well MIB-02 using 5.0 MMscf as simulation gas injection flow rate, subject to injection pressure of 973.24 psig, temperature of 130.93°F and depth of 1134.3 ft MD. Figure 10 illustrates the simulation of gas injection at depth to determine the precise location of valves in the well. Table 9 provides the values found in Figure 10. This valve location simulation is made from the prosper software using design data from the MIB-02 well.

Table 9. *Results obtained after simulation on the number of valves, depth and pressure of the valves of the MIB-02 well*

Well	**Number of Valves (1)**	**Measured depth (Feet)**	**Tubing pressure (Psig)**	**Valve pressure**		**Casing pressure**		**Injected Gas rate, MMscf/day**
				Opening (Psig)	**Closing (Psig)**	**Opening (Psig)**	**Closing (Psig)**	
MIB-02	Valve 1	662.273	597.443	1013.590	1006.520	1000	992.925	1.67121 with 950 psig injection pressure
	Orifice	1129.470	670.598			950		

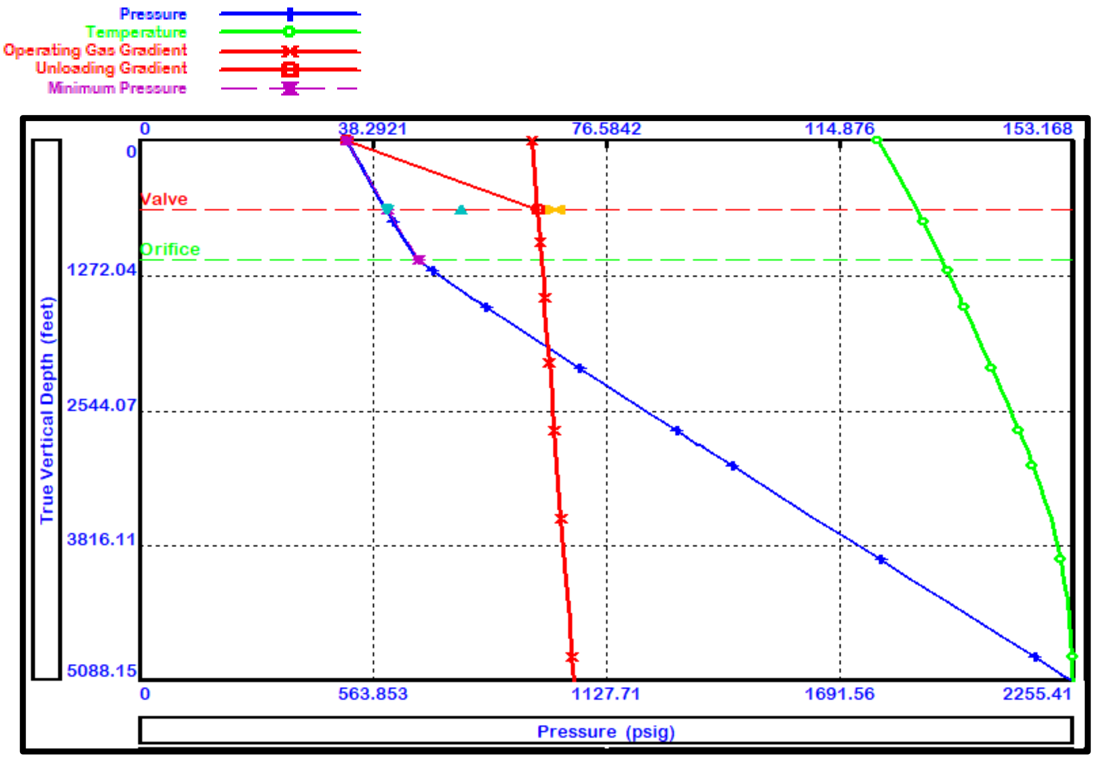


Figure 10. *Simulation curves on the location of deep valves in the MIB-02 well*

Gas-lift stability criteria

According to Harald Asheim (1988), the criteria for the stability and efficiency of the gas-lift in a well usually include the following elements [13]:

- the gas rising speed is adequate for carrying the liquid, while it is high enough to avoid deformation of the gas jet;
- the available gas pressure is sufficient to keep the gas-lift running;
- position the immersion depth of the small conduit properly to ensure an optimal mixture between the gas and the liquid;
- the gas bubbles size must be adequate to ensure efficient dispersion in the fluid;
- gas jet remains consistent and does not disintegrate during the process of raising the gas.

To assess the stability of the flow of gas and liquid in a well, Harald Asheim uses criteria F1 and F2 to assess the criteria of stability for the gas-lift. Here's the meaning of F1 and F2:

- F1: The amount of Froud needed for the flow of the gas. It is by comparing the velocity of the gas to the square root of the product of the gravitational acceleration and the difference in density between the gas and the liquid that it is calculated. The F1 test is used to assess the stability of the gas flow in the gas-lift process;
- F2: The amount of Froud needed for the flow of the liquid. It is by comparing the speed of the liquid to the square root of the product of the gravitational

acceleration and the difference in density between the gas and the liquid that it is calculated. The F2 system is used to assess the stability of the flow of the liquid into the lift gas.

Thus, the stability conditions of the gas-lift in a well require that the Froude numbers (F1 and F2) be less than 1 in order to guarantee process stability. The Froude number is a dimensionless parameter used in hydrodynamics to compare inertia forces with gravity forces. The gas-lift uses F1 and F2 to assess the stability of the gas and liquid flow. If F1 and F2 are less than 1, the gravitational forces are higher than the inertia forces, which allows a stable flow of gas and liquid. When F1 and F2 are greater than 1, this can cause instability, disturbance and poor management of the gas-lift. The table below shows the process stability criteria obtained after simulation (Table 10).

Table 10. *Gas-lift stability criteria for MIB-02 well*

Inflow Response Criterion	
Lift Gas Density @ standard conditions	0.045962 lb/ft3
FVF of Gas @ Injection point	0.015271 ft3/scf
Lift Gas Flow Rate @ standard conditions	1.67121 MMscf/day
Liquid Flow Rate @ standard conditions	3800.32 stb/day
Productivity Index of well	17.6039 stb/day/psi
Orifice Efficiency Factor	0.9 fraction
Injection Port Size	0.069221 in^2
F1	1.39108
Pressure-Depletion Response Criterion	
Tubing Volume Downstream Of Injection point	96.5057 scf
Gaz Conduit Volume	266.905 scf
Acceleration Due To Gravity	32.174 ft/sec/sec
Reservoir Fluid Density @ Injection point	58.328 lb/ft3
Lift Gas Density @ Injection point	3.001 lb/ft3
Liquid Flow Rate @ Injection point	3924.76 stb/day
Lift Gas Flow Rate @ Injection point	0.0255521 MMscf/day
F2	-1.42876

We note that the value of F2 is less than 1, this means that the flow of the liquid will be stable and efficient in the well and as F1 is greater than 1 so the outflow of the gas will be unstable in the MIB-02 well.

Results on Oil Production Rate

After considering various variable scenarios such as water cut (0 to 67.1%), GOR (0 to 300 scf/stb), first node pressure (0 to 500 psig) and analyzing the results on the amount of gas to inject and injection depth. We obtained the simulation results in the form of graphs and tables. Figure 11 below shows several points of encounter arising from the intersection of the IPR and VLP curves, one of which will be the realistic point or optimal solution for the resumption of production of the MIB-02 well. Table 11 illustrates the results of one of the simulations with values such as 33.5% of WC, 225 scf/stb of GOR and 375 psig of first pressure node.

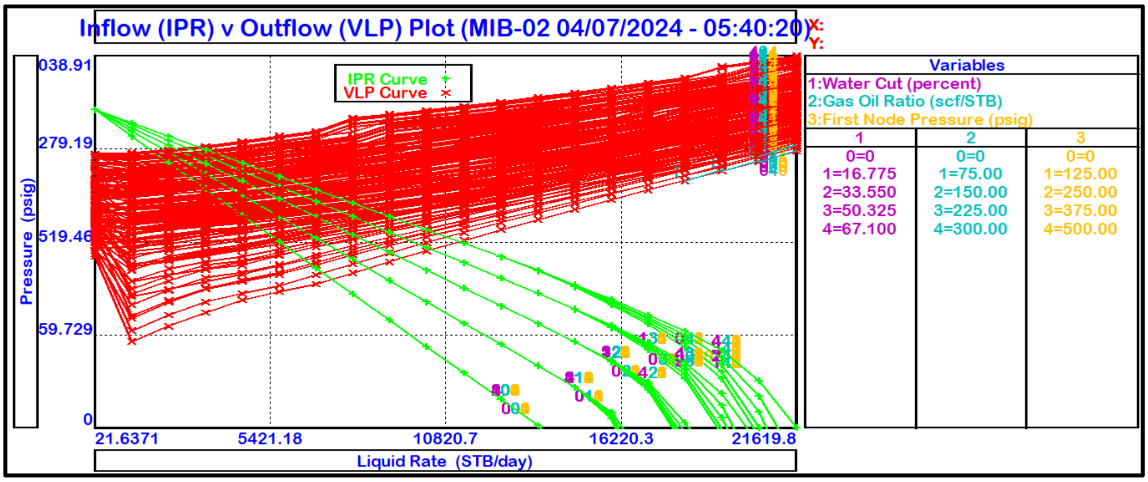


Figure 11. *Operating points resulting from the intersection of IPR and VLP curves in the MIB-02 well*

Table 11. *Illustration of one of the results after sensitivity of the water cut, GOR and first node pressure variables in the MIB-02 well*

Liquid Rate	5185.8	*(STB/day)*
Oil Rate	3445.9	*(STB/day)*
Water Rate	1739.8	*(STB/day)*
Gas Rate	0.77534	*(MMscf/day)*
Injection Depth	1129.5	*(feet)*
Solution Node Pressure	2031.43	*(psig)*
dP Total Skin	0	*(psi)*
dP Perforation	0	*(psi)*
dP Damage	0	*(psi)*
dP Completion	0	*(psi)*
Completion Skin	0	
dP Sand Control	0	*(psi)*
Sand Control Skin	0	
Total Skin	0	
Water Cut	33.550	*(percent)*
Wellhead Liquid Density	55.593	*(lb/ft3)*
Wellhead Gas Density	1.258	*(lb/ft3)*
Wellhead Liquid Viscosity	2.7566	*(centipoise)*
Wellhead Gas Viscosity	0.012306	*(centipoise)*
Wellhead Superficial Liquid Velocity	4.086	*(ft/sec)*
Wellhead Superficial Gas Velocity	11.550	*(ft/sec)*
Wellhead Z Factor	0.95617	
Wellhead Interfacial Tension	15.3117	*(dyne/cm)*
Wellhead Pressure	375.00	*(psig)*
First Node Liquid Density	55.593	*(lb/ft3)*
First Node Gas Density	1.258	*(lb/ft3)*
First Node Liquid Viscosity	2.7566	*(centipoise)*
First Node Gas Viscosity	0.012306	*(centipoise)*
First Node Superficial Liquid Velocity	4.086	*(ft/sec)*
First Node Superficial Gas Velocity	11.550	*(ft/sec)*
First Node Z Factor	0.95617	
First Node Interfacial Tension	15.3117	*(dyne/cm)*
First Node Pressure	375.00	*(psig)*

After the different scenarios in Figure 11, we get the realistic point or solution of the MIB-02 well production system (Table 12 and graph 12).

The result obtained after the activation mode conversion can be effective if and only if the conditions resulting from the simulation results at the point on Gas-Lift Valve Placement are indeed met.

Table 12. *System solution data*

Liquid Rate	3783.8	(STB/day)
Oil Rate	1244.9	(STB/day)
Water Rate	2539.0	(STB/day)
Gas Rate	0.37346	(MMscf/day)
Injection Depth	1129.5	(feet)
Solution Node Pressure	2237.56	(psig)
dP Total Skin	0	(psi)
dP Perforation	0	(psi)
dP Damage	0	(psi)
dP Completion	0	(psi)
Completion Skin	0	
dP Sand Control	0	(psi)
Sand Control Skin	0	
Total Skin	0	
Water Cut	67.100	(percent)
Wellhead Liquid Density	58.638	(lb/ft3)
Wellhead Gas Density	1.622	(lb/ft3)
Wellhead Liquid Viscosity	1.6195	(centipoise)
Wellhead Gas Viscosity	0.012542	(centipoise)
Wellhead Superficial Liquid Velocity	2.952	(ft/sec)
Wellhead Superficial Gas Velocity	7.667	(ft/sec)
Wellhead Z Factor	0.94211	
Wellhead Interfacial Tension	16.8305	(dyne/cm)
Wellhead Pressure	500.00	(psig)
First Node Liquid Density	58.638	(lb/ft3)
First Node Gas Density	1.622	(lb/ft3)
First Node Liquid Viscosity	1.6195	(centipoise)
First Node Gas Viscosity	0.012542	(centipoise)
First Node Superficial Liquid Velocity	2.952	(ft/sec)
First Node Superficial Gas Velocity	7.667	(ft/sec)
First Node Z Factor	0.94211	
First Node Interfacial Tension	16.8305	(dyne/cm)
First Node Pressure	500.00	(psig)

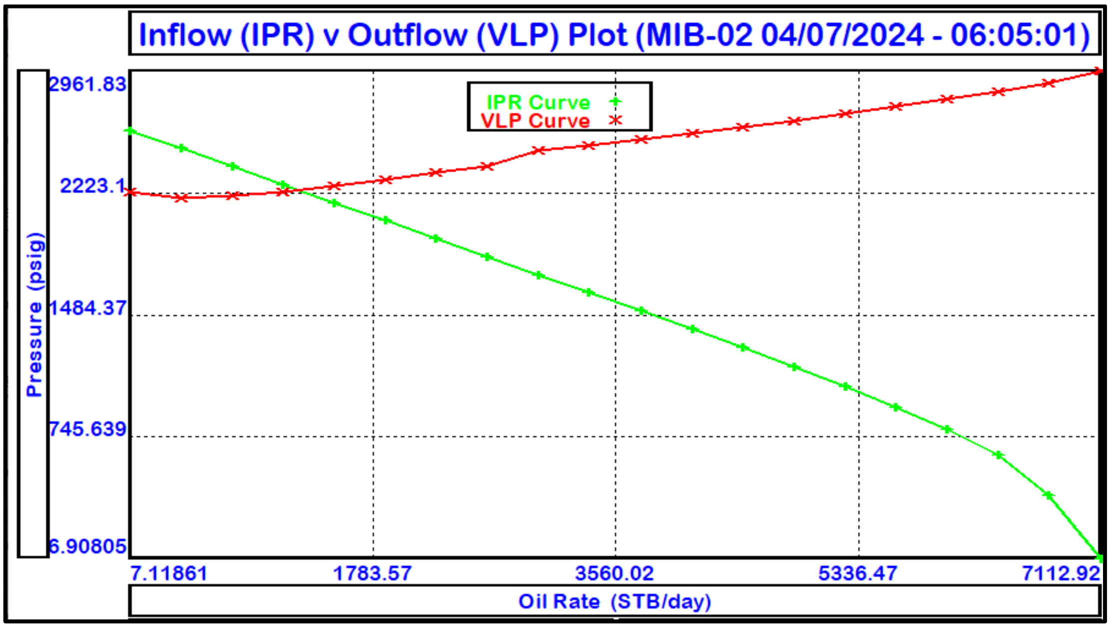


Figure 12. *MIB-02 well IPR and VLP curves after gas-lift conversion (Solution point)*

Dynamic Pressure Gradient and Depth Matching

In view of the results obtained on the stability criteria of the gas-lift process in the well, it is essential to identify the behavior of gases at different depths of the tubing to take useful precautions. For this, we have to find the Hold-up of liquid which is in turn a function of several factors such as the flow of gas, liquid and the viscosity of oil, etc. so it represents the ratio between the volume of liquid in a pipe section to the total volume of that same section.

The data from the dynamic pressure gradient test were entered into the gradient matching option to compare the VLP curve correlations with the test points obtained at different depths of the well, as illustrated in Figure 13. This operation was conducted as an alternative technique to control the quality of the correlations used and determine the Hold-up [19].

The hold-up in the MIB-02 well is between 0.3 and 0.86 and the flow is in slug flow from the surface up to a depth of 1328.3 ft. That is, by increasing the gas flow, the GOR increases the height of the fluid waves until the peak touches the pipe walls. At a depth of 1406.5ft to the bottom of the well; the hold-up is between 0.89 and 1 and the flow is in bubble flow (i.e. the GOR values are reduced) (Figure 13).

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Bottom Measured Depth	True Vertical Depth	Pressure	Temperatu re	Gradient	Holdup	Regime	Heat Transfer Coefficient	Hydrates Formation	Static Gradient	Friction Gradient	Friction Pressure Loss	Gravity Pressure Loss	Slip Liquid Velocity	Slip Gas Velocity
feet	*feet*	*psig*	*deg F*	*psi/ft*			*BTU/h/ft2/*		*psi/ft*	*psi/ft*	*psi*	*psi*	*ft/sec*	*ft/sec*
0	0	500.00	119.95			WellHead					0	0		
220.8	220.8	532.03	122.23	0.1451	0.30146	Slug	8.0000		0.13323	0.011781	2.60	29.41	9.800	10.636
441.5	441.5	564.34	124.43	0.14636	0.30412	Slug	8.0000		0.13465	0.011635	5.17	59.14	9.728	10.036
662.3	662.3	597.23	126.56	0.14897	0.31041	Slug	8.0000		0.13753	0.011375	7.68	89.50	9.544	9.544
669.1	669.1	598.27	126.62	0.15154	0.31696	Slug	8.0000		0.14033	0.011144	7.76	90.46	9.353	9.353
676.0	676.0	599.31	126.69	0.15169	0.31736	Slug	8.0000		0.1405	0.01113	7.83	91.43	9.342	9.342
721.5	721.5	606.24	127.12	0.15228	0.31898	Slug	8.0000		0.14114	0.011077	8.34	97.85	9.296	9.300
767.0	767.0	613.22	127.54	0.15332	0.32164	Slug	8.0000		0.14227	0.010987	8.84	104.32	9.222	9.226
861.5	861.3	627.83	128.42	0.15466	0.32605	Slug	8.0000		0.14375	0.010851	9.86	117.91	9.101	9.118
956.0	955.6	642.65	129.28	0.15683	0.33159	Slug	8.0000		0.1461	0.010673	10.87	131.71	8.955	8.972
1042.7	1041.6	656.35	130.05	0.1579	0.33735	Slug	8.0000		0.14734	0.010507	11.78	144.49	8.807	8.842
1129.5	1127.6	670.21	130.82	0.15988	0.34243	Slug	8.0000		0.14947	0.010354	12.68	157.46	8.681	8.716
1228.7	1225.9	705.71	131.68	0.35756	0.85687	Slug	8.0000		0.35278	0.0043051	13.11	192.47	3.472	3.537
1328.0	1324.3	741.65	132.52	0.36213	0.8695	Slug	8.0000		0.35756	0.0042527	13.53	227.97	3.426	3.495
1406.5	1401.1	770.13	133.18	0.36277	0.89913	Bubble	8.0000		0.35862	0.0041515	13.86	256.12	3.317	4.117
1485.0	1477.9	798.81	133.82	0.36539	0.90669	Bubble	8.0000		0.36131	0.0040809	14.18	284.48	3.292	4.092
1531.5	1523.1	815.76	134.20	0.36436	0.91238	Bubble	8.0000		0.36033	0.0040287	14.36	301.24	3.274	4.074
1578.0	1568.2	832.76	134.57	0.36574	0.91643	Bubble	8.0000		0.36175	0.003992	14.55	318.06	3.262	4.062
1672.5	1659.6	867.39	135.32	0.36643	0.92232	Bubble	8.0000		0.36249	0.0039395	14.92	352.31	3.244	4.044
1767.0	1750.9	902.25	136.05	0.36889	0.92974	Bubble	8.0000		0.36502	0.0038743	15.29	386.81	3.221	4.021
1955.5	1922.6	968.38	137.47	0.35081	0.93962	Bubble	8.0000		0.34702	0.0037899	16.00	452.22	3.193	3.993
2144.0	2094.3	1035.15	138.82	0.35424	0.95117	Bubble	8.0000		0.35055	0.0036932	16.70	518.30	3.162	3.962
2206.5	2145.8	1055.32	139.26	0.3226	0.95796	Bubble	8.0000		0.31896	0.0036381	16.93	538.23	3.144	3.944
2269.0	2197.3	1075.53	139.69	0.32335	0.96092	Bubble	8.0000		0.31974	0.003614	17.15	558.22	3.137	3.937

***Figure 13**. Illustration of the evolution of deep hold-up in the MIB-02 well*

DISCUSSIONS

After conversion, the MIB-02 well is expected to produce of 1244.9 BOPD and 2539 BWPD, and a gas rate of 0.37346 MMscf/day which shows that there is a sharp increase in production compared to the last production which was 351 BOPD (Table 12). Unfortunately, the studies conducted in 2016 did not quantify the water reserves in the reservoir and did not identify the presence of an aquifer in the vicinity of the reservoir. It is noted that the wells traverse over 361 million stock tank barrels (MMstb) of oil reserves contained in the diverse lithological nature (limestone, dolomite, and sandstone) of the upper Pinda reservoir.

Although all conditions seem to be met for the well to be activated in Gas-lift mode, after a thorough analysis of the data and results obtained during the evaluation and optimization of the production system of the Mibale field from MIB-02 well i.e, taking into account the production capacity of the well and the result of optimization, it is clear that other factors influence the productivity of a well. Therefore, other factors may contribute to the decline in oil production in the Mibale field, including:

- Reservoir pressure decline necessitating an enhanced recovery method ;
- Petrophysical characteristics of the reservoir ;
- Oil flow obstruction due to sediment accumulation, particles, or other substances in the reservoir pores (porosity plugging) ;
- Aging or damage to production equipment (technical issues, equipment failures, or delays in equipment replacement such as pumps or valves);
- Insufficient bottom-hole pressure limiting fluid flow to the surface.

After reviewing various reports from the operating company, it appears that workover studies were conducted in 2010 to replace old equipment and clean MIB-02 well with the aim of improving well productivity. Therefore, considering the factors mentioned earlier, the issue of equipment aging can be excluded. Additionally, one of the objectives of converting the activation mode is to more effectively control bottom-hole pressure. Hence, the problem of insufficient bottom-hole pressure in MIB-02 well is completely resolved by the activation mode conversion.

Given the limitations of nodal analysis techniques in detecting all potential issues in a production system, results are often combined with reservoir simulations to enhance precision regarding the performance of the production system. This integration can lead to more informed decisions when optimizing production. Consequently, the unsatisfactory results obtained from this study have prompted the proposal of additional complementary studies on reservoir behavior and quantification of remaining reserves in the present day to assist the upper Pinda reservoir. The reservoir simulation will address the limitations of nodal analysis in the following ways:

- Detailed Reservoir Modeling: Reservoir simulations will provide a better understanding of the interaction between the wells and the reservoir, taking into account the complex geometry of the reservoir, heterogeneities, aquifer barriers, etc.;
- Reservoir simulation models will integrate mass and energy conservation equations to simulate multiphase flows, interactions between gas and liquid, capillary effects, etc., providing a more comprehensive view of production processes;
- Production Scheme Optimization: Reservoir simulations will offer a more in-depth approach to various production strategies, injection schemes, optimal production rates, etc., to maximize the oil field's yield.

Therefore, it is essential to complement this study with reservoir simulations to identify the true factor contributing to the low production in the Mibale field.

CONCLUSION AND PERSPECTIVE

In today's world, investments in the oil industry have become scarce due to the energy transition initiated by funders. However, oil and gas remain the primary source of energy consumed in various forms globally, accounting for over 60% of energy consumption. To avoid an energy crisis during this transition period, it is crucial to maximize the extraction of already discovered reserves, such as the mature fields being exploited in the Congo Central province of the Democratic Republic of the Congo.

These discovered fields face various challenges, including reservoir pressure decline, aging well equipment, inappropriate well activation methods, and reservoir recovery techniques. Therefore, our study aimed to evaluate and optimize the production system of the Mibale field, focusing on MIB-02 well located offshore in the coastal basin of the DRC. The main objective of our study was to enhance the performance, efficiency, and sustainability of the hydrocarbon production system in the Mibale field by proposing suitable activation method for MIB-02 well.

MIB-02 is one of the three wells in the Mibale field but currently only produces 351BOPD. Given this low production, we conducted an analysis of the production system in the Mibale field based on one well.

After collecting and analyzing geological, reservoir, and production data using appropriate tools and techniques such as Excel simulation software and IPM Prosper for establishing production curves and modeling the production system, we evaluated MIB-02 well based on three key elements. The first element was the Inflow Performance Relationship (IPR) to assess the production capacity of the well in relation to the reservoir. The second element was the Vertical Lift Performance (VLP) to identify well performance, including tubing pressure losses. The third element involved dynamic production parameters such as water cut, Gas-Oil Ratio (GOR), pressure at the first node, etc., to better understand well production dynamics and optimize overall performance. This evaluation aimed to determine whether it was opportune to optimize well production.

By plotting IPR and VLP graphs, we observed that MIB-02 still has the capacity to produce a liquid flow rate of 16,564.52, including 4100.62 BOPD and 12,463.9 BWPD. From this production capacity assessment, it was evident that the well could still yield a significant amount of oil. Hence, the proposal to convert the activation mode from ESP to Gas-lift for MIB-02 was made to potentially increase their production.

Using simulations from the IPM Prosper software, we obtained the necessary parameters and conditions for the well to produce under the new activation mode. For MIB-02, we determined the number of valves, their depths, opening and closing pressures, gas injection rate, and optimal orifice depth. Once these conditions are met, the well will produce an oil rate of 1244.9 stb/day, a water rate of 2539 stb/day, and a gas rate of 0.37346 MMscf/day for 1.67121 MMscf gas injection rate.

Based on the results obtained from this nodal analysis, which is part of our work in this field, we are considering further studies on simulating the upper Pinda reservoir to understand petrophysical parameter variations and estimate remaining oil reserves. This approach will allow us to resume water injection, which was halted in 2010 due to process inefficiencies, potentially leading to a significant improvement in the production of the Mibale field and the management of the well production system. Since the upper Pinda reservoir is multi-layered, selecting the layer for water injection would require simulating the seven layers comprising this reservoir while considering their petrophysical characteristics and fluid contents. This would necessitate another study on revising surface facilities for injection water treatment and possibly converting some producers into injectors or drilling new wells.

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Abbreviations

B_o : oil volumetric factor in bbl/stb

F_t : the friction in the tubing expressed in height

V_m : Mixture surface speed

r_e : drainage radius in feet

H_d : height or vertical distance (in ft) from wellhead to estimated production fluid level at design capacity

P_d : the friction in the surface pipe expressed in height

P_r : reservoir pressure in psi

P_{wf} : downhole flow pressure in psi

Q_o or q_o : oil flow rate, stb/day

R_s : Ratio of gas dissolved in oil

r_w : wellbore radius in feet

μ_o : oil viscosity in centipoise

d : diameter of tubing, in

ft : feet

VLP : Vertical Lift Performance

k : permeability in mD

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