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Research Article

Enhanced Oil Recovery from Carbonate Reservoir through Low Salinity Water Flooding-A Simulation Case Study

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Abstract

Low salinity water flooding is a very famous secondary as well as tertiary recovery process. Research has proven that low salinity waterflooding is an economical and environmentally friendly process and it can give a higher amount of oil recoveries than the conventional waterflooding method. This study aims to run sensitivity analysis of water injection parameters like salt concentration, pattern selection, and injection rates. Secondly to use the pressure maintenance technique instead of pressure enhancement. The result indicated that the optimum injection rate was achieved at 6000 bbl/day with a salt concentration of 0 to 5000ppm, while high saline water indicated no or little change in production. As far as flooding pattern is concerned, single injection and single production gave the optimum results. In a nutshell, low saline waterflooding is proved to be successful in carbonate reservoirs.

Keywords: *Low Salinity Waterflooding, Injection Rates, Pressure Maintenance, Low salinity, high salinity, flooding patterns.*

1. Introduction

As a matter of fact, water flooding is no doubt the most employed method of enhancing the oil recovery in the world of petroleum engineering. As for as economics is concerned this method has proven to be successful among other recovery methods.

In Secondary recovery methods, water flooding method and gas flooding methods are the most applied methods in oil industry in which separate injection wells are created to push oil to the surface. Both injection methods can also be used for pressure maintenance during primary recovery mechanism in which gas or water will be injected in their respective oil or gas zone. The difference between secondary recovery methods and pressure maintenance is that, in secondary methods the water or gas will be injected for the sake of pushing oil to the surface, while in pressure maintenance oil and gas is injected in the similar oil and gas zone respectively as discussed above.

The third and the most complicated recovery method is tertiary method in which formation characteristics and oil properties are going to be changed by injected fluid or chemicals to get oil at the surface and to get additional recoveries. Although it is important to evaluate the formation before going for any of the process because secondary and tertiary methods are very much expensive (Vladimir Vishnyakov, 2020) (Green DW, Willhite G (1998).

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Most of the world's oil reserves are found to lie in carbonate formation. Water flooding is the most common technique that is employed most for a good number of decades. However, a multiple of studies in the last decade have yielded the result that water salinity is important factor to be considered for the handsome recovery of oil (Adeel Zahid et al. 2012, Jawad et al. 2021).

The salient advantage of low salinity water flooding (LSWF) lies in enhancing the oil recovery by altering the wettability, improved injectivity, and by lowering scaling and reservoir souring in contrast to produced water re-injection. The method resembles traditional water flooding from the operational dimension and has lower capital and operating expenditures as matched to other recovery methods (Ramez A. Nasralla et al (2018).

1.1 Mechanisms in carbonate reservoirs

1.1.1 Rock Dissolution

The rock dissolution mechanism was first proposed by Hiorth in 2010, and given a concept that low amount of calcium, magnesium and sulphate (potential determining ions) will interact with rocks(mineral composition of calcium carbonate, calcium magnesium bi carbonate and calcium sulphate) and will disturb their equilibrium because of dissolution of rock minerals and will recreate their equilibrium with injected LSW water , as a result the adsorbed oil components will eventually get release and rock will be water wet. Therefore, oil recovery improved (Hiorth et al. 2010).

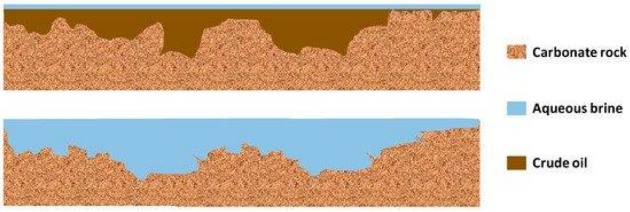

Fig.1 Wettability alteration by before and after dissolution mechanism dissolution mechanism

1.1.2 Surface Ion Exchange

It has been from researches that rocks are accumulated by some ions on its surface and at some point, of time, the rock surface are negatively charged with crude oil components. If a higher affinity to the rock surface maximized by the determining ion (e.g., sulphate), then, the anion, are absorbed and an oil is de-adsorbed. Therefore, we can say that if the low saline water can decrease more charge on surface, the recovery of oil would also be going to increase (Robin Gupta et al, 2011).

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2. Methodology

The structure is situated in the eastern part of ABC Basin. The reservoir is of Carbonate type. Mainly, the number of formations that are giving production is two. X is the assumed name for formation-1, which is Dolomite and Z is assumed name for formation-2, which is Limestone. At the early stage, drilling of a well was performed into formation-Z. Then, an oil-field namely, ABC was discovered in the year 1989. Later, up to 1996, the drilling of two wells was performed in these formations. These two wells were named as well no. 1 and well no. 2. Two types of fractures were observed from these wells drilled on the structure. The oil was produced through these fractures only. While, matrix was too tight to contribute in the flow system. The initial reservoir pressure of formation-Z was determined to be 5709 psia in case of well no. 1. However, in the year 1989, well no.2 came under smooth stream. In 1995, an inspection showed that reservoir pressure had declined from 5709 psia to 2477 psia, which is lower that the bubble point pressure of 2948 psia. As a result of this depletion below bubble point pressure, production declined from 3800 bbl/day to 2000 bbl/day. Here, a decision of drilling well no. 3 was made. The purpose of drilling this well was to perform water flooding with help of the water having low salinity. The OOIP with the help of material balance equations are found to 35MMSTB.

So, integrated reservoir simulation study was conducted to address the reservoir management problems of the field such as remaining recoverable reserves, requirement of proper pattern and specific salinity of water to yield optimum recovery of the oil from the field. The study was carried out in two parts. In the first go, reservoir engineering, petrophysics, sedimentology, geology and geophysics were encompassed. Furthermore, after reinterpretation of geophysical data a novice depth structure map was created. This map was then utilized for constructing a three-dimensional simulation model. The determination of the drive mechanism and of the reserves was made through using material balance. The collected data from the above-mentioned field was utilized to create a model with the help of a reservoir simulator.

2.1 Case Definition

The foremost requirement while making the reservoir model is defining the basic reservoir case including type of modeling strategy used and numerical simulation control. Also, the primary information of the model such as model dimensions is asked by the simulator. For reservoir model following information is required.

2.2 Rock Modeling

In rock modeling, the no. of grid cells in X-Y-Z direction to develop the required model is defined. This section is constructed by putting rock properties and some other specifications like permeability, porosity, depth of top facies, and the size of the grid block. The variation of permeability and porosity are also represented.

2.3 Fluid Modeling

Having defined the rock properties, the next process is to generate fluid model. The necessary factors required for data incorporation are formation volume factor, density, compressibility relative permeability and viscosity etc.

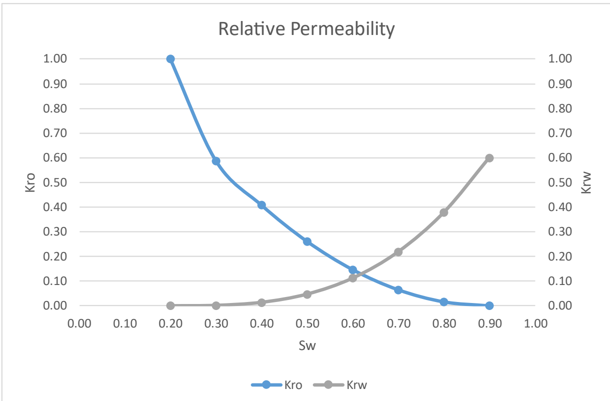

Fig.2 Kro vs Krw with respect to Sw

It has been shown from various researches that if the reservoir is oil wet, it would have high residual saturation of oil, while the relative permeability of oil is low and relative permeability of water is high, therefore, it is not good for high saline waterflooding. Similarly, on the other side if the reservoir is water wet, it will have relative permeability to oil which is high and relative permeability to water which is low, and low residual oil saturation. As this data shows water wet reservoir, therefore water wet model is applied. The idea to generate different models at different salinities is to provide best model which gives highest ultimate recovery.

2.4 Initialization

There are some of the very important parameters like initial pressure saturation condition in reservoir and fluid properties which are part of this section and must be highlighted.

3. Base Case on Natural pressure

First Figure shows recovery from a carbonate reservoir by using the natural pressure of the reservoir in which we can see that from the natural recovery just 39.8% (Compared to the OOIP i.e., 35MMSTB) of oil can be obtained but this oil production can be enhanced if we inject the water in the earlier phase of recovery. The question of saline water injection remains intact. So, this is answered by using the simulation technique.

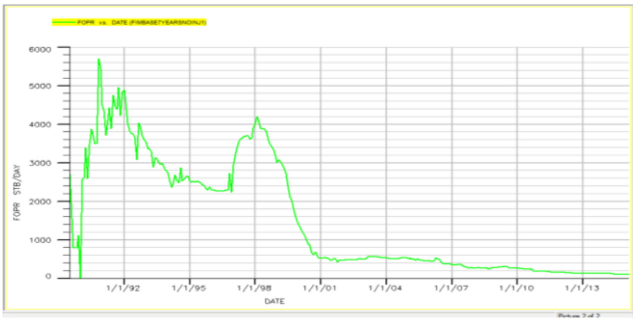

Fig. 3 Production Rate

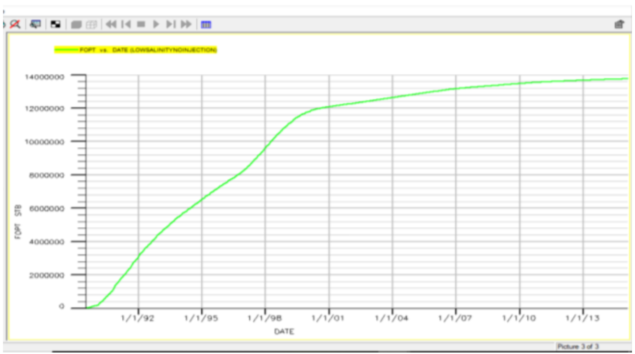

Fig. Cumulative oil recovery

Case-1: Investigating optimum recovery at different Injection rates

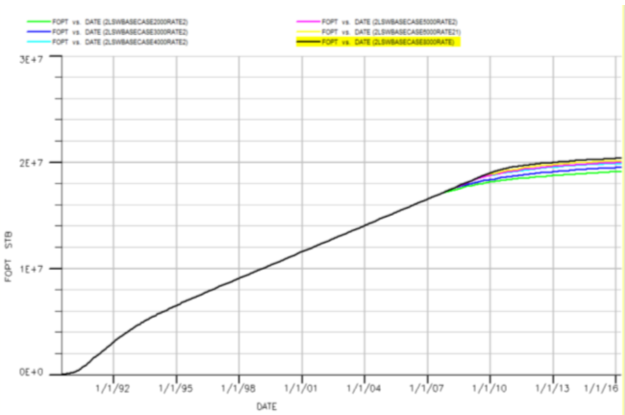

Fig. 4 Cumulative oil production at different rates

Table 1 Results related to case 1

Injection Rate (bbl/day)	Cumultive oil Recovery(MMSTB)	Recovery Factor %
2000	19.1	54
4000	19.8	56.5
6000	20.2	57.7
8000	20.3	58

Note: All injection rates are at zero salinity.

Case- 2: Decision for optimum salt concentration

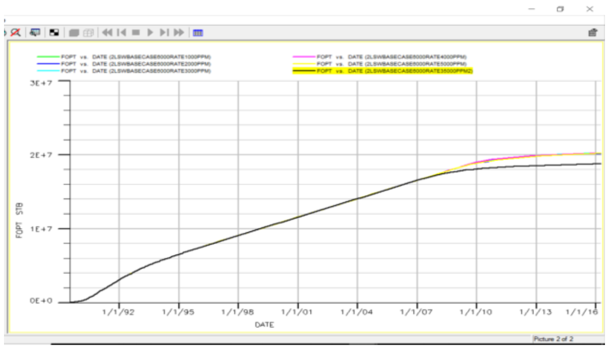

Fig. 4 Cumulative oil Recovery

Table 2 Results related to case 2

Injection Rate(bbl/day)	Salinity concentration(ppm)	Cumulation oil production (MMSTB)	Recovery factor (%)
6000	0	20.2	57.7
6000	1000	20.1	57.4
6000	2000	20.1	57.4
6000	3000	20	57.1
6000	5000	20	57.1
6000	35000	18.7	53.4

Case-3: Selection of waterflooding pattern for optimum recovery

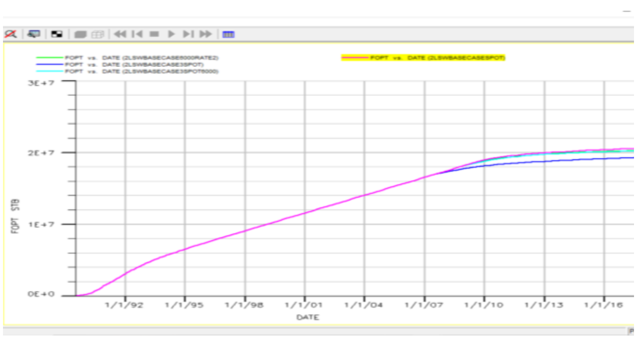

Fig. 5 Cumulative oil Recovery

Table 3 Results related to case 3

Injection Pattern	Injection Rate(bbl/day/well)	Cumulation oil recovery (MMSTB)	Recovery Factor (%)
Single injection well	6000	20.2	57.7
3 spot pattern	2000	19.25	55
5 spot pattern	2000	20.4	58.2

Note: All injection rates are at zero salinity

Conclusion

1) It has been seen from the results that waterflooding has got very positive influence on production rate, cumulative recovery and recovery factor.
2) Case-1 conclude that there is not much progress in recovery factor and cumulative recovery after increasing rate more than 6000 bbls/day (at zero salinity) i.e., 57.7% and 20.2 MMSTB respectively. Therefore, 6000bbl/day chosen to be the best injection rate.
3) Case-2 conclude that as salinity increases the oil production decreases earlier than low salinity cases. Although, recovery factor and cumulative oil recovery is higher in low salinity concentration.
4) Case-3 suggest that by changing patterns and production rates, the cumulative recovery and recovery factor will also be going to change. So, by looking at their results it is concluded that there is insignificant difference between single injection and 5 spot pattern, though the recovery is high in 5 spot pattern but keeping in view the economics, single injection well is the best possible way to increase oil recovery in much economical way.
5) In last, it is also concluded from this research that the waterflooding in the middle or early phase of recovery can be beneficial.

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