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Estimation of the Performance and Prediction of the Decline Time of Reservoir: A Case study of Libwa field, Democratic Republic of Congo

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ABSTRACT

During oil exploitation, the amount of oil originally in place decreases and the pressure of the reservoir declines. So it is imperative to do a thorough study on the future behaviour of the reservoir in the face of the pressure drop and to predict its decline time. Knowing that the upper Pinda reservoir of the Libwa field produced by dissolved gas drainage mechanism, this allowed us to estimate the future performance of the same reservoir from the gas solubility. The gas solubility value is found from empirical correlations using parameter values (Volume and Temperature) of the reservoir fluids. It was noticed that the value of the instantaneous gas-oil ratio of the Petrosky correlation was so close to that of the Libwa field therefore to 552 standard Cubic feet per stock tank Barrel (scf/Stb) and could predict the volume behaviour of the Libwa field. The evolution of the reservoir performance was determined from the cumulative gas-oil ratio using the material balance equation, this gave us as a result of the gas-oil ratio Cumulative at 5250 standard Cubic feet per stock tank Barrel (scf/Stb) and this latter, by extrapolation, determined the current reservoir pressure at 1567 pound per square inch atmospheric. Referring to the different decline curves, the exponential decline curve predicted that the end of oil production in this field is expected in 2044. These results sufficiently show the interest that the operator company in the libwa field for the performance of the reservoir to resort to the so-called "Gas Repressering" method of enhanced recovery that would allow it to maintain the Gas-oil ration Cumulative as low as possible in order to postpone the time of decline of the field.

Keywords: *Oil-gas ratio, reservoir pressure, dissolved gas drainage mechanism, material balance, exponential decline*

1. INTRODUCTION

To estimate the performance of a reservoir, petroleum engineers always use the material balance equation, which is a basic tool in reservoir engineering. The most significant aspect of the material balance equation is that it does not contain time as a parameter; this means that although a calculation of the material balance equation may tell us what will happen but it cannot tell when it will happen (Ref. No. RE/1, Version 1.0: Material Balance Equation Department of Petroleum Engineering, Heriot-Watt University, 2002) [1]. Thus, all the methods that have been developed to predict the future performance of a reservoir are essentially based on the use and combination of the relations of the equation of the material balance, the saturation equations, the gas-oil ratio (GOR) instantaneous and the equation linking the cumulative gas-oil ratio to the instantaneous gas-oil ratio "GOR" [2].

The degree to which the results of a calculation of the balance-sheet equation are invalidated depends on the magnitude of variations in the initial properties of fluids, for example, a change in the bubble point. However, in the development plan of an oil field, knowledge of the gas-oil ratio is of great importance because it is one of the parameters which allows to determine the evolution of the pressure of the reservoir and to examine when this energy will have to be supplemented in order not to compromise the chances of oil recovery. In addition, if the reservoir is under natural drainage, the oil-gas ratio can be used to determine whether this reservoir in natural drainage is either in gas drive solution or in expansion gas drive. To achieve this, the equation of the material balance, depending on the parameters (Pressure, Volume and Temperature) of the fluids, will be applied in order to estimate the performance of the Pinda Superior Reservoir in the Libwa Field. Since the start of the exploitation of the upper Pinda reservoir of the Libwa field, large quantities of gas have been produced, resulting in a rapid decrease in the pressure, which is conditioned by the presence of cumulative gas. In December 2009, cumulative gas production was 75.8 billion cubic feet, which would have resulted in a pressure drop of up to 1775 psia with only 13.3 million Barrel stock tank (MMSTB) of oil produced; and at the end of the same year, the cumulative GOR was estimated at 5300 standard Cubic feet per stock tank Barrel (scf/Stb) with an oil recovery factor of 2,91% whereas at the initial reservoir pressure is estimated at approximately 2670 pound per square inch atmospheric (psia). This observation of the rapid decrease in pressure led to this study, which makes it possible to estimate the production potential of oil (oil) of the upper Pinda reservoir of the Libwa field taking into account the gas solubility in that reservoir and predicting the time of decline of that reservoir in that field based on the previous production data of the field in order to consequent provisions that could enable the recovery of reserves not yet recoverable.

The Libwa field is located 7kilometres from the coast of the Democratic Republic of Congo as shown in Figure 1 and the water depth is about 6metres (Figure 1). The field normally produces oil and gas from the upper Pinda limestone reservoir. The latter is known as a carbonate impermeable reservoir with permeability ranging from 0.04 milliDarcy to 19 milliDarcy (Muanda International Oil Company, Geosciences Perenco RDC (MIOC), 2013[3]). With regard to the geology of the field, the development of the Libwa field to date is largely focused on its northern portion. It is predicted that significant undeveloped reserves exist in its southern part, however, knowledge of reservoir quality in this area remains limited. To date, 16 wells have been drilled in this field and only 11 wells have been produced in the Offshore infrastructure. The drainage mechanism of the reservoir is that of the expansion production of dissolved gas. And no secondary recovery method has been used to date.

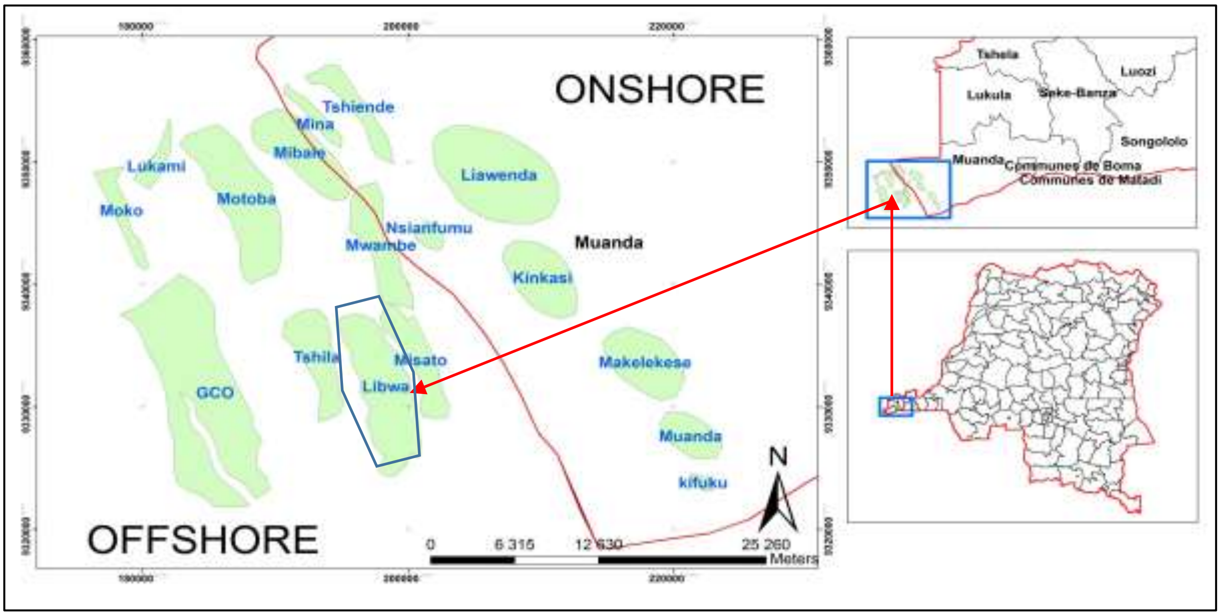

Fig.1: Location of Libwa field in the coastal basin of the Démocratic Republic of Congo

2. MATERIAL AND METHOD

2.1. Material

We used a laptop containing: le Word, l'Excel, Arc-Gis.

2.2. Data collection and processing

The behaviour of a reservoir can only be known from observations in wells, mainly flow measurements, pressure measurements and fluid analysis [4]. However, it is rather difficult to obtain quantitative data as many of these data are confidential due to their strategic nature and, are simply misguided or difficult to reconcile due to methodological inaccuracies in society [5]. In order to deal with the subject and meet the objectives assigned in this study, we used data collection :

- drilling techniques of two wells, Libwa-3 drilled to the north of the reservoir and Libwa-5 drilled to the south, which allowed characterization of the upper Pinda reservoir of the Libwa field ;
- PVT (Gas Volume Factor (bg), Instant Gas-Oil Ratio (Rs), Cumulative Gas-Oil Ratio (Rp) and Oil Volume Factor (Bo)) to estimate the performance of the top Pinda reservoir in the field using Petrosky-Farshad correlation ;

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- Libwa field average production from 2014 October to October 2015, in order to plot the decline curve to predict the end of life of the Libwa field in the upper Pinda reservoir.

3. RESULTS AND INTERPRETATION

3.1. Description and Zoning of Upper Pinda Reservoir in Libwa Field

3.1.1. Reservoir Description

The fluids contained in a virgin deposit, which are at a fairly high pressure, are likely to relax. As fluids are produced in relation to the drop in reservoir pressure, the rate of pressure drop is controlled by the drainage mechanism. The reservoir drainage mechanism depends on the rate at which the fluid increases to fill the space evacuated by the fluid produced (Dr. E. H. SADOK, 2010 [6]). In many cases, reservoirs can be chosen as having primarily a primary type of drainage mechanism to which all other mechanisms have a negligible effect [7].

The natural drainage regime of the Pinda Superior reservoir in the Champ Libwa is of the dissolved gas expansion type (gas drive solution), that is, the drainage of the oil from the reservoir is done by the expansion of the dissolved gas in the oil that is released in the form of bubbles, thus promoting the movement of the oil first towards the production well, then towards the surface with the clean energy of the deposit, that is by eruption.

The trap is a tilted defective block, vertically sealed by the shales (Shales) covering the Kinkasi Formation. The Libwa carbonate tank has a substantial cap of gas above the oil column. Libwa production comes from the Pinda Superior reservoir, which has 8 zones. The whole depositional environment was probably a bit deep; carbonate continental shelf adjacent to the predominantly clastic coast. The geophysical study relating to the seismic interpretation of the Libwa field and the ratio of the physics of the rock suggested structural conductive lines of history (leads) to the prediction that the southern termination of the Libwa field could have the potential of a better quality reservoir as this area may well have been the crest of the structure during the departure of the reservoir before the activity on the northern fault and South-West has not deposited this ridge to the north of the field [3]. On the other hand, the prediction of the best reservoir quality in the southern part of the field is in contradiction with the low permeability encountered by the Libwa-2 and Libwa-5 wells. It is possible that the southwest zone near the barrier fault of the field can continue to exhibit an improved quality of reservoir (figure 2).

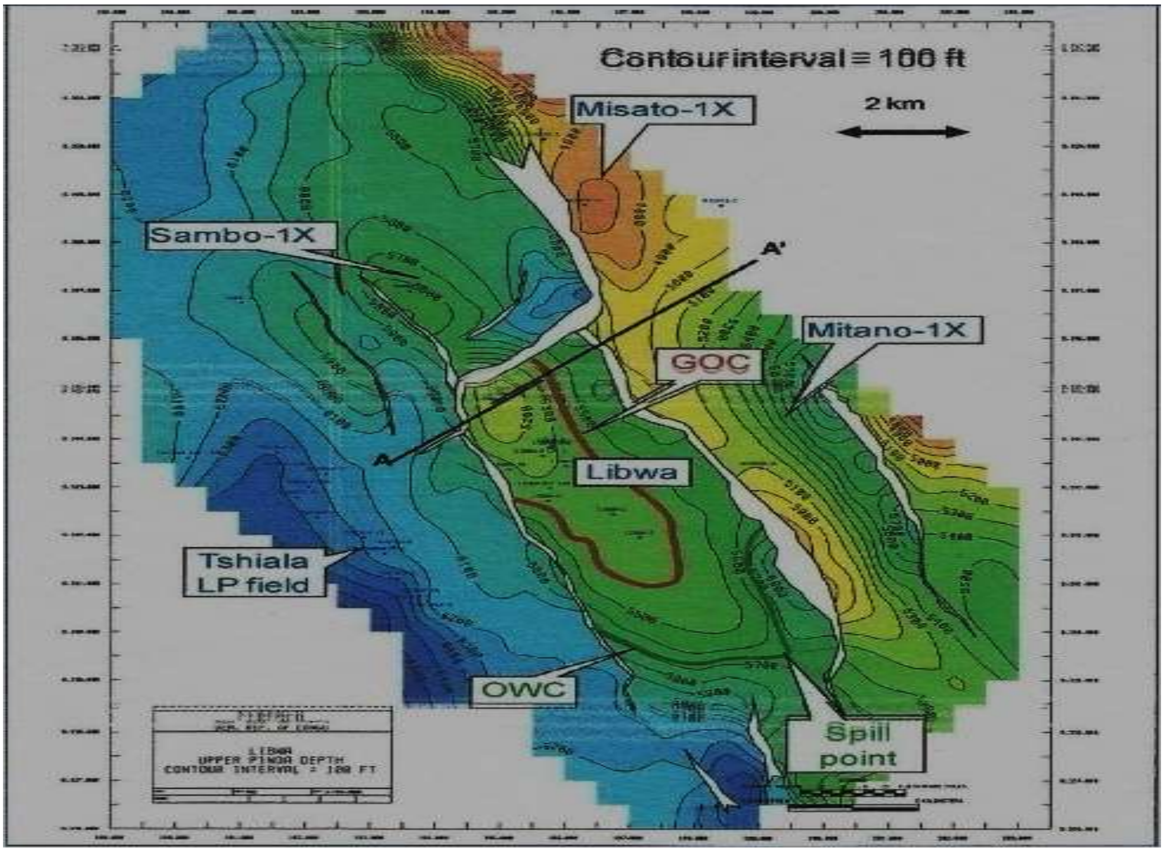

Fig.2 : Chart of Depth of the Summit of the Upper Pinda reservoir (MIOC, 2010 [8])

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3.1.2. Zoning of Upper Pinda reservoir

The core is the only way of direct access to the reservoir [9]. The study of the Libwa-3 and Libwa-5 cores subdivided the Pinda Superior reservoir of the Libwa field into 8 Lithofacies, divided into Table 1.

Table 1: Description of the geological model and simulator model (Compilation of MIOC data [8]).

Laying environments (Géological model)	Model of the simulator
Horizon de Transition (TL = Transition layer)	Upper Pinda_1
Plateau Continental (S = Shelf)	Upper Pinda _2
Squelettique Haut Fond Complexe (SGC = Skeletal Grainstone Complex)	Upper Pinda _3
Squelettique Bas Fond Granulaire (SGF = Skeletal Grainflat)	Upper Pinda _4
Complexe Haut Fond à Ooïdes (OGC = Ooidal Grainstone Complex)	Upper Pinda _5
Lagon (L = Lagoonal)	Upper Pinda _6
Bas Fond Granulaire de Lagune (LGF = Lagoonal Grainflat)	Upper Pinda _7
Grès Dolomitique (DS = Dolomitic Sandstone)	Upper Pinda _8

Note : The 8 lithofacies TL to DS are the geological model, while the zones UP_1 to UP_8 constitute of the simulator model.

3.2. Characterization of the Upper Pinda Reservoir from core samples from Libwa-3 and Libwa-5 wells

To characterize an oil reservoir and to obtain accurate information, continuously, with excellent depth control, petrophysical measurements are made on and in carrots [10] and [11].

3.2.1. Sample Results

The core analysis results for Libwa-3 and Libwa-5 are listed in Figures 3 and 4.

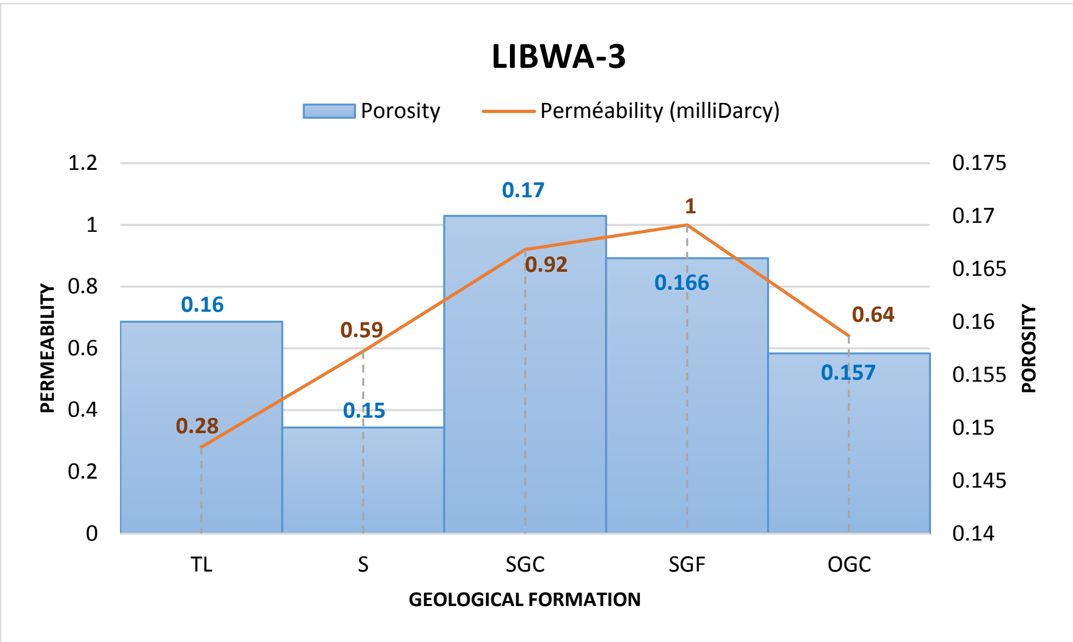

Fig.3: Core analysis results on Libwa-3

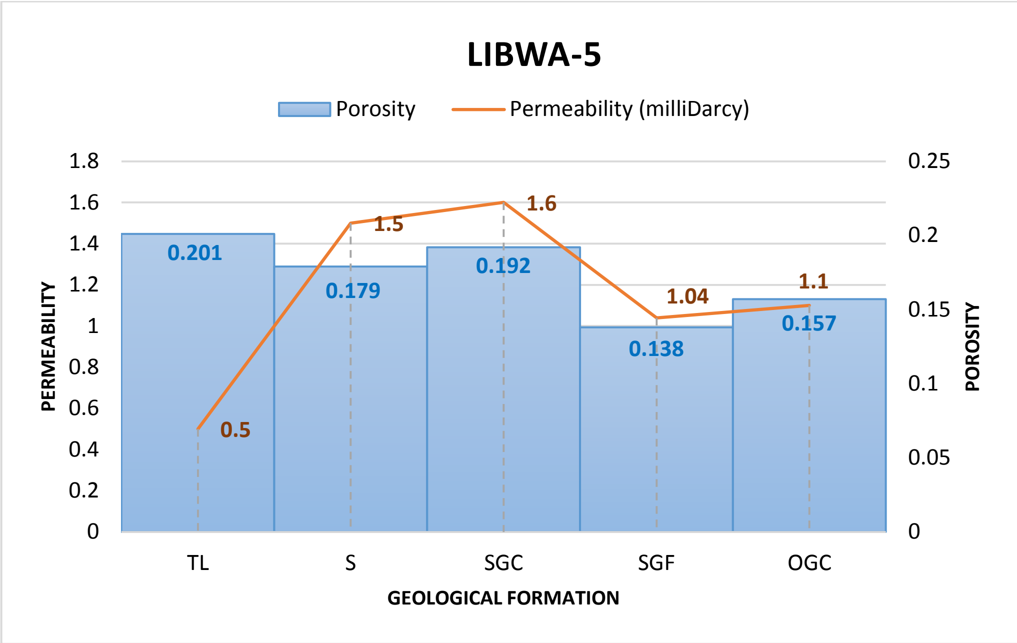

Fig.4: Core analysis results on Libwa-5

3.2.2. Interpretation and explanation of core results from two wells

Porosity and permeability analyses were performed on core samples from Libwa-3 well and Libwa-5 well. The average results of each formation specify the values of porosity and permeability of each Lithofaciès or formation in each well. Although the reservoir appears well laminated, the areas with good porosity and permeability are scattered throughout the cored interval. These results show us and lead us to determine total averages and values of porosity and permeability (Figure 5).

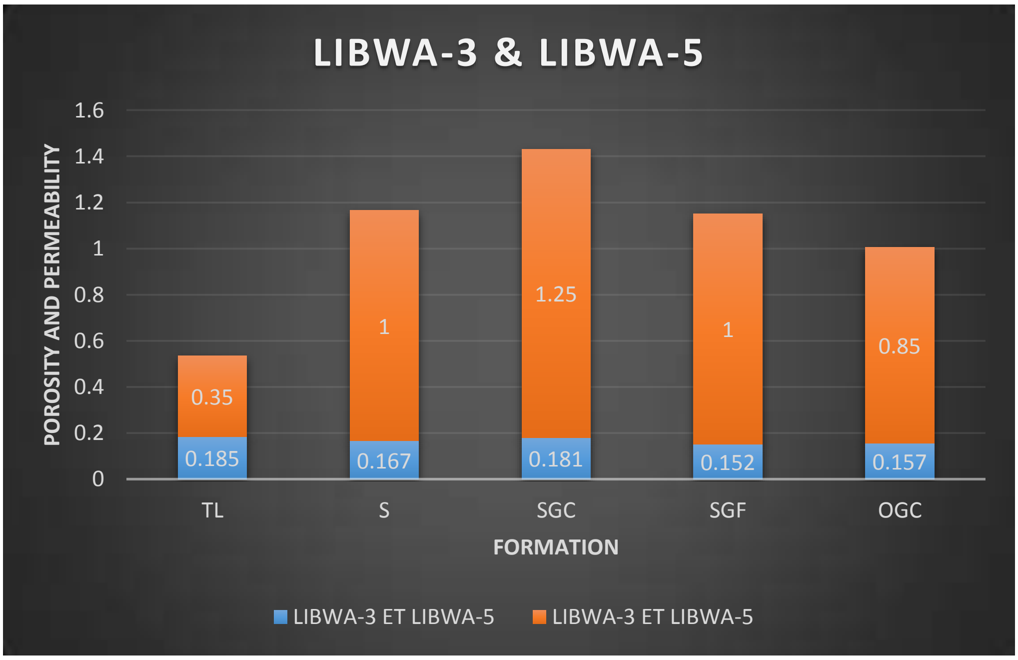

Fig.5 : the total averages of the porosity and permeability values of Libwa-3 and Libwa-5.

Ultimately, the porosity of the Upper Pinda reservoir in the Libwa field is medium and its permeability is very low. These different coring properties are one of the elements (wells, seismic, cores) that describe the properties of the reservoir in equilibrium (at a given moment). They are part of the elements describing the static model.

3.2.3. Properties of the Upper Pinda Reservoir Fluids in the Libwa Field

The fluid properties of the upper Pinda reservoir in the Libwa field are listed in Table 2. Table 2.

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Table 2. PVT properties of the Libwa field [8].

	PVT already in practice in the oil bloc of the D R Congo	PVT from the analysis of the libwa-3 well tests carried out in 1989.
Reservoir Température	169 Degré Farenheit (°F)	169° F
Gravity of the oil (γ_o)	33.8 Degree American Petroleum Institute (°API)	32.1°API
Specific gravity of the gas (γ_g)	0.82	0.82
Gas-oil Ratio (GOR) in solution (R_S)	550 Standard cube feet(Scf)/Stock tank barrel (Stb)	470 Scf/ Stb
Bubble point pressure (Pb) at reservoir temperature	2583 pound per square inch atmospheric (psia)	2540 psia
Volume Factor of Oil (Bo) and Volume Factor of Initial Oil (Boi)	1.31 reference barrel (rb) / Stb	1.254 rb / Stb
Viscosity of the oil at Pb (μ_{ob})	1.38 Centipoises (Cp)	1.37 Cp
No hydrocarbon components (impurities)	H_2S = 0 % ; CO_2 = 0 % N_2 = 0 %	
Water salinity	25 000 part per million (ppm)	
Gas deviation factor (Z)	0.85 square inch per pound (psi^{-1})	

3.3. Estimation of the performance of the upper Pinda reservoir of the Libwa field

The performance of a reservoir depends on the type of drainage mechanisms that produce the average pressure of the reservoir; this pressure may decrease with time or with cumulative production [12]. For this reason, for the prediction of the Pinda Superior Reservoir of the Champ Libwa, knowledge of PVT parameters (Gas Volume Factor (bg), Oil Gas Ratio (Rs) and Oil Volume Factor (B0) is required.) at each stage of depletion, that is, at each pressure drop. This led to the understanding that this reservoir is characterized by very high gas-to-oil ratios and the drop in reservoir pressure (Pr) is lower than the bubble pressure (P_B) that is to say, $P_r(1775\ psia) < P_B(2580\ psia)$, which allowed to determine the mechanism of drainage of dissolved gases as the main mechanism of production. So the equation of the ratio of gas to instant GOR oil is of fundamental importance in the analysis of the reservoir because by using this information, primary field recovery performance can be predicted with declining pressure [2].

3.3.1 PVT parameters of reservoir fluids as a criterion of reservoir performance

The ratio of gas to oil (GOR) in solution Rs is measured in PVT laboratories. Empirical correlations are also valid and based on PVT derived data [13]. The initial gas solubility of the Champ Libwa is estimated at 550 Standard cube feet per Stock tank Barrel (scf/Stb). We proposed to estimate the solubility of gases by empirical correlations in order to predict the evolution of the GOR oil-gas ratio in the field at each stage of depletion. The PVT properties of some parameters will be used from Table 5 above. The following 5 empirical correlations to determine gas solubility(Rs) are given below:

1. Correlation of Standing

Standing (1947) proposed a graphical correlation to estimate gas solubility as a function of the pressure, gravity °API and system temperature. Standing (1981) expressed its proposed graphical correlation in the following more suitable mathematical form [14]:

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

$x = (0.0125\,\gamma_o) - 0.00091(\mathrm{T} - 460)$ (2)

By replacing each parameter with its value, x=0.24746 and R_s=645.5 scf/stb.

2. Correlation of Vasquez-Beggs

Vasquez and Beggs (1980) presented an improved empirical correlation for estimating Rs as a function of pressure, temperature, oil-specific gravity and gas gravity [12] and [15]. The proposed equation has the following form:

$R_s = C_1 \gamma_{gc} P^{C_2} e^{\left[C_3 \cdot \frac{°API}{T+460}\right]}$ (3) ; the values of the coefficients are as follows (Table 3) :

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Table 3 : Coefficients of Vasquez and Beggs

Coefficients	*API≤30°*	*API>30°*
C_1	*0.0362*	*0.0178*
C_2	*1.0937*	*1.1870*
C_3	*25.9310*	*23.9310*

Referring to Table 3, the degree of API is higher than at 30° thus C_1=0.0178 ; C_2=1.187 ; C_3=23.931. Vasquez and Beggs proposed the following relationship for adjusting the gas gravity (γg) to the separator reference pressure :

γ_{gc}=$\gamma_g\left[1+5.912.10^{-5}(T_{sép}-460)log\frac{P_{sép}}{114,7}\right]$ (4)

Where

γgc= Gas Gravity at Separator Reference Pressure ;

γg=Gas Gravity at Separator Psép and Tsép Actual Conditions ;

Psép (Separator Actual Pressure) = 100 psia ;

Tsép (Separator Actual Temperature) =75°R.

The use of parameter values in the two equations (3) and (4), we have : γgs=0.81 and

$Rs=0.0178.0.813.2583^{1.187}exp\left[23.931.\frac{32.1}{629}\right]$, this gives us, Rs=554 scf/stb.

3. CORRELATION OF GLASO

Glaso proposed a correlation to determine gas solubility as a function of gravity °API, pressure, temperature and specific gravity. The proposed relationship has the following form [16] :

R_s=$\gamma_g\left[\frac{API^{0.989}}{(T-460)^{0.172}}.P_b^*\right]^{1.2255}$ (5), where $P_b^*=10^x$ (6) et

$x=2.8869-[14.1811-3.3093logP]^{0.5}$(7).

By replacing each parameter with its value in equations (5), (6) and (7), this gives us: $x=1.187089216$, $P_b^*=15.38$ et Rs=531 scf/stb.

4. CORRELATION OF MARHOUN

Marhoun (1988) developed an expression to determine the saturation pressure of the crude oil systems of 160 experimental saturation pressure data. The proposed correlation for determining gas solubility is [17] :

R_s=$\left[a\gamma_g^b\gamma_o^cT^dP\right]^e$ (8) ; a, b, c, d et e and e are Coefficients of equation (8) with values : a= 184.843208 ; b=1.8778480 ; c=3.1437 ; d= -1.32657 et e=1.398441.

By replacing the values of each parameter in equation (8), we have : Rs=631 scf/stb.

5. CORRELATION OF PETROSKY-FARSHAD

Pétrosky et Farshad (1993) ont utilisé un logiciel de régression multiple non linéaire pour développer une corrélation de la solubilité de gaz. Ils ont proposé l'expression suivante [2] :

R_s=$\left[\left(\frac{P}{112.727}+12.34\right)\gamma_g^{0.8439}.10^x\right]^{1.73184}$ (9);

X=7.916(10-4)(°API)1.541-4.561(10-5)(T-460)(1.3911) (10)

By replacing the values of each parameter in equations (9) and (10), we have : x=0.108654515 and Rs=552 scf/Stb. Using the different correlations, the gas solubility (Rs) at the bubble point pressure is estimated and compared with the experimental value in terms of the absolute mean error Absolute average error (AAE). This allows us to summarize the values of Correlations Rs found with AAE (Table 4).

Table 4: Summary of calculation of Rs by empirical correlations

Corrélations	***R_s* *(scf/STB)***	***AAE(%)***
Standing	645.5	17.36
Vasquez-Beggs	554	0.73
Glaso	531	3.45
Marhoun	631	14.73
Petrosky-Farshad	552	0.36

It is noted that the value of the solubility of the Rs gas calculated by the Petrosky-Farshad correlation is very close to that of the Libwa Field determined by PVT analyses with a deviation or AAE of 0.36%, this allows the oil in place to be classified as volatile oil [18]. This clearly shows that Petrosky-Farshad's correlation can predict the volumetric behaviour of the Libwa Field. It is also

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necessary to determine the oil background volume factor (Bo) with Standing correlation is [19]: B_o=$0.9759+0.00012\left[R_s\left(\frac{\gamma_g}{\gamma_o}\right)^{0.5}+1.25(T-460)\right]^{1.2}$ (11) ; by replacing the values of each parameter in equation (11), we have : B_o=$1.088\ rb/stb$.

From Rs determined by Petrosky-Farshad, we have established the complete table of PVT parameters (Rs, bg and Bo) according to the pressure (Table 5)

Tableau 5 : Rs, Bg et Bo en fonction de la pression [8]

Pression (psia)	Rs (scf/stb)	Bo (rb/stb)	Bg (bbl/scf)	Bo/Bg	(Bo-Boi)/Bg+(Rsi-Rs)	Np/N (%)
2670	550	1.238	0.00101			
2583	550	1.31	0.00103			
2500	532	1.303	0.00106	1229.24	11.39	1.32
2300	485	1.279	0.00116	1102.58	38.27	1.67
2100	441	1.256	0.00127	988.97	66.48	2.1
1900	398	1.234	0.00141	875.17	98.09	2.58
1700	357	1.213	0.00159	762.89	131.99	3.11
1500	318	1.194	0.00183	652.45	168.61	3.7
1300	281	1.176	0.00214	549.53	206.38	4.3
1100	246	1.159	0.00257	450.97	245.24	4.97
900	213	1.144	0.0032	357.5	285.12	5.65
700	181	1.129	0.00419	269.45	325.8	6.36

3.3.2. Evolution of the performance of the Pinda upper reservoir in the Libwa field

This consists in studying the evolution of the oil production as a function of the pressure of the reservoir using as a basic parameter the Gas-to-Gas ratioCumulative gas oil (Rp). The cumulative gas-oil ratio Rp shall be clearly distinguished from the instantaneous gas-oil ratio (GOR) Rs [2]. This study was made possible by extrapolating the oil recovery factor based on the cumulative gas-oil ratio (Rp) from the material balance of a gas-drive solution reservoir. The matter balance equation then becomes: [20]: $F_R=\frac{N_p}{N}=\frac{\frac{(B_o-B_{oi})}{B_g}+(R_{si}-R_s)}{\frac{B_o}{B_g}-R_s+R_p}$ (12) et $R_p=\frac{G_p}{N_p}$ (13)

We note that the oil recovery factor which is the ratio between the cumulative oil production (Np) on the quantity of the initial oil in place (N) is in inverse relation to Rp. And this gives us an idea of the speed of the curve for estimating the performance of the Libwa field Pinda reservoir based on the recovery factor (F_R) against the cumulative GOR (R_p). This curve can tell us about:

- the possibility of increasing the recovery factor under the same pressure ;
- the current recovery factor ;
- the future performance of a tank in terms of pressure and GOR.

Since the oil recovery factor of the Champ Libwa was estimated at 4.8% and that at the end of 2009, the cumulative oil and gas production are respectively 14.3 Million Stock Tank Barrel (MMSTB) Original Oil In Place (OOIP) 491MMSTBN; and Standard Cube feet (BSCF) 75.8 Billion Standard Cube feet : $R_p=\frac{75800}{14.3}=5300\ {}^{scf}/_{stb}$ et $F_R=\frac{N_p}{N}=\frac{14.3}{491}=0.0291\ ou\ 2.91\%$. However, oil production between October 2014 and October 2015 is 17.19 MMSTB, respectively (Figure 7). This allowed us to find its recovery factor (F_R) at 0.03501 or 3.501%, which shows that recovery increased compared to 2009. With regard to this value of the oil recovery factor and referring to the figure of the evolution of the performance of the upper Pinda reservoir of the Libwa field as well as to Table 5, the pressure is 1500psia and 1700 psia. After several extrapolation tests, the pressure corresponding to this oil recovery factor is estimated at 1567psia and Rp is 5250 scf/Stb. We understand that the performance of the Pinda Superior reservoir of the Libwa field based on the oil volume factor and cumulative GOR (Rp)is at a pressure of 1567 psia and 5250 scf/Stb so there is a drop in pressure compared to 2009 and a very small decrease in GOR (Figure 6).

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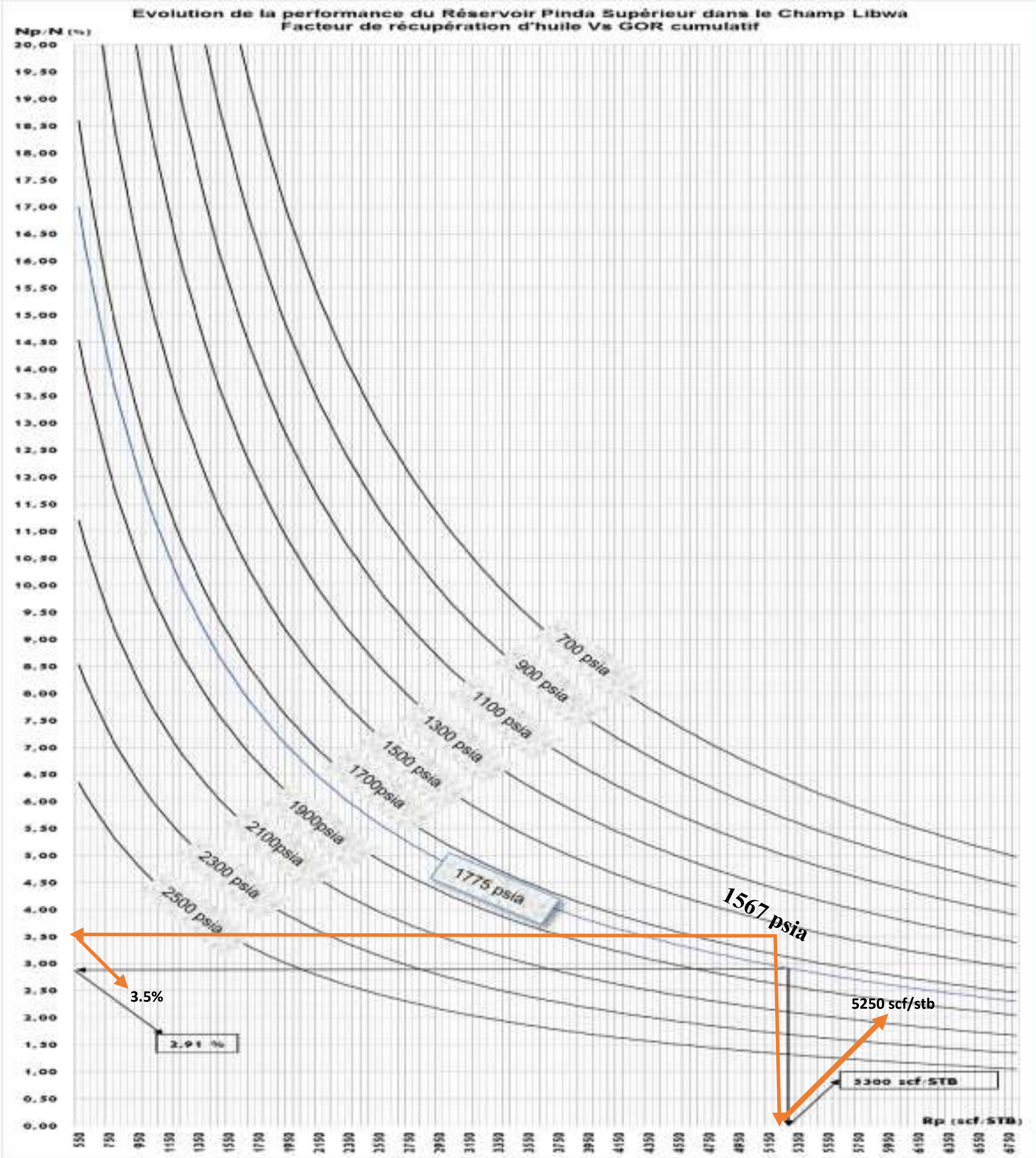

Fig.6 : Evolution of the upper Pinda resservoir performance of the Libwa field

3.3.3. Prediction of the decline time of the upper Pinda reservoir of the Libwa field by the analysis of the decline curve

We apply the Analysis of the Decline Curve «ACD» in order to predict the depletion of the upper Pinda reservoir of the Libwa oil field based on the production of the entire field and also give an initial reservoir concept that can be used to design a study of the model. Analysis of the production decline curve is one of the traditional means of identifying much more production problems and predicting the performance of the well or reservoir based on real production data [19]. Data used including pressure data. In this respect, the evolution of the reservoir pressure is physically linked to the cumulative production (and not directly to the time) and the drainage mechanism involved [21].

In the development and production phase, the use of new data acquired during development and dynamic production data improves the realism of the model by calibrating dynamic data in order to establish more reliable production forecasts [22]. This is how we use the relationship between flow rate and time for producing wells that allows us to have the decline curve in order to predict the time of decline of the reservoir in a field. Assuming the constant flow pressure, we have the following mathematical expression [20] and [23] : $b = -\frac{1}{q}\frac{dq}{dt}$ (14), Where «b» is an empirically determined constant or time factor of decline and q is the rate of production and t is the time of production. From this mathematical relationship, three decline curves have been identified, each of which is applicable depending on the drainage mechanism of the reservoir. These are [20] :

- ✓ the exponential decline curve: $q = q_0\, e^{-btc}$ (15), where q0 is the initial production rate;
- ✓ the hyperbolic decline curve corresponds to: $b = -\frac{1}{q}\frac{dq}{dt} = cq^{\frac{1}{a}}$ (16). By developing this equation, this give up :

$a = \frac{ln\frac{q_0}{q}}{ln\left[1+\frac{bt}{a}\right]}$ (17), where a is the constant ;

- ✓ the harmonic Decline Curve: $\frac{1}{q^2}\frac{dq}{dt} = -bq_o{}^d$ (18), d is a constant; the execution of the prediction of the production of a hydrocarbon extraction system that follows a harmonic decline is determined when d=1 and a=1. We will bring this expression back and integrate; by inserting the integration terminals q and qo et, t et 0 ; this operation gives us an expression of the flow as follows: $q = \frac{q_0}{1+bt}$ (19)

It should be noted that the hyperbolic decline model is the most widespread and encompasses the other two models of decline. This model of production decline is determined if and only if the constant d is between 0 and 1. But all three curves will lead to determining the abandonment time of production and can be applied to the different wells or to the whole tank, this time is given by the following equation: $t = \frac{1}{bd}\left[\sqrt[\frac{1}{d}]{\frac{q_0}{q}} - 1\right]$ (20)

Knowing the type of drainage mechanism of the upper Pinda reservoir, the decline considered is that of exponential decline. Then, the cumulative output of the analysis of the decline curve is the integral of the rate from the initial rate Qo at time t = 0, at the rate of q at time t. Thus, the cumulative output of the exponential decline is given by [23]: $N_p = \int_0^t q dt = \frac{q_o - q}{b}$ (21) ; N_p varies linearly with q and the decline curve is a straight line for log q as a function of time (semi-log). We represent the daily average and cumulative Libwa field production data to which the decline was observed (Figure 7).

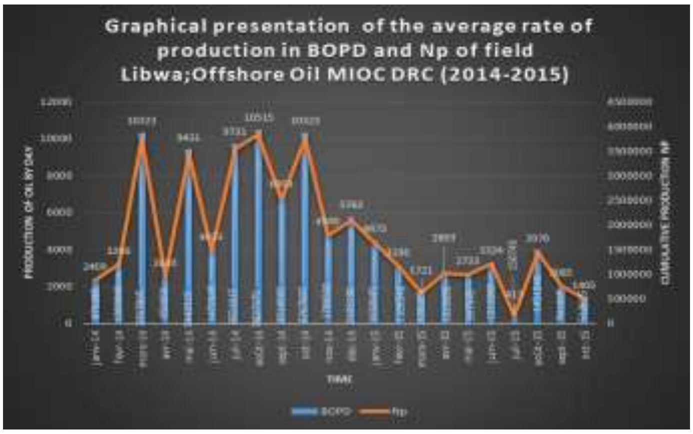

Fig. 7 : Curve showing the average rate of oil production in the Libwa field.

a. Determination of constants b and d

The constant b is the rate of continuous decline in the production of a well or reservoir. This value can be determined based on historical production data available in the phase of decline (Ntumba K., 2018[24]). It is known that if the flow rate (rate) of production and time are available: the constant b can be obtained on the slope of the half-plane of the straight line. This implies that the data should form a straight line; the slope of b on the representative curve of log(q) facing time t by taking two points on the curve such as : (t_0, q_1) and (t_1, q_2). This gives us :

$b = \frac{1}{(t_1 - t_0)} ln\frac{q_1}{q_2}$ (22), *with* $t_1 = 1\; et\; t_0 = 0,$; referring to figure 7, $q_1 = 5762$ barrels (December 2014) ; $q_2 = 4473\; barrels\; (January\; 2015)$ then the value of b est 0.253.

It is considered as being inversely proportional to the situation a [24]: $d = \frac{1}{a}$. In the case of hyperbolic decline, the value of a is 2 and for harmonic decline, a is equal to 1 [20]. Knowing that d is between 0 and 1, we take d= 0.5.

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b. Determination of production abandonment time

Once production data from the phase of decline and constants b and d are available, the abandonment t period is:

$t = \frac{1}{bd}\left[\sqrt[\frac{1}{d}]{\frac{q_0}{q}} - 1\right]$, taking q_0=10323 BOPD (October 2014).

We know that oil production starts from scratch, in the end it will return to zero because the time of formation of hydrocarbons is extremely long compared to the human time scale, the oil stock can be considered as a finite value, and therefore production will by definition be zero once all has been produced [5]. So to determine q, it will be obtained by the end-of-life time q=0 of the Libwa field using the extrapolation method: $Q = q_0 * e^{-bt}$ (barrel) with t=1 and considering Q_0= 1405 BOPD (October 2015), this gives us the value of q to 1090.94 BOPD (October 2016). By replacing the values of each parameter in mathematical expression of abandonment time t of production (equation 20), this gives us t equals 16,4 years from 2016. This explains why the company would have abandoned when it produced its last q at ±15 BOPD so in 2032 years and 4 months.

c. Extrapolation of production rate in barrel oil per day (BOPD)

Extrapolation of the production rate in BOPD and the cumulative production np in barrel of the LIBWA field as a function of time; MIOC OFFSHORE DRC is taken by admitting stable activities in the reservoir is given in the form of this curve (figures 8), on the basis of the equation of decline, to predict that the upper Pinda reservoir of the libwa oil field will be able to experience the decline in oil production during the year 2044 , therefore in 25 years from this year (2019) , in this case the company will produce its last q at least 1 BOPD.

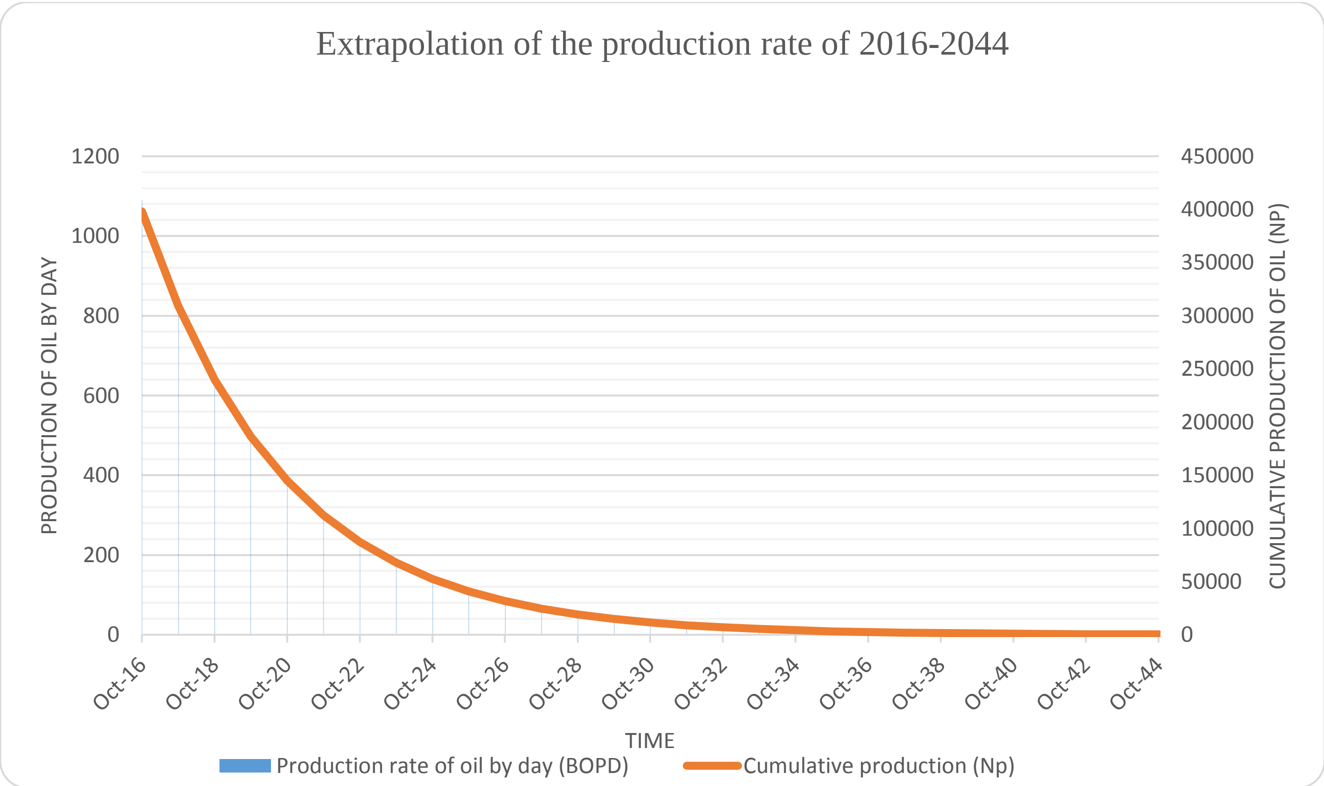

Fig.9 : Chart of extrapolation according to the time of the the production rate in BOPD and cumulative production Np (2016-2044).

4. CONCLUSION AND SUGGESTIONS

In the maritime part (Offshore of the Democratic Republic of Congo), Libwa constitutes one of the important productive oil fields. For this purpose, an estimation study of the performance of the upper Pinda reservoir was conducted using oil production data from two wells, libwa-3 and Libwa-5, drilled in the upper Pinda reservoir of this Libwa field. The results are as follows :

- On reservoir performance, oil recovery can be improved by keeping cumulative GOR as low as possible or constant ;

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- On the prediction of the decline time of the upper Pinda reservoir, we affirm our prediction of the decline of the upper Pinda reservoir in the Libwa field in 2044 (either in 25 years).

In order to optimize the production of the upper Pinda reservoir of the Libwa field in improving the drainage of oils and pushing its decline time beyond 2044; we suggest to the company MIOC-Offshore/ DRC of :

- ✓ Being able to set up a campaign of gas injectors (Gas repressering Wells) in order to assist the top Pinda reservoir to the level of the gascap ;
- ✓ Design a new modelling of the upper Pinda reservoir in the Libwa field in order to optimize its productivity and better locate the sites of gas injection wells.

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