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PRODUCTION AND OPTIMISATION OF A WELL BY HYBRID ARTIFICIAL ACTIVATION

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https://doi.org/10.47800/PVSI.2024.06-05

Summary

This paper focuses on proposing a hybrid activation mechanism for the production and optimisation of a well called X101 (for confidentiality reasons), which has become non-eruptive. Completion, pressure, volume, temperature (PVT), reservoir, and the X101 well profile data are processed by Pipesim and Excel software and integrating a certain number of calculations using nodal and decline curve analysis methods. The activation of the X101 well by an electric submersible pump (ESP) having 450 stages provided an oil production flow rate of 9189.329 stock tank barrels per day with a bottom-hole pressure of 2746.151 psi. Over time, the X101 well activated by the ESP having 450 stages faces a succession of maintenance operations occurring in very short time intervals following the reduction in the efficiency of the ESP. To overcome the problem of frequent maintenance which disrupts production times, the gas lift is added to the X101 well activated by a new ESP having 199 stages. The installation of the gas lift reveals that the adequate gas injection flow rate is 2 million standard ft^3 per day and 2 valves must be installed at 4,959 ft and 3,966 ft to suitably meet the production requirements. The X101 well activated by the combination of ESP and gas lift delivered a production flow rate of 7954.601 stock tank barrels per day with a bottom-hole pressure of 2873.623 psi and its optimisation made it possible to obtain a net oil flow rate of 9,035 stock tank barrels per day at the bottom-hole pressure of 2,762 psi. The profitability of the X101 well activated by the combination of ESP and gas lift is USD 73,163,517 for a return on investment after 9 months and 22 days for 13 years of production.

Key words: Non-eruptive well, hybrid activation, gas lift, electric submersible pump, nodal analysis, sensitive analysis, payback period.

1. Introduction

The natural exploitation of the so-called primary oil deposits involves the energy stored in the reservoir as pressure in the rock and the compressed fluid [1 - 3]. As the wells are exploited, over time, their reservoirs begin to be depleted, and the productive capacity of wells decreases [4 - 6]. This decline is caused by a decrease in the reservoir's ability to deliver fluid to the well (a drop in blowout energy) and in some cases is caused by increased pressure losses in the production string [1, 7 - 9]. When this energy does not meet production constraints despite the reserves in place being significant, well-activation techniques (artificial lift) and secondary recovery are introduced in order to improve the well potential and enhance production [7, 10]. This is the case of the reservoir of the X101 well, which is a horizontal well producing simultaneously in three distinct zones of the same reservoir in the field called X (for confidentiality reasons). After a few years of production, the X101 well was unable to continue to adequately deliver hydrocarbons to the surface due to total depletion occurring in its reservoir. Following an in-depth analysis of this constraint, the operating company of the field took the initiative to activate the X101 well with the ESP while considering its advantages over other

Date of receipt: 19/1/2024.
Date of review and editing: 19/1 - 6/8/2024.
Date of approval: 6/8/2024.

well activation mechanisms, namely: The gas lift, the progressive cavity pump, the hydraulic pump and the rod pump [11 - 15]. Under the effect of the depth, the number of layers to be produced, and the requirements on the minimum production flow, the motor of this pump was subjected to a very high number of stages (450) which mainly led to the shortening of its lifespan. Concerned by maintenance operations, which were very recurring due to the short lifespan of the installed ESP, the authors of this paper propose to the company a hybrid artificial lift. This technology, which is still little known in the oil industry, consists of combining two activation mechanisms in the same oil well [16 - 19]. This hybrid artificial lift aims to reduce the number of stages of the ESP in order to extend its lifespan and obtain a greater margin of time between maintenance operations.

The problem is to know which configuration of the hybrid artificial lift is the best to properly produce the hydrocarbons at the desired flow rate (minimum 7,500 stock tank barrels per day). Thus, this study aims to propose a combination of two activation mechanisms making it possible to maximise production in the X01 well in an efficient manner. To accomplish this research investigation, the following steps (specific objectives) were considered (which gives the necessary steps in implementing this oil well activation technique):

To carry out the initial design of the X101 well to highlight its profile;

To evaluate the nodal analysis to have an idea of the state of the X101 well with and without the contribution of the ESP having 450 stages;

To choose and justify the use of the second artificial lift;

To design the design of the combination of the 2 artificial lifts selected;

To evaluate the performance of the well while taking into account the combination of these 2 mechanisms;

To optimise production to better understand how the parameters relating to the activation mechanisms influence the production rate and produce an economic assessment of the operations.

To achieve these objectives, the nodal analysis method and the method relating to the design of the different activation mechanisms are used to better assess the performance and optimisation of the well with this combination of artificial lift. Analysis and manipulation of data are done using Pipesim and Excel software. The other parts of the paper are formatted in sections. The preceding section is the data and results while the conclusion is presented in the last section of the paper.

2. Data and results

The data in Tables 1 to 3 consist of completion data, reservoir or PVT data, and petro-physical data.

The data in Tables 1 - 3 make it possible to carry out and design the completion, the design of the activation mechanisms and also the simulations involving nodal and sensitivity analysis in the X101 well using the Pipesim software. The Excel software is employed for calculations concerning predictions and the economic balance sheet.

Figure 1 shows the profile and nodal analysis of the X101 well in the initial state.

The initial design of the X101 well allows the observation of the well profile and the depth of the equipment as shown in Figure 1a. The X101 well is a deviated well going from the surface to 15,000 ft, which should be producing normally at three distinct zones of the same reservoir simultaneously. The X101 well is non-eruptive because the IPR and VFP curves do not meet as shown in Figure 1b.

Table 1. *Completion data*

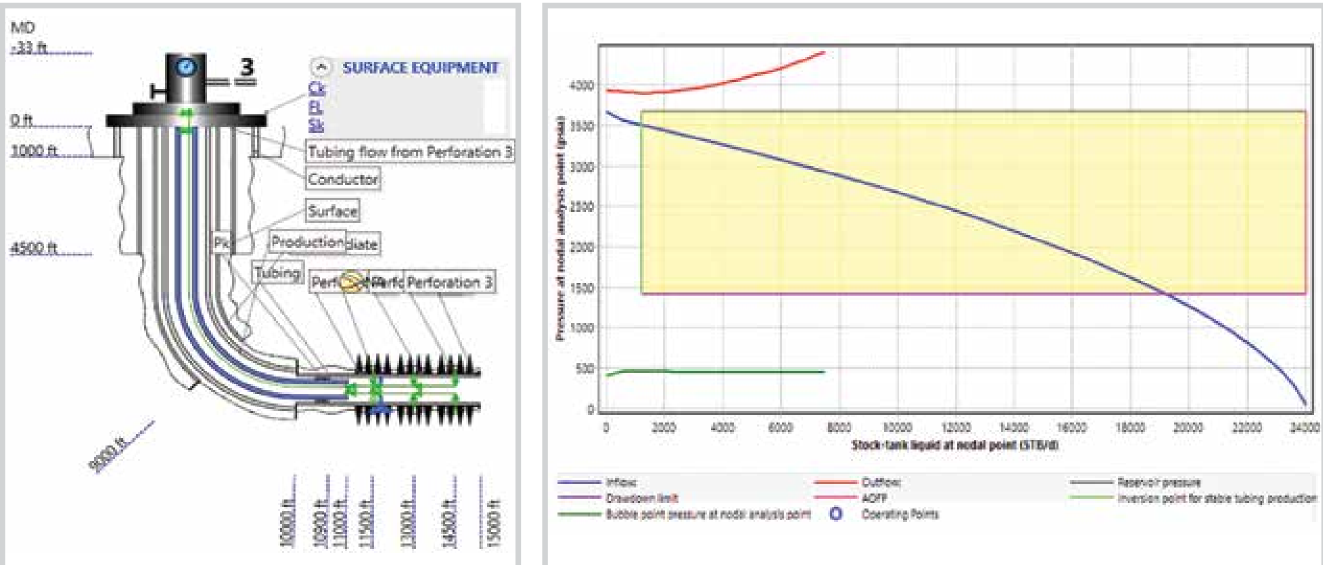
Parameters	Depth (ft)	ID (inch)	OD (inch)	Grade
Conductor casing	1,000	27.75	30	B
Surface casing	4,500	19	20	M65
Intermediate casing	9,000	12.375	13.625	L80
Production casing	10,000	8.435	9.625	L80
Tubing	11,000	3	4.5	L80
Liner	10,000 - 15,000	6.004	7	L80
Packer	10,900			
Choke		3		
SCSSV	1,500			
Flow line	2,500	2.5		

Table 2. *Reservoir data*

Parameters	Values
Pressure and temperature of the first zone	3,500 psi and 120°F
Pressure and temperature of the second zone	3,600 psi and 205°F
Pressure and temperature of the third zone	3,700 psi and 210°F
PI for the three zones	2.5 stock tank barrels/Psi.d
Average permeability	80 md
Medium porosity	20%
Water salinity	10,000 ppm
Skin	0
API	38°
GOR	100 SCF/STB
Water cut	70%
Oil formation volume factor	1.2
Oil viscosity	1.3 CP
Number of stages	450 to 250 maximum
Wellhead pressure	300 psi

Table 3. *Deviation data*

MD (ft)	TVD (ft)	MD (ft)	TVD (ft)
0	0	8,000	7831.951
1,000	1,000	9,000	8539.058
2,000	2,000	10,000	8556.51
3,000	3,000	11,000	8565.237
4,000	4,000	12,000	8565.237
5,000	5,000	13,000	8565.237
6,000	6,000	14,000	8565.237
7,000	6965.926	15,000	8565.237

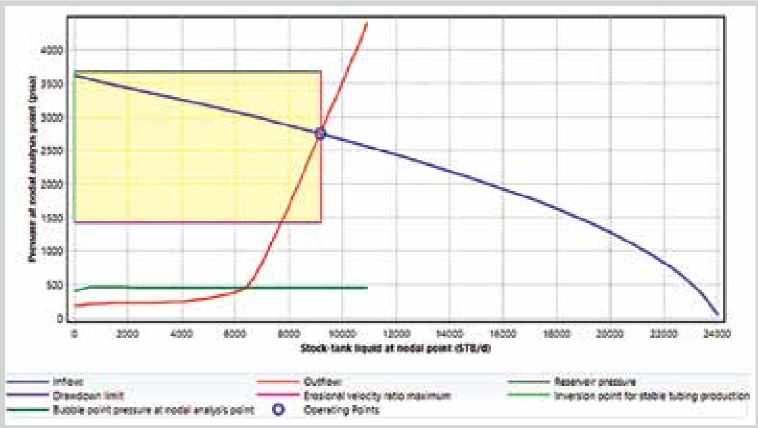


(a) (b)

Figure 1. *Profile (a) and nodal analysis (b) of the X101 well in the initial state.*

2.1. Production of the X101 well activated by the combination of ESP and gas lift

To make the X101 well eruptive again, an ESP must be installed as an activation mechanism that meets the requirements of the well and the production conditions. Figure 2 highlights the production results following the activation of the X101 well by the ESP and the performance curves of the ESP respectively.



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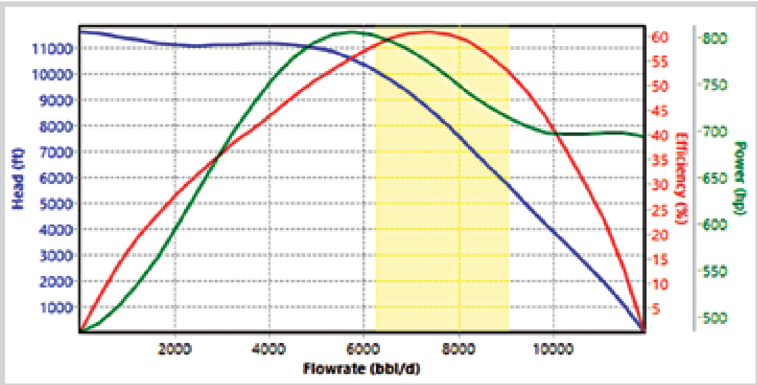

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Figure 2. (a) Nodal analysis of the X101 well activated by the ESP and (b) ESP performance curves for the X101 well.

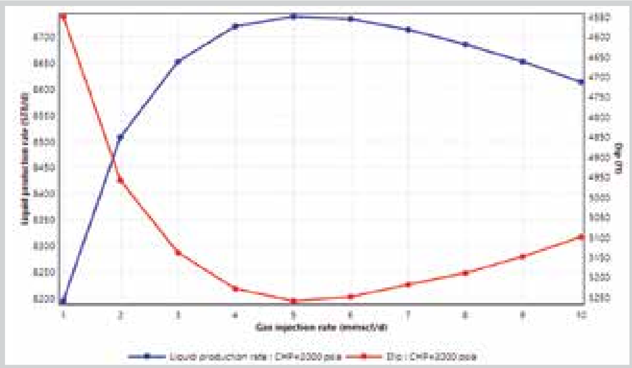
Table 4. Parameters of the new ESP

Parameters	Values
Pump	ALNAS ANA545 55Hz
Stages	199
Speed	3499.992 rpm
Efficiency	60.25224%
Power	314.4059 HP
Head	3506.842 ft
Differential pressure	1427.495 psi
Discharge pressure	4345.753 psia
Fluid temperature rise	3.471007°F

The ESP activation of the X101 well yields an oil production rate of 9189.329 stock tank barrels per day and a bottom-hole pressure equal to 2746.151 psi as shown in Figure 2a. Figure 2b indicates that the ESP operates at its maximum capacity at 450 stages, a speed of 3,500 RPM, and a frequency of 55 Hz. It is important to remember here that the X101 well is centrally located in a horizontal field that has become non-eruptive and a candidate for the ESP. This well had been put into production with an optimal flow rate greater than 7,500 stock tank barrels per day and its activation by the ESP makes it possible to continue to adequately produce at this flow rate despite the depletion occurring in the reservoir. Over time, the operating company faced a succession of maintenance operations occurring in very short time intervals because of the reduction in the efficiency of the ESP. This reduction in ESP's efficiency is largely due to a high number of stages (450), which created a certain load on the engine and pushed the ESP continuously to work with its maximum capacity. This load associated with corrosion occurring on pumps can considerably reduce the lifespan of this ESP and increase maintenance operations. Hence, the authors of this paper propose to install a second activation mechanism associated with the ESP to benefit from increased production time and extended maintenance intervals. After implementing components such as the desirable oil recovery flow rate, the inside diameter of the casing, the pressure at the head of the well, the data relating to the X101 well and the reservoir, and the placement of the separator at the bottom, Pipesim allows one to obtain the characteristics of the new ESP used to activate the X101 well as presented in Table 4.

After obtaining the parameters linked to the new design of the ESP, the new ESP is installed in the X101 well and serves as a support (reference) for the realisation of the gas lift design. Designing the gas lift system consists of finding the injection points, the flow rate with which the gas is to be injected as well as the number of valves necessary to facilitate the rise of the oil as shown in Figure 3.

Figure 3a reveals that the value of 2 million standard ft^3 per day is retained as the injection rate and used for the simulations presented in Figures 3b and 3c. Figure 3b reveals that the first valve will be placed at a depth of 4,959 ft for a good design of the system combining the two activation mechanisms. Figure 3c reveals that two SLB (Camco), Series R20, IPO type valves are to be installed, where the deepest of which will have a minimum port size of 0.5 inches and the tallest, a port size of 0.25 inches. It also provides the depth of the second valve which is equivalent to 3,966 ft. Figure 4 presents the profile and nodal analysis of the X101 well activated by the ESP and gas lift combination.



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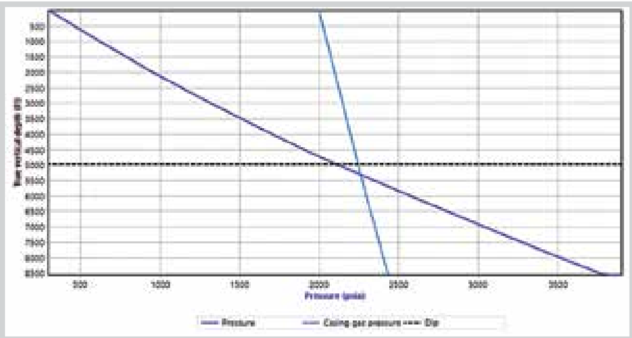

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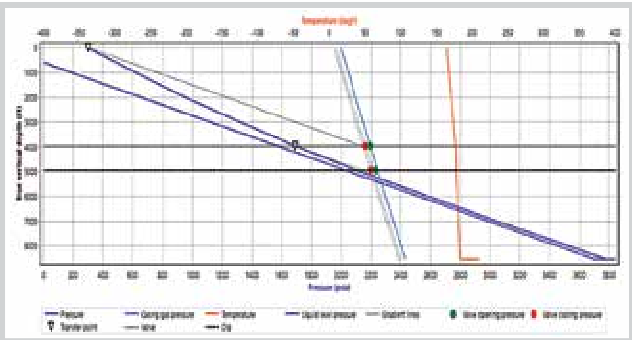


(c)

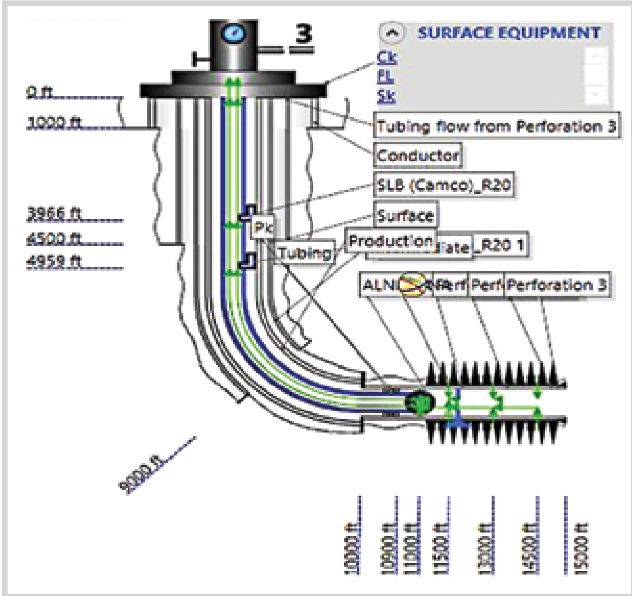
Figure 3. *(a) Gas lift response, (b) deepest injection point, and (c) gas lift design.*

The initial design of the X101 well activated by the ESP and gas lift combination allows the observation of the profile of the X101 well and the depth of the equipment as shown in Figure 4a. Figure 4b reveals that the X101 well activated by the ESP and gas lift combination has an oil production flow rate of 7954.601 stock tank barrels per day and a bottom-hole pressure of 2873.623 psi.

2.2. Optimisation of the production of the X101 well activated by the combination of ESP and gas lift

It is imperative to recall here that the factors on which this optimisation was focused are: The gas injection rate, the diameter of the flowline, the pressure at the wellhead, the number of stages, and the frequency of the ESP.

- Sensitivity analysis on the X101 wellhead pressure



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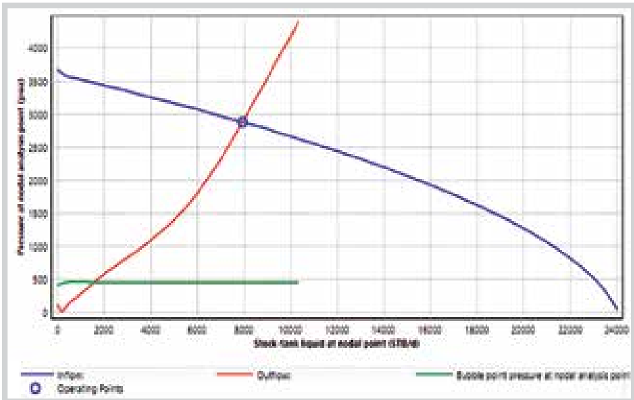

(b)

Figure 4. *(a) Profile and (b) nodal analysis of the X101 well activated by the combination of the ESP and gas lift.*

Wellhead pressure has a major influence on production flow. For the X101 well activated by the ESP and gas lift combination, the reduction in pressure at the wellhead led to a remarkable increase in production flow rate. This can be explained by the fact that it allows an increase in the volume of oil sucked up by the ALNAS ANA545 55Hz pump and tends to reduce pressure losses in the production tubing. Choosing to reduce the pressure at the wellhead is an efficient idea because it increases the efficiency of the pump without affecting it. The optimal wellhead pressure value retained for the X101 well is 100 psi. This pressure will allow the well to produce safely while avoiding a significant production of successive sand from eroding the production tubing and the pump.

- Sensitivity analysis on the number of stages

The number of stages directly increases the production flow rate. An increase in the number of stages could increase the production flow but at the risk of creating a load on the pump's motor which could lead to a reduction in its lifespan. The X101 well was activated by the combination of the ESP and gas lift with a reduced number of stages set at 200 to limit the load on the engine and the long lifespan of the pump which will allow a greater margin of time for maintenance operations.

- Sensitivity analysis on the pump's frequency

The production flow rate is proportional to the frequency of the ESP. For this purpose, to avoid a very large production which could lead to the production of sand, the appropriate frequency for the ESP ALNAS ANA545 is 55 Hz and it can be adjusted after the installation of the VSD for the adjustment of the pump's parameters.

- Sensitivity analysis on the gas injection flow

In the X101 well activated by the ESP and gas lift combination, it is easy to see that from a certain gas injection flow rate, the production flow rate is inversely proportional to the injected gas flow rate. Indeed, from the injection interval of 1 to 2 million standard ft^3 per day, the injection rate is fairly stable and from 2 to 5 million standard ft^3 per day the injection rate was inversely proportional to the production rate. When we continue to increase the injection flow rate, the injected gas creates turbulence which will reduce the production flow rate and give rise to high gas production. Therefore, 2 million standard ft^3 per day is maintained and used as the optimal value for the gas injection flow.

- Sensitivity analysis on the diameter of the flowline

The production rate increases with the diameter of the flowline. In the X101 well activated by the combination of ESP and gas lift, the optimal value of the internal diameter of the flowline retained is 3.5 inches simply because it allows production with a flow rate approximated to that of the first ESP. Using the optimal values obtained, Figure 5 presents the nodal analysis of the X101 well activated by the combination of ESP and gas lift.

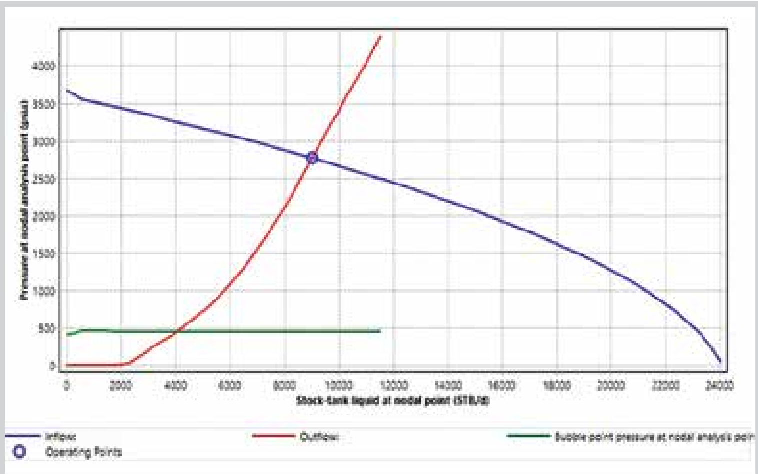

Figure 5. Nodal analysis of the X101 well activated by the combination of ESP and gas lift with the integration of optimal values.

Figure 5 reveals that the X101 well activated by the combination of ESP and gas lift produces at a constant flow rate of 9,035 stock tank barrels per day and a bottom-hole pressure of 2,762 psi while having an acceptable time margin between maintenance operations.

Table 5. Capex and Opex

Capex	
Services	**Cost**
Gas lift equipment	USD150,000
Downhole and surface equipment for ESP	USD 100,000
Opex	
Services	**Cost**
Water treatment	USD 160,000
Annual maintenance	USD 45,000
Cost of oil	USD 10 per barrel
Energy cost	USD 20 per day

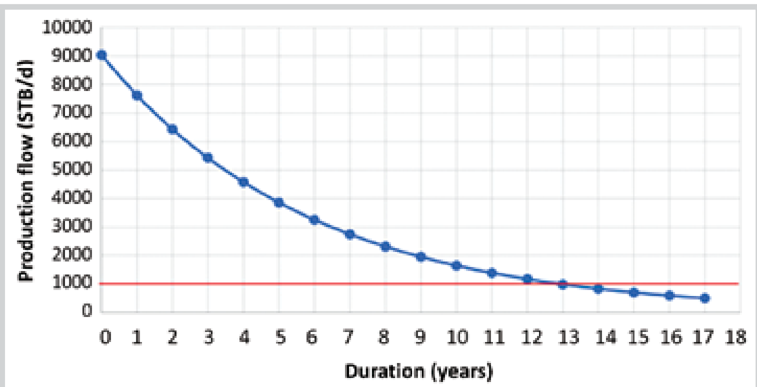

Figure 6. Production decline curve for the X101 well activated by the ESP and gas lift combination.

2.3. Economic assessment

Table 5 presents the Capex and Opex.

Before calculating the entire expenses

Table 6. NPV of the project

Expenses	Income	Cash flow	NPV
USD 57,430,786	USD 535,238,417	USD 358,355,723	USD 73,163,517

associated with putting the X101 well into production with the proposed artificial lift combination, it is first necessary to have an idea of the future production of the well based on the analysis of the curve of decline. This analysis revealed the behavior of production up to the production limit set by the company (100 stock tank barrels per day). Future production rates are plotted graphically in Figure 6.

With the production limit of 1,000 stock tank barrels per day, the interpretation of Figure 7 leads to a prediction about the next 13 years of production. So, to have the total expenses, it is necessary to add up all the investments as follows while taking into account the oil flow:

$$Expenses = 150{,}00 + 160{,}00 + Total\ energy\ cost\ (20 \times 365 \times 13) + Total\ cost\ of\ oil + (45{,}000 \times 13)$$

This results in a total expenditure of USD 57,430,786. The NPV is obtained by applying the discount rate to the net cash flow after taxes. The result of this operation is given in Table 6.

Table 6 shows that the NPV of the project is positive. Therefore, the use of an ESP and the gas lift to activate the X101 well is indeed a profitable project. The payback period $\left(PBP = \frac{57{,}430{,}786}{9{,}035 \times 0.3 \times 365 \times 95 \times (1-0.25)} = 0.81\right)$ is obtained from the 9th month and 22nd day of production.

3. Conclusion

This paper aimed to propose a hybrid activation mechanism that made it possible to activate and maximise production at the X101 well while having an acceptable time margin between maintenance operations. For this purpose, data containing information on the completion, the reservoir, the profile of the X101 well, and the installed electric submersible pump were used. Firstly, it was necessary to highlight the initial design of the X101 well and its nodal analysis which showed that the X101 well had become non-eruptive.

The X101 well was initially activated using an electric submersible pump with 450 stages, which provided an oil production flow rate of 9189.329 stock tank barrels per day at a bottom-hole pressure of 2746.151 psi. But over time, it faced frequent maintenance issues due to the reduced efficiency of the electric submersible pump. To overcome this problem, a gas lift system was added to the well, using a new electric submersible pump (ALNAS ANA545 55Hz) with 199 stages, requiring an injection flow rate of 2 million standard ft^3 per day and the installation of two valves at 4,959 ft and 3,966 ft, which provided a production flow rate of 7954.601 stock tank barrels per day at a bottom-hole pressure of 2873.623 psi. Further optimisation of this system allowed the well to achieve a net oil flow rate of 9,035 stock tank barrels per day at a bottom-hole pressure of 2,762 psi. The economic assessment showed the profitability of the solution proposed in this study by presenting an NPV of USD 73,163,517 and a payback period of approximately 9 months and 22 days of production over 13 years of production.

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