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Heightened the Productivity of an Eruptive Petroleum Well with Two Reservoirs by Jet Pump and Infill Well

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ABSTRACT

In a confidential field, several producing wells exist, including Well Y, which has two reservoirs, S1 and S2. Production initially occurred from reservoir S1, but it has since ceased. Although Well Y is unable to access reservoir S2, which possesses favorable petrophysical characteristics, optimizing production at Well Y requires implementing an effective optimization technique. With reservoir S1 non-viable, the focus shifts to optimizing production at both the S1 and S2 scales through the same well. Key objectives include justifying the optimization method, designing completion strategies, improving production, and developing economic assessments. This study employs PIPESIM, Prosper, and Excel software, along with completion and PVT (Pressure, Volume Temperature) data, to follow an established methodology involving infill drilling (horizontal well) and activation via a jet pump. Results indicate that after activating reservoir S1 with the jet pump, Well Y could produce 4404 STB/d at a pressure of 3581.55 psi. Decline curve analysis suggests a production lifespan of 10 years, yielding an estimated total output of 8.70 million barrels. The optimization and maintenance costs are projected at $69.98 million, while hydrocarbon sales revenue is estimated at $780.91 million, resulting in a gain of $140.31 million and a payback period of approximately 8 months and 19 days.

1. INTRODUCTION

World energy markets have been affected by the COVID-19 crisis in the years 2020-2021 [1, 2]. Investment in hydrocarbons has fallen sharply, leading to a profound imbalance between energy supply and demand [3, 4]. Although the progress of solar and wind energy over the last 10 years has been on the positive increase, they have only added to the energy supply, without replacing fossil fuels [5]. As a result of this steady increase in global demand for hydrocarbons and the decline in the number of discoveries yearly, it is necessary to increase oil production more efficiently and economically [6-10]. Oil production by oil wells is not constant over time, but their flow rates keep falling over time [11-14].

Oil production from wells is characterized by a declining flow rate over time due to various factors, including depletion of reservoir pressure, changes in reservoir characteristics, and increased viscosity of the crude oil. As oil is extracted, the natural pressure that drives the flow diminishes, leading to reduced production rates. This decline necessitates enhanced recovery techniques to maintain output levels. In specific considerations, these properties of a well are studied and optimized to increase production [15, 16]. This is the case for Well Y in field X, which has two reservoirs including the S1 reservoir and the S2 reservoir, where the S2 reservoir is below the east-facing S1 reservoir. Oil production by Well Y through reservoir S1 is natural, and over time the reservoir pressure dropped to a level where it became lower than the pressure at the bottom of the well. At the moment, with the Well Y at a standstill, there is a need for activation using the artificial lift method [17-20]. The reservoir S2 has the right petro physical characteristics (porosity, permeability, saturation, etc.), hence the need to reach it via the same well and bring it on stream. Reservoir S1 requires a well-scale optimization method, and so does reservoir S2. According to the literature, artificial lift is an excellent means of well-scale optimization, including the gas lift, the electric submersible pump, the rod pump, the progressive cavity pump, the hydraulic pump, and gas injection by coiled tubing [19-23]. There are also several activation methods at the reservoir level, such as the infill well (deviated well, horizontal, vertical, etc.), secondary recovery (injection of water and gas into the reservoir), and tertiary recovery (thermal injection, micro-organisms). It would therefore be important to implement an appropriate optimization technique to improve the production at Well Y. This paper aims to optimize production at the scale of reservoir S1 and optimize production from reservoir S2 via the same well. To achieve this, the following objectives have been considered: (1) justify the optimization method; (2) develop the design and application of the optimization methods; and (3) improve production and draw up an economic assessment.

This article is organized into four sections: The first section deals with the introduction, the second section presents the data and tools, the third section presents the results obtained and finally the fourth section concludes the paper.

2. DATA, MATERIALS, AND METHODS

Infill drilling, particularly through horizontal wells, along with activation via a jet pump, presents several advantages over traditional drilling methods. Horizontal wells enable access to a larger reservoir area, increasing the potential for oil and gas recovery without the need for multiple vertical wells. This approach minimizes surface disruption and reduces the environmental footprint. Jet pumps, on the other hand, provide an efficient means of lifting fluids from the wellbore, especially in low-pressure environments. They can operate effectively in a variety of fluid compositions and do not require moving parts, which enhances reliability and reduces maintenance needs [10, 24].

From a technical feasibility standpoint, infill drilling combined with jet pump activation is often more cost-effective in mature fields where conventional methods have led to declining production rates. This method allows for the extraction of remaining hydrocarbons that might otherwise be left behind due to pressure drops or reservoir heterogeneities. Additionally, the flexibility of jet pumps in handling different fluid types and their ability to operate in challenging environments further bolster their appeal. Overall, this combination not only enhances production rates but also optimizes resource utilization, making it a viable option for operators seeking to maximize output from existing wells.

Table 1. Completion data

Casing Type	Measure Depth	OD	ID	Grade
Conductor	1000 ft	22 in	20 inches	B
Surface casing	3500 ft	16 in	15.01 inches	J55
Intermediate	8500 ft	13.325 in	12.105 inches	C90
Production	9500 ft	9.625 in	8.435 inches	L80
Liner	9500 to 12000 ft	7 in	5.92 inches	C95
Tubing	10000 ft	3.5 in	2.75 inches	M65
Packers 1 and 2	9800 ft and 10700ft	-	-	-
Reservoir 1	10500 ft	-	-	-
Reservoir 2	11500 ft	-	-	-

In order to optimize production from Well Y in field X, a certain amount of data was used: completion data, PVT data from the two reservoirs (S1 and S2), tilt data from reservoir S2, and jet pump injection data. Table 1 presents the data used to set up the initial well completion of Well Y with reservoirs (S1 and S2).

Table 2. Trajectory of Well Y

Measured Depth (ft)	True Vertical Depth (ft)
0	0
1000	1000
8000	8000
8900	8852.2
9500	9292.3
9800	9448.9
10200	9543.7
10700	9576.8
11000	9582
11200	9582
11400	9582
11600	9582
11800	9582
12000	9582

The inclination data in Table 2 will be used to access reservoir S2 by infill well obtained by using measure wire line drilling (MWD) during drilling.

Table 3. Presentation of PVT data for reservoir S1

Parameters	Values
Reservoir pressure	2500 psi
Reservoir temperature	210°F
GOR (Gas to Oil Ratio)	200 SCF/STB
Bo	1.125
Bubble pressure	1825 psi
Permeability	176 md
Water cut	60%
Oil density (API)	35°
Productivity index	0.5 STB/d.psi
AOFP (Absolute Open Flow Potential)	695 STB/d
Gas density	0.75
Pressure at the top of the well	300 psi
Water salinity	15000 ppm
Oil viscosity	1.2 cp
Total compressibility	5×10^{-6} pa^{-1}
Skin	2
Reservoir height	250 ft
The radius of the linking drainage	2000 ft
Rw (Well radius)	0.291 ft

The data presented in Table 3 show the petrophysical characteristics of reservoir S1.

The data presented in Table 4 show the petrophysical characteristics of reservoir S2, providing evidence of the reservoir's condition.

The fluid injection data in Table 5 are the data used to activate the well at reservoir S1 by jet-pumping a fluid at a measured flow rate through Well Y.

The data in Tables 1-5 are processed using PIPESIM and Microsoft Excel. To optimize the production of Well Y in field X, the following sub-sections deal with the choice of optimization methods using coiled tubing and horizontal wells. The choice of optimization methods using coiled tubing and horizontal wells, design of the completion, and applying the optimization methods to improve production and finally, to make prognoses for economic reasons.

Table 4. Presentation of PVT data for reservoir S2

Parameters	Values
Reservoir pressure	4500 psi
Reservoir temperature	220°F
Water cut	0%
GOR	600 SCF/STB
Oil density (API)	38°
Productivity index	2.5 STB/psi
Permeability	150 md
Oil FVF	1.2
Oil viscosity	1.1 cp
Total reserve	25×10^6 barils
Skin	0
Reservoir height	400 ft
The radius of the linking drainage	2000 ft
Rw	0.291 ft

Table 5. Jet pump injection data

Parameters	Values
Pump depth	10000 ft
Maximum ID	3 inches
Surface injection rate	2500 STB/d
Surface injection pressure	3500 psi

3. RESULTS

The tangent method is used to reach reservoir S2 located 12000 ft below reservoir S1 located at 10500 ft through Well Y to produce at the scale of reservoir S2. In this practice, a borehole with a 90° inclination is drilled to reach the reservoir S2, as shown in Figure 1.

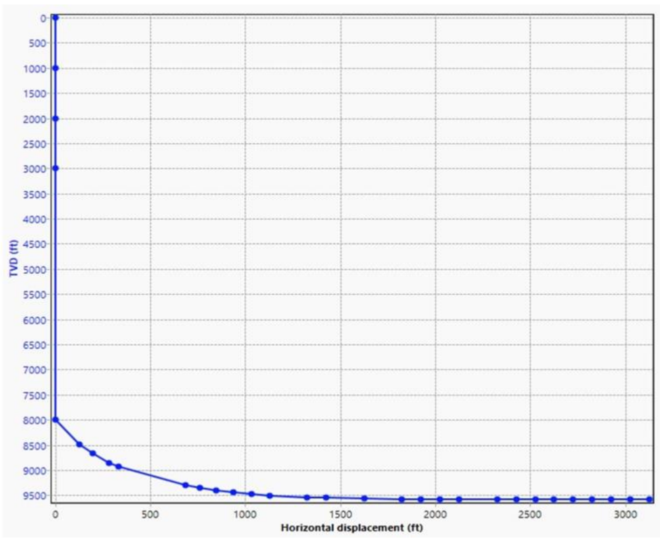

Figure 1. Diagram implementing the tangent method

In Figure 1, the inclination of Well Y starts at 8000 ft with an angle of 15° and becomes horizontal from 10900 ft (measure depth) with an inclination of 90°. The trajectory of the well remains constant until it reaches reservoir S2 at 12000 ft (measure depth). The results of the Well Y deviation are presented in Table 6.

The design of Well Y after drilling has reached reservoir S2 is shown in Figure 2.

Figure 2 shows the positions of reservoirs S1 and S2 with their successive depths of 10500 ft and 12000 ft respectively, then the placement of the down hole equipment such as the packers 1 and 2, the sleeve, the well tubing, and finally the extension of the liner to reach the reservoir S2. The nodal analysis to see the productivity of reservoirs S1 and S2 is shown in Figure 3.

Table 6. Deviation results of Well Y

	MD ft	TVD ft	Horizont. Distance ft	Angle Deg.
1	0	0	0	0
2	1000	1000	0	0
3	2000	2000	0	0
4	3000	3000	0	0
5	8000	8000	0	15
6	8500	8482.963	129.4095	20
7	8700	8670.901	197.8136	25
8	8900	8852.163	282.3372	30
9	9000	8938.766	332.3372	45
10	9500	9292.319	685.8906	50
11	9600	9356.598	762.495	60
12	9700	9406.598	849.0976	65
13	9800	9448.86	939.7284	70
14	9900	9483.062	1033.698	75
15	10000	9508.943	1130.29	80
16	10200	9543.673	1327.252	85
17	10300	9552.389	1426.871	86
18	10500	9566.34	1626.384	87
19	10700	9576.807	1826.11	88
20	10800	9580.297	1926.049	89
21	10900	9582.042	2026.034	90
22	11000	9582.042	2126.034	90
23	11200	9582.042	2326.034	90
24	11300	9582.042	2426.034	90
25	11400	9582.042	2526.034	90
26	11500	9582.042	2626.034	90
27	11600	9582.042	2726.034	90
28	11700	9582.042	2826.034	90
29	11800	9582.042	2926.034	90
30	11900	9582.042	3026.034	90
31	12000	9582.042	3126.034	90
…	…	…	…	…

Note: Horizont. refers to horizontal and Deg. means degree.

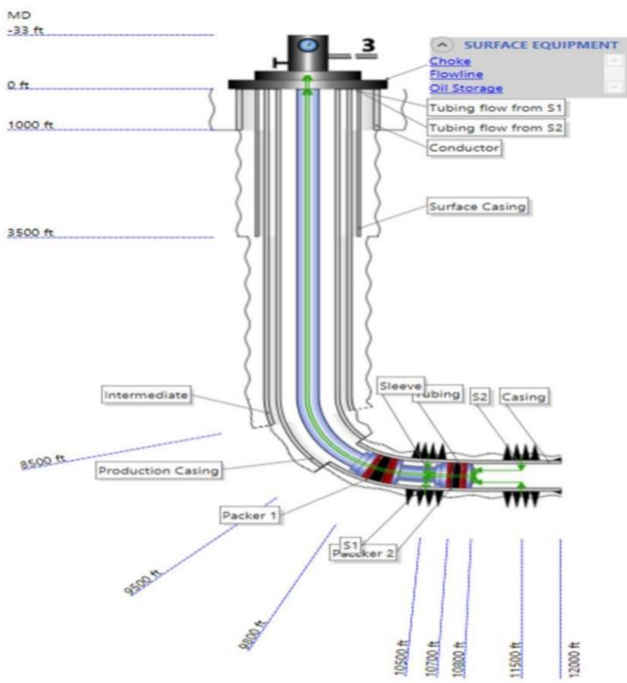

Figure 2. Design of Well Y passing through reservoirs S1 and S2

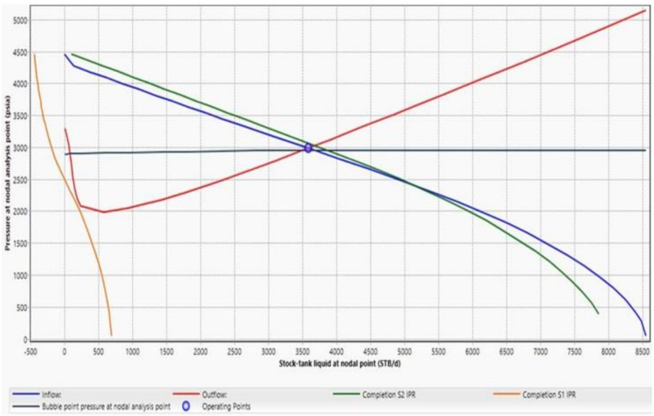

Figure 3. Nodal analysis of reservoirs S1 and S2 at Well Y

Figure 3 shows that the IPR2 curve (green curve) for reservoir S2 crosses the VLF curve (red curve) of Well Y, so reservoir S2 naturally produces 3581.55 STB/d at a pressure of 2980.45 psi. On the other hand, the IPR1 curve (orange curve) for reservoir S1 does not cross with the VLF curve (red curve) of Well Y, so reservoir S1 does not produce any hydrocarbons. The nodal analysis of reservoir S1 of Well Y is shown in Figure 4.

Figure 4 below shows that Well Y was initially unable to produce oil through reservoir S1 until it was activated by the jet pump, which is justified by the fact that the two curves VLF and IPR do not intersect.

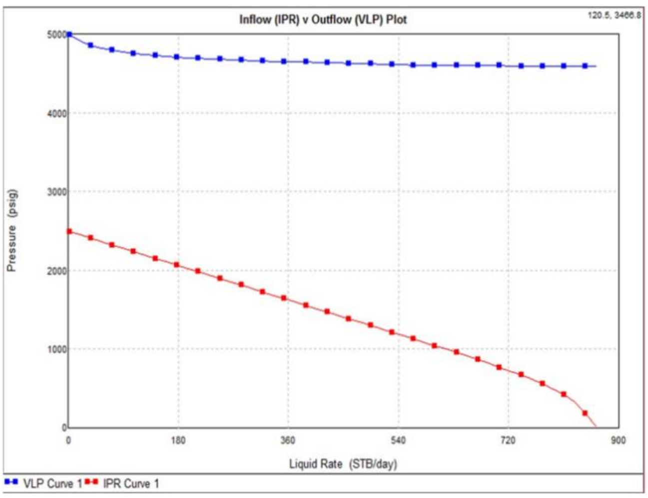

Figure 4. Nodal analysis of reservoir S1

3.1 Activation of Well Y at reservoir S1 by using the jet pump

The jet pump is used to activate Well Y at reservoir S1. The specificity of this pump allows hydrocarbons to be produced from both reservoirs S1 and S2. The reference jet pump has a nozzle diameter (Dj) of 0.265 inches and a throat diameter (Dt) of 0.996 inches with a fluid flow rate of 4091.23 STB/d. The characteristics of the jet pump are shown in Table 7.

After the activation of Well Y at reservoir scale S1, Table 8 gives the production characteristics.

Once the first production zone is activated, a nodal analysis is carried out to check the reservoir's productivity.

Table 7. Characteristics of the jet pump used

Jet Pump Specification	Value
Area ratio (R)	0.00781
Aj (nozzle area)	0.055182
At (throat area)	0.77961
Dj (nozzle diameter)	0.26507 inches
Dt (throat diameter)	0.996631 inches
Power fluid rate (Min Dj = 0.00371)	0.78362 STB/day
Power fluid rate (Actual)	4091.23 STB/day
Power fluid rate (Max Dj = 0.25715)	3764.68 STB/day
Mc (Ic = 0.80)	10.6863
Mc (Ic = 1.35)	9.62788
Mc (Ic = 1.67)	0.14025
Power fluid static gradient	4125.13 psi
Power fluid friction gradient	-199.158 psi

Table 8. Productivity of reservoir S1 after using the jet pump

Parameters	Values
Flowing BH pressure	1043.6 psi
Pump intake pressure	647.2 psi
Pump intake rate	692.3 RB/d
Free GOR entering the pump	66.7 SCF/STB
Pump discharge rate	1227.3 RB/d
Head required	9567.6 ft
Fluid power required	40.5 hp

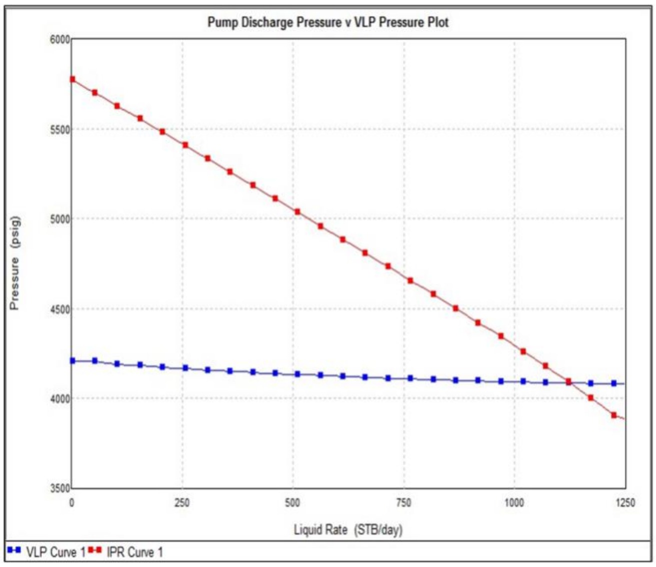

Figure 5. Nodal analysis of reservoir S1 in Well Y after activation

Table 9. Well productivity combining reservoirs S1 and S2

Parameters	Values
Flowing BH pressure	3966.6 psi
Pump intake pressure	3926.6 psi
Pump intake rate	793.5 RB/d
Wellhead pressure	434.2 psi
Pump discharge pressure	4251.6 psi
Pump discharge rate	4917.1 RB/d
Head required	1069.33 ft
Mass flow rate	195553 IBM/d

Figure 5 shows the VLP curve (blue) and the IPR curve (red) rise as the tank can produce following its activation by jet pump. These curves increase because the pump can reduce the pressure at the bottom of the well, resulting in the well flowing at a value of 1124.9 STB/d with an oil flow rate of 449.9 STB/d. The production from reservoirs S1 and S2 takes place simultaneously through the same Well Y. This shows that the pressure at the bottom of the well rises to 3966.6 psi and the pressure at the top of the well to 434.2 psi as shown in Table 9.

3.2 Infill well used to reach the reservoir S2 of the Well Y

After reaching reservoir S2 by infill well and activating reservoir S1 by jet pump from Well Y, the productivity of Well Y changed. The oil production rate increases to 4342.81 STB/d and a gas flow rate of 2.53 MMSCF/d with almost no water production, as shown in Table 10 and Figure 6.

Table 10. Productivity results for Well Y combining reservoirs S1 and S2

Solution Inflow	Values
Liquid rate	4342.81 STB/day
Oil rate	4342.81 STB/day
Water rate	0 STB/day
Gas rate	2.53178 MMSCF/day
Solution node pressure	2719.06 psig
dp friction	733.148 psi
dp gravity	3190.66 psi
Pump intake pressure	2678.81 psig
Pump discharge pressure	4208.13 psig
Average rate through the pump	5788.4 RB/day
Pump head generated	5061.51 feet
Pump power requirement	301.954 hp

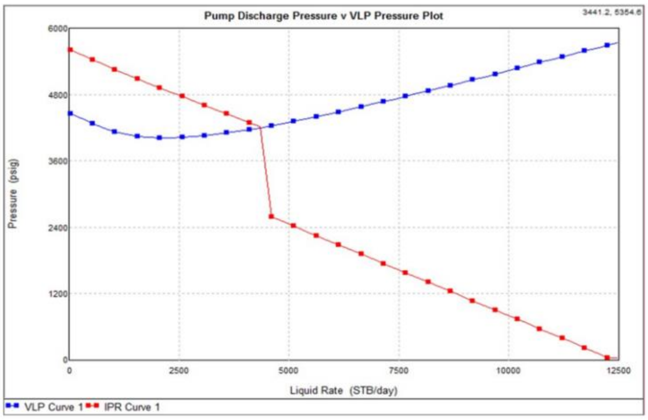

Figure 6. Nodal analysis of the productivity of Well Y

Sensitivity analysis made it possible to vary the fluid injection pressure in the well in order to decide on the flow rate at which production should take place. The sensitivity tests were based on injection pressure at 2500 psi, 3000 psi, and 3500 psi. As shown in Table 11 and Figure 7 production from Well Y increases with increasing injection pressure.

Production goes from 4365.34 STB/d at an injection pressure of 2500 psi, then when the injection pressure reaches 3000 psi, production rises to 4382.82 STB/d, and finally when the injection pressure reaches 3500 psi, production increases to 4404 STB/d. The well produces very little gas and almost no water. The variation in injection showed that as the injection rate increased, so did production. This allowed us to choose a jet pump injection rate of 3500 psi and a total production of 4404 STB/d from the two reservoirs through Well Y as shown in Figure 8.

Table 11. Results obtained for: (a) Injection pressure 2500 psi by jet pump, (b) Injection pressure 3000 psi by jet pump, and (c) 3500 psi injection pressure by jet pump

Characteristics	(a)	(b)	(c)
Liquid rate	4356.34 TB/day	4382.82 STB/day	4404 STB/day
Oil rate	4356.34 TB/day	4382.82 STB/day	4404 STB/day
Water rate	0 STB/day	0 STB/day	0 STB/day
Gas rate	253967 MMSCF/day	25551 MMSCF/day	256745 MMSCF/day
Solution node pressure	2714.55 psig	2705.73 psig	2698.67 psig
dp friction	854.828 psi	859.358 psi	862.982 psi
dp gravity	3162.57 psi	3162.02 psi	3161.59 psi
Pump intake pressure	2674.3 psig	2665.48 psig	2658.43 psig
Pump discharge pressure	4121.53 psig	4125.79 psig	4129.19 psig
Average rate through the pump	5810.9 RB/day	5850.25 RB/day	5881.99 RB/day
Pump head generated	4789.83 feet	4828.46 feet	4858.62 feet
Pump power requirement	285.747 hp	274.328 hp	265.224 hp

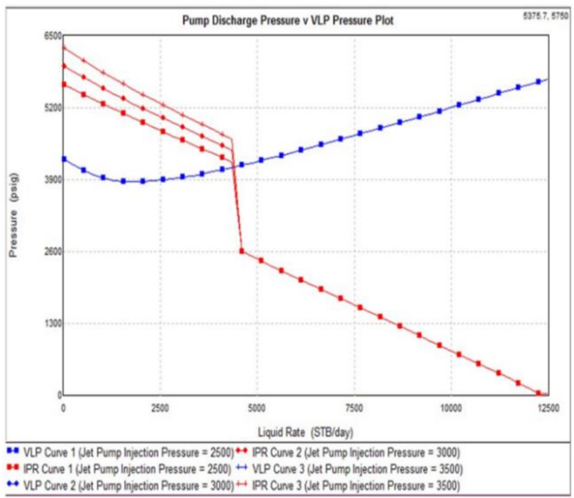

Figure 7. Nodal analysis of fluid injection pressure variation

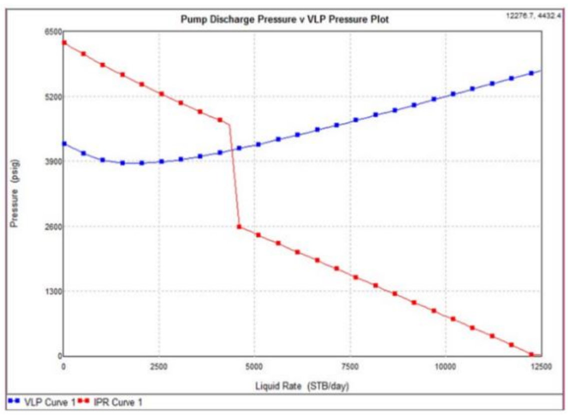

Figure 8. Nodal analysis of production from Well Y

3.3 Economic balance

The production target is estimated at a flow rate greater than or equal to 1000 STB/d because, at a flow rate of less than 1000 STB/d, production will no longer be sufficiently profitable. By using the exponential model, the production curve for Well Y is obtained and presented in Figure 9.

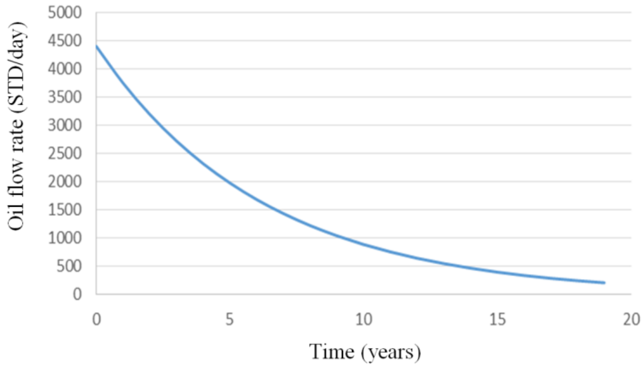

Figure 9. Production prediction curve for Well Y

Figure 9 shows that from the tenth (10th) year onwards the production flow rate production rate falls below the requested production rate. Hence the productivity of Well Y is evaluated over a period of 10 years (0 to 9). Expenses are made up of CAPEX and OPEX as shown in Table 12, which summarises all project costs.

Table 12. Presentation of the various costs

Parameters	Costs ($)
Surface equipment	160,000
Total revenue taxes (33%)	47,741,562
Jet pump	6,500
Infill well drilling (Horizontal well)	180,000
Treatment of injection fluid	500,000
Pump maintenance (once/2 years)	18,000
Water treatment	30,000
Barrel costs $8/barrel	69,414,435.2
Energy costs $15/day	54,750

Total expenditure over the ten years of production is estimated at 148.20 million. Evaluations have shown that over the ten years of production, the MW-1D well could produce a total volume of around 8.70 million barrels, and the price of a barrel on the international market is estimated at $90, with total revenues estimated at 780.91 million over the ten years of production. The resulting cash flow is $710926711.2 and the net cash flow obtained is $476320896.5. The NPV obtained is $140318586.1. The duration of the return on investment is evaluated at 0.72 years, which is equivalent to eight months, nineteen days, and four hours of production period.

The reliability of these findings is demonstrated by an economic balance sheet showcasing successful research results in oil well optimization using hybrid methods. By integrating techniques such as infill drilling and jet pump activation, operators can greatly improve production efficiency, lower costs, and prolong the life of wells. This strategy ultimately enhances profitability and promotes sustainable resource management in the oil sector. It is important to note that the selection of techniques is tailored to the specific characteristics of each well.

4. CONCLUSIONS

This paper aims to optimize the production of Well Y with two reservoirs S1 and S2 as adequately as possible. The data involved in this study were well completion data, the PVT data for reservoirs S1 and S2, the fluid injection data, and the inclination data required to reach reservoir S2 via the infill well. These data were processed by PIPESIM, Prosper, and Excel software to be able to determine and justify the optimization method, design the well while applying the chosen method, seek to improve the well's production, make forecasts and draw up an economic balance sheet. The well's productivity increased to 4404 STB/d at a pressure of 3581.55 psi with an estimated total production of 8.7 million barrels over a ten-year production period based on predictions of a production rate of 1000 STB/d or more. This has estimated the cost of the project at 69.98 million dollars, the revenue from the sale of oil at 780.91 million dollars, and gains of 140.31 million dollars. The return on investment is eight months, nineteen days, and four hours. A limitation of the current approach is that the selection of methods and validation techniques is manual, especially in an era increasingly dominated by artificial intelligence and smart systems. In future considerations, the integration of artificial intelligence will be explored for optimizing parameters and techniques, aiming to enhance production and improve return on investment.

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