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Enhancing The Productivity of an Eruptive Petroleum Well by Reduction of Water Inflows

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Abstract

The issue of water inflows is one of the major concerns in the oil industry. This paper presents studies conducted in 2020 on the X field's well M.01, which, over the years, encountered challenges related to water inflows, though its initial production had no such issues. The primary objective of this paper is to propose a viable solution to reduce water inflows, thereby maximizing surface oil production in a cost-effective manner. To achieve this, a nodal analysis was conducted to evaluate the well's performance in terms of liquid flow (water and oil). Production logs were used to identify the new oil saturation zone, where new perforations were made. Finally, an economic assessment was performed using the production decline prediction curve. Confidential data, including completion, reservoir, log, and economic data, were processed using PIPESIM and EXCEL software. According to the results, water inflows in well M.01 were caused by the displacement of the water-oil contact, due to partial penetrations via the water cone phenomenon, which reduced oil flow from 3005.585 STB/d to 241.9834 STB/d. To address this issue, a perforation was made using coiled tubing at the 100% oil saturation zone, and the two levels were isolated using a plug via a slickline. This intervention resulted in an oil flow of 2931.087 STB/d, with a water flow of 325.6764 STB/d. After production optimization using wellhead pressure sensitivity curves and flowline diameter adjustments, oil flow increased to 3872.435 STB/d, and water inflow decreased by 90%. The critical flow rate calculation indicated that production must not exceed 5150 STB/d to avoid a rapid water breakthrough. The project to perforate only in the oil saturation zone for optimal production is projected to remain profitable for 11 years, with a return on investment in 1 year, 7 months, and 8 days.

Keywords: Water inflow, water-oil ratio, well production, breakthrough in water, optimization, perforation, return on investment.

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تعزيز إنتاجية بئر نفط اندفاعي من خلال تقليل تدفقات المياه

الخلاصة:

المشكلة المتعلقة بتدفق المياه تُعد واحدة من أبرز التحديات في صناعة النفط. تقدم هذه الورقة دراسات أُجريت في عام 2020 على البئر M.01 في حقل X، الذي واجه على مر السنين مشكلات مرتبطة بتدفق المياه، رغم أن إنتاجه الأولي لم يكن يعاني من مثل هذه المشكلات. الهدف الرئيسي من هذا البحث هو اقتراح حل عملي للحد من تدفقات المياه، مما يزيد من إنتاج النفط السطحي بطريقة فعالة من حيث التكلفة.

لتحقيق ذلك، تم إجراء تحليل عُقدي (Nodal Analysis) لتقييم أداء البئر من حيث تدفق السوائل (الماء والنفط). تم استخدام سجلات الإنتاج لتحديد منطقة التشبع الجديدة بالنفط، حيث تم عمل ثقوب جديدة. وأُجري تقييم اقتصادي باستخدام منحنى التنبؤ بتراجع الإنتاج. تم التعامل مع البيانات السرية، بما في ذلك بيانات الإنجاز والخزان والسجلات والبيانات الاقتصادية، باستخدام برمجيات PIPESIM و EXCEL.

وفقًا للنتائج، كان سبب تدفق المياه في البئر M.01 كانت ناجمة عن إزاحة اتصال الماء بالنفط، نتيجة للاختراق الجزئي عبر ظاهرة المخروط المائي، ما أدى إلى انخفاض تدفق النفط من 3005.585 برميل نفط في اليوم (STB/d) إلى 241.9834 برميل نفط في اليوم.

لمعالجة هذه المشكلة، تم تنفيذ عملية تثقيب باستخدام أنابيب ملفوفة (Coiled Tubing) في منطقة التشبع بالنفط بنسبة 100%، وتم عزل المستويين باستخدام سدادة عبر تقنية الـ Slickline، أسفرت هذه العملية عن تدفق نفط بلغ 2931.087 برميل في اليوم، مع تدفق ماء بلغ 325.6764 برميل في اليوم.

بعد تحسين الإنتاج باستخدام منحنيات حساسية ضغط رأس البئر وتعديلات قطر خط التدفق، زاد تدفق النفط إلى 3872.435 برميل في اليوم، وانخفض تدفق المياه بنسبة 90%.

أشارت حسابات معدل التدفق الحرج إلى أن الإنتاج يجب ألا يتجاوز 5150 برميل في اليوم لتجنب اختراق الماء السريع، ومن المتوقع أن يظل مشروع التثقيب في منطقة تشبع النفط فقط لإنتاج مثالي مربحًا لمدة 11 عامًا، مع عائد على الاستثمار خلال سنة واحدة و7 أشهر و8 أيام.

1. Introduction

The global energy market was severely affected by the COVID-19 pandemic in 2020–2021 [1, 2]. Investment in hydrocarbons fell sharply, leading to a significant imbalance between energy supply and demand [3, 4]. Although the development of solar and wind energy over the last decade has been positive, these renewable sources have only supplemented the energy supply without replacing fossil fuels [5]. Given the continuing rise in global demand for hydrocarbons and the declining number of new discoveries each year, increasing oil production more efficiently and economically has become essential [6–9]. Water inflow competes with oil production [10–12]. Globally, daily water production is approximately 210 million barrels, accompanying 75 million barrels of oil, which equates to an average of three barrels of water for each barrel of oil [13–15]. Water production in wells presents technical, economic, and environmental challenges during oilfield development [16–18]. It rapidly reduces productivity and may even lead to well closures, increasing operational costs due to the need to transport, separate, and store large volumes of water, assuming that water and oil are incompressible and immiscible fluids. This is the case for well M.01 in the X field, where excessive water production has reduced oil recovery performance. To

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improve production and well longevity, numerous techniques have been studied to understand the sources and mechanisms of water inflow, as well as to plan and monitor production wells [19, 20]. Various methods for minimizing water inflow and improving oil production have been proposed in the literature [21], including mechanical, chemical, and completion solutions [22–26]. Often, a combination of these approaches is required to control water inflows effectively.

The authors of [22] have used non-aqueous cement slurries for many years to prevent unwanted water or gas production and to repair holes, cracks, or other pathways in the casing, cement column, or interface. Best practices and mistakes in applying ultra-fine cement slurry systems in offshore Mexico to seal unwanted water flowing through natural fractures or behind the casing are detailed in [23]. Successful applications of polymer gels to control undesirable water production in mature, fractured reservoirs in northern Italy are described in [24]. In several South Mexican fields, waterless cement slurry squeezes have been demonstrated as effective solutions for unwanted water production, as shown in [25]. In [26], the selected solution for controlling water breakthrough was a combination of two conformance technologies designed to seal high-permeability channels and fractures while providing selective water control. One technology uses a swelling polymer to shut off water channels or fractures, and the other uses hydrocarbon-based slurry cement that reacts upon contact with water.

In [27], a technical and economic analysis was conducted on multilateral well architecture as an alternative to combat uncontrolled water inflows from active aquifers. A numerical simulation workflow using local grid refinement analysis was proposed to represent the active aquifer inflow phenomenon. The study demonstrated that adequately managing water inflow could increase oil production and recovery. Wells drilled in unsealed areas with strong aquifer inflow quickly exceeded 99% water cut and had to be shut down after producing only 40,000 barrels of oil. Bilateral or multilateral well configurations made it possible to manage water inflow mechanically, keeping water cut below the economic limit (99.5%), increasing cumulative oil production, and extending well life.

The authors of [28] explored innovative ways to combat water coning in mature oil and gas fields, enhance productivity, optimize well flow, and reduce costs and environmental impact. They integrated multilateral drilling and smart completion technologies with inflow control devices (ICDs) and downhole monitoring systems. In [29], the significance of ICDs in steam-assisted gravity drainage (SAGD) operations was analyzed, including their impact on well performance in various reservoir conditions. In [30], Autonomous Inflow Control Valve (AICV) completion

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technology was applied in horizontal wells in the UAE, accelerating oil production while reducing unwanted water production, which lowered operating expenses (OPEX) and positively impacted greenhouse gas (GHG) emissions.

The aim of this paper is to propose a solution to reduce water inflow and maximize oil production. The following specific objectives were set: to identify the primary cause of water inflow, justify the selected method for water control, calculate the critical flow rate to prevent water breakthrough, and conduct an economic assessment to evaluate project profitability using the production decline method. The research was guided by the following questions:

- What are the main causes of water inflows, and how can they be addressed?
- Which method is most effective in tackling water inflows?
- What is the critical oil flow rate, and how long will it take for water breakthrough to occur?
- How profitable is this project?

To answer these questions, nodal analysis techniques, production logs, and the production decline prediction curve were applied to completion, reservoir, log, and economic data using PIPESIM and EXCEL software. Production logs analysis involves examining the data collected from production logs to assess the performance of the well over time. Production logs provide crucial information on the rates of oil, gas, and water production, as well as the pressure and temperature profiles within the wellbore. By analyzing this data, we can identify trends and anomalies in production behavior, enabling us to pinpoint the origins and mechanisms of water inflow. This step is essential for understanding the well's operational efficiency and the impact of water on oil recovery.

Nodal analysis is a method used to evaluate the performance of a well by analyzing the flow dynamics between the reservoir and the surface. This technique involves constructing a flow system model that includes the well, reservoir, and surface facilities. In our analysis, we will identify the nodal points—locations where pressure, flow rate, and fluid properties change. By modeling these nodes, we can optimize the production system by assessing different scenarios and operational strategies. This helps in determining the optimal production rates and pressure conditions necessary to enhance oil recovery while managing water inflows.

Prediction of production decline involves utilizing historical production data to project future performance trends. This is critical for understanding how production rates will evolve over time and for planning effective management strategies. In this paper, we employ PIPESIM software, a specialized tool for simulating fluid flow in pipelines and production systems, to model production

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decline scenarios. PIPESIM allows us to create detailed simulations that account for various factors, including reservoir characteristics, fluid properties, and operational parameters. The results from PIPESIM simulations can be complemented with Excel software to perform additional calculations and analyses, such as financial evaluations and optimization of operational strategies. By integrating these methodologies, this paper aims to provide a robust analysis of the well's performance, identify effective solutions for minimizing water inflows, and ultimately maximize oil production. This multifaceted approach ensures a comprehensive understanding of the dynamics at play and supports the development of targeted interventions.

Water inflows were reduced mechanically. Mechanical solutions, while maintaining well productivity and operational efficiency, may interfere with other operations like logging, well testing, and maintenance, adding complexity and potential downtime. Therefore, mechanical solutions are often combined with other methods such as chemical treatments (e.g., polymer gels), reservoir management techniques (e.g., selective production), and advanced completion technologies (e.g., inflow control devices) to manage water inflows effectively.

The novelty of this approach lies in its dual focus: proposing a mechanical solution to water inflows while optimizing operations for a shorter return on investment. This paper is divided into five sections: the introduction, the data, tools and methods used, the results and their interpretations, and the conclusion.

2. Methodology

2.1 Tools

PIPESIM and EXCEL are the appropriate software tools for carrying out this study.

2.1.1 PIPESIM

PIPESIM is a simulator designed by Schlumberger. It provides flow assurance flow assurance to organizations handling oil, water and other fluids by simulating their simulating their performance during transport and storage. The system also offers integrations with a range of external software solutions, unifying multiple workflows on a single screen.

Typical PIPESIM applications;

- Perform nodal analysis and diagnose liquid loading;
- Optimize production through completions by modeling downhole flow downhole flow control valves;
- Multilateral well modeling with multiple layers.

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- Calculate optimal burial depths and insulation requirements for pipelines;
- Accurately characterize fluid behavior with a wide variety of black oil and models and fluid compositions.

PIPESIM can help production or reservoir engineers to predict flow and temperature in tubings and pipelines with accuracy and speed.

2.1.2 EXCEL

Microsoft EXCEL enables data to be formatted, organized and calculated in spreadsheets, to facilitate data analysis and easy visualization of information as data is added or modified.

This software will enable you to draw up an economic balance sheet, to assess the profitability of the perforation project.

2.2 Method

The method is an overview of how a given search is carried out. It defines the techniques or procedures used to identify and analyze information concerning a specific research topic. The aim of this work is to reduce water ingress to optimize oil production.

The method used in this study is production log analysis, nodal analysis and the production decline prediction method, using the PIPESIM and EXCEL software.

2.2.1 Nodal analysis

Nodal analysis is used to evaluate a complete production system (from static pressure to static pressure to separators) and predict throughput. It is an optimization technique which can be used to analyze production problems and improve well performance well performance.

The nodal system analysis approach can be used to;

- Select pipe size;
- Select flowline size;
- Evaluate well stimulation;
- Analyze the effects of perforation density;
- Analyze multi-well production system;
- Predict the effect of depletion on production capacity;
- Analyze existing system for abnormal flow restrictions

Nodal analysis is characterized by IPR (pressure drop in the porous medium) and
VLP (head loss in the production column).

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a. Inflow Performance Relationship-IPR

Flow to the well depends on the pressure drop between the reservoir and the downhole. The relationship between flow rate and pressure drop in the porous medium can be very complex and depends on several parameters, such as rock and fluid properties, flow regime flow regime, fluid saturations, drainage radius and degree of formation damage of formation damage.

Gilbert (1954) plotted the dynamic bottom pressure Pwf as a function of production rate q, the IPR (Inflow Performance Relationship), as shown in the figure below: Above the bubble point, where there is only one phase, the IPR curve is a straight line and the productivity index is equal to the inverse slope of the IPR curve. Below the bubble point, gas leaves the solution and flow becomes difficult; leading to a decrease in the productivity index.

b. Vertical Lift Performance-VLP

The Vertical Lift Performance (VLP) curve shows the system's capacity and its influence on flow as a function of the head losses generated influence on the flow as a function of the head losses generated dynamic bottom pressures calculated by one of the head loss correlations for different production rates. The aim of this nodal analysis is to determine the well's performance in terms of water and oil flow. A well's operating parameters (flow rate and bottom hole pressure) are represented by the coordinates of the intersection point of the two curves, namely the reservoir performance curve (IPR) and the tubing performance curve (VLP). When the reservoir is an active aquifer, there is a risk of excessive water production.

2.2.2 Production logs

Production logs provide instantaneous measurements using sensors in the well. Production logs are the methods applied after wells have been put into production wells. In addition, the ability to assess formation fluid saturation through the casing gives greater clarity to the well's production potential. The tool that will be used to assess production in this study is PLT (Production Logging Tools).

PLTs provide point-by-point diagnostic information on fluid inflows and give an indication of perforation efficiency. PLT measurement in this study involves flow measurement (spinner). The flowmeter can detect production zones; determine and evaluate the stimulation program; can establish a flow balance for secondary recovery, temperature measurement

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Measures temperature at any time during ascent or descent used to locate production or injection zones; monitoring fracturing performance fracturing performance; fluid movement behind the casing.

Density measurement

Density is measured by two methods, one of which uses gamma decay in horizontal wells, and differential pressure gradient of the fluids in the wells used in vertical and inclined wells. These results are used for fluid identification and multiphase production profiling. Temperature logs, combined with density logs and flow meters, are used to determine the water level, the new oil saturation zone in which the perforation is done.

2.2.3 Production decline prediction method

This is the method used to draw up the economic balance sheet. It is a method for reserves and oil rate prediction. It generally shows the rate at which rate at which production is expected to decline over the lifetime of an energy asset. This curve is used to determine the estimated ultimate recovery (EUR) for an oil reserve. It is of the utmost importance that drilling projects reach an acceptable EUR threshold for a project to be considered viable and profitable. The decline prediction method is based primarily on well conditions; three types of decline curves can be applied;

The exponential model:

$$Q(t) = q * e^{-bt} \tag{2.1}$$

The harmonic model:

$$Q(t) = \frac{q}{1+bt} \tag{2.2}$$

The hyperbolic model:

$$Q(t) = \frac{q}{\left(n + \frac{bt}{a}\right)^{a}} \tag{2.3}$$

However, the exponential model is preferable.

To maximize production, several steps are required;

- **Perform nodal well analysis**

Here, we present the design of the well from the bottom to the top, and its performance in terms of its performance in terms of oil flow and water flow production combining the IPR curve (from

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reservoir to bottom of well) with the VLP curve (from bottom to surface) from the bottom to the surface).

- **Identifying the main cause**

The main cause will be determined on the one hand with the help of production system mechanisms based on the cone phenomenon, and secondly by logs to eliminate probable causes eliminate probable causes (channeling completion, presence of a normal fault, hydraulic fracturing, cone phenomenon, poor casing condition, etc.). Once the main cause of the water ingress at the bottom of the well has been determined, the PLT will help to determine the new oil and water saturation zones in the tank in the option of having the new zone perforated.

- **Method justification**

The choice of method will be based on technical and economic considerations.

- **Completion design**

The solution is to identify the new zone to be oiled, and to perforate it again, according to the following steps the following steps: perforation mode (underbalance or overbalance); perforation characteristics: specify filler density, diameter, length and depth of perforation; appropriate fluid to maintain hydrostatic pressure with :

$$Ph = G * H \tag{2.4}$$

where Ph = hydrostatic pressure (psi), G= fluid gradient in hydrostatic column (psi /ft) and H= height (ft). The neww completion is presented and a nodal analysis performed.

- **Optimize production**

Once the new oil saturation zone has been perforated, a nodal analysis will be required to see the well's performance in terms of oil volume and water volume, and an analysis of the sensitivity curves of the flowline diameter and the wellhead pressure will enable us to improve the production rate.

- **Calculating critical flow**

This calculation is based on the MEYER correlation, with a safety margin to minimize the cone phenomenon.

$$Q_c = 0.0000246 * \left[(\rho_w - \rho_0) / \left(\ln\left(\frac{re}{rw} \right) \right) \right] * \left(\frac{K_0}{\mu_0 * B_0} \right) * \left(h^2 - hp^2 \right) \tag{2.5}$$

with ρ_w being the density of water.

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- **Economic balance sheet**

To determine the profitability of the project, it is necessary to determine the point at which the well would no longer be profitable, and output the production profit over time. Here, the decline curve (exponential model) is used. This exponential model will give the time frame in which the economic balance sheet will be drawn up. To determine the project's profitability, we need to study.

- **Expenses**

This is the cost of completion (new perforation) and clean-up. They are grouped into two (02) categories: Capex (for the purchase of equipment, perforation and water treatment); Opex (corresponds to the money needed to carry out the perforation and the money used to produce 1 barrel of oil).

- **Revenues**

This is the money obtained from the sales of hydrocarbons, which must be proportional to the production rate; taken at $90.D/STB per barrel of oil. Production profit is a function of the flow rate throughput delivered by the well. Revenues are calculated using the following formula:

$$R(\$) = Q_0(stb/d) * 365 * \text{cost of 1barrel of oil}(\$ \cdot \text{d/stb}) \quad (2.6)$$

- **Calculating profit**

For the company, profit represents the benefits obtained from operations. It is the difference between revenues and expenses, using the relationship below;

$$\text{Profit}(\$)=\text{Revenue}(\$)-\text{Expenses}(\$) \quad (2.7)$$

Profit enables an investor to validate or invalidate a project. If;

- Profit <0 the project is not economically profitable;
- Profit =0 the project is balanced and may or may not be launched, depending on additional factors;
- Profit > 0 the project is economically profitable.

3. Data

The data for well M.01 in field X are confidential and comprise completion data, reservoir data, logs and economic data. The completion data presented in Table (1) are used to represent the physical model of the well from the downhole equipment to the surface equipment.

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Table (1): Completion data.

Casing types	Depth	External diameter	Internal diameter	Grade
Conductor	800 ft	30 inches	28 inches	X56
Surface	3500 inches	20 inches	19.24 inch	H40
Intermediate	8500 ft	16 inches	14.688 inch	K55
Production	11000 ft	10 inches	8.556 inch	N80
Tubing	10300 ft	4.5 inch	3.5 inch	M65
Choke			3 inches	
Flowline			2.5 inch	
Packer	9500 ft			

The reservoir data shown in Table (2) can be used to identify the type of fluid in the reservoir, the nature of the reservoir (saturated or unsaturated) and to determine the potential leaving the reservoir.

Table (2): Reservoir data.

Parameters	Values
Reservoir pressure	45000 PSI
Reservoir temperature	200 ^{0}F
Absolute open flow potential	5000 STB/d
Gas oil ratio	600 SCF/STB
Water cut	80 %
Oil density	42 API
IPR model (Vogel)	Two-phase flow (oil-water)
Bubble pressure	2427 PSI
Skin	2
Oil volume factor	1,05
Oil viscosity	1.1 cp
Reservoir permeability	800 md
Drainage radius	850 ft
Well radius	0.42 ft
Gas relative density	0.65
Vogel coefficient	0.8
Reservoir head pressure	100 PSI
Effective oil permeability	776 md
Relative oil permeability	0.97
Water density	1.2

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The log data presented in Table (3) is used to determine the depth to which the perforations should be made (to create the hole-layer bond), to determine the depth of the oil-water contact, and the height of the reservoir.

Table (3): Logging data.

Parameters	Values
Reservoir height	300 ft
Height of oil in reservoir	180 ft
Height of water in reservoir	120 ft
Drilling height	10790 ft

The economic data presented in Table (4) will be used to carry out an economic assessment of the project.

Table (4): Economic data.

Parameters	Values
Cost of oil	8 $
Tax	10 %
Price per barrel	90 $
Rentals of drilling equipment	500 $/h

PIPESIM and EXCEL are the appropriate software for carrying out this study. The method used in this paper is the analysis of production logs, nodal analysis and the method of predicting production decline by using PIPESIM software and EXCEL software.

4. Results and interpretations

This section presents the main results obtained from the nodal analysis, log analysis and the production decline prediction curve.

4.1 Results obtained from log and nodal analyses

Based on the log data, the initial design of well M.01 is shown in Figure (1).

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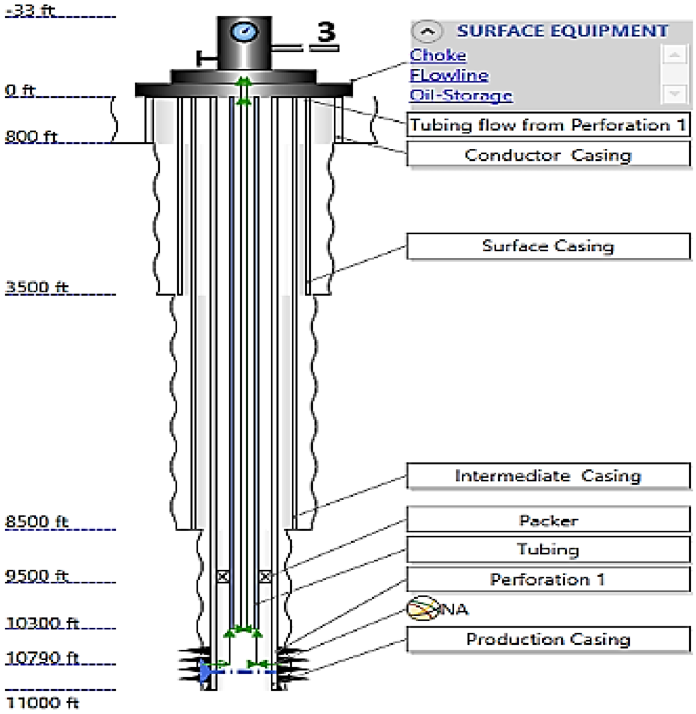

Fig. (1): Design of well M.01 completion in its initial state.

In Figure (1), the initial depth of the perforations is 10790 ft, the distance between the top of the reservoir and the tubing is 400 ft, the thickness of the reservoir 300 ft with 180 ft of oil thickness and 120 ft of water thickness. When the M.01 well produces with the natural energy of the reservoir in the oil saturation zone, the initial nodal analysis illustrated in Figure (2) shows good oil production with a flow rate of 3005.585 STB/d at a pressure of 2664.438 PSI and 0 STB/d of water flow.

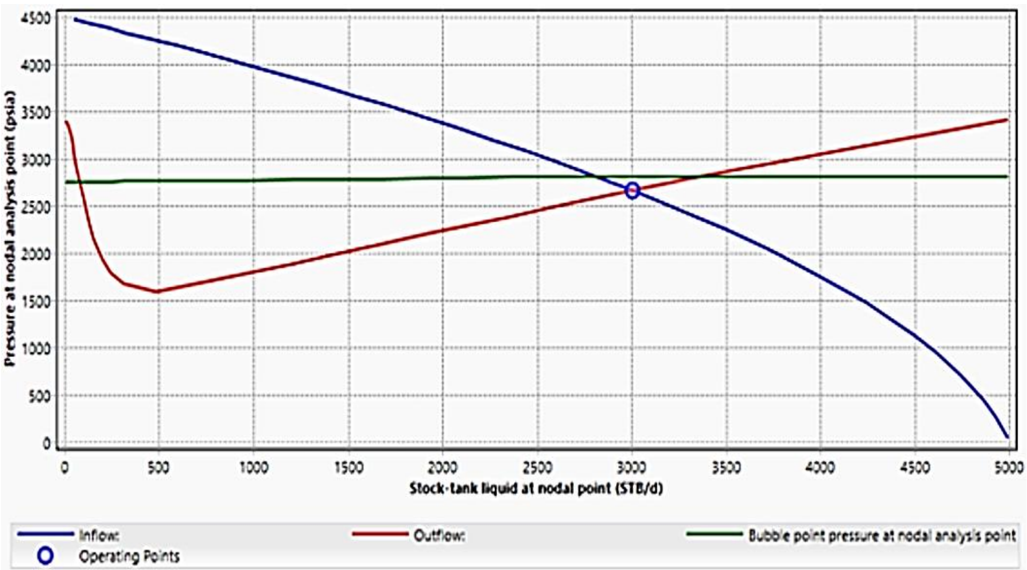

Fig. (2): Performance curve for well M.01 in its initial state.

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Figure (3) shows the performance curves for well M.01 after several years of production.

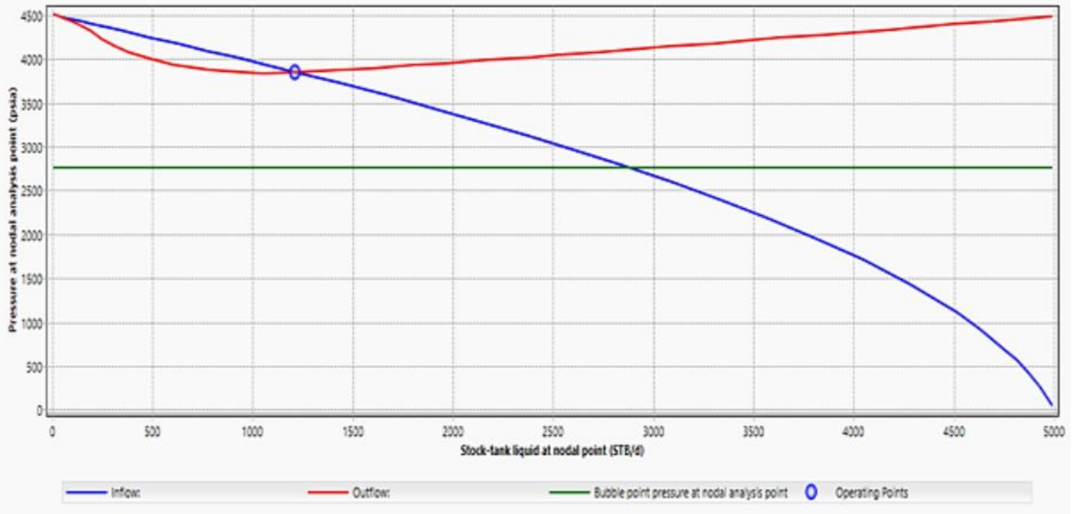

Fig. (3): Performance curve for well M.01 after several years of production.

In Figure (3), the nodal analysis carried out under these conditions gives a liquid flow rate of 1209.917 STB/d with a pressure of 3853.799 PSI, an oil flow rate of 241.9834 STB/d and 967.9338 STB/d of water flow rate. The water flow rate increases considerably, causing the oil flow rate to fall. Water begins to be produced excessively.

4.1.1 Main cause of water inflow and justification for the choice of water inflow control method

As the completion was well done, there was a good cement-lining bond. The reservoir is 300 ft thick, with an oil depth of 180 ft and a water depth of 120 ft. To produce only the hydrocarbons, a partial perforation was made in the oil saturation zone, through which the oil flow rate was 3005.585 STB/d, with a pressure variation of 1836 PSI and high vertical permeability. The partial perforations cause water to move into the oil well. The rise in the oil-water contact will be 10880 ft. Thus, the water coming into well M.01 is mainly due to partial penetrations through the oil saturation zone.

The reduction of water inflows becomes paramount in order to ensure good well oil production. We propose a mechanical solution to this problem. This consists of plugging the old perforations by cementing them in place using coiled tubing. Once the water zone has been plugged, a plug must be lowered through a slickline to isolate the two (02) levels (oil zone from water zone), so that new perforations can only be made in the 100% oil saturation zone. The chemical solution is not appropriate because the water and oil are already mixed. Injecting chemicals will cause severe

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corrosion of the equipment, which could make separation difficult. Downhole oil-water separation can minimize water production by using technologies that do not prevent water from entering the well, but that reduce the volume of water transported to the surface. However, this solution is not suitable because it is not only costly (presence of separators, submerged electric pump), but also because there is no more basic aquifer zone to inject pumped water into the reservoir. The mechanical solutions also have some limitations. For example, mechanical solutions like packers and plugs may fail to entirely isolate water-bearing zones, especially in complex or highly fractured reservoirs; resulting to continued water inflow despite intervention. Installing mechanical devices such as packers, plugs, and casing patches can be challenging in deviated or horizontal wells, where proper placement and sealing can be difficult to achieve. Mechanical components can degrade over time due to corrosion, erosion, and other downhole conditions, leading to potential failure and the need for repeated interventions. Issues such as setting failures, seal failures, and mechanical breakdowns can reduce the effectiveness of these solutions.

4.1.2 Geological setting and description of field X

The most probable geological settings for a petroleum well with water inflows typically involve the presence of water-bearing formations in proximity to the hydrocarbon reservoir. For aquifer-associated reservoirs, we can either have edge water drive reservoirs or bottom water drive reservoirs. They respectively refer to reservoirs which are adjacent to large aquifers that provide natural water drive to push hydrocarbons towards the wellbore and reservoirs that have an aquifer located beneath the hydrocarbon-bearing formation. With continued production, the water from below can move upward into the wellbore, a phenomenon known as water coning. However, the geological composition of field X is void of aquifers but rather made of reservoirs with high-permeability channel sands which are connected to water-bearing sands. Water migrates through these high-permeability channels into the well.

4.1.3 Completion design of well M.01 with the new perforation

The perforation was made at the oil saturation zone at 10790 ft. The water-oil contact, which was at 10880 ft during the three years of production, was moved to 10790 ft. Once the well has been shut in, the new oil saturation zone is higher up at 10790 ft, so half of this height, i.e., 10745 ft, has to be perforated. Perforation is carried out using a tool called a coiled tubing, with an external diameter of 1.5 inches and an internal diameter of 1 inch, on which the charges are hooked. The detonation is therefore caused at the surface by an electric current. The following criteria were

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taken into account when making the perforations. The perforation was carried out in Under balance, i.e., with a reservoir pressure higher than the hydrostatic pressure, in order to avoid damage and to be able to send the debris caused by the explosion of the charges at the bottom of the well and circulate it on the surface. The fluid used to exert this hydrostatic pressure is drizzle (salt water). The hydrostatic pressure is 4400 PSI. The positions of the charges are shown in Figure (4).

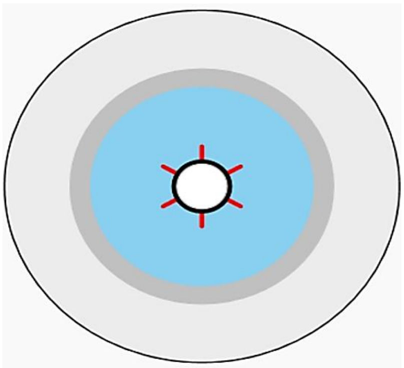

Fig. (4): Charge positions.

In Figure (4), the charges in red color are centered in relation to the perforated zone in blue color. After entering the charge, the depth, the type of reservoir (sand), its porosity (0.2), the type of fluid (oil) and the diameter of the open hole into PIPESIM, then simulation is launched to obtain the results shown in Table 5 which shows the perforation and gun systems.

Table (5): Perforation results.

(a) Perforation system

Cases	Phase angle	Perforation density	Gun position	Stand-off	Total pen. average	Formation pen. average	Formation dia. average	Csg EH dia. average**	Area open to flow (AOF)**
	(degrees)	(shots/ft)		(inch)	(inch)	(inch)	(inch)	(inch)	(inch^2/ft)
#1	60	6.00	Centered	3.15	8.68	5.45	0.28	0.12	0.07

(b) Gun system

Cases	Gun type	Mass of charge	Gun OD	API penetration	API entrance hole	API test edition	Penetration model
		(g)	(in)	(in)	(in)		
#1	2-1/4*HSD, PowerJet Omega 2006, HMX	7.30	2.25	21.80	0.22	198 1st Ed	Rock based

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Figure (5) shows the completion design for well M.01 with the new perforation.

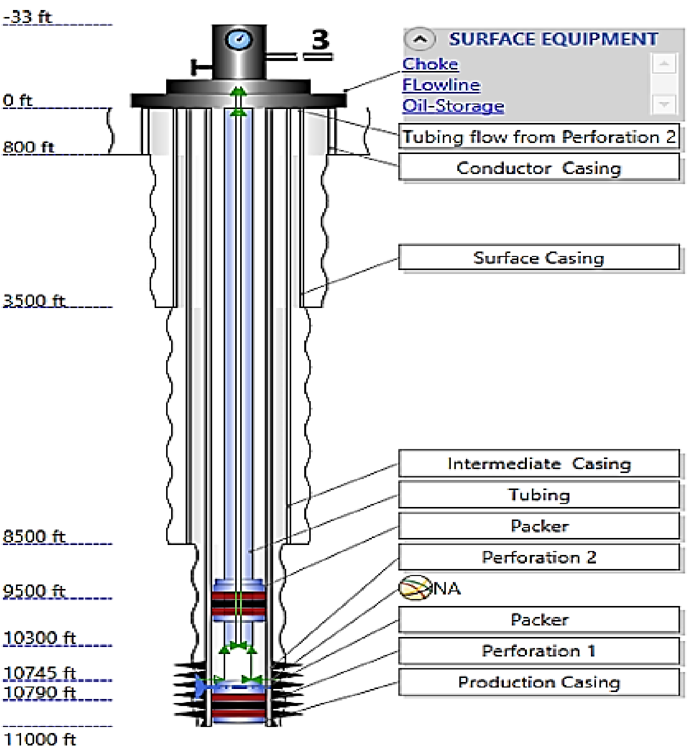

Fig. (5): Design of well M.01 completion with the new perforation.

In Figure (5), the new perforation zone is 10,745 ft because, after the well was shut in, the new oil saturation zone is at 10790 ft. Half of this zone has therefore been perforated. The results of the nodal analysis of well M.01 with the new perforation zone are shown in Figure (6).

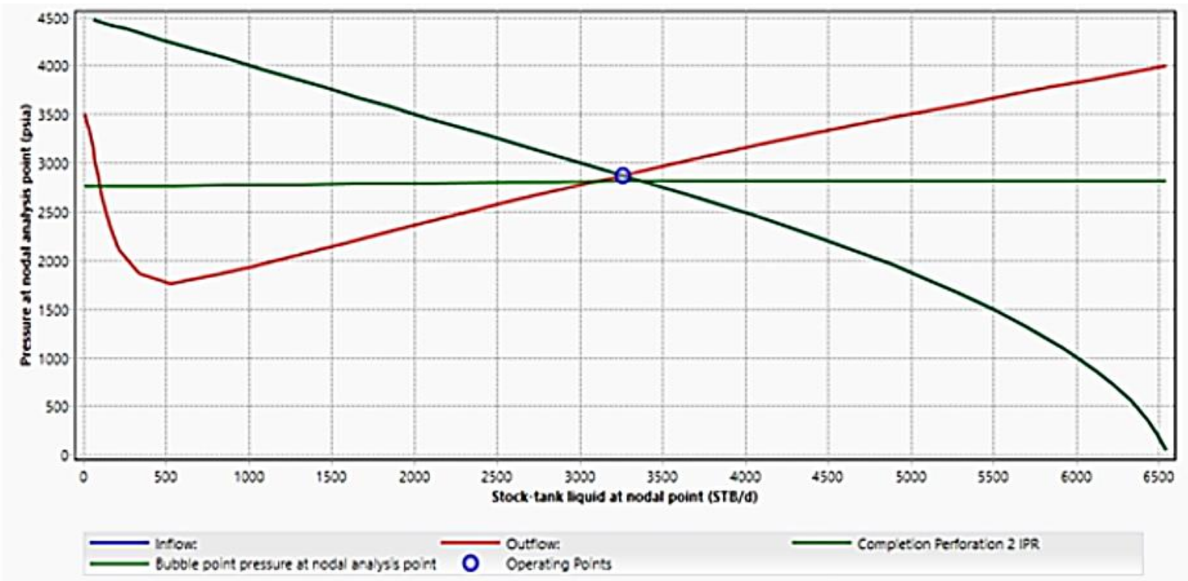

Fig. (6): Performance curves for well M.01 with the new perforated zone.

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In Figure (6), the new well performance, assessed by nodal analysis of the new perforated zone, gives a liquid flow rate of 3256.764 STB/d with a pressure of 2871.618 PSI and an oil flow rate of 2931.087 STB/d compared with a water flow rate of 325.6764 STB/d.

4.1.4 Production improvement and critical flow rate

Production improvement is achieved by analyzing the sensitivity curves at the wellhead and the flowline diameter. By varying the flowline diameter from 2.5 to 4.5 inches and the wellhead pressure from 50 to 100 PSI, the results obtained are shown in Figure (7).

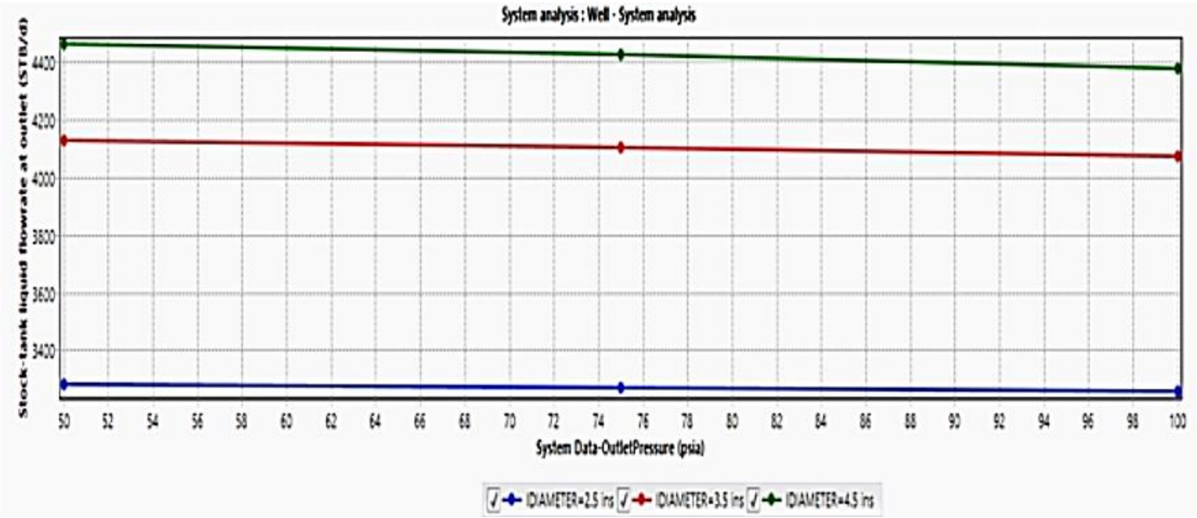

Fig. (7): Sensitivity of well M.01 with the new perforation zone by varying the diameter of the flow line and the wellhead pressure.

In Figure (7), by decreasing the wellhead pressure while increasing the diameter of the flow line, the production rate increases considerably. In the range 100 to 75 PSI and in 3.5 to 4.5 inch, the production rates no longer vary considerably, which means that the optimum zone has been reached. By replacing these new values (flow line diameter and wellhead pressure), the optimum flow rate is obtained by using the nodal analysis, illustrated in Figure (8).

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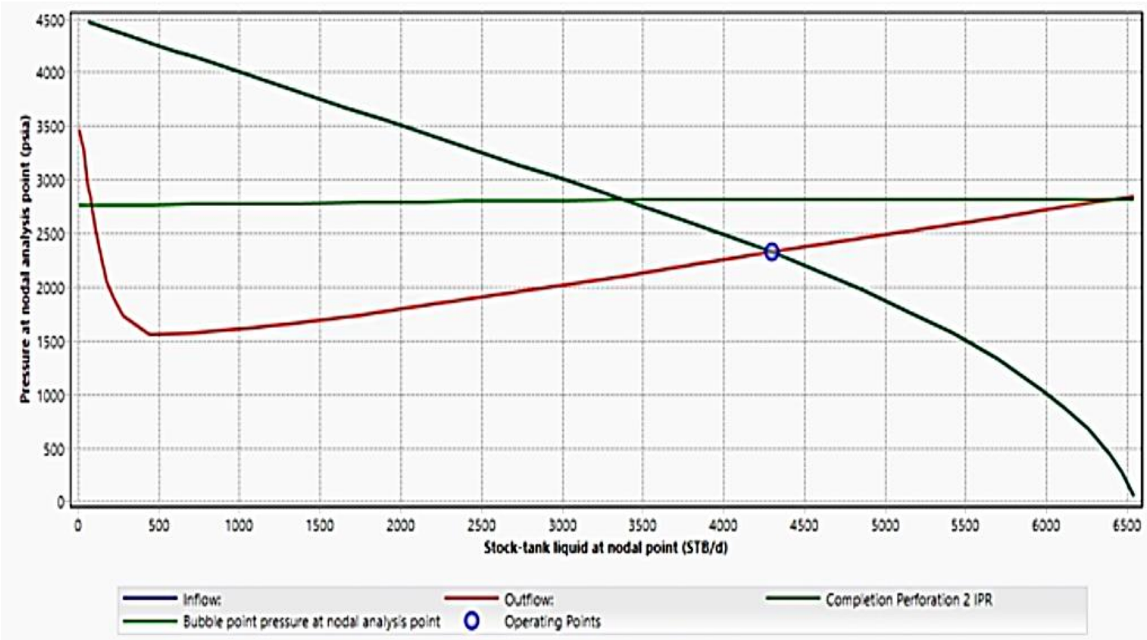

Fig. (8): Optimum production rate for well M.01 with the new perforation zone.

Figure (8) gives a liquid flow rate of 4302.706 STB/d at a pressure of 2317.864 PSI and an oil flow rate of 3872.435 STB/d compared with a water flow rate of 430.2706 STB/d. Oil production increases and water inflow decreases. The volume of water has been reduced to a maximum of 90%.

Calculating the critical flow rate is a method of preventing water ingress. It makes it possible to regulate the production flow rate, because when the flow rate is high, it causes water to advance rapidly towards the perforations, resulting in excessive water production at the surface. After calculation, the critical flow rate for M.01 well is 5150 STB/d. The optimum production rate for well M.01 with the new perforation zone is 4302.706 STB/d, which is well below the critical rate, so the producer must not exceed this rate.

4.2. Results obtained using the production decline prediction method

The economic assessment is based on the exponential model of the production decline curve for well M.01 with the new perforation zone shown in Figure (9).

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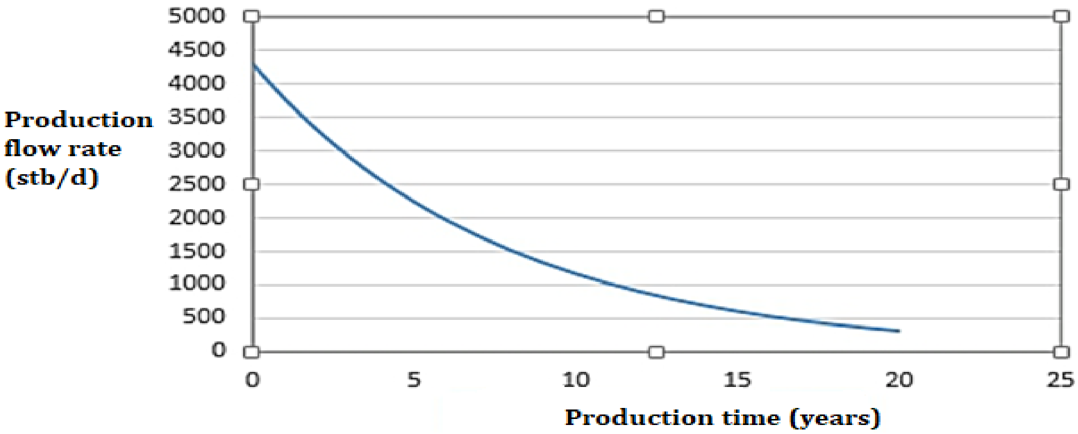

Fig. (9): Predicted production decline curve for well M.01 with the new perforation zone.

The operator's objective is to produce at a rate greater than or equal to 1,000 STB/d, because production below this rate will no longer be profitable. According to Figure (9), from year 12 onwards, production is no longer profitable for the operator. The project will therefore be economically viable over a period of 11 years. Hence the need to determine the project's expenditure, revenue and profit, based on Table (6) showing CAPEX and OPEX.

Table (6): CAPEX and OPEX.

Parameters	Costs
Purchase of surface equipment	100000 $
Taxes	207757213 $
Water treatment	20000 $
Well maintenance	120000 $
Total oil production costs	74898707,3 $
Perforation equipment rental	24000 $
Cost of perforation	25000 $

According to Table 6, total expenses and revenues for the 11 years of production are $15944,8753 and $150,086,415, respectively. The profit (= total revenues - total expenses) is $692,524043. Since the profit is greater than zero, the project is profitable and the return on investment is 1 year 7 months and 8 days, i.e., the period during which the company will recover all its expenses.

Water inflow has an irreversible impact on the environment and is a key component of production costs. They make well production uneconomical for operators. This was the case for well M.01, which had a water breakthrough characterized by a BSW of 80%. The aim of this paper was therefore to find an appropriate solution to reduce these water breakthroughs. The results

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obtained are summarized in 6 main conclusions. The main cause of water inflow in well M.01 was partial perforation due to displacement of the water-oil contact at the perforations. Oil production with the natural energy of the reservoir initially gave an oil flow rate of 3005.585 STB/d, with no water production. After a few years of production, there was a water breakthrough with a flow rate of 967.9338 STB/d, compared to an oil flow rate of 241.9834 STB/d. That is, the water inflows caused oil production to decrease by 91.95%. Production increased after perforation of the oil saturation zone and cementing of the old perforations, with an oil flow rate of 2931.087 STB/d and a decrease in the water flow rate to 325.6764 STB/d. This shows a decrease in water flow rate by 66.35 % and an increase in oil flow rate by 1111.3 % compared to the production with the inflow of water. The volume of water was reduced to the maximum, when the wellhead pressure varied from 100 to 75 PSI and the diameter of the flowline from 3.5 to 4.5 inch. Optimum production was then achieved, giving an oil flow rate of 3872.435 STB/D with a water flow rate of 430.2706 STB/d. Therefore, optimum production is about 1500 % of the production with water inflows. The calculation of the critical flow rate for the M.01 well showed that the production threshold is 5150 STB/d to avoid a water breakthrough. The project to make a new perforation in the oil saturation zone only, will be profitable over a period of 11 years, the total expenditure is $159,448,753, the total revenue at the end of 11 years of production is $150,086,415 with a profit of $692,524,043, the return on investment is 1 year 7 months, from which the company will recover all its expenses. In the event of a new water breakthrough, the installation of an electric submersible pump is recommended. That way, the two fluids can be produced separately.

5. Conclusions

This paper was tailored towards improving the productivity of a petroleum well by reduction of water inflows. There were four main research questions viz: what are the main causes of water inflows, and how can they be addressed, which method is most effective in tackling water inflows, what is the critical oil flow rate, and how long will it take for water breakthrough to occur and how profitable is this project? The case study was well M.01, which had a water breakthrough characterized by a BSW of 80%. One of the main aims of the paper was to identity the main causes of the water inflows. The main cause of water inflow in well M.01 was found to be partial perforation due to displacement of the water-oil contact at the perforations. Oil production with the natural energy of the reservoir initially gave an oil flow rate of 3005.585

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STB/d, with no water production. After a few years of production, there was a water breakthrough with a flow rate of 967.9338 STB/d, compared to an oil flow rate of 241.9834 STB/d. This caused oil production to decrease by 91.95%. Production increased after perforation of the oil saturation zone and cementing of the old perforations, with an oil flow rate of 2931.087 STB/d and a decrease in the water flow rate to 325.6764 STB/d. A decrease in water flow rate by 66.35 % was recorded and an increase in oil flow rate by 1111.3 % compared to the production with the inflow of water. The volume of water was reduced to the maximum, when the wellhead pressure varied from 100 to 75 PSI and the diameter of the flowline from 3.5 to 4.5 inch. The optimum oil flow rate of 3872.435 STB/D was recorded; with a water flow rate of 430.2706 STB/d. This represents about 1500 % of the production with water inflows. The calculation of the critical flow rate for the M.01 well showed that in order to avoid water breakthrough, the production threshold is 5150 STB/d. The project to make a new perforation in the oil saturation zone only, will be profitable over a period of 11 years, with the return on investment realized in 1 year 7 months. Productivity can subsequently be improved by installing an electric submersible pump whenever there is new water breakthrough. This will permit the water and the oil to be produced separately.

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LIST OF ABBREVIATIONS

Abbreviation	Full meaning
IPR	Inflow performance relationship
CAPEX	Capital Expenditures
OPEX	Operating Expenditures
PSI	Pounds per Square Inch
md	Millidarcies
cp	centipoise
API	American Petroleum Institute (in the context of API gravity)
STB/d	Stock Tank Barrels per Day
LDICDs	Liner deployed inflow control devices
SAGD	Steam-assisted gravity drainage
SCF/STB	Standard Cubic Feet per Stock Tank Barrel
^{0}F	Degrees Fahrenheit

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