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Producer-To-Injector Conversion to Enhance Oil Productivity and Profitability

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Abstract.: Infill new injection wells are utilized to increase the recovery of producing well as it reduces the spacing that existed between the old production wells that yields higher capital costs. Therefore, the decision, then must be made to convert old producers to the injectors. This work deals with the subject of converting existing producing wells for injection purposes. This evaluation was done by investigation the strategy of converting the producers to water injectors by design, simulation model and the optimum oil productivity and profitability was evaluated. In this project each phase of the petroleum recovery (primary and secondary) was modelled and changed through several scenarios in expression of conversion of production to injection wells as well as utilizing different injection patterns by using simulation program. Eclipse-100 and Petrel was used as the simulation software and the optimum oil productivity and cost effect of conversion wells, profit gain and optimum profitability were evaluated. Findings showed that, primary plans' RF after modification raced up 42%. Whereas, secondary recovery plan was developed to approximately 56%. This recovery increment is basically due to the additional oil that was swept microscopically by water and its effect in the injection of the converted wells. In addition, an economic analysis supported the results of the project with a net revenue value of $ 2,325,002,016 over the net income of the base case. In summary, conversion producer wells into injection wells is the best option to get the optimum oil productivity and profitability.

Keywords : higher capital costs, petroleum recovery, Eclipse-100 , Petre

I. INTRODUCTION

The generation of energy has become more complicated in recent times as the oil and gas industries have turned into the biggest and most requested source of energy generation. Thus, countries that are involved in oil production have to enhance the method of production in order to sustain the energy sources [1].

There are three main processes that is utilized by the oil industries to recovers its hydrocarbon in the subsurface. Those process are primary recovery, secondary recovery and tertiary recovery. Primary recovery is the process of oil and gas extraction naturally through the energy supplied naturally within the reservoir. Secondary recovery is increasing the production of oil and gas by applying external source of energy from the surface introduced to the reservoir such as fluid injection (water or gas) either to maintain reservoir pressure or replace portion of the hydrocarbon within subsurface.

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Tertiary recovery refers to hydrocarbon recovery of that residual oil by fluid injection and use external energy that not exist in the reservoir [2].

Generating additional production from mature fields is both a priority and a challenge. On the one hand, as new finds become ever more expensive, mature fields are gaining importance in the oil & gas industry with each passing year. On the other hand, mature fields offer no easy opportunity: they usually suffer from higher operating costs, decreasing oil production, ageing equipment, and a complex subsurface configuration of pressure and saturation. These issues jointly contribute to making new investment both less attractive and riskier[3].

Secondary recovery, which includes the involvement of external energy into the reservoir by one well and oil produced from another well. Secondary hydrocarbon involved the immiscible processes of water and gas injection or water-gas combination injections, which is called water alternating gas injection (WAG). Nevertheless, water is the most common fluid injected due to several reasons such as availability of water, low cost, and high specific gravity which facilitate injections [4].

Primary oil recovery is optimized by the approach via the application of secondary recovery at initial stages of the primary phase before the depletion of reservoir energy. This method would result in higher oil production compared to the oil produced by a single action of the natural drive mechanism [5]

The main four considerations of conversion producer to injector are as follows [4]. A bottom-hole location is the first factor to consider when converting existing wells to the injectors. Many times the surface location is thought to reflect an accurate bottom-hole location. However, due to natural drift while drilling and past drilling practices, the bottom hole location may be some distance from the surface location, in this case, the existing well that is being considered for conversion to injector may have a bottom hole location that is out of pattern [4].

Casing size is the next factor to be consider in converting wells to the injectors. The casing size of existing wells should be of sufficient size to allow the desired pattern injection rate. Thus, the casing should be large enough to permit the installation of the proper size tubing string. If the dual tubing string is planned, the casing must be large enough to accommodate them. Also, the subsurface injection control devices are to be installed such as side-pocket mandrels. The casing should be large enough to permit the proper size subsurface devices [6]

The condition of the casing should be determined in each well being considered for conversion. This may require pressure test of casing using tubing methods of testing the casing's integrity. Production well with worn or corroded casing may not currently pose problems. However, an injection well requires good casing for a proper packer seating. The casing of injection wells must be able to withstand a mechanical integrity test to prove that shallower formations containing potable water are not being polluted [7]. Completion is the next factor to consider in converting wells to injectors techniques that were used to complete the existing wells should have compared with current completion practices. Thus, this work deals with the subject of converting existing producing wells for injection purposes through investigation the strategy of converting producers to water injectors, design simulation model and evaluate the optimum oil productivity and profitability. In fact, usually the worst producers are converted to the injectors. These may include the producers with the highest WORs, lower production rates, and even dry holes. Each work in this phase of the petroleum recovery (primary and secondary) is modelled and changed through several scenarios in expression of conversion of production to injection wells.

II. METHODOLOGY

Reservoir simulation tool

The reservoir simulation used in this work were Schlumberger Eclipse-100 (Black oil) and Petrel applications. Eclipse 100 applications was used as the main tool for the primary and secondary recovery methods. A set of information in DATA format was produced in accordance with the specification of the reservoir, and it was evaluated in order to conduct the most suitable measures for reservoir -X. The data is subjected to be changed based on operation date, amount of production & converted wells, injection rate, BHP, interval of properly spacing and perforations. Injection designs are modelled and upgraded to attain the optimum result that can be gained. Schlumberger Petrel software was used to visualize the reservoir in terms of its geological construction of the reservoir such as locations and petro physical properties along with determination of distribution of porosity among the reservoir, permeability maps in (X, Y and Z) directions.

Reservoir model description

Reservoir-X comprises three liquid phases (oil, gas and water) according to the PROPS section of the data that was given for the specific reservoir. The reservoir was divided into four sections (1, 2, 3 and 4) that are split by the faults inside the reservoir as shown in Figure 1. The figure is shown the top-view of Reservoir-X, thus each section contained a set quantity of infill and production wells.

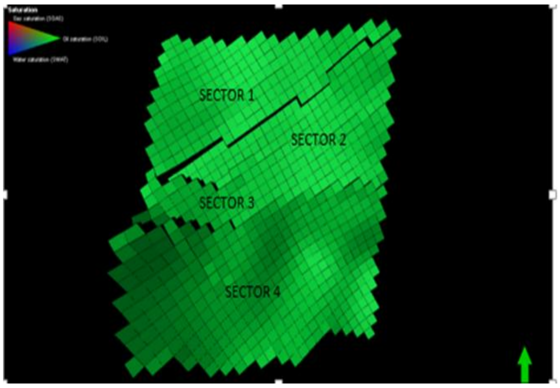

Fig. 1 Top view of Reservoir-X.

Reservoir faults

The reservoir model included 11 faults such as the boundaries of the reservoir and four internal faults that split the reservoir in to four portions. Fig. 2 displays the four internal faults in different indicator colours. Those faults were the constraint that controlled the injection mechanisms as it was preventing the injected fluid to flow over the sections and made the recovery process even more difficult.

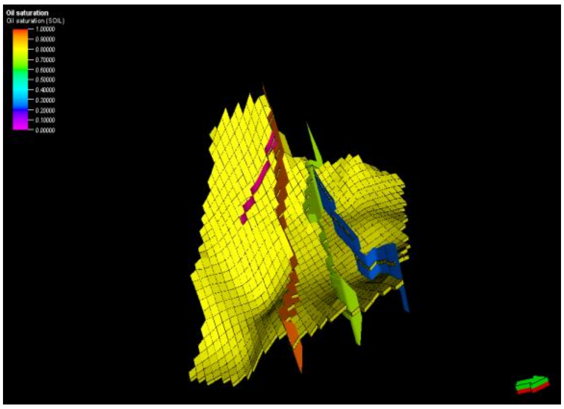

Fig. 2 Location of the internal faults within the reservoir.

Reservoir-X (Base Case) Plan

Reservoir-X was put through to be operated through two stages of production primary and secondary (water flooding). The base case was basically operating the reservoir with initial six oil producers distributed in each section of the reservoir without any injection of secondary processes in order to obtain a comparison between the two stages and investigate how much incremental in the recovery factor over each stage. The history matching was not conducted for Reservoir-X because it was considered as new discovered oil reservoir that has not been operated before, and need to be evaluated for acquisition possibility. The original volume in place of Reservoir-X for the three phases (oil, gas and water) is summarized in Table 1.

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Table. 1 Initial volume in place for oil, gas and water

Phase	Original in place (OIP)
Oil	126,887,162 STB
Gas	45,602,463 MSCF
Water	118,806,987 STB

Primary and secondary recover plan

In this stage the reservoir was operated with no injection well (gas or water), the primary method of oil recovery included additional wells that were drilled and changes in some of the production locations except the basic case well locations. The plan was evaluated by many trials; with hundreds of simulation runs for the code that were conducted in order to select the best scenario among many scenarios. Only the best three scenarios and what changes that were made over the base case are discussed. The secondary recovery was conducted for the purpose of maintaining the pressure within the reservoir when the natural energy of the reservoir becomes less sufficient to withdraw the oil into the wellbores of the production wells as well as to displace the residual oil that has not been produced by the primary method. The time of initiating this plan was based on the recovery factor (RF) curve of the primary plan, thus the secondary recovery was performed when the recovery factor curve started to decline throughout the years of production. The secondary recovery was applied by converting the shut oil producer that have high water cut and its oil production reach to minimum limit to a water injector, which will maintain the pressure and reduce the expenses. The secondary recovery is a process of maintain the pressure in the reservoir which can be done by develop the reservoir with (water or gas) injector. This process can be achieved by drilling new injection wells or convert some oil production wells to injectors. As it was developed four scenarios that production wells have been converted to water injection wells. Therefore new scenarios will be discussed with new injection wells at same region that converted wells were to compare the two methods of applying secondary recovery and see the best recovery and profitability among the two method in this Reservoir-X.

Economic feasibility

Economic analysis excel sheet were one of the tools that was used evaluate every scenario individually in term of the net profit value and total cost during the field operation life. Summary of the variables given in economic sheet can be seen in the Table2.

Table. 2 Capital investment and operation costs

Investment item	Cost (USD$)
Monthly field operation	200,0000
Vertical well	1,000,000
Horizontal well	3,000,000
Water injection well setup	500,000
Gas injection well setup	1,000,000
WAG injection well setup	2,000,000
Injected water	1.0 per STB
Injected methane	4.0 per MSCF
Water production	5.0 per STB

III. RESULT AND DISCUSSION

Simulating the base case is about recording the total oil, gas and water production as well as the hydrocarbon recovery factor in Reservoir-X. This record will be compared with primary and secondary recovery scenarios in term of enhancing and improving the hydrocarbon recovery and total oil, gas and water production. The base case start production with 5200 STB/DAY field oil rate for four years where six basic wells were developed as history matching period for future simulation. The production started to decrease to reach 3600 STB/DAY which means the high capability of the reservoir to deliver much oil. Therefore, adding more wells for the next scenarios is the appropriate development option for Reservoir-X The gas production rate started at 4800 MSCF/DAY to reach 2900 MSCF/DAY as well as water production was too low comparing oil and gas production with initial production rate 60 STB/DAY which was increased slightly along 20 years' production period. The oil, gas and water production total volumes are in Fig. 3 as 31,644,356 STB, 26,880,810 MSCF and 881,152.81 STB in the inclined green, red and black line respectively.

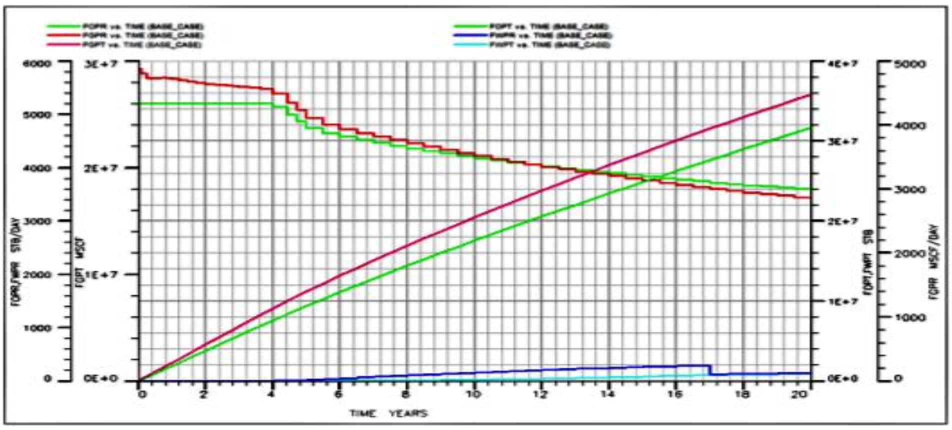

Fig. 3 Oil and gas production total versus oil and gas production rate

The base case was simulated with six oil producer wells that located near to reservoir boundary from each direction to study the reservoir delivery energy which will be developed later at primary recovery period, the production was performed without any secondary or EOR process and the fraction of recovery factor was 25% for 20 years' production as can be observed in Fig. 4

Fig. 4 Recovery factor (FOE) for base case simulation

The oil recovery factor in Fig.5 shows the conclusion of the primary recovery stage as it can be seen that the first scenario achieved RF of 36% represented in the light green line while the second scenarios accomplished RF of 40% represented in the blue while the third scenario attained RF of 42.6% represented in the dark green. Consequently, the third scenario was selected to proceed to the next stage of the field operation (secondary recovery).

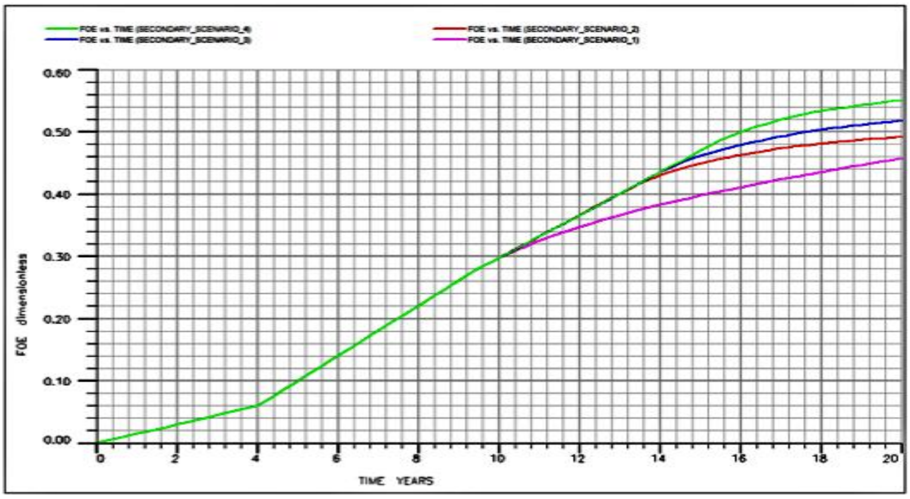

Fig. 5 Recovery factor for the four scenarios of primary recovery

Based on Fig. 6 it can be noticed that scenarios-1, scenarios-2, scenarios-3 and scenario-4 have 46%, 50%, 52%, and 56% with pink, red, blue and green colour lines respectively. However, the selected scenario-4 has the highest fraction of the recovery factor starting from year 10 till year 20 of the production life time. Therefore, water flooding scenario-4 was chosen because of the reasonable results that were obtained with fulfilling all the challenges that were faced in the previous scenarios.

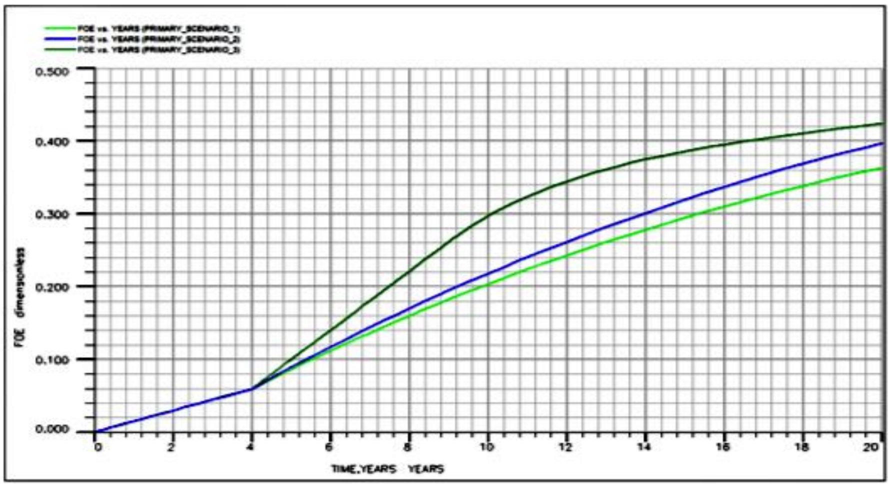

Fig. 6 Recovery factor for the four scenarios of primary recovery

Based on Fig. 7, it can be noticed that scenarios-4, and scenario-7 have 56%, and 56% with, blue and green colour lines respectively. However, the selected scenario-4 has the highest fraction of the recovery factor starting from year 10 till year 20 of the production life time. Therefore, water flooding scenario-4 was chosen because of the reasonable results that were obtained with fulfilling all the challenges that were faced in the previous scenarios. The economic feasibility is a critical parameter which can determine the actual validity of the project and the possibility of executing that project in real life. Table 3 is showing the summary of the net profit value (npv) for each scenario in the two stages of oil recovery in order to select best scenario in every process. The npv of the base case was found as $USD 1,653,481,665.15 so the developed operation's npv was calculated by economic excel sheet and compared with the base case in order to distinguish the optimum incremental in profit. The npv of secondary process scenario-4 was slightly higher than the secondary process scenario-7 with profit difference of $ 2,997,369. However, it was selected because converted wells were reducing the cost expenses comparing with scenario-7 that new drilling wells were required

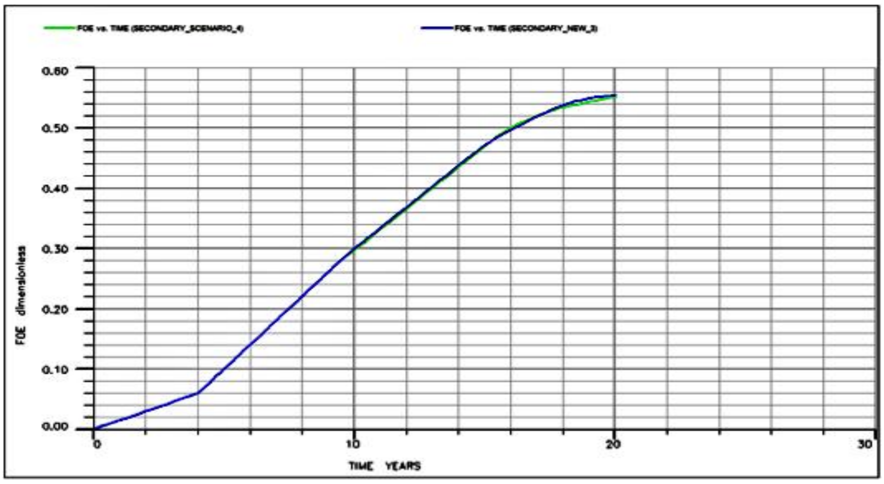

Fig . 7 Comparison of Water Flooding Rf Curves Between Scenario-4 And Scenario-7

Table. 3 NPV values for the production recovery operations

Production Stage	Net Profit Value (NPV)
Base Case	$1,653,481,665.15
Primary scenario 1	$2,562,417,181.40
Primary scenario 2	$2,834,653,492.55
Primary scenario 3	$3,145,563,081.70
Secondary scenario 1	$3,362,514,812.20
Secondary scenario 2	$3,609,747,838.20
Secondary scenario 3	$3,760,185,379.20
Secondary scenario 4	$3,978,483,681.20
Secondary scenario 5	$3,366,491,312.20
Secondary scenario 6	$3,624,933,004.20
Secondary scenario 7	$3,975,486,312.20

IV. CONCLUSION

Reservoir X was managed through two strategies of oil recoverability primary and secondary. By conducting several scenarios of each strategy that the rest of oil was recovered. Several parameters were evaluated and ran during the scenarios including production well locations, injection patterns, completion perforation control, and location of the wells to the faults and the permeability & porosity of the reservoir as well as injection flow rates of water and production flow rate of oil with ECLIPSE simulation applications. By converting four existing oil producers to water injectors the RF was improved from 25% of the base-case up to 56% in secondary recovery (water flooding) passing on the primary recovery. Also, an economic analysis supported the results of the project by getting a distinction in the net revenue value of $ 2,325,002,016 over the net income of the base case. Injecting water to the reservoir was the main reason to increase the sweep efficacy and enhance oil recovery that was attained basically.

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