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QUANTITATIVE ANALYSIS OF WELL PRODUCTION BY POETTMANN AND CARPENTER CORRELATION AND CHOICE OF AN ACTIVATION MODE. CASE OF THE KINKASI-C1 WELL IN THE KINKASI FIELD

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ABSTRACT

With a strong focus on optimizing the performance of a producing well, our work performs a nodal analysis of the subsurface production subsystem. Using data from the Kinkasi-C1 well on the Kinkasi field, producing in the Vermelha, it analyses the elements of this subsystem, focusing on the analysis of head losses in the production tubing. Knowing the daily production rate and having determined the inflow performance relationship (reservoir pressure and physical properties of the fluids), the wellhead pressure that was lacking was determined. Starting from the pressure node at the bottom of the well, the Poettmann & Carpenter correlation provided us with the head losses along the tubing and, in turn, the wellhead pressure for the company's daily flow rate. Given that this correlation requires tedious calculations, we used Java programming to develop software to support its calculation algorithm. After this stage, the possibility of producing more with or without activation was studied. By prioritizing oil production, activation by pumping, more specifically using an ESP, was the appropriate means of optimizing KK-C1's performance.

Keywords: performance, tubing, pressure, production system

INTRODUCTION

In an era where oil reigns supreme, a country that possesses this resource plans to exploit it in order to strengthen its economy and the quest for greater well-being. The Democratic Republic of Congo, which is classified as a developing country, has this resource in its various basins (coastal basin, central basin and East African Rift Basin), although only the hydrocarbons in the coastal basin are currently exploited.

Hydrocarbons buried at great depths are not easy to locate and require oil exploration to unearth them. This initial phase, which is already very costly, ends with exploration drilling. It is this drilling that certifies the presence or otherwise of hydrocarbons. Estimates are then made to determine the economic profitability of the oil in place. It is only after this phase that the field can be exploited.

The hydrocarbons in the reservoir are under pressure, and to allow them to flow we need to create a pressure difference between the reservoir and the bottom of the well. Once this difference has been created, the fluids move from the reservoir, where the pressure is high, to the bottom of the well, where the pressure is low. Once the fluid has reached the bottom of the well, it still has to rise to the surface. If the well allows the fluids to reach the surface, it is considered to be eruptive. If not, it is either not eruptive or insufficiently eruptive.

As the oil continues to flow out of the reservoir, the pressure inside the reservoir gradually decreases and the quantity of gas in the liquid is reduced. As a result, the flow rate of the fluid in the well slows down and less gas is released. The fluid may not reach the surface and an artificial flowback system must be installed to allow crude oil production to continue.

A well can be activated in two ways, by gas-lift or by pumping. The second is the one we are interested in. It requires an assessment of the head losses along the production tubing in order to be able to propose a suitable pump, which will be able to drain the fluid to the surface.

Better evaluation of the well during production means that it is not destroyed and, better still, that capital expenditure does not increase. After all, while exploration is a very expensive phase, production is even more capital-intensive [1]. So we need to think about and apply the best methods for achieving optimum production.

Our study is based on the Poettmann and Carpenter model, using data from the KINKASI C1 well, producing from the Vermelha reservoir in the KINKASI field. This brief asks two questions:

- ✓ What is the status of the VERMELHA reservoir in the KINKASI field?
- ✓ What can be done to obtain an optimum flow rate that will meet the requirements of the reservoir and the well?

The main objective of this work is to analyse the production subsystem, focusing on the quantification of pressure losses in the production tubing. The aim is to understand how to orientate the completion of the tubing in order to optimise production. The secondary objective is to solve the problem of the losses suffered by the fluids, which exceed their energy, while studying the possibility of producing a daily quantity of fluids greater than that produced in 2014.

MATERIALS AND METHOD

To carry out this work, we used a computer with the Office pack to construct the IPR curve, the MBK-Pierre Augustin software to bypass the iterative calculations of the Poettmann and Carpenter correlation, the PipeSim software for the performance curves for the choice of pump as well as the image of its completion and the Paint software for image processing.

The Poettmann and Carpenter correlation is one of the mathematical models for analyzing the performance of production tubing located in a well. In this case, an oil well. This analysis consists of evaluating the loss of energy (or pressure) that the fluid has from its arrival at the bottom of the well to the top of the well. In this way, a curve called the TPR is constructed. To do this, we need to understand the behavior of the fluid coming from the reservoir towards the well. In our case, this is the Kinkasi C1 well. And from the well to the wellhead, and finally from the wellhead to the other operating sites (which will not be discussed in this article); all this makes up an oil production system.

In the general case, the production system is the system that transports reservoir fluids from underground to the surface, processes them, and preparing them for storage and transfer to a buyer. The following are the basic elements of the production system:

- ✓ The reservoir: this is the source of fluids for the production unit. This is a highly porous and permeable medium in which fluids are stored and through which the fluids flow to the borehole. It also provides the primary energy for the production system;
- ✓ The wellbore: this is the access pipe to the reservoir from the surface. It is made up of the drilled well, which is cemented and cased;
- ✓ Tubular and related products equipment: underground production equipment;
- ✓ Well head from the surface, flow lines and processing equipment: represents the mechanical surface equipment needed to control and treat fluids from the reservoir to the water surface and prepare them for transfer to a buyer. The mechanical equipment includes wedges (nozzles), manifolds, outflow lines, separators, handling equipment, measuring devices, tanks, etc.
- ✓ Artificial lifting equipment. [2]

It is important to mention that in some cases, the reservoir is not capable of supplying sufficient energy to produce fluids at the surface at economic rates throughout the life of the reservoir. When this problem arises, artificial lift is used to increase production yields by injecting additional energy into the production system.

The additional energy can be supplied directly to the fluids by underground pumps or by injecting gas at the base, known as a gas-lift. So the design of a well or the adequate prediction of the production rate requires a systematic analysis to incorporate the system's components. This is what is known as nodal analysis. For effective well control, this is essential to have a good understanding of the flow of hydrocarbons in the production system, in particular the performance of the inflow, which is the operation of the well, and the performance of the outflow, which is the operation of the production system. [2]

The understanding of the principles of fluid movement in the production system as illustrated in Figure 1 is key to estimating the well performance and its optimization as well as the profitability of the well reservoir. We will therefore divide this section into three parts as follows.

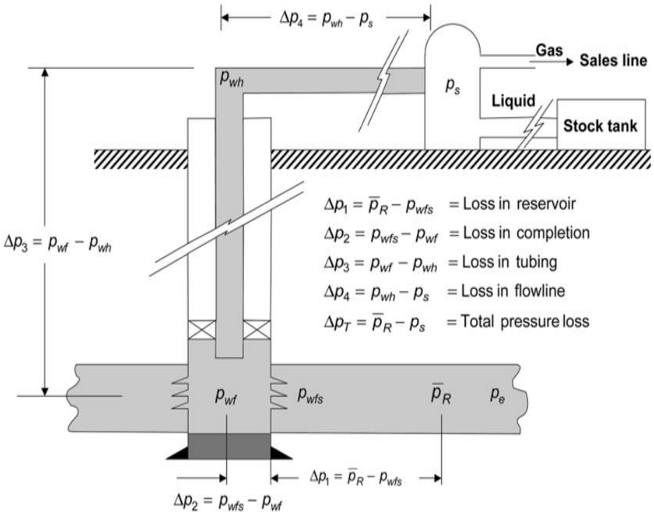


Figure 1. *Schematic diagram of an oil production system* [2]

From Reservoir to Downhole

Hydrocarbons can move from a source rock to a reservoir rock and from the reservoir rock to the trap in a uniform or non-uniform flow. The flow is said to be uniform when the velocity components are independent of the spatial coordinates; and it is said to be non-uniform when the velocity components are related to the spatial coordinates.

These hydrocarbon movements are studied in multiphase flows. By multiphase flow, we mean a flow composed of several phases of fluids (in our case we have liquid and gaseous hydrocarbons), as opposed to a single-phase flow which has only one phase. However, when a vertical, horizontal or inclined well is placed in contact with the reservoir after perforation, the hydrocarbons in the reservoir tend to flow towards this structure. The movement of hydrocarbons towards this well becomes radial, and not uniform. It can be non-permanent, permanent or pseudo-permanent. The flow of a fluid is said to be permanent (or stationary) when the velocity components are independent of the time variable; otherwise it is said to be non-permanent. In this way, the reservoir responds to the call for pressure from the bottom of the well, knowing that fluids always flow from the point of high hydraulic potential towards the point of lower hydraulic potential, following the direction of the steepest slope (the direction of the hydraulic gradient).

The hydraulic potential or hydraulic head (φ) is an energy expressed in length and is equal to:

$$\varphi = z + \frac{p}{\varpi} + \frac{v^2}{2g} \tag{1}$$

with:

- z: height at which the fluids rise, relative to a reference plane, the point where the energy, φ of the fluid studied is determined;
- p: pressure of the fluid at this point;
- ϖ: specific weight of the fluid;

- v: velocity of the fluid at this point;
- g: acceleration of gravity.

As these fluids are real fluids, when they leave point 1 (reservoir) towards point 2 (bottom of the well), there is a loss of head (loss of energy) due to the friction of the fluid particles with each other and/or with the walls and the length of the wall. The potential difference that controls the movement of the fluid from point 1 to point 2 is $\Delta\varphi = \varphi_1 - \varphi_2$ which we call "head loss". Similarly, we say that the flow rate between the reservoir and the well bottom depends on the pressure drop in the tank $(p_e - p_{wf})$. The relation between the rate of flow and the pressure drop in the porous medium can be very complicated. and depends on a number of parameters, such as the petrophysical properties of the rock and the properties of the fluids, the flow regime, the fluid saturation of the rock, the compressibility of the fluids, the damaged or stimulated formation, etc.

The IPR curve is constructed by taking into account the downhole pressure and the reservoir production rate, using the formula:

$$J^* = \frac{Q}{p_e - p_{wf}} \tag{2}$$

with p_e: reservoir pressure

The production well and tubing

In this section, we will attempt to analyse the performance of a production well by evaluating the head loss between the bottom and the top of the well. Knowing this pressure drop and its causes will enable the engineer to design the well equipment that will provide the best expected production under the best economic conditions.

Oil can be produced by the tubing or the production line. The tubing is defined as the pipe that carries the effluent from the reservoir to the surface in the case of a production well, or from the surface to the reservoir in the case of an injection well. In addition, a judicious choice of pipe diameter ensures a fluid flow regime and therefore energy consumption. In the tube, the fluid can flow in one or more phases, depending on whether or not it reaches the bubble point. The fluid flowing through the tube towards the surface is made up of oil, natural gas, water and sand dust.

To simplify the study, multiphase flow is generally considered to be two-phase, i.e. composed of two phases, liquid and gas.

Several models for determining the TPR have been developed; They can be grouped into three categories. Of course, each of them varies in terms of complexity and technique. A table in the next section supports these writings. So we have:

- ✓ Category A: No slip effect or flow regime is considered. This is the category by Poettmann & Carpenter and Fancher & Brown.
- ✓ Category B: The effect of slippage is taken into account, but no flow regime is considered. Hagedorn & Brown and Gray are the two authors of this category.
- ✓ Category C: Slip and flow regime are taken into account. In this category, we find the correlation of "Beggs & Brill, Orkiszewski" and that of "Duns & Ros".

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

- ***Poettmann and Carpenter correlation***

This is a model which considers the flow of hydrocarbons to be homogeneous. It was proposed by Poettmann and Carpenter, as the name suggests, in 1952; this model considers that the change in energy in the pipe is due solely to the friction of the three fluids (oil, gas and water) between their own molecules and also against the inside wall of the tubing. So they consider that this loss of energy (ΔW) through a segment of the tubing of length Δh and internal diameter D is calculated by:

$$\Delta W = 4f_f \frac{u^2 \Delta h}{2gD} \tag{3}$$

If the velocity of the mixture in this segment is u and f_f the coefficient.

These assumptions lead to

$$\Delta p = (\bar{\rho} + \frac{\bar{K}}{\bar{\rho}}) \frac{\Delta h}{144} \tag{4}$$

$$\bar{\rho} = \frac{\rho_1 + \rho_2}{2} \tag{5}$$

With:

- Δp: the pressure loss in the tubing segment (psi);
- $\bar{\rho}$: the average specific mass of the mixture in the segment (lb/ft3);
- ρ_1: the specific mass of the mixture at the top of the tubing segment;
- ρ_2: the specific mass of the mixture at the base of the tubing segment;
- Δh : the length of the segment (ft) ;
- $\bar{K} = \frac{f_{2F} Q_o^2 M^2}{7{,}4137 * 10^{10} D^5}$;
- f_{2F}: Fanning resistance factor of two phases (liquid and gas);
- Qo: oil flow rate (STB/D);
- M: total mass (water + oil + gas) associated with 1 STB of oil (lbm);
- D: internal diameter of the pipe (ft).

Note that the specific mass of the mixture at a point in the tubing can be calculated by dividing the mass flow rate, M, of the mixture by the volume flow rate (Vm) of the mixture:

$$\rho = \frac{M}{V_m} \tag{6}$$

with:

$$M \left(\frac{lb}{bbl}\right) = 350{,}17 \left(\frac{lb_m}{bbl}\right) (d_o + WOR * d_w) + GOR \left(\frac{cf}{bbl}\right) d_g * 0{,}0764 \left(\frac{lb}{cf}\right) \tag{7}$$

When the volume of water or oil is expressed in barrels, it is converted into cubic feet (cf) by multiplying the barrels by 5.615 cf/bbl

$$V_m(cf) = 5{,}615(B_o + WOR * \beta_w) + (GOR - R_s)\left(\frac{14{,}7}{p}\right)\left(\frac{T}{520}\right)\left(\frac{z}{1}\right) \quad (8)$$

Where:

- d_o : oil density;
- WOR: water-oil ratio (BBL/STB);
- d_w : density of water (1 for fresh water at 4°C);
- GOR: product gas-oil ratio (scf/STB);
- d_g: gas density (1 for air);
- B_o: oil volume formation factor (RB/STB);
- R_s: solution gas ratio (scf/stb);
- Bw: water formation factor (rb/stb).
- z : gas compression factor (dimensionless)

In the event that experimental measurements to determine Rs and Bo are not available, these parameters can be estimated using the following formulae [4]:

$$R_s = d_g\left[\frac{p}{18}\frac{10^{0{,}0125(°API)}}{10^{0{,}000916t}}\right]^{1{,}2048} \quad (9)$$

$$B_o = 0{,}9759 + 0{,}00012\left[R_s\sqrt{\frac{d_g}{d_o}} + 1{,}25t\right]^{1{,}2} \quad (10)$$

Where, *t* is the in-situ temperature (°F).

The two-phase resistance factor (f_F) is calculated according to the following equation

$$\frac{1}{\sqrt{f_F}} = -4\log\left\{\frac{\epsilon}{3{,}7065} - \frac{5{,}0452}{R_e}\log\left[\frac{\epsilon^{1{,}1098}}{2{,}8257} + \left(\frac{7{,}149}{R_e}\right)^{0{,}8981}\right]\right\} \quad (11)$$

This equation has been used to calculate the resistance factor of two phases whatever the two-phase flow regime and whatever the type of mixture (homogeneous or heterogeneous), only the way of determining the Reynolds number R_e differs from one case to another.

In Poettmann and Carpenter's formula (4), $\bar{\rho}$ is involved, the value of which depends on Vm. However the value of Vm is calculated by involving parameters such as B_o and R_s, all determined using temperature, t (°F) and pressure which all vary, from the bottom to the wellhead. So formula (4) gives good estimates of the dependent variable, Δp, only for small values of the independent variable, Δh, in which variation of the parameters involved in it for the calculation of $\bar{\rho}$ is negligible. If Δh is taken as the height between the bottom of the well and the head of the well, the use of formula (4) would only be lawful for wells where the vertical distance between the bottom and the head is small. If this vertical distance is large, it would be necessary to divide this height into small segments in which it is assumed that the parameters indirectly involved in equation (4) vary little or not at all. Equation (4) is then iterated to calculate the pressures at each end of the segment, segment by segment. The calculation starts from the extreme segment where the pressure is known at its terminal end and by iteration we calculate the pressure at its other end. The pressure thus calculated at the other end will be the known pressure at one of the ends of the second segment, from which the pressure at its other end will be calculated, again by iteration, and used as the known pressure at one of the ends of the third segment, and so on until the pressure at the other end of the pipe is determined [4]. There is a software package with the same name as the correlation; the Poettmann-Carpenter BHP.xls software package, which is capable of bypassing these long iterative calculations.

The Poettmann and Carpenter correlation runs following the algorithm below:

(1) To begin with, the characteristics of the reservoir and the fluid in the reservoir ($\bar{\rho}$, $\bar{\mu}$,)or estimate them as well as the RPI of the well must be available.

(2) Divide the total height of the tubing into small segments H1, H2, ... and Hn, such that the first segment starting from the bottom of the tubing is H1H2 and the last segment at the head of the tubing is Hn-1 Hn. Here we assume that the known pressure is that prevailing at the lower end of the tubing at the bottom of the well; it also happens, even very often, that the pressure set in advance is that at the head of the well which allows the hydrocarbons to be led to the separators without the use of a pump or compressor.

(3) The IPR gives the flow rate for each pwf.

(4) Assume that the temperature (t) varies linearly from the bottom to the top of the well. This allows us to determine ti (i varying from 1 to n) at each end of the segment, so that t1 is equal to the temperature at the bottom of the well and tn is equal to the temperature at the top of the well. We have assumed a variation of 15F every 1000ft for our geothermal gradient [5]

(5) Equation (8) is used to calculate the value of M at the end where p is known. Note that the parameters involved in calculating M do not vary with either temperature or pressure, so this value of M will be constant throughout the tubing.

(6) Equation (9) is used to calculate the value of V_m at the end where p is known. And using equation (7), we determine ρ_1. However, equation (9) includes parameters that vary along the length of the tubing, i.e. in each segment, and therefore differ from one end of a segment to the other. These are pressure (p), temperature (T) and z. The appropriate values must therefore be used for each end. T varies linearly along the length of the tubing, so it is easy to determine at each end of a segment. The value of z depends on T but also on p, which is only known at one end of the first segment. So p is determined by an iterative calculation as follows

(7) At the other end of the segment, any value of p is given, which makes it possible to determine z at the end of the segment where p has just been arbitrarily fixed and to calculate V_m and ρ_2 in this way.

(8) Having ρ_1 et ρ_2 of the first segment we calculate the average density of the homogeneous mixture, $\rho_{m1}$by equation (5).

(9) Using equation (20), we determine Δp. If the value of Δp is compatible with the value of p chosen arbitrarily, then p is correct and is retained as the known pressure of the second segment, continuing the calculation from point 6. If there is no compatibility, another pressure p is chosen arbitrarily and the calculation is continued from point 7.

(10) The compatibility of Δp is established as follows: if p known $\pm$ Δp gives p arbitrarily fixed, there is compatibility, if not, there is not. We add Δp to known p if we start from the head of the well towards the bottom of the well or we subtract Δp from known p if we start from the bottom of the well towards the head of the well.

(11) This is done from segment to segment until the end of the tubing where p is unknown and must be determined.

This calculation, repeated for different downhole pressures (p_{wf}), produces a set of pairs (p_{wf}; p_{wh}) that can be used to draw graphs. Each pair corresponds to a flow rate, because each pwf determines a given flow rate. This is the algorithm we used to develop software called MBK Pierre-Augustin to bypass the tedious calculations required by correlation in order to minimize errors.

Activation by pumping

Activation is a technique for producing wells that are not or are insufficiently eruptive. For oil-producing wells, activation may be required from the start of production when the reservoir does not contain enough energy to lift the fluid from the bottom to the surface treatment facilities, or when the productivity index is deemed insufficient. A distinction is made between the gas-lift activation method (lifting by gas) and the pumping activation method [6].

ESP pump downhole tools are classified according to their outside diameter (from 3.5 to 10.0 in.). The number of stages to be used in a given ESP outside diameter is dictated by the oil to be produced at surface, and the depth of the well from which this flow is to start.

The output flow rate depends on the back pressure. The increase in pressure is generally expressed as the pumping head, i.e. the equivalent height of fresh water that the differential pressure can support (pumps are fresh-water tested by the manufacturer). On site, Anglo-Saxon units are used, with pumping head (h) being expressed as:

$$h = \frac{\Delta p}{0{,}4329 * d_L} \qquad (12)$$

With :

- h : pumping height (ft)
- Δp: pressure increase (psi): $\Delta p = p_{discharge} - p_{suction}$
- $P_{discharge}$: Discharge pressure;
- $P_{suction}$: Pump suction pressure;
- d_L: density of the liquid to be pumped

To obtain the pump's suction pressure, we need to know the depth at which the pump is installed (H_{pump}) and the depth of the production layer (H) given by the following formula:

$$H_{pump} = H - \frac{p_{wf} - p_{suction}}{0{,}4329 * d_L} \quad (13)$$

there are certain operating conditions which significantly reduce pump efficiency, including :

- the presence of free gas in the oil (risk of pump cavitation) ;
- high temperature at great depths (limits pump life);
- high viscosity of the oil produced (reduces pumping head);
- the presence of sand in the fluid produced (increases pump wear);
- the presence of synthetic kerosene in the pumped fluid (increases pump clogging and shortens service life).

RESULTS

- *Result 1: IPR curve production*

There are several formulas for determining J* (IPR) depending on whether the regime is transient, permanent or pseudo-permanent. For our well, we have considered the permanent regime. For the Kinkasi C-1 Well, we constructed the IPR curve of the reservoir as shown in figure 2 below:

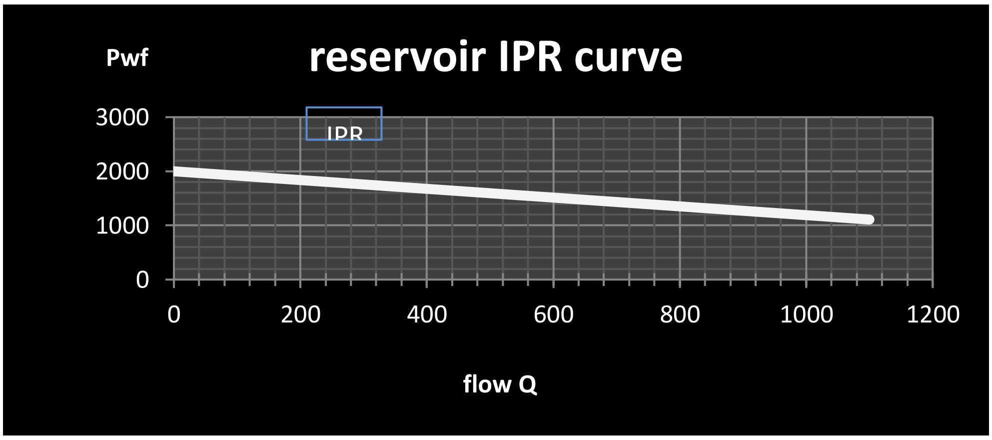
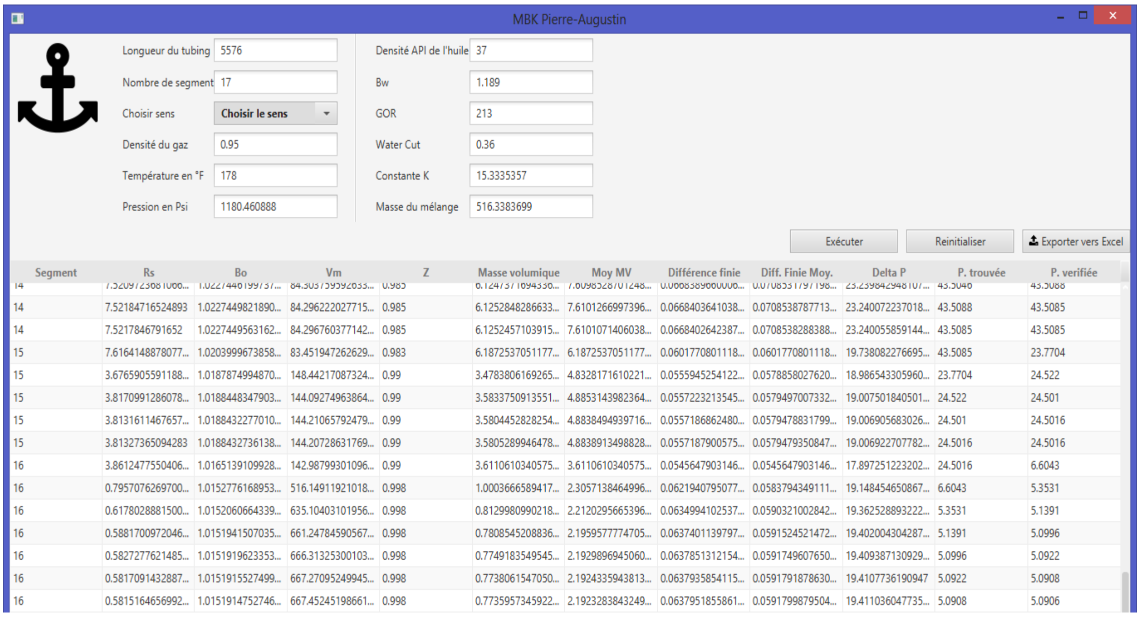


***Figure 2**. IPR curve Well KK-C1*

- *Result 2: Tubing performance analysis*

Once we had found the downhole pressure for a production of 600 BOPD, we used the Poettmann and Carpenter correlation to determine the pressure at which the fluids arrive at the wellhead. This model, capable of giving us the pressure losses in the tubing, requires tedious calculations (iterative calculations). To do this, we developed a small piece of software called MBK Pierre-Augustin using the Java language. The figure 3 below illustrates its calculation interface.



Segment	Rs	Bo	Vm	Z	Masse volumique	Moy MV	Différence finie	Diff. Finie Moy.	Delta P	P. trouvée	P. verifiée
14	7.52184716524893	1.0227449821890...	84.296222027715...	0.985	6.1252848286633...	7.6101266997396...	0.0668403641038...	0.0708538787713...	23.240072237018...	43.5088	43.5085
14	7.5217846791652	1.0227449563162...	84.296760377142...	0.985	6.1252457103915...	7.6101071406038...	0.0668402642387...	0.0708538288388...	23.240055859144...	43.5085	43.5085
15	7.6164148878077...	1.0203999673858...	83.451947262629...	0.983	6.1872537051177...	6.1872537051177...	0.0601770801118...	0.0601770801118...	19.738082276695...	43.5085	23.7704
15	3.6765905591188...	1.0187874994870...	148.44217087324...	0.99	3.4783806169265...	4.8328171610221...	0.0555945254122...	0.0578858027620...	18.986543305960...	23.7704	24.522
15	3.8170991286078...	1.0188448347903...	144.09274963864...	0.99	3.5833750913551...	4.8853143982364...	0.0557223213545...	0.0579497007332...	19.007501840501...	24.522	24.501
15	3.8131611467657...	1.0188432277010...	144.21065792479...	0.99	3.5804452828254...	4.8838494939716...	0.0557186862480...	0.0579478831799...	19.006905683026...	24.501	24.5016
15	3.81327365094283	1.0188432736138...	144.20728631769...	0.99	3.5805289946478...	4.8838913498828...	0.0557187900575...	0.0579479350847...	19.006922707782...	24.5016	24.5016
16	3.8612477550406...	1.0165139109928...	142.98799301096...	0.99	3.6110610340575...	3.6110610340575...	0.0545647903146...	0.0545647903146...	17.897251223202...	24.5016	6.6043
16	0.7957076269700...	1.0152776168953...	516.14911921018...	0.998	1.0003666589417...	2.3057138464996...	0.0621940795077...	0.0583794349111...	19.148454650867...	6.6043	5.3531
16	0.6178028881500...	1.0152060664339...	635.10403101956...	0.998	0.8129980990218...	2.2120295665396...	0.0634994102537...	0.0590321002842...	19.362528893222...	5.3531	5.1391
16	0.5881700972046...	1.0151941507035...	661.24784590567...	0.998	0.7808545208836...	2.1959577774705...	0.0637401139797...	0.0591524521472...	19.402004304287...	5.1391	5.0996
16	0.5827277621485...	1.0151919623353...	666.31325300103...	0.998	0.7749183549545...	2.1929896945060...	0.0637851312154...	0.0591749607650...	19.409387130929...	5.0996	5.0922
16	0.5817091432887...	1.0151915527499...	667.27095249945...	0.998	0.7738061547050...	2.1924335943813...	0.0637935854115...	0.0591791878630...	19.4107736190947	5.0922	5.0908
16	0.5815164656992...	1.0151914752746...	667.45245198661...	0.998	0.7735957345922...	2.1923283843249...	0.0637951855861...	0.0591799879504...	19.411036047735...	5.0908	5.0906

Figure 3. *Extract of segmentation and calculation in the tubing with MBK-Pierre-Augustin*

To obtain results that minimise errors, we have subdivided the tubing into seventeen segments. Two of the variables used by the model do not vary throughout the calculations: the mass and the constant K, which have the values 516.3383699 lb for 1 bbl and 12.26682856 respectively, calculated using the company's daily flow rate.

In addition to the mass and K determined above, the software asks for other inputs such as the GOR, the density of the gas, and others. The first interface of the software is illustrated in the figure below.

After these various iterations, the loss of charge amounts to 1481.204 psia, enabling us to find the wellhead pressure, which is therefore 32.7961 psia.

This first stage of our analysis confirms that well KK-C1 is capable of producing 600 BOPD with a bottomhole pressure of 1514 psia and 32.7961 psia at the wellhead. This confirms that the KK-C1 well was blowout in 2014, which prompted Perenco-Rep's engineers to prepare a well proposal in order to complete the well at the appropriate time. [7]

On the basis of this analysis and with a view to proposing a better yield from the well while taking into account our maximum flow rate (single-phase AOF equal to 1100 BOPD with a bottom pressure pwf of 1109 psia), we repeated the analyses, but this time with a flow rate of 1000 BOPD.

For this daily flow rate, the single-phase IPR above prescribes a well-bottom pressure equal to 1190 psia.

So let's estimate the pressure drop using our software once again. Considering the result in the table we see that the fluids do not reach the surface and are limited to 209 m depth. The well is therefore not eruptive enough.

Increasing the flow rate of KK-C1 to 1000 BOPD therefore implies its immediate activation. We are going to modify its completion by inserting a pump, and this one is an ESP (Electric Submersible Pump).

- *Choosing the pump*

Knowing the desired flow rate and the head pressure at which we want to produce, we used the ESP catalogue incorporated in the PIPESIM 2017 software to make our choice.

The ESP TA1200, which has a maximum efficiency zone in which our flow rate falls, is the one we have chosen to activate our well. Its characteristic curves are shown below in the figure 4.

After selecting the pump, we decided to place it at a depth of 1701 m (5579.28 ft) and determine its suction pressure using formula (12). Its value is 1180.46008 psia.

The next step is to determine the pressure losses using the Poettmann and Carpenter model for a flow rate of 1000 BOPD. The MBK Pierre-Augustin software gives us the value of the pressure drop, which is 1191.782374 psia.

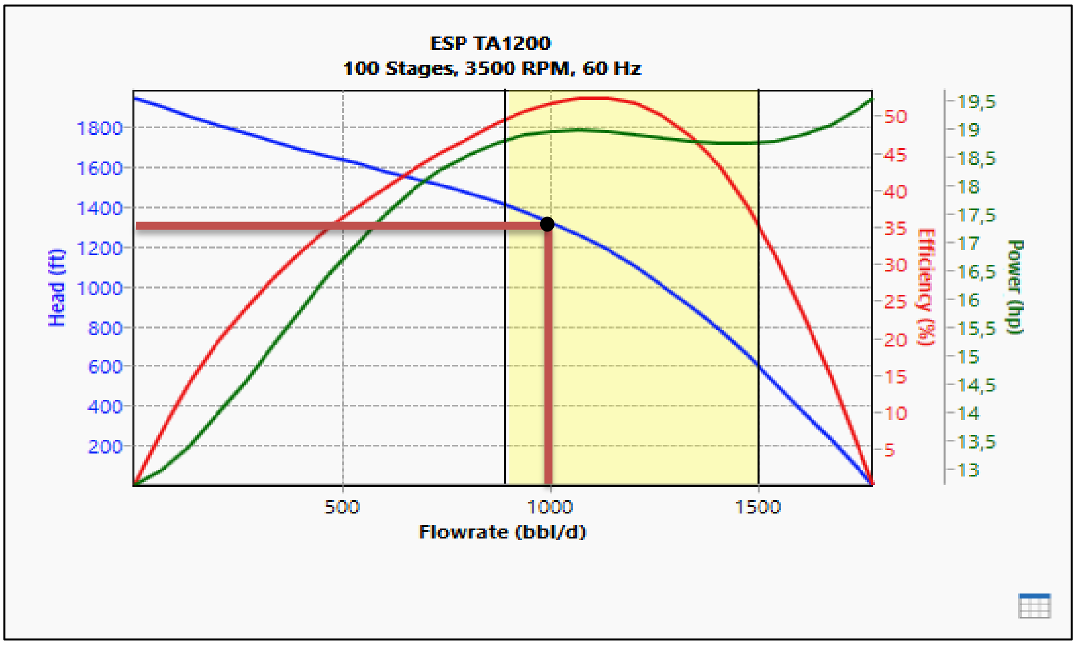


***Figure 4**. ESP TA1200 characteristic curves (PIPESIM catalog)*

At the fifteenth section, the fluid pressure is close to atmospheric pressure, so the fluids stop at this point. The pressure drop for the last two sections is 35.8202 psia, which we add to 1155.9591 psia. Our software therefore gives us an overall head loss value of 1191.782374 psia. To produce 1000 BOPD with a head pressure of 32.7961 psi, we need to add 44.1177 psi to this head loss value.

To find the pumping head of our pump, which will then determine the number of stages we need to place in series for optimum efficiency, we will use the formula (12);

Given 1585.020414 psia as discharge pressure, 1180.4609 psi as Pump suction pressure and 0.839762611 as density of the liquid to be pumped we obtain 152.5010 ft of pumping head.

Referring to our choice of pump, the ESP TA1200, its performance curve tells us that 100 stages of this pump overcome a head of 1326.21 ft. This means that 1 stage of this ESP can overcome 13.2621 ft. Knowing that the pressure differential we still have to overcome is 371.763426 psia, so we'll need 11.499 stages, which we will round off to 12 stages.

CONCLUSIONS

Our study has achieved its objective of investigating the possibility of improving the daily flow rate from well KK-C1.

Using a detailed analysis based on the performance of the Vermelha and that of well KK-C1, our study has shown that it is possible to produce 600BOPD using natural drainage, with a head pressure of 32.7961psia. At this stage our analyses have shown, obviously without taking into account the surface process, that well KK-C1 can produce 600 BOPD without activation. This is not the case if we take into account the well's completion diagram.

Next, the possibility of producing more than 600 BOPD, i.e. 1000 BOPD, was considered. With this new flow rate, the KK-C1 well proved insufficiently eruptive. With this problem solved, our work, prioritising oil production, proposed using an ESP to activate it. It was therefore necessary to find a suitable pump that would respond to the well conditions, which was a difficulty apart from that linked to the Poettmann and Carpenter algorithm.

As there were no pump manufacturers in our town, we used the catalogue incorporated in the Pipesim software to make our choice. The pump placed in the network while avoiding cavitation and temperatures capable of damaging it, was able with 12 stages to enable our well under study to produce this flow rate of 1000 BOPD.

We conclude by saying that production from the KK-C1 well could reach 1000 BOPD in 2014. However, since this analysis was carried out on the subsurface subsystem of the production system, surface elements would have to be taken into account to perfect it.

A number of problems have plagued the progress of this work, and each time we have been able to get round them. The confidentiality of petroleum data was a serious obstacle to obtaining data, so this work was built around the data in our possession. For the characteristic curves of the pump of crucial utility, obtained as mentioned above.

The iterative calculations of the correlation used to estimate the pressure losses were, for their part, bypassed by programming in Java. This small piece of software, developed and supporting Poettmann and Carpenter's algorithm, which will inevitably be improved, is what makes this work even better.

We cannot close without making some proposals that could be part of the continuity of this work. We therefore recommend studies into the possibility of installing a variable speed drive to make the pumping system more flexible, and a nodal analysis of the production system for the KK-C1 well.

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