MINISTRY OF EDUCATION AND SCIENCE OF THE REPUBLIC OF KAZAKHSTAN

СӘТБАЕВ УНИВЕРСИТЕТІ
SATBAYEV UNIVERSITY

School of geology, petroleum and mining engineering Department of Petroleum Engineering

DIPLOMA PROJECT

Modeling Wettability Alteration using Chemical Enhanced Oil Recovery Methods

5B070800 – Oil and Gas Business

Almaty 2021

MINISTRY OF EDUCATION AND SCIENCE OF THE REPUBLIC OF KAZAKHSTAN

School of geology, petroleum and mining engineering Department of Petroleum Engineering

APPROVED FOR DEFENSE
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Engineering Department ,

Dairov Zh. K. , MSc

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Modeling Wettability Alteration using Chemical Enhanced Oil Recovery Methods

5B070800 – Oil and Gas Business

Performed by: Bekzhan Ye.

Scientific adviser

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Almaty 2021

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Автор
Бежан Еділ

Научный руководитель
Жанар Байбусинова

Подразделение
ИГНиГД

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СӘТБАЕВ УНИВЕРСИТЕТІ SATBAYEV UNIVERSITY

School of geology, petroleum and mining engineering

Department of Petroleum Engineering

CONFIRM

Head of the Petroleum
Engineering Department,

Dairov Zh. K. , MSc

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TASK

For completing the diploma project

For students: Bekzhan Ye.

Topic: "Modeling Wettability Alteration using Chemical Enhanced Oil Recovery Methods" Approved *by the order of university rector №762 -b from "18 "may 2021*

Deadline for completion the work *" 18 " May 2021*

Initial data for the diploma project: Laboratory data of experiment

Summary of the diploma project:

a) *Presenting visual image of compositional simulations.*
b) *Comparison of the experiment data with the data obtained from the simulator.*

List of graphic material: presented 15 slides of presentation of the diploma project.

Recommended main literature:

1. *Technical Description, Version 2011-7, KMGEsim*
2. *Reference Guide, Version 2011-7, KMGEsim*

THE SCHEDULE

For the diploma work preparation

Name of sections, list of issues being developed	Submission deadlines to the scientific adviser	Notes
Theoretical part	1.03.2020	Task completed
Technological-modeling part	16.03.2020	Task completed
Calculations part	10.04.2020	Task completed
Simulation part	30.04.2020	Task completed

Signatures

Of consultants and standard controller for the completed diploma work, indicating the relevant sections of the work (project).

The section titles	Consultant name (academic degree, title)	Date	Signature
Theoretical part	MSc, Baibussinova Zh. B.	1.03.2020	
Technological-modeling part	MSc, Baibussinova Zh. B.	16.03.2020	
Calculations part	MSc, Baibussinova Zh. B.	10.04.2020	
Simulation part	MSc, Baibussinova Zh. B.	30.04.2020	
Normcontrol	MSc, Baibussinova Zh. B.	15.05.2020	

Scientific adviser ______________ Baibussinova Zh.

Signature

The task was accepted by students: ____ ___ Bekzhan Ye.A

Signature

Date “18”May 2021

АҢДАТПА

Бұл дипломдық жұмыста мұнай бергіштікті арттыру үшін әртүрлі химиялық әдістерді пайдалану тиімділігі сипатталады.Бұл жұмыста жұққыштықты неғұрлым су-жұққыш жағдайына қарай түрлендіруді қамтитын табиғи жарықшақты коллекторлар үшін жаңа химиялық әдістердің аспектілерін модельдеуге арналған.

Көбінесе ылғалды мұнай карбонаттарының жұққыштығы сілті және/немесе беткі белсенді заттардың ерітінділерін пайдалана отырып, су-жұққыш жағдайларына дейін өзгертілуі мүмкін. Бұл жарықшақтардан матрицаға судың өздігінен сорылу жылдамдығын арттыру есебінен мұнай өндіруге көмектеседі. Суландыруды өзгерту моделі KMGEsim химиялық су басу симуляторында әзірленді және іске асырылды. Содан кейін зертханалық эксперименттер мен модельдеу нәтижелерін үйлестіру осы процеске қатысатын механизмдерді және олардың салыстырмалы маңыздылығын түсіну үшін пайдаланылады.

АННОТАЦИЯ

В этой дипломной работе описывается эффективность использования различных химических методов для повышения нефтеотдачи.В этой работы посвящена моделированию аспектов новых химических методов ЭОР для естественных трещиноватых коллекторов, включающих модификацию смачиваемости в сторону более влажных условий воды.

Смачиваемость преимущественно влажных карбонатов масла может быть изменена до более влажных условий воды с использованием растворов щелочей и/или поверхностно-активных веществ. Это помогает добыче нефти за счет увеличения скорости самопроизвольного всасывания воды из трещин в матрицу. Модель изменения смачиваемости разработана и реализована в симуляторе химического затопления KMGEsim. Затем сочетание результатов лабораторных экспериментов и моделирования используется для понимания механизмов, участвующих в этом процессе, и их относительной важности.

ANNOTATION

This thesis describes the effectiveness of using various chemical methods to improve oil recovery.This paper is devoted to modeling aspects of new chemical methods of EOR for fractured reservoirs, including modification of wettability towards water-wet conditions.

The wettability of predominantly wet oil carbonates can be changed to water-wet conditions using solutions of alkalis and / or surfactants. This helps oil production by increasing the rate of spontaneous suction of water from the cracks into the matrix. The wettability change model is developed and implemented in the KMGEsim chemical flooding simulator. A combination of laboratory experiments and simulations is then used to understand the mechanisms involved and their relative importance.

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Introduction

The closer oil resources are to depletion, the more difficult it is worldwide to find the first easy targets for oil production. Secondly, the demand for energy and crude oil is growing rapidly. These formations require more efficient extraction of existing oil resources by conducting intelligent methods of the second and third oil supply. Chemical flooding processes help to increase recovery rates of existing oil reservoirs and overcome existing energy crises. Examples of classic flooding chemical processes include polymer flooding, surfactants/polymer flooding, and alkaline/surfactants/polymer flooding. The above methods have been well studied for simple (single-depth) sand collectors.

The change in chemical induced water content over the past few years has been investigated by many researchers as one of the new methods of chemical flooding. This method will increase oil production from natural faults (NFR), consisting mainly of carbonates. Most carbonate collectors are mostly wet with oil. This significantly reduces the oil supply of such a layer of the second and third level, since the matrix does not absorb the dump phase. Thus, the pumped aqueous phase is formed mainly through a network of cracks without improving the recovery of vaginal carbonates from oil. Changing watering under the most water-wet conditions can significantly increase the efficiency of producing such layers by improving the spontaneous absorption of the aqueous phase into the matrix and displacing the olein phase into cracks. The mechanisms involved in this process must be fully understood before they are applied to the field. One of the goals of this work is to study these mechanisms and simulate the process of moisture change based on laboratory measurements. Then, on the basis of laboratory experiments, the large-scale dependence of oil production should be investigated by such methods in order to conclude the time required for oil production on a commercial scale.

1.Wettability Alteration in Fractured Reservoirs

The effect of humidification on enhanced oil recovery mechanisms in layers with natural debris differs from the effects of traditional oil layers. Water-wet conditions are considered favorable for oil production in a natural fault (Hatiboglu and Babadagli, 2004; Babadagli, 2003), since oil production from broken layers mainly depends on spontaneous absorption of water and the transition from the matrix to the oil fault line. (Chen and others, 2000). Thus, in the presence of a natural broken layer, the tendency to absorb water by the matrix (containing all oil reserves) is very important both for the final production of oil and for the recovery rate. Thomas (1987) concludes that for low conductivity, broken hydrophobic boron, significant improvements can be obtained by pumping water through oil pumping. This is no different from the control of Wang (1986), since he stops oil production due to the fact that heavily watered nuclei diverge. Austad (1997) investigated the spontaneous absorption of water into boron with low conductivity at different humidification abilities using surfactants. He investigated the effect of interfacial tension, the amount and watering of the core on the production of oil from surfactants and without them nuclei. He noted the good productivity of water recovery with saline, especially for short cores. He also found that with the help of cationic surfactant, water can be absorbed into boron moistened with oil. To describe this process, he proposed that the surfactant moistens boron during irrigation. Many scientists believe that when the state of irrigation of the matrix changes to a multilayer state of water, the final extraction of oil from naturally measurable layers increases. So, recently, NFR tried to change humidity to water-water conditions. There are two main methods of changing moisture. One is an increase in temperature or thermal procedures, the other is the use of surface active agents or surfactants. The second way of changing humidification, that is, superficial active injection, is the main area of work.

Al-Hadherami and Blunt (2000) investigated the thermal changes in humidity and, by raising the temperature, were able to change the state of wetting of carbonate depending on the humidity of water, which led to the absorption of water and an increase in fat. They concluded that the desorption of asphalts from the surface of rocks is responsible for changing moisture. Due to the increase in temperature (1991), during the main floods, there was an increase in oil production from wet oil nuclei. He concluded that this humidity would depend on a change in the situation. There are other examples of variation in thermal-induced humidity in the literature, but this is beyond the scope of this work.

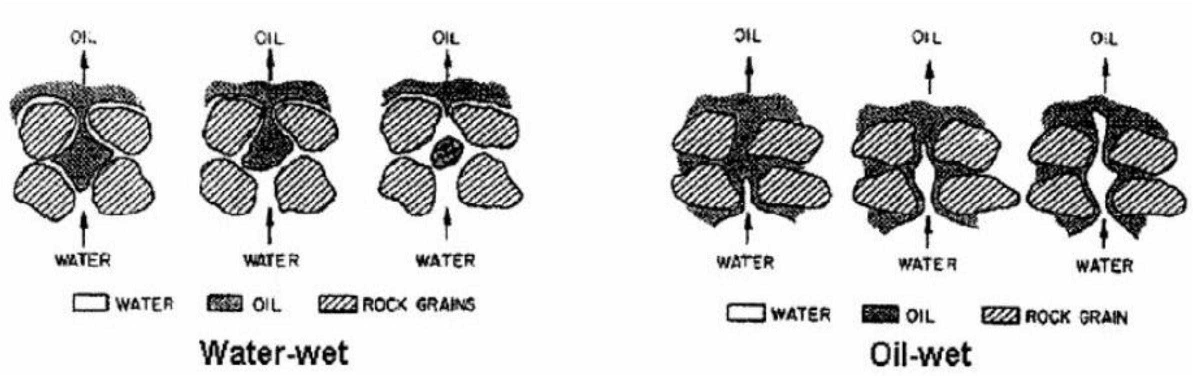


Figure 1. Water-wet and oil-wet

1.1 Impact of Wettability on Residual Oil Saturation

The humidification phase is more susceptible to contact with the rock surface, which results in the expansion of the thin film phase in small skin holes and on the surface of large skin holes. This is no more mobile wetting phase, less mobile to the separation and/or wetting phase, with large and effective, higher capillary forces (Hirasaki et al., 2004).

1.2 Impact of Wettability on Relative Permeability

Spreading the vaginal phase to small openings, as mentioned above, makes it difficult for this phase to proceed, which means a decrease in the relative conductivity of the irrigation phase when saturated with a uniform phase (Anderson, 1987). Therefore, in general, it can be concluded that the wetting of the phase and its relative conductivity are inversely proportional, if the watering of the phase increases, then its relative conductivity decreases.Craig (1971) gives some positions relative to relative conductivity curves for various irrigation cases. He states that usually the primary water supply of systems saturated with water exceeds 21-26%, and for oil systems - less than 16%. Craig (1971) also gives a rule regarding the point of intersection of the relative conductivity of water and oil. According to him, the intersection point occurs when less than 50% of water is saturated in wet water systems and 50% for wet oil systems. This can be described by the endpoints of the relative conductivity of the two phases under different reflux conditions. In a very wet system, the high relative conductivity of the oil endpoint (usually about 1), but the low endpoint of the relative conductivity of the water (from 0.14 to 0.32), which leads to an intersection point when saturated with water of more than 50%. The wet endpoint of the relative conductivity of water in the oil system is usually large (0.41-0.71), and the relative conductivity of oil is less than one, which leads to an intersection point when saturated with water of more than 50% (et al. Hirasaki, 2004).

1.3 Impact of Wettability on Capillary pressure

Capillary pressure is defined as the pressure difference between the humidifying and the unrefined phases. Lake (1989) says that capillary pressure is associated with high curvature of boundaries between different homogeneous phases. The Young-Laplace equation is used to bind capillary pressure to the bond angle, sponge curvature, and interface tension. To prevent the vaginal phase from entering the opening, its pressure must exceed the inlet pressure of the capillary, which is a function of the diameter of the skin sponge. The smaller the diameter of the sponge, the higher the capillary inlet pressure. Since in wet oil tanks oil is divided into small lips and capillary inlet pressure on these lips is large, most of the oil enters water flows. One method of overcoming capillary forces is to reduce the phase voltage between two phases. This can be done through surfactants or surfactants.

Capillary pressure is generally defined as oil pressure when the water pressure in the reservoir is relieved and is formed due to saturation of the water. Based on the condition of seed irrigation, such plots may have positive and negative values, such as those indicated by Craig (1971). Based on this definition of capillary pressure, if the rock is strongly wetted with water, that is, i ~ 1, then its spontaneous absorption curve will be only positive, and at zero capillary pressure, oil saturation is achieved. If the rock has intermediate or neutral moisture, then it is prone to spontaneous absorption of water, and the saturation of the oil of this floor is higher compared to very wet water at the end of spontaneous absorption. In this case, it is possible to increase the saturation of the water by forced imbibing resulting in a capillary pressure curve with positive and negative zones. If the rock is fatty, there is no water absorption process resulting in negative capillary pressure.

2. EOR methods

Willhite (1986) defines an increase in oil production as any process that will help to extract more of its energy from the reservoir. This is a very general definition and includes gas injection to maintain pressure and flooding. Lake (1989) defines EOR as the process of producing oil from a tank by pumping materials not present in the tank. This definition accurately and refutes the above processes. Based on the second definition of EOR processes, three categories can be distinguished: thermal oil production, mixed flooding and chemical flooding. The latter is the subject of this study. Several chemical flood processes are identified and discussed below.

2.1 Flooding of polymer

Polymer flooding is the simplest chemical process . The main goal of polymer floods is to increase the efficiency of floods by reducing the mobility of water (Sorbi, 1991). This is done by introducing water-soluble polymers that increase the viscosity of water and reduce the mobility of water. Reduced water mobility helps prevent viscous instability in the nose of the polymer/oil ant. The higher the viscosity of the water, the lower the fractional flow rate and the more efficient the displacement. The effect of reducing polymer permeability reduces the effective conductivity of high permeability channels and improves the zoning efficiency of sweeping. Recent studies have shown that the introduced polymer weight increase improves the control of mobility and throwing efficiency, which leads to great profitability (Anderson soavt., 2006). For field use, two types of polymers were used: polysaccharides and partially hydrolyzed polyacrylamides. Recent advances in polymer technology have significantly increased the limits of polymer flooding. Levitte and Poup (Levitt and Pope, 2008) offered polymers with high viscosity at high salinity (to 160000 ppm NaCl, more than 16000 ppm CaCl2-den). It has also been shown that if the calcium concentration is below 190 ppm, polyacrylamide polymers can be used up to 110 C. Levitt and Pope (2008) also suggest that copolymers such as sodium metabolate or methyl sulfate 2-acrylamide-2 methyl propane can be used to increase resistance to calcium at high temperatures. Huh and Pope (2008) showed that in the case of using polymer flood as a repeated mechanism for restoring polymer floods, residual oil is able to reduce saturation to values below saturation of oil before flooding, i.e.

2.2 Flooding of alkaline

In this chemical process, the EOR alkaline agent is incorporated into the reservoir. Previously, the classical cause of alkaline injections was the creation of in-situ soaps (surfactant) from acidic components of crude oil, which then helps to reduce the phase stress between oil and water and mobilize strained oil. When the alkaline substance is introduced into the tank, the hydroxide anions reduce the concentration of hydrogen in the aqueous phase. This contributes to the insolubility of some components of the acid oil in the aqueous phase and the formation of soaps in-situ.

In addition to the above-mentioned application of alkaline irrigation, researchers recently drew attention to the effect of changing the beauty of some alkalis. Most of the world's oil reserves are found in carbonate layers (Roehl and Choquette, 1985), most of which are naturally destroyed. The crack network has a higher conductivity than the matrix. Most of these carbonate collectors are mixed wet and mainly petroleum (Downs and Hoover, 1989). The combination of low matrix conductivity and oil-rich predominantly carbonate layers results in low primary oil recovery ratios of the layers in such reservoirs. Irrigation of these layers is ineffective due to the extremely low tendency to absorb an aqueous solution with an oil-fuel matrix. To increase oil recovery of such formations, an increase in the rate of absorption of the injected aqueous phase into the matrix is required. One of the ways to achieve this goal is to change the beauty of matrix rocks depending on water-wet conditions. Recently, many researchers have investigated the rate of absorption by aqueous solutions of mainly petroleum carbonate rocks. Hirasaki and Zhang (2004) and Adibhatla and Mohanty (2008) investigated oil production from such layers with anion surfactants (propoxylethoxyl sulphates) and alkali (sodium carbonate). They concluded that with very low ELISA available through anionic surfactants, oil can be reduced due to a change in buoyancy and beauty. Zhang et al. (2008) showed a sharp decrease in the contact angle of an oil drop with quartz (SiO2) and calcite (CaCO3), like sodium carbonate. Angle of initial bond 125 ° on quartz surface is reduced to 104 ° after 4.7% hours of aging in solution Na2CO3 24. The influence of alkali on moisture change was even greater on the calcite surface, where the initial bond angle of 110 ° after 24 hour decreased to 74 °. Such a significant change in the irrigation characteristics of carbonate surfaces can lead to an increase in the absorption rate of pumped aqueous solutions into the floor of the broken carbonate matrix and a significant increase in the extraction coefficient. A detailed determination of the humidification and bonding angle is provided in this chapter earlier.

2.3 Surfactants used to improve oil recovery

Surface-active substances or surfactants are generally large molecules having at least one hydrophilic and at least one hydrophobic moiety. This dual nature allows surfactants to be at the boundary of water and other liquids (e.g. oil) and reduce surface energy.

At a low concentration, anionic surfactants, as described below, are ionized into cation and anionic monomer when melting in the aqueous phase (Axtinate, 1981). As the surfactant concentration increases, the lipophilic parts of the monomers combine to form micelles, which may contain several monomers. A further increase in the surfactant concentration after a certain concentration called critical micelle concentration increases the micelle concentration.

2.3.1 Types of surfactants

- Cation: a positive charged polar part leads to a cationic surface active substance. The molecules of these surfactants are electrically neutralized by the inorganic anion. This group of surfactants has not been widely used in chemical processes, since they are easily adsorbed with negatively charged interstitial clay surfaces.
- Anionics: The molecule is electrically neutralized by an inorganic metal cation. When dissolved in the aqueous phase, the molecule ionizes to the cation and

monomer of the anion. This group of surfactants is widely used in the petroleum industry, has good endurance, stability and low cost.

- Nonionics: these molecules reflect the properties of surfactants associated with electrical contradictions between their constituent parts. Nonionic surface active substances work worse than anionic surfactants, but much better under conditions of high salinity. This group of surfactants has been widely used as primary surfactants during chemical floods.
- Amphoterics: these surfactants reflect the properties of two or more groups of previously discussed surfactants and are not used in chemical floods.

2.3.2 The action of the surfactant/brine/oil phase

Typically, the action of the surfactant/oil/salt phase is reflected in a three-dimensional diagram, and typically the pseudoactive surfactant component is placed on the upper apex, on the straight lower left apex, and the lower right apex on the oil. Surfactants used in chemical flooding processes generally show good solubility in the aqueous phase and poor solubility in the oil phase at low salinity. Thus, with low salt salinity, the total composition in the two-phase zone is divided into two phases: the excess oil phase and the phase of the external aqueous microemulsion. The excess oil phase is pure oil, and the microemulsion phase consists of salt, surfactant, and a certain amount of salt oil located in the center of the micelle. This phase medium is called a type first Winsor system, a low-phase microemulsion, or a type second system. The last terminology is that the system consists of two phases and has a negative slope of communication networks in a two-phase zone.

The solubility of surfactants in the aqueous phase with high salt salinity is dramatically reduced by electrostatic forces. Thus, the total composition in the two-phase zone with high salt salinity is divided into an external microemulsion phase of oil and an excess salt phase. In this case, the salt phase is substantially free of surfactant and a portion of the salt phase is dissolved in the microemulsion phase at the center of the micelle. This system is called the Winsor Type second system, the upper microemulsion, or the Type second (+) system.

In salt salinity, there is a third type of phase effect between the two boundaries provided above, in which three phases (salt phase, microemulsion phase and oil phase) coexist together. The microemulsion phase may contain water or oil depending on salinity and total composition. This Winsor Type third system, mid-phase microemulsion

2.3.3 Polymer / Surfactant Flooding

This is a chemical EOR method, perhaps the most investigated and applied process after polymer flooding. Surfactants or surfactant groups and other chemicals, such as co-solvents, are adapted and adapted to the mining system of the target reservoir. The chemicals are introduced into the reservoir in the form of the last slurry, which contains a polymer to control mobility. These chemical ingots then run into polymer driven wells. The surfactant helps to obtain oil in two important ways: salt oil and mobilize oil. The first is the result of the formation of a microemulsion phase. Microemulsions are thermodynamically stable phases containing surfactants, aqueous electrolytes and olein components. Oil mobilization is the result of a decrease of the surfactant . The mobilization process is discussed in the following sections.

An important advantage of the surfactant/polymer process from polymer flooding is the production of residual oil. Polymer flooding can have a low level of oil saturation compared to the flood (Huh and Pope, 2008), which cannot reduce the saturation of residual oil to values close to zero. On the other hand, surfactants/polymers are able to reduce residual oil to low values (Osterioh and Jante, 1992; Wang et al., 2008). In fact, many laboratory tests report a reduction close to 100% OOIP (Delshad, 1990; Zhao et al., 2008; Flaaten et al., 2008). Other important steps are needed to successfully flood surfactants/polymers on site, along with selecting chemicals that match the actual properties of the target reservoir. The most important of these steps is the design and optimization of field-scale floods. It is then that digital modeling plays a decisive role in the design and optimization of chemical floods.

2.3.4 Alkaline/Surfactant Flooding

As mentioned above, the resources assigned to carbonates with a natural fracture are very large and can have a great impact on energy security if they are released from the lock. Hirasaki and Zhang (2004) and Adibhatla and Mohanty (2008) used anionic surfactants to achieve very low IFT. Since the surface of carbonate rocks is generally positively charged at low pH, they have used alkalis such as sodium carbonate to reduce the adsorption of surfactant anions on the surface of the carbonate. This is possible since the carbonate surface has a negative charge in the presence of sodium carbonate. Hirasaki and Zhang (2004) suggest that trapped oil in carbonate rocks will be stored in a capillary and irrigation state. If the capillary forces are reduced by ultraviolet and the watering is changed to wet aqueous conditions, the resulting oil can be obtained. They show that in the absence of capillary forces by conventional experiments on the testing of imbibition cells and with a change in humidity, fat moistened with oil can be obtained under the influence of gravitational drainage. Hazard and others (2005) suggested that the watering of carbonate surfaces is controlled by asphalt adsorption. They found that anionic surface active substances remove adsorbed asphalts and lead to partial humidification of water. Adibhatla and Mohanty (2008) also investigated the production of oil from carbonate rocks using anion surfactants and alkaline solutions. They concluded that the surfactant reduces IFT and changes the flexibility of diffusion to the matrix, gravity allows the oil to flow up. They state that as the conductivity of the matrix increases, the height of or the distance between the cracks decreases, and the varying water-cutting properties of the surfactant increase, the oil production rate increases. They also found that with an increase in the concentration of surfactant, oil yield does not necessarily increase, and this is due to the fact that neither the decrease in IFT nor the change in moisture have a linear relationship with the concentration of surfactant. Adibhatla and Mohanty (2008) called this oil production mechanism "gravitational drainage through surfactants."

Some researchers have proposed the use of nonionic and cationic surfactants to alter watering and increase the rate of water uptake in nfrs (Ostad and Milter, 1997; Ostad et al., 1998; Standes and Austad, 2000). They conducted their studies on the cores of oily moist boron and used nonionic and cationic surfactants to prevent adsorption of surfactants to the positive charged surface of boron. Since cationic surface actives do not reduce ELISA to very low values, capillary immibation of the aqueous phase is still a priority reduction mechanism. Chen et al. (2000) also used neon surfactants to enhance spontaneous imbibition and Backs and others. To improve the natural impact of the boron samples, 45 types of available surfactants were evaluated. Austad et al. (2007) proposed pumping seawater into Cretaceous formations as an improved method of oil production and proposed a chemical model of the changing effect of seawater on Bohr surface irrigation. They noticed that neutral/moderately wet water, the boron surface is wet when in contact with sea water. Note: Positive charged boron surface is fatty as a result of adsorption of negatively charged carboxylic acids in crude oil. Free, divalent cations contained in seawater (Ca2 +, active at low temperatures and Mg2 +, active at high temperatures) attract carboxylic acids and separate them from the surface of boron. This leads to the formation of a water-wet surface, which contributes to the spontaneous absorption of the aqueous phase, increases oil production. This recovery method is not investigated in this work.

3. EOR Methods for fractured reservoirs

Most of these ESM processes are tested on a laboratory scale prior to transition to pilot or commercial operations. It is very important to determine the effectiveness of these processes on a field scale. In other words, will recovery efficiency change from laboratory to field scale? How are the various recovery mechanisms scaled depending on the volume of the tank? Two methods are presented here to derive the effectiveness of some field reduction mechanisms from their effectiveness in laboratory conditions. The first method is based on a dimensionless study of the system. The second method is based on quantitative modeling, in which the results of a laboratory experiment are compared with the corresponding digital model. You can then use the appropriate parameters to investigate the effect of the tank quantity on the various extraction mechanisms.

3.1 Non-dimensional analysis of laboratory experiments

The dependence of laboratory experiments on the size of the layer can be determined using dimensionless recovery curves or immeasurable recovery times. Laboratory alkaline and surface-active floods showed great potential in increasing oil recovery of naturally destroyed formations with low conductivity of mixed-wet matrix rocks. Broken, mixed moist layers tend to have poor irrigation characteristics, since the pumped water flows into the cracks, and spontaneous absorption of the matrix is usually insignificant. Surface active substances or alkalis are successfully used to increase oil production by changing wetting and increasing water absorption into the matrix floor. Oil recovery mechanisms using mixtures of surfactants and alkalis increase sensitivity and mobility due to decrease of interface voltage, decrease of mobility coefficient and change of humidity. An important question is how do these recovery mechanisms correspond to the volume of the tank?

4. Modeling Wettability Alteration in a Fractured Block

This experiment was conducted in the Department of oil and Geosystems engineering at the University of Texas. The experiment was conducted by Dr. K. P. Nguyen and his researcher J.Zhang .

After the experiment, the corresponding parameters are used to study the impact of various structural and reservoir parameters on oil production. The next chapter presents the results of a large-scale study using the conditions of this experiment.

4.1 Description of the experiment

This experiment is designed to help you understand at the highest level the mechanisms that naturally occur in the flow of liquids, such as alkalis and surfactants, in broken formations. Experience helps us raise our knowledge of capillaries ,the relative importance of viscous and lifting forces. A surfactant solution was used to reduce interval tension and enhance oil extraction by emulsifying the oil, and an alkaline agent was used as a hydration modifier (Fathi et al., 2008).

In this study, matrix rock became a limestone of Texas cream. Crude oil was McElroy oil and alkaline sodium was a metabolate. Viscosity and density of oil at temperature 29 ° C are 9.9 Pa· s and 844.7 kg/m3, respectively. The fractured composite block has a length of 9 inches(23,36 ft), a width of 3 inches(7,82 ft), and a height of 1(2,54 ft) inch and extends horizontally as shown.

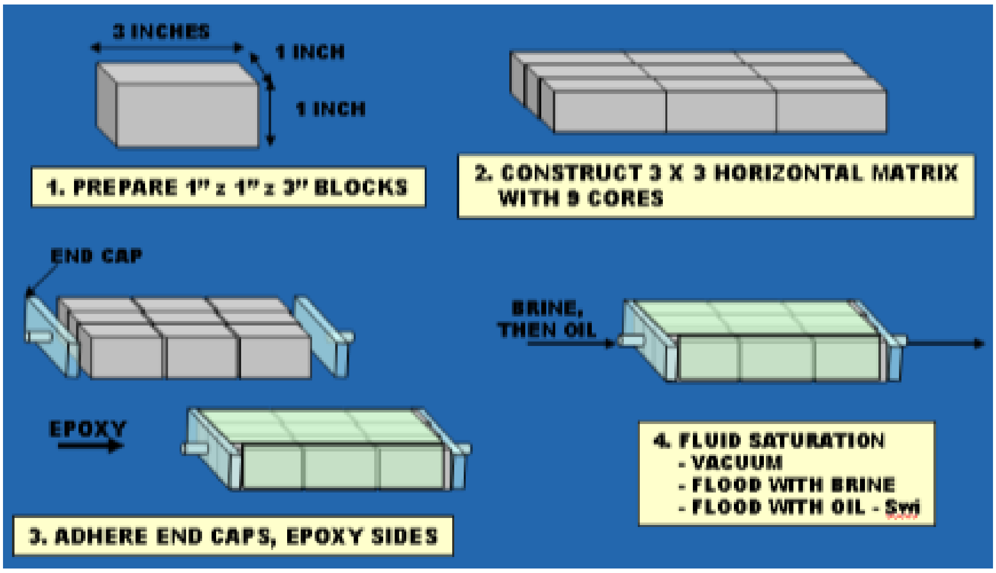
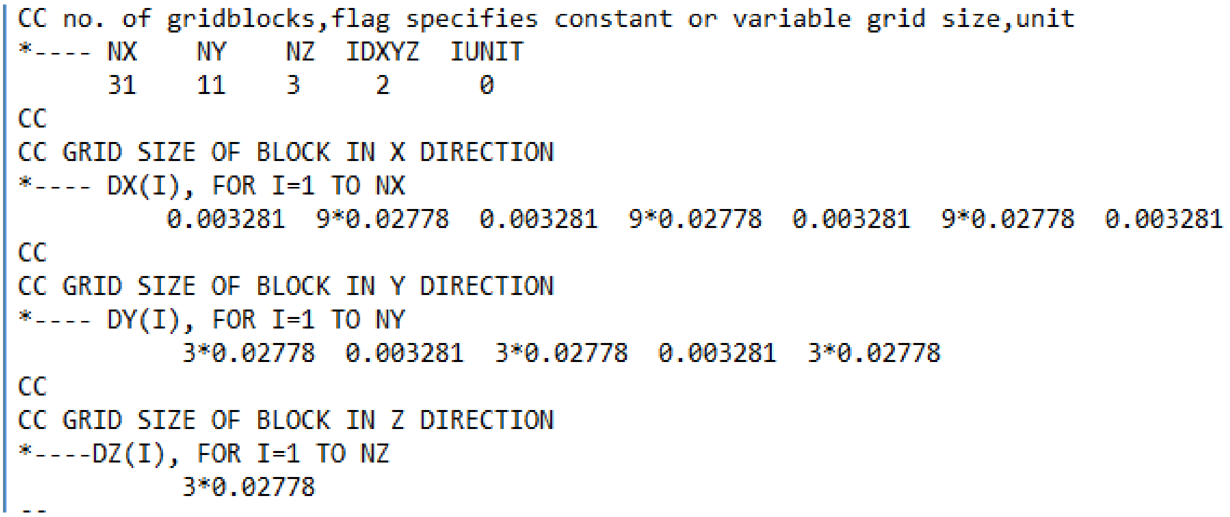


Figure 2. Diagram of preparation and final setting of broken unit for setting

The fracture was non-measurable and irregular and significantly less than 1 mm. Two extreme covers are designed for uniform transfer of injection fluid to the entire surface of the unit. During the experiment, the entire cover is coated with epoxy to ensure permanent placement of the rods and constant opening of the crack. Then the core was saturated with crude oil. The outlet of the first unit was closed, air was removed from the unit for 3 hours. Reduced pressure is obtained below -12 psi. To prepare the landing stage, the plant retained a reduced pressure even after the evacuation was stopped. This showed that there were no leaks at the system . The crude oil and water were then pumped in a stable volume containing 94% oil and 6% water. The discharge flow rate of the unit was closed until the pressure inside the unit exceeded atmospheric pressure, as indicated on the pressure gauge. Then, the injection continued for 7 days through an open opening, oil and water were obtained. The volume production coefficient differed from the transition distillation coefficient (about 3 days), after which the system entered a stable state and the pumping and production coefficient was the same. The experimental installation was replaced every half hour to avoid gravitational segregation. The porosity of the rocks was 119 ml, which was determined by measuring the change in its mass before and after oil saturation. Material balance methods are more accurate than volume calculations. There is relatively large uncertainty in the size of sponges calculated by volumetric methods, depending on the holes of various fragments and the irregularity of the matrix. Using a 0.3 matrix sponge and a gap hole of 1 mm, the plant porosity of 133 ml can be calculated, which is close to the value obtained by the material balance method. The porosity of the matrix porosity may not be equal to 0.3, and the fracture may be different and at some points less than 1 mm. Therefore, the size of the sponge obtained using the material balance is reliable and used in simulations. The block of the department noted that the process with the antiquity of crude oil 40ºC for 3 weeks. It was cooled to room temperature prior to the first stage of liquid injection.

A three-dimensional discrete fracture model of 6 fragments was applied (Figure 5). four cracks are perpendicular to the flow direction. The last covers were modeled as debris and distillation, and production wells were placed on these slots to simulate situations such as in practice. The size of each matrix array was 0.02778 feet. The aperture of the fragment was 1 mm (0.003281 feet). In this simulation, the finite difference method is applied in the third order (Liu and others, 1994), which reduces quantitative variance and eliminates instability due to a sharp change in grid size. The sensitivity of the results to the size of the matrix block is presented later. Scrap cell blocks 0 for matrix blocks have 1 porosity compared to 298 (based on the equilibrium of laboratory materials). The conductivity of the debris was used as an appropriate parameter, since the aperture of the fracture was not accurately measured and was different during the installation. In Figure 5, applied on the basis of laboratory measurements 34 of the conductivity of a homogeneous and isotropic matrix, one can see the 3D of conductivity distributions in the main modeling model. The initial saturation, based on the measured values, was uniform.



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CC no. of gridblocks,flag specifies constant or variable grid size,unit
*---- NX    NY    NZ  IDXYZ  IUNIT
      31    11    3     2      0
CC
CC GRID SIZE OF BLOCK IN X DIRECTION
*---- DX(I), FOR I=1 TO NX
          0.003281  9*0.02778  0.003281  9*0.02778  0.003281  9*0.02778  0.003281
CC
CC GRID SIZE OF BLOCK IN Y DIRECTION
*---- DY(I), FOR I=1 TO NY
           3*0.02778  0.003281  3*0.02778  0.003281  3*0.02778
CC
CC GRID SIZE OF BLOCK IN Z DIRECTION
*----DZ(I), FOR I=1 TO NZ
           3*0.02778
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Figure 3. Input data in the KMGEsim simulator

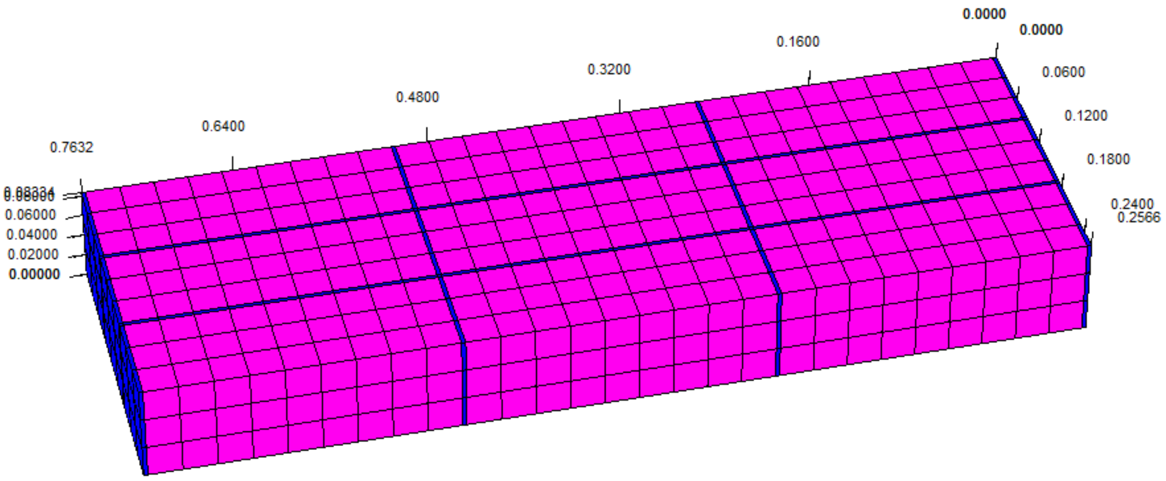

Figure 4. 3D KMGEsim model

4.2 Waterflood Part of the Experiment

The capillary forces are greater in the water part of the experiment, and the relative permeability and capillary pressure must be correctly evaluated,as this is important for modeling the part. According to measurements from the laboratory, the first wetting of the Rock was mixed-wet. This is important information, as it is necessary to select the initial curves of relative conductivity and capillary pressure.It is expected that the refractive relative permeability curves are higher and more linear than the Matrix curves. It is assumed that the residual saturation in the matrix is higher than in the scrap. Since the flood water experiment is controlled by capillary forces, a reasonable estimate of the end point of the initial capillary pressure is necessary. The capillary pressure of the fracture was zero. To obtain an initial estimate of the capillary pressure of the matrix, The Cosenium correlation (Eg. 1.1) was used and capillary pressure of cylindrical tube (Eg. 1.2) was used.

$$\square = \sqrt{\left(\frac{8 * \square}{\emptyset}\right)} \qquad \text{Eg. 1.1}$$

$$P_c = \frac{2\delta\cos(\theta)}{R} \qquad \text{Eg. 1.2}$$

where k is the permeability,

φ - porosity, R - average pore throat radius. Eq.1.1 gives an average pore throat radius of 0.94 μm for matrix blocks. With help oil / water capillary pressure of 30 psi is obtained by equation 1.2 using ift 85 mn / m (based on laboratory measurements using the ring method) and the contact angle of 0.58°. This is only the first assumption about the final value of the capillary pressure curve. The capillary pressure curve is one of the most important and unknown parameters, and the last curve obtained from the coincidence of history is shown in the figure 6.

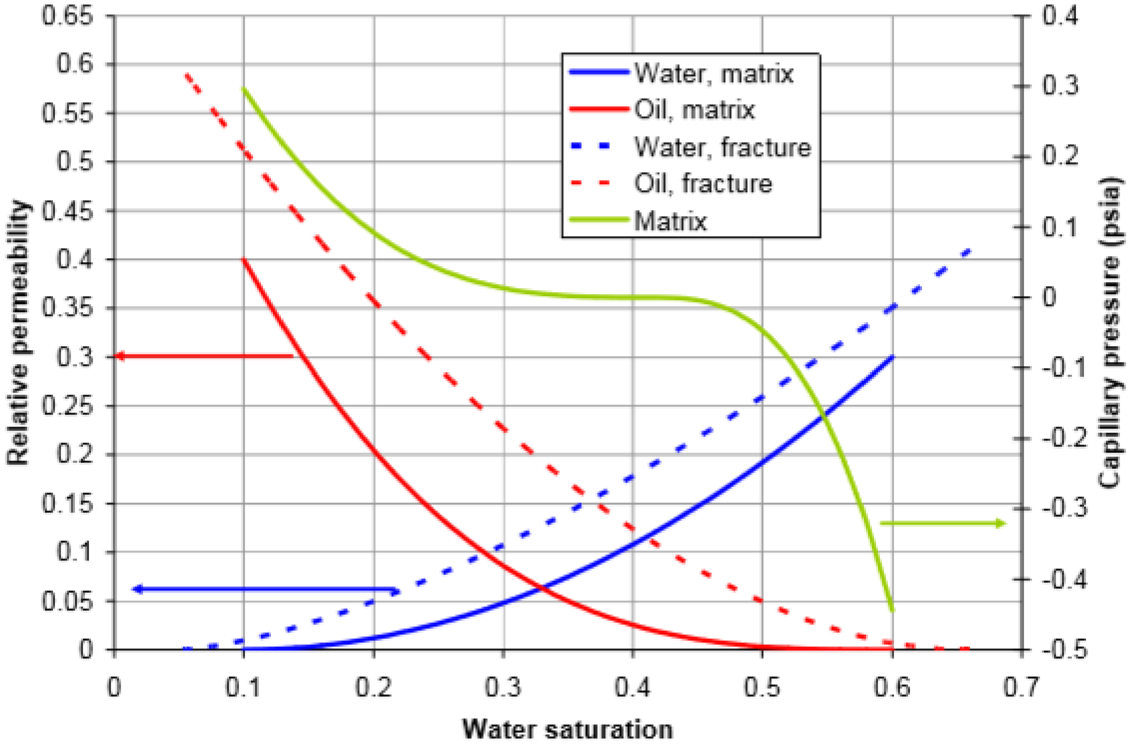

Figure 5. Capillary pressure and relative permeability curves used for modeling the waterflood part (initial wetting, mixed-wet)

Table 1 shows the parameters of capillary pressure and relative conductivity, and Figure 6 shows the resulting curves of relative conductivity and capillary pressure used to simulate the waterflood experiment. We know that the curves were in the original mixed-water state of the matrix floor. Figure 7 shows very well the data on flood production. This indicator shows the first time of the experiment when oil production was not observed. It also gives a reasonable correspondence between recovery and recovery at any time during the discharge of water.

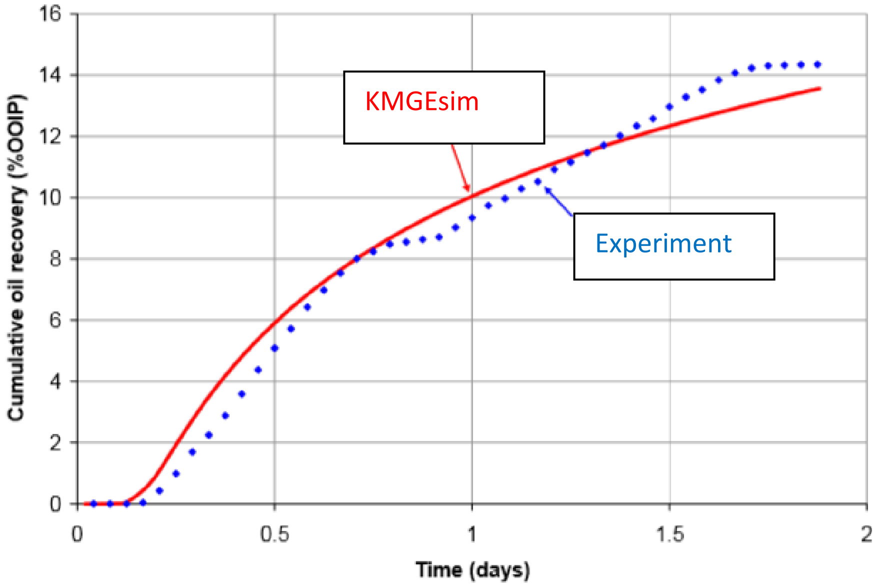

Figure 6. Similes of laboratory and simulated oil recovery

The main reason for maintaining oil in a smooth place and the formation of vegetation at the completion of the flood is negative capillary pressure (Figures 6,7). As the saturation of the water in the cell block increases, the capillary pressure decreases to zero when the water is saturated with 0.42. This is called critical water saturation, at which the capillary pressure attribute changes as this saturation occurs. The saturation of the water increases because the viscous pressure gradient directs a large amount of water into the mesh block, but from that moment the capillary pressure has a negative value and has a negative value as the saturation of the water increases. The pressure gradient of the binding water of the mesh block reaches a level equal to the effective negative capillary pressure, as a result of which oil production is stopped. On images 7-14, pressure profiles, oil saturation, during floods on the middle floor are indicated above. Analysis of the results obtained:

- Capillary impregnation of water occurs uniformly throughout the modeling zone. The distribution of oil saturation after simulating static (without viscous pressure gradient) infiltration after 1.9 days to reflect . Note that the color scale range in this image has been changed to love the saturation gradient. The white portions of the graph are out of range.
- The pressure gradient decreases over time.
- The front of the saturation of the water moves much slower on the matrix than on the debris.
- Between fat saturation in matrix cells on both sides of the fracture, there is a significant difference in the perpendicular direction of flow. This depends on the binding forces and absorption directions. For cells to the left of the opening, the

impregnation proceeds in the opposite direction to the volumetric flow, but for cells to the right of the crack, these two phenomena go in the same direction. As a result, the fat saturation of the cell on the right side of the fracture is higher compared to the left cell.

- After 1.9 days of watering, water saturation is also uniform at critical water saturation, and the rest of the oil is stored in the matrix under the influence of capillary forces (Figure 4.19).
- Oil saturation in fractures (perpendicular to flow direction) is higher than in matrix(figures 7-10). This can be explained by 2 phenomena: one artifact of digital modeling, another artifact of an experimental installation. The viscosity gradient pushes the oil forward and toward the battery limits due to the presence of two-wire debris in the flow direction. Since the cracks in the Y direction are closed, the only way to transport material from these cracks is in the X direction (the viscosity gradient in the Y direction pushes to a dead end). This leads to an accumulation of oil transported from the wreckage of direction X to the wreckage of direction Y and. Another factor in this construction is the artifacts of digital modeling associated with the calculation of conductivity**.** Figure 4.15 shows that for the saturation range in matrix blocks for matrix cells, the relative conductivity of the oil in the primary watering state is much lower than in the water-relative conductivity. Figure 4.15 compares the relative conductivity of oil within the same saturation with the relative water tightness on the fragments. This means that oil is easy to transport from matrix to debris due to flow expectations, and it is difficult to transport from debris to matrix. Thus, oil accumulates on the wreckage, and oil saturation increases on the wreckage.

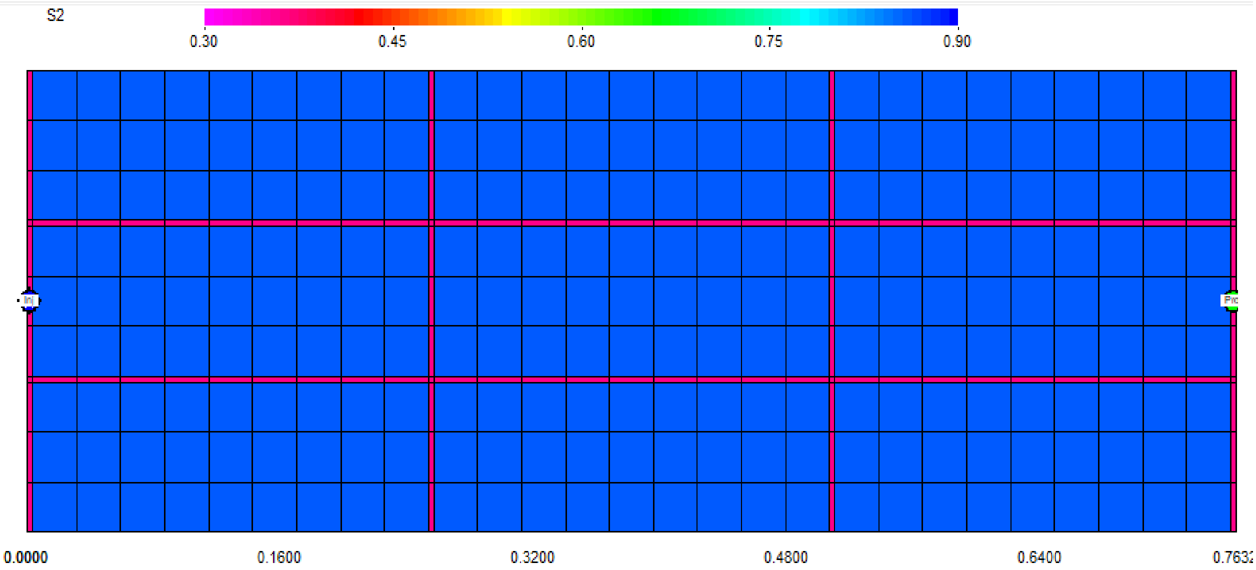

Figure 7. Initial oil saturation

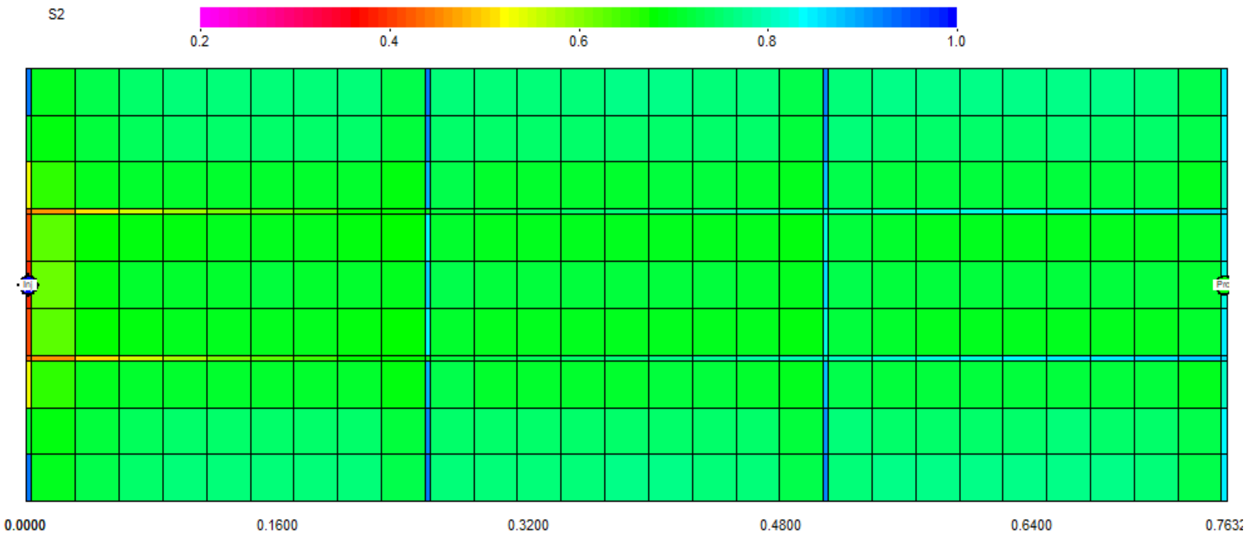

Figure 8. After 0.6 days (S_o)

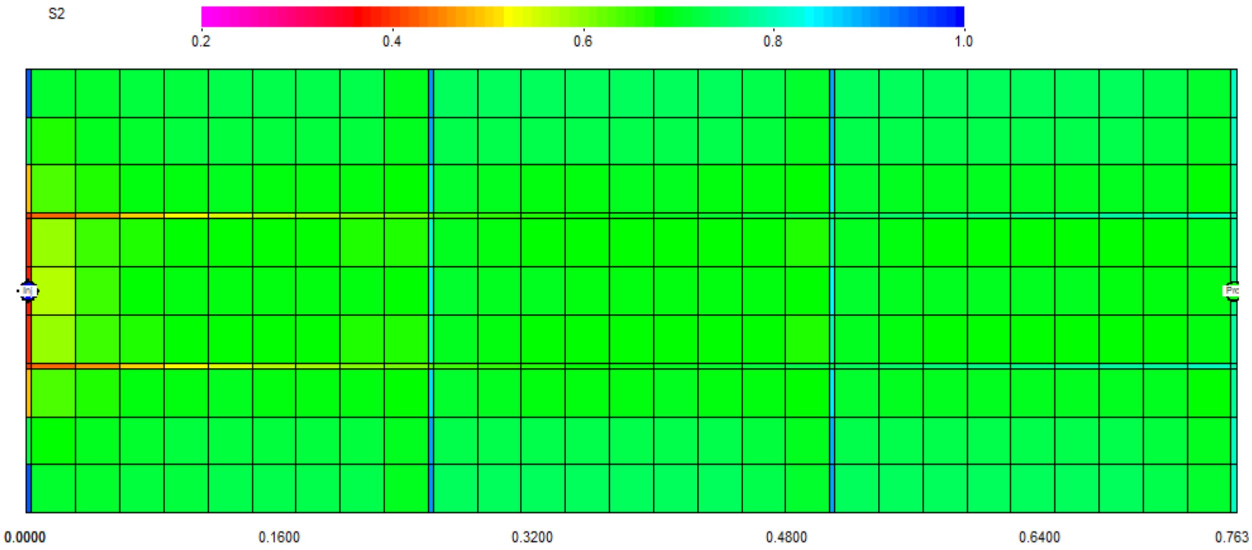

Figure 9. After 1.2 days (S_o)

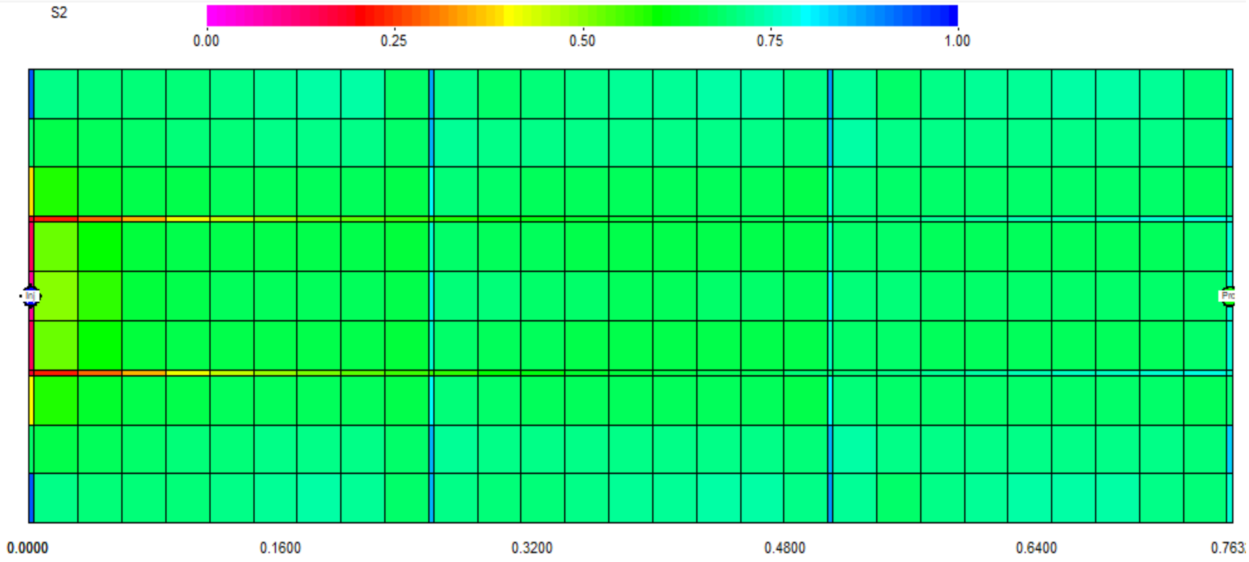

Figure 10. After 1.9 days (S_o)

- The experiment is carried out at a minimum gradient of not more than 1psi/ft, and a single gradient corresponds to the experimental data (Figures 11-14). At the same time, given the correspondence of oil, it is indicated that the model is the main mechanisms that are in the experiment to create a special block.

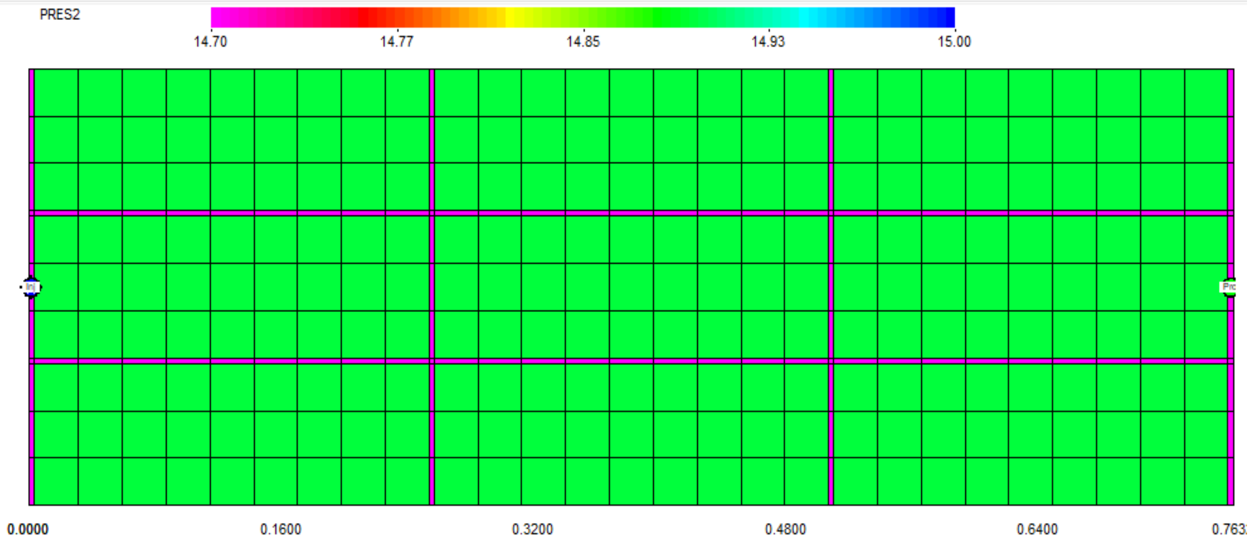

Figure 11. Initial oil pressure

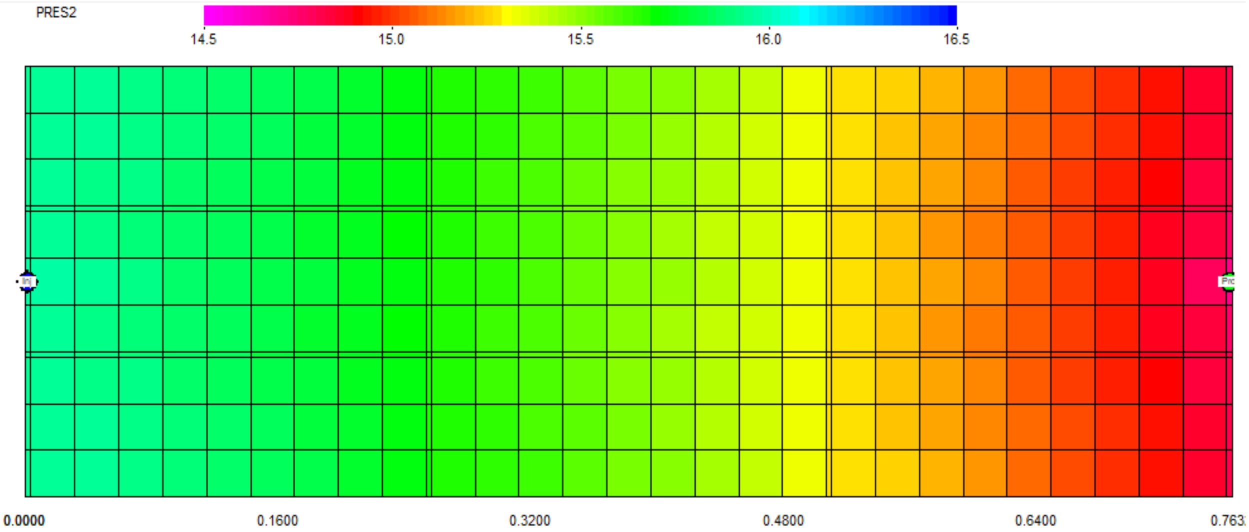

Figure 12. After 0.6 days (oil pressure)

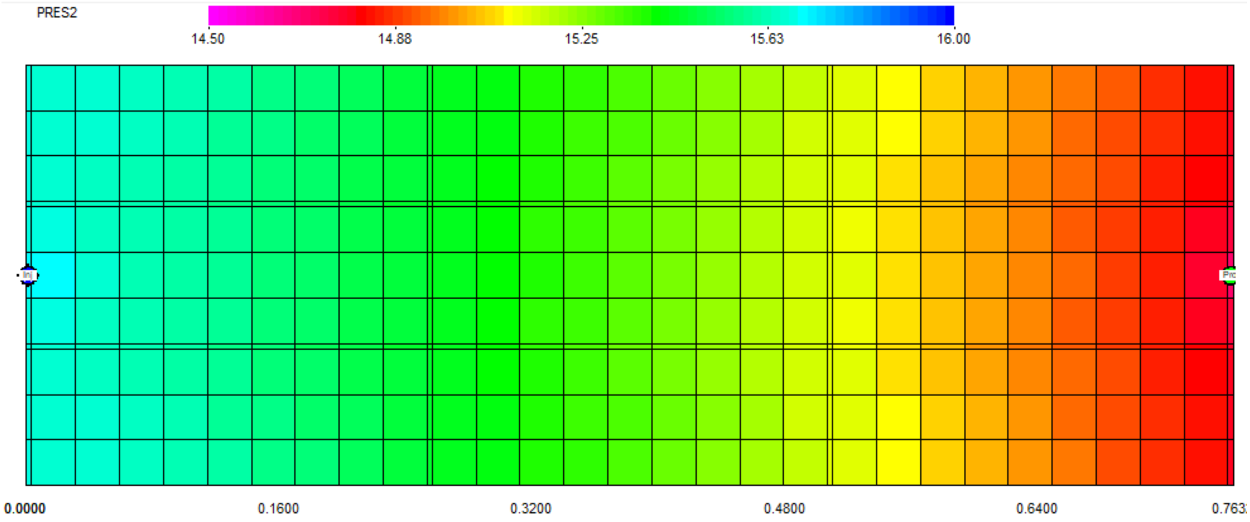

Figure 13. After 1.2 days (oil pressure)

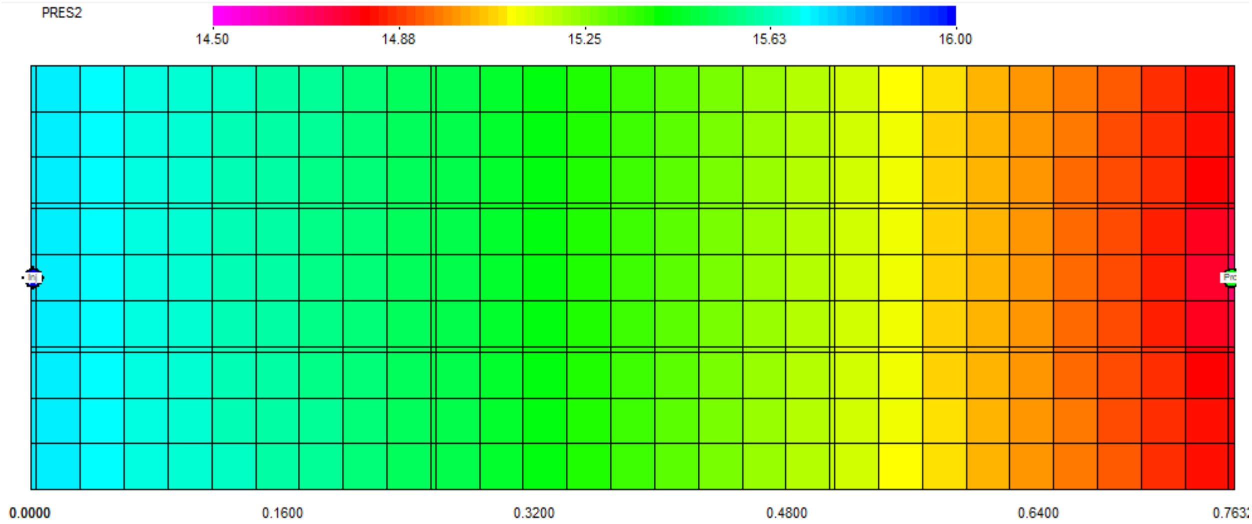

Figure 14. After 1.9 days (oil pressure)

4.3 Simulation of alkaline floods is part of the experiment

To obtain the oil contained in the matrix at the end of the flood, it is necessary to overcome the capillary forces responsible for retaining the oil remaining in the matrix. One way is to change the state of sexual irrigation into a wet state with an agent that changes irrigation, like an alkali solution. Watering, watered with water, exerts positive capillary pressure and can independently absorb water. In water-wet rocks, where water humidity decreases and oil mobility increases, relative conductivity curves are favorable. In this work, sodium metabolate was used to change watering to a wet state. In order to simulate the alkaline part of water-filling practice, it was assumed that the front curves of relative conductivity and capillary pressure would remain and correspond to the primary watering of the layer. The second set of curves of relative conductivity and capillary pressure is presented, which is a changed state of irrigation. The moisture change model is applied and the IWALF = 2 option is added. This option simulates a humidification change based on the concentration of the indicator, which is considered a humidification change agent. Figure 4.15 compares the matrix relative conductivity curves for the initial and final reflux conditions. The primary irrigation curves (solid curves in Figure 4.15) intersect with water saturation of 0.33, and the last watering curves intersect with water saturation of 0.61. Another important difference between the two curves is the relative conductivity of the endpoint. The end point of primary irrigation oil (mixed irrigation) compared to the last irrigation (water irrigation), and vice versa, is smaller for water endpoints. This coincides with an increase in oil viscosity under water humidification conditions.

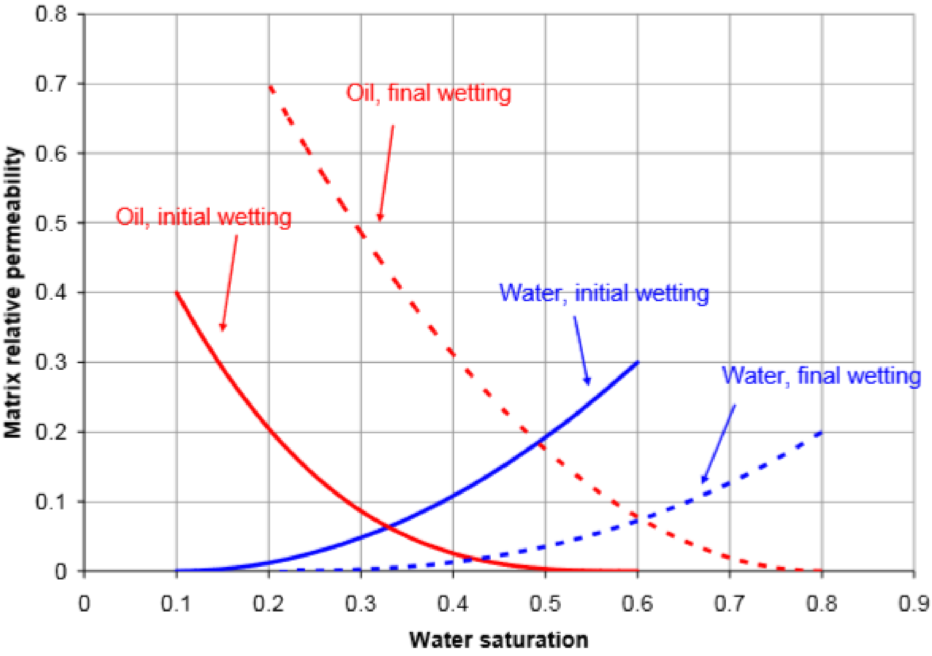

Figure 15. Relative permeability curves in matrix

Image 4.16 show the relative refractive conductivity curves of the matrix and capillary pressure, respectively. Compare shape 4.16 show that refractive curves have a smaller curve and maximum points for each irrigation phase and state compared to matrix curves. Takes into account that the flow of liquid in these fragments is much easier than in the matrix, depending on the nature of the fracture. It should be borne in mind that we do not accept the relative conduction curves of direct fracture in low capillary numbers **(**Figure 4.16).

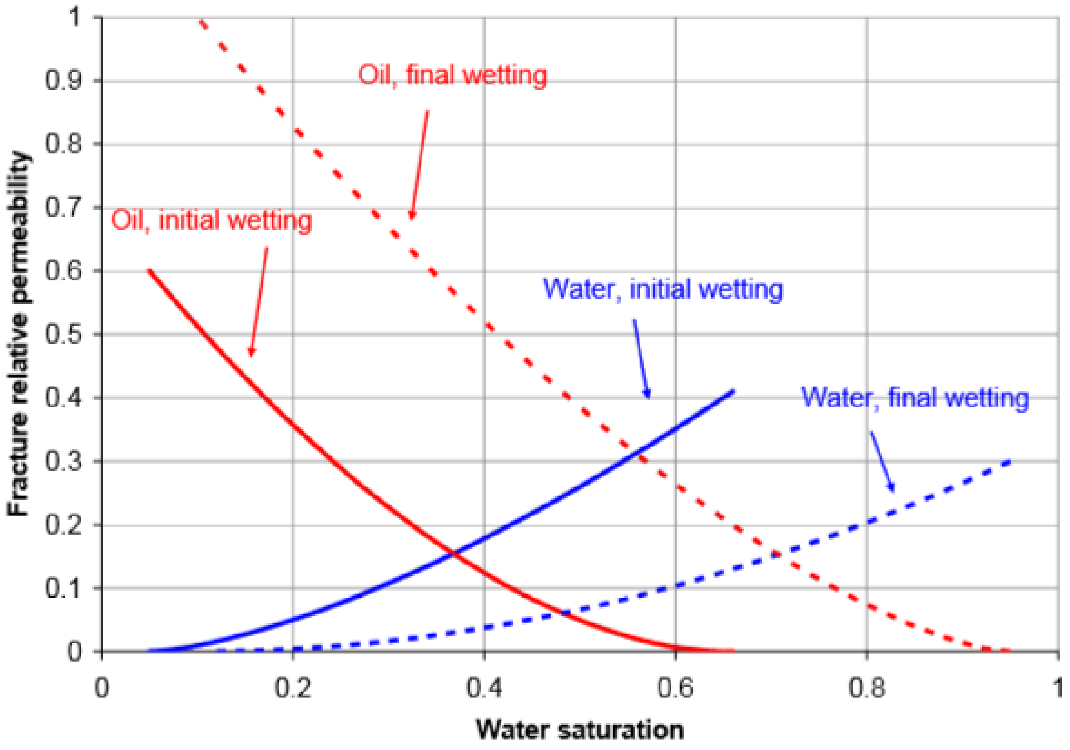

Figure 16. Relative permeability curves in fracture

It takes into account that debris is not ideal cracks and that relative conductivity curves may be absent due to the roughness of the edges, which makes the space of the winding hole from 4.15.. Images 4.17-4.19 a show the distribution of the oil saturation of the middle layer of the model during flooding of alkalis and, accordingly, the normalized alkali concentration. The color scale in the image 4.17-4.19 is selected as in figures 7-10 for consistency. It is clearly seen that oil is removed from places filled with alkalis. At the same time, we take zero physical dispersion and molecular diffusion of alkali. Mesh blocks near the border and remote from debris not covered with alkalis still have high residual oil saturation.

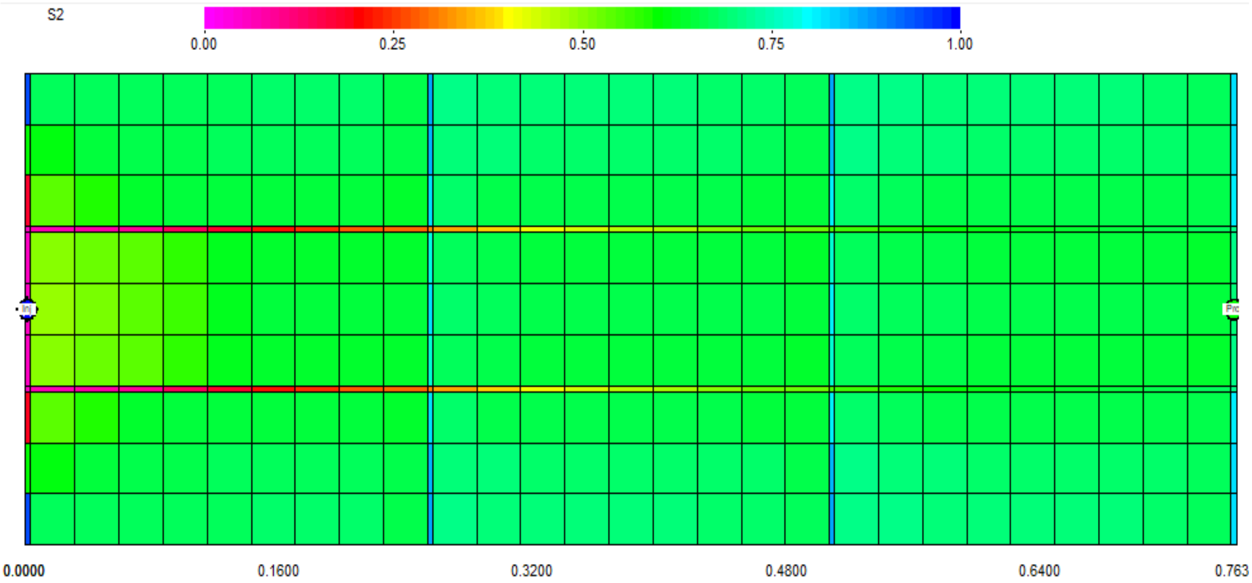

Figure 17. After 3.3 days (S_o)

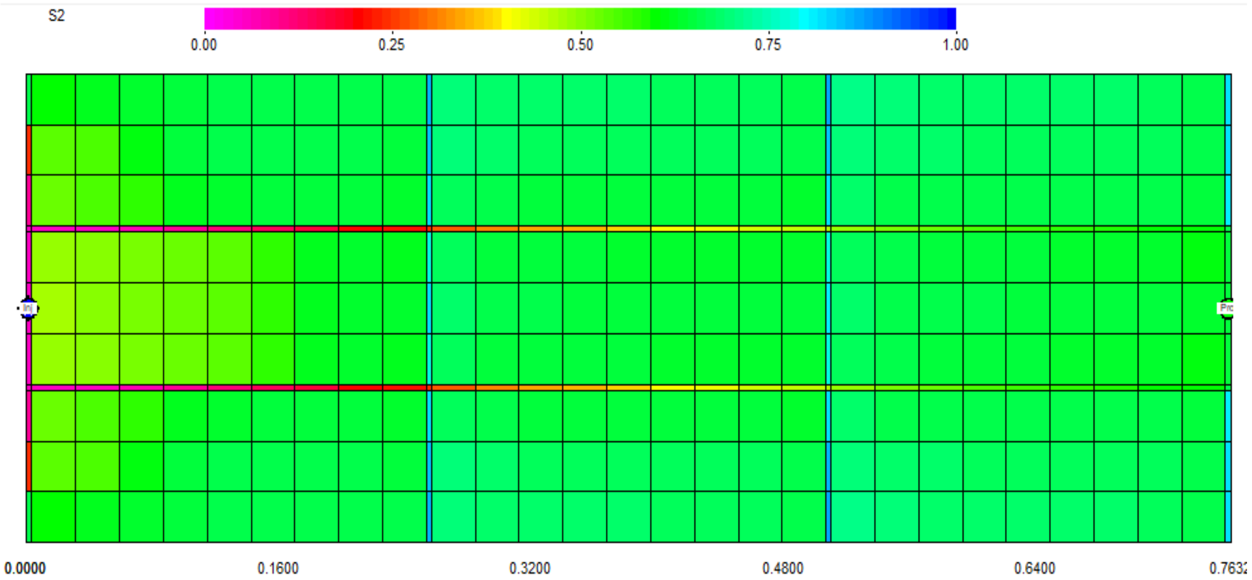

Figure 18. After 4.7 days (S_o)

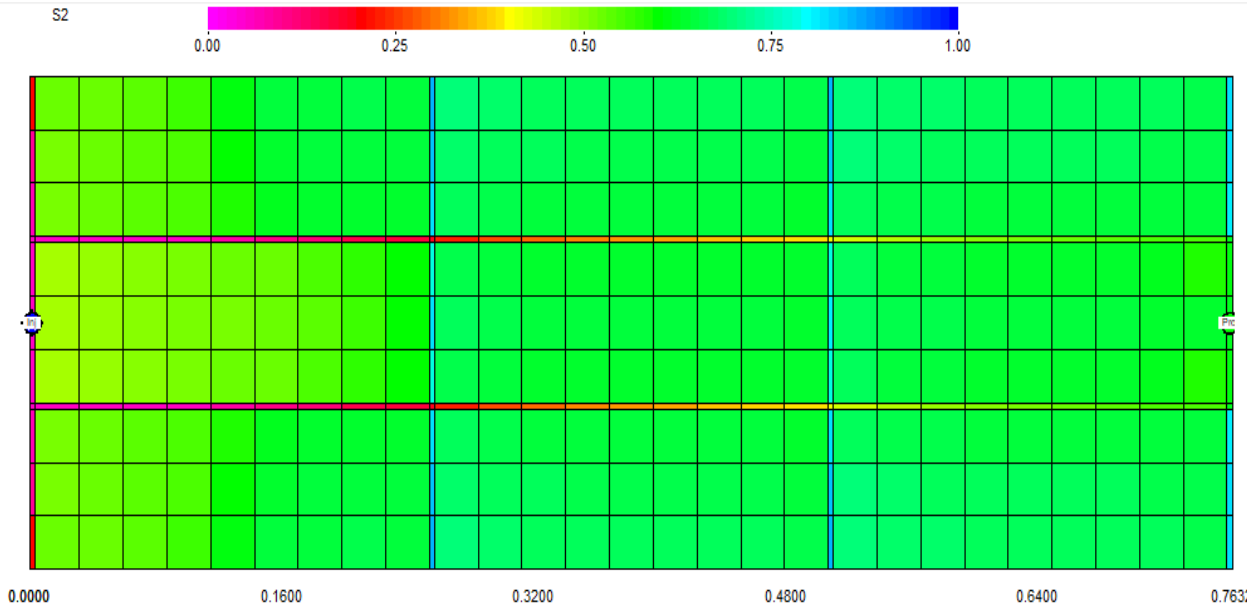

Figure 19. After 6.4 days (S_o)

As a result, after the alkali flood (after alkali injection of 1.68 PV), only about 1/3 of the matrix blocks were flooded with alkali one. Therefore, depending on the conditions of mixed-wet or intermediate irrigation of the layer, it is recommended to use fine capillary gradients and start alkaline flooding in the first stage of secondary recovery from natural broken structures in order to push the alkalis to the matrix if possible. for moisture and oil recovery. The sensitivity of oil production to the injection scenario is indicated later in this chapter.

Figure 4.20-4.22 shows pressure profiles indicating a very low pressure gradient compared to that seen in the water profile (Figures 4.11-4.14).

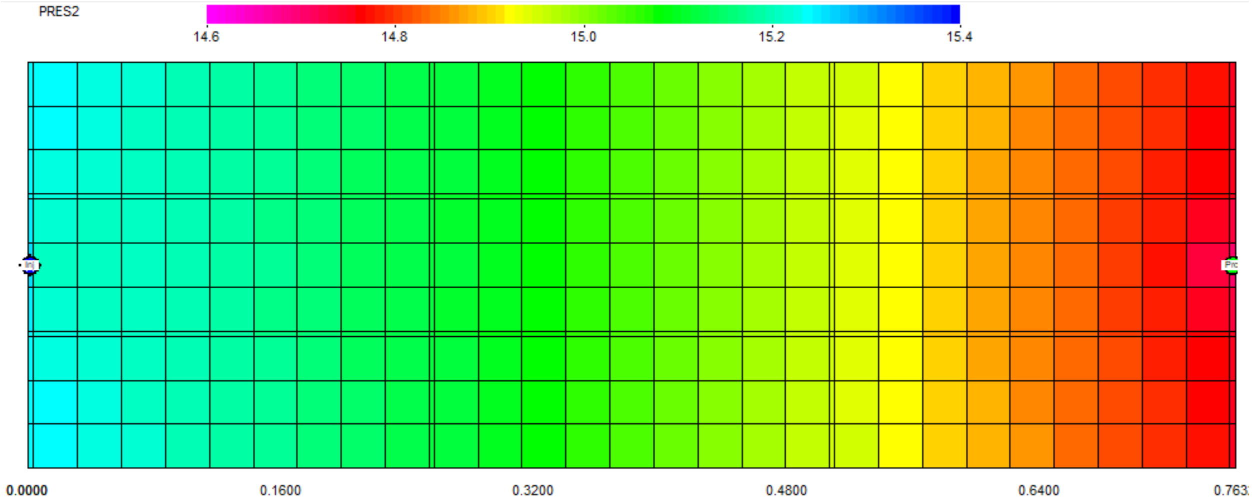

Figure 20. After 3.3 days (oil pressure)

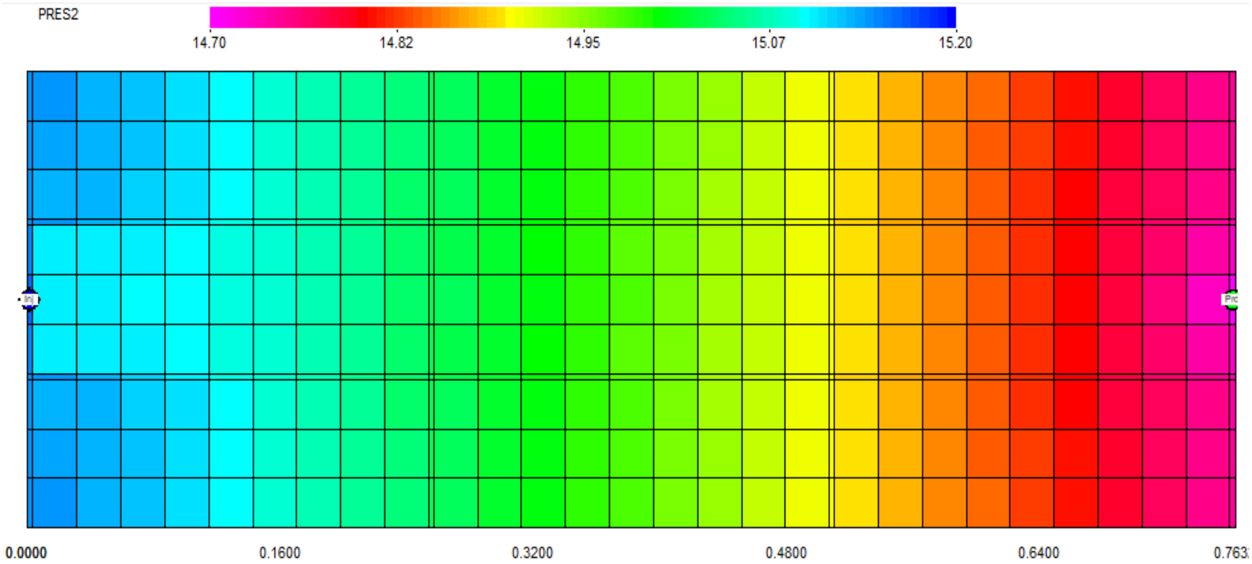

Figure 21.After 4.7 days (oil pressure)

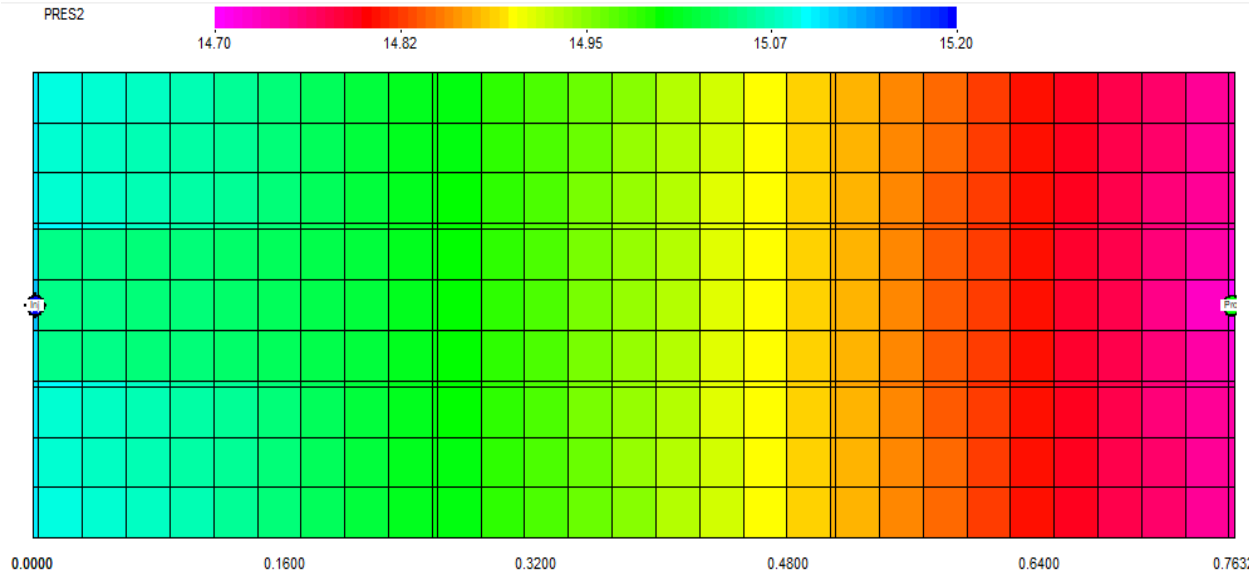

Figure 22. After 6.4 days (oil pressure)

4.4 Simulation of alkaline/surfactant streams in the experiment

Although alkalinity produces an additional 14% of oil after watering due to a change in matrix watering, it cannot reduce IFT and remove oil held by capillary forces. At the end of the alkaline stream, the matrix contains a large amount of oil. Injections of the surfactant solution can reduce oil/water leakage and restore residual oil by both salinity and mobilization. Alkalinity is still included in the surfactant solution, the primary goal of changing its watering, as well as reducing the adsorption of the surfactant and maintaining equal salinity of the alkaline stream (1.0 wt% sodium metaborate and 3.7 wt% NaCl) for consistency. The relative conductivity and capillary pressure used in comparing floods and alkaline floods is still recommended for experimental simulations of surfactant/alkali. Therefore, the corresponding parameters of the surfactant flow were capillary desaturation curves to simulate the effect of interface stress or the total amount of effect on relative conductivity and capillary pressure. Comparison of simulation results and experimental oil recovery for all three stages of the experiment. As shown in this figure, the model can significantly correspond to the measured oil production, indicating that the digital model shows the physics of the experiment. Results of oil supply in layers depending on volume of injected liquid. As shown in this figure, during the whole experiment, about 3.14 PVA is included in the broken block. This is really close to what will happen for the tank and makes the results much more interesting and practical. In the figures 4.23-4.25 alkali/surfactant indicates oil saturation profile during floods figure 4.23-4.25 By the end of the experiment, most of the fractured block shows normalized alkali concentration profiles filled with alkali(figures 4.23-4.25). The spread of surfactant concentration is recommended. Comparative image. In the figure 4.23-4.25.In figures 4.23-4.25 show low oil saturation compared to surface-inactive blocks of mesh blocks washed with surfactant. After injections of 1.2 PVA, the surfactant penetrated a relatively small portion of the rock volume due to the low mobility of the viscous microemulsion phase rich in surfactant and the high conductivity contrast between light and matrix.

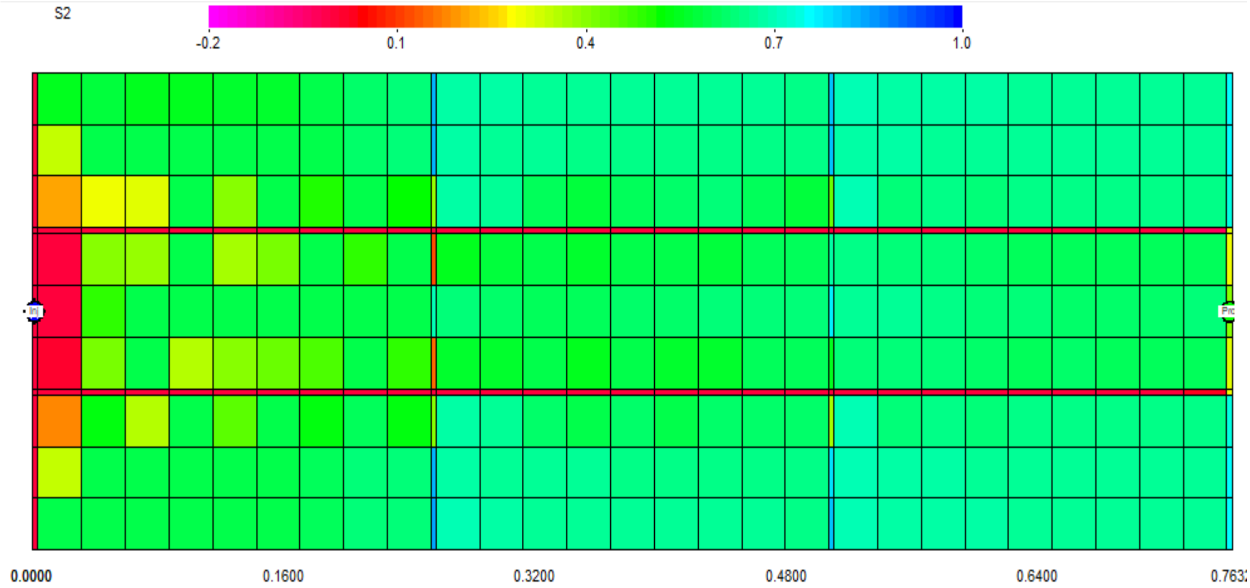

Figure 23. After 6.9 days (S_o)

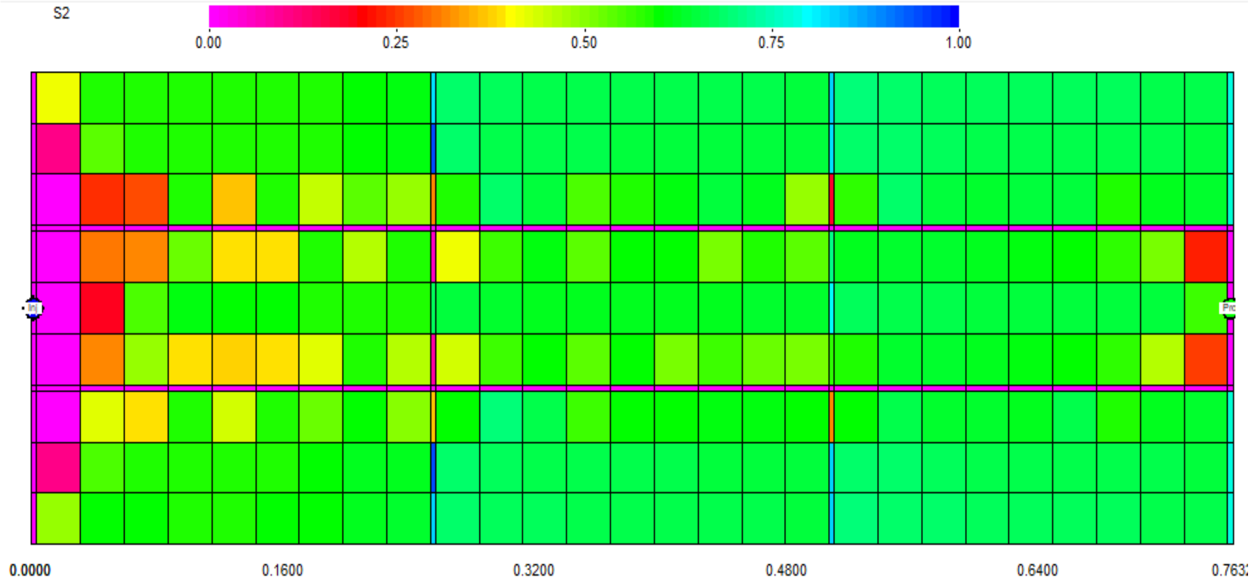

Figure 24. After 7.5 days (S_o)

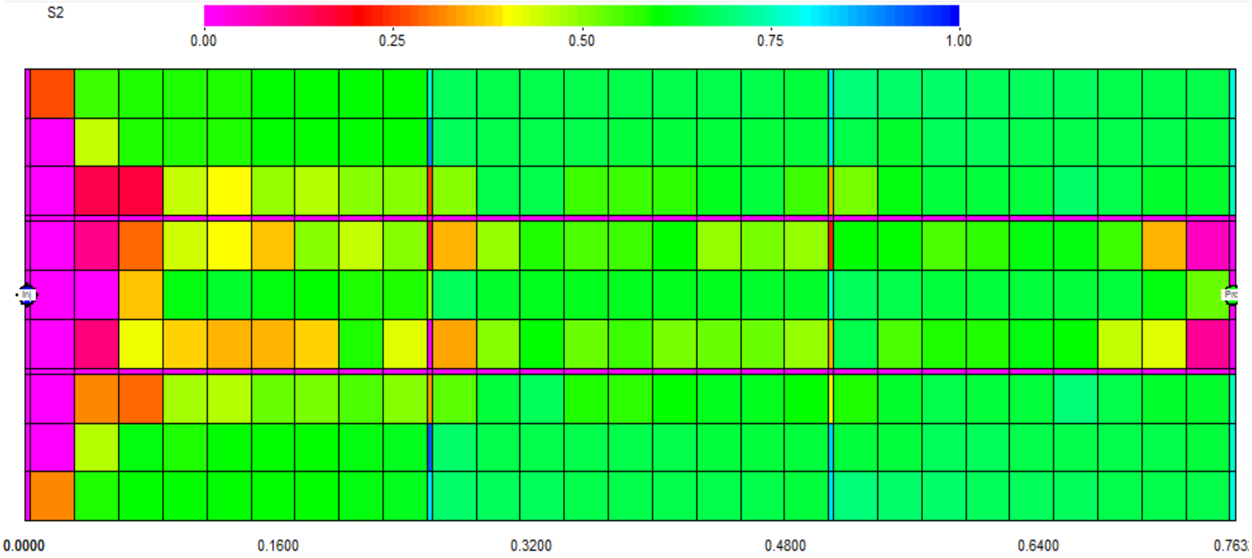

Figure 25. After 8.1 days (S_o)

The oil pressure profiles shown in figures 4.26-4.28 cause a higher pressure gradient than the alkaline high viscosity microemulsion flow (maximum 20 Pa/s vs. 10 and 1 Pa/s for oil and water, respectively). These results indicate the need to monitor a very important aspect of surface active flooding of natural fracture, in particular mobility. To improve sweeping efficiency, as well as flooding the surfactant in conventional homogeneous layers, we need a mobility control agent like foam.

Smaller grid sizes are a digital dispersion, which leads to sharp fronts and high oil production. It is worth noting that the above conclusion is relevant with the usual for only like-minded people and conducted collectors, as well as for possible incorrect collectors. The main problem of broken systems is the large conductivity loop between the cracks and the matrix, limiting the transportation of fused liquids to the matrix. In this case, rigid grids (large digital dispersion) help and this facilitates transportation. Therefore, when modeling broken collectors, the mesh becomes thinner, the lower.

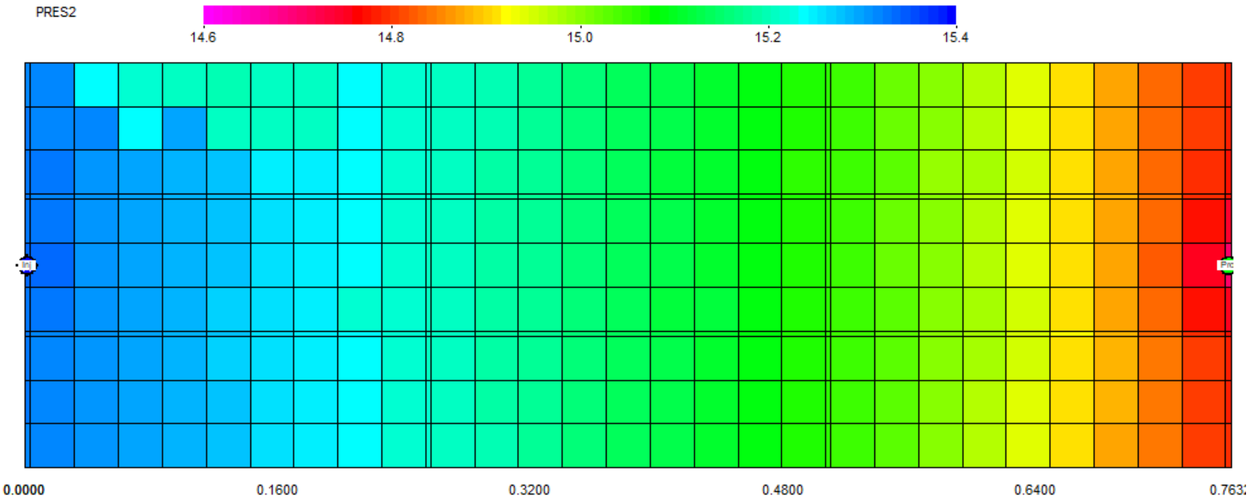

Figure 26. After 6.9 days (oil pressure)

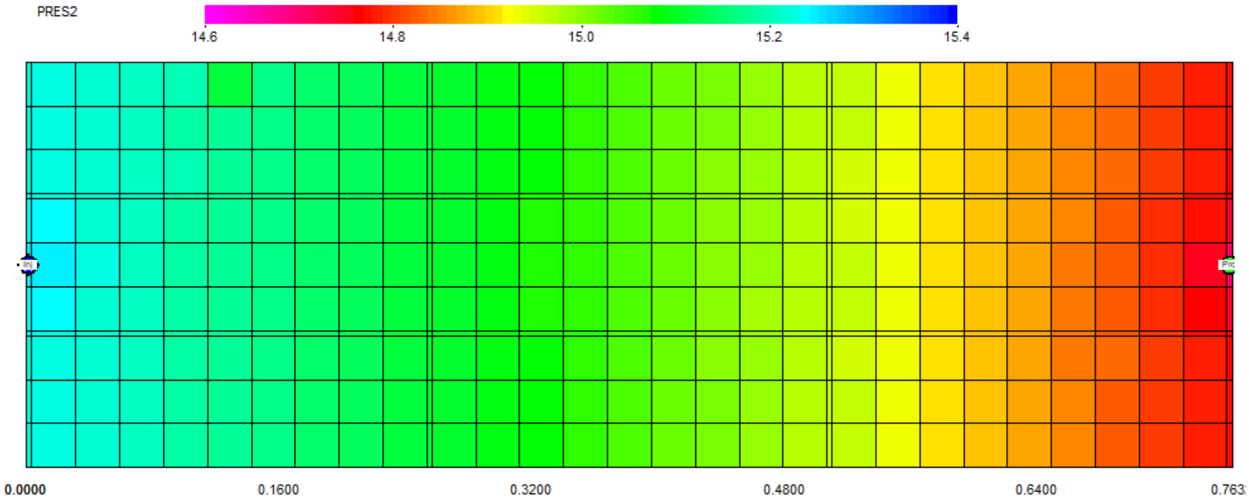

Figure 27. After 7.5 days (oil pressure)

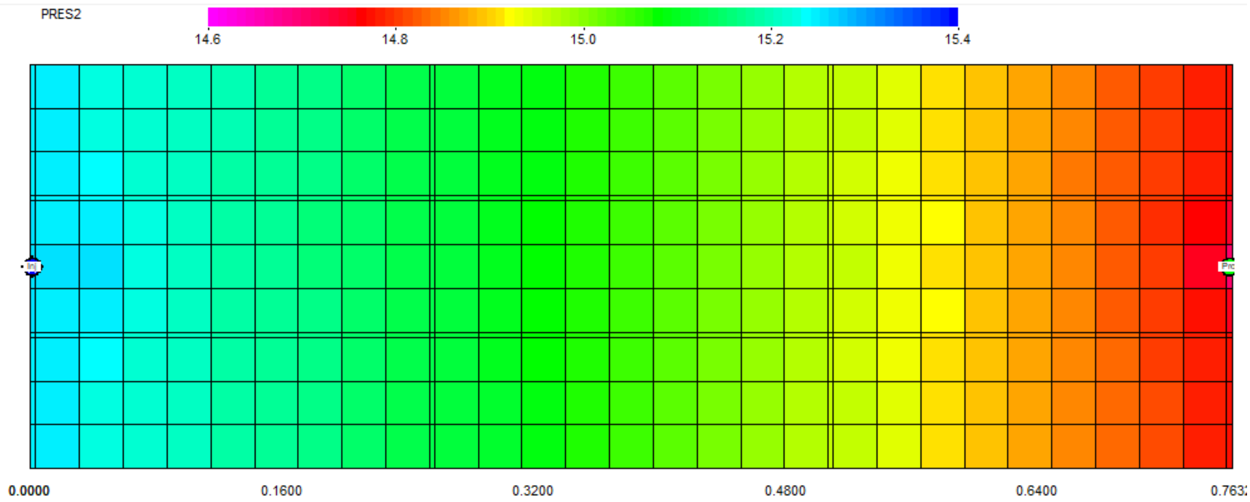

Figure 28. After 8.1 days (oil pressure)

4.5 Results

In the figure 3. shown oil production at three different stages of liquid injection. The introduction of a 4.7% NaCl solution at a rate of 5 ml/hr resulted in a reduction of about 14% OOIP. In the first few hours of sailing on water, oil did not leave the setup. This delay depended on the volume of piping linking the fraction to the sampling unit. Then, 0.9 wt% sodium metaborate (NaBO2) and 3.7% water with NaCl additional 14% OOIP were used at the same rate. By the end of the alkaline floods, the oil produced decreased to zero. The alkali/surfactant mixture was then loaded at the same flow rate, 6% provided a gradual reduction in OOIP (Figure 2). The solution of surfactant contains 1.4% PetroStep ® S-1 and 0.4% PetroStep ® S-2, 2% second butanol as an auxiliary solvent, 1% sodium metabolate and 3.7% NaCl. This surfactant formula formed a crude oil microemulsion, showing an IFT of 0.0007 mN/m. It should be borne in mind that the pressure gradient during the experiment was about 0.7 psi/ft. The gradient of this pressure corresponds to the pressure difference between the arrival and flow rate of the setup.

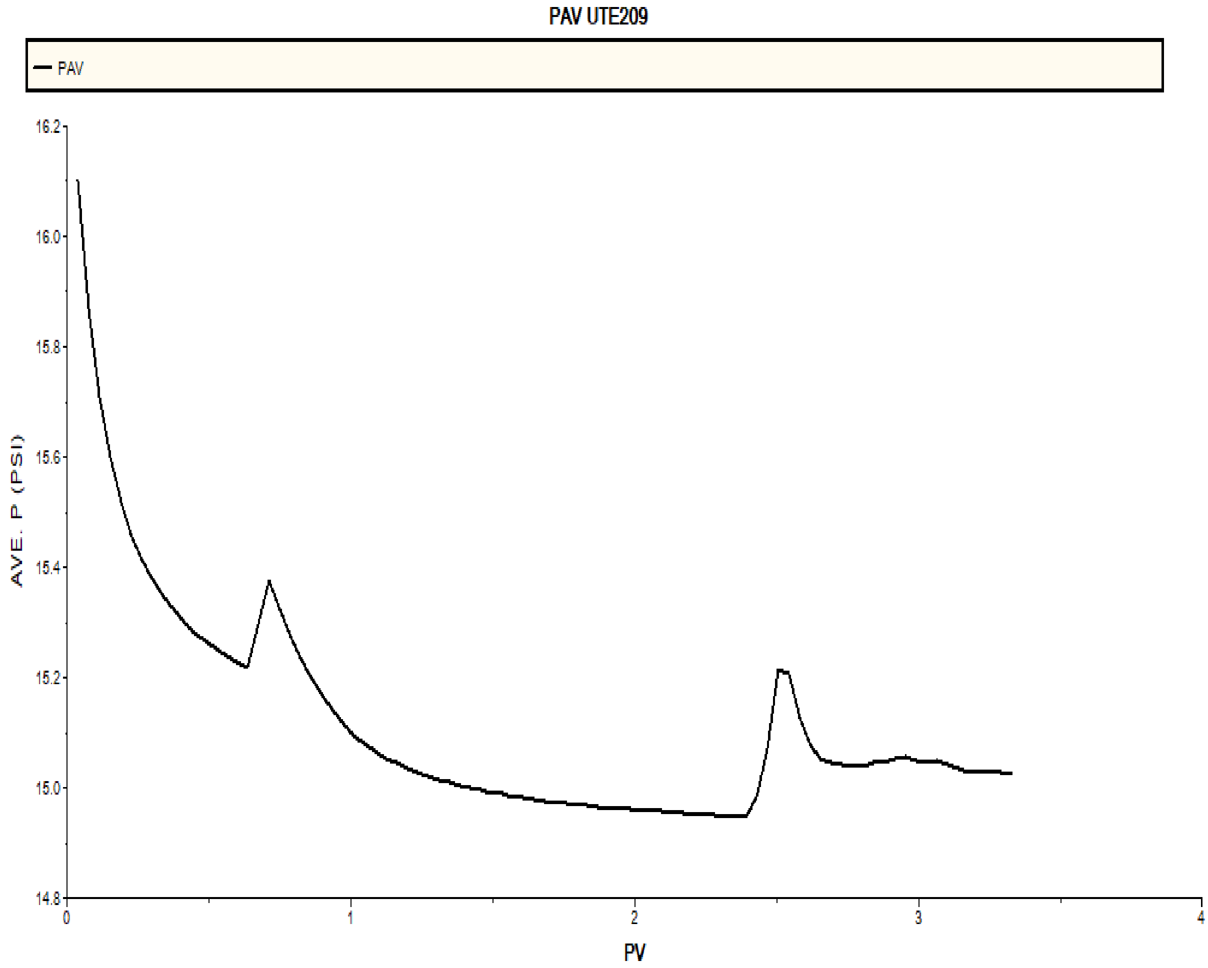

Figure 29. Change in the average pressure over the liquid injected volume (1 PV=2.72 days)

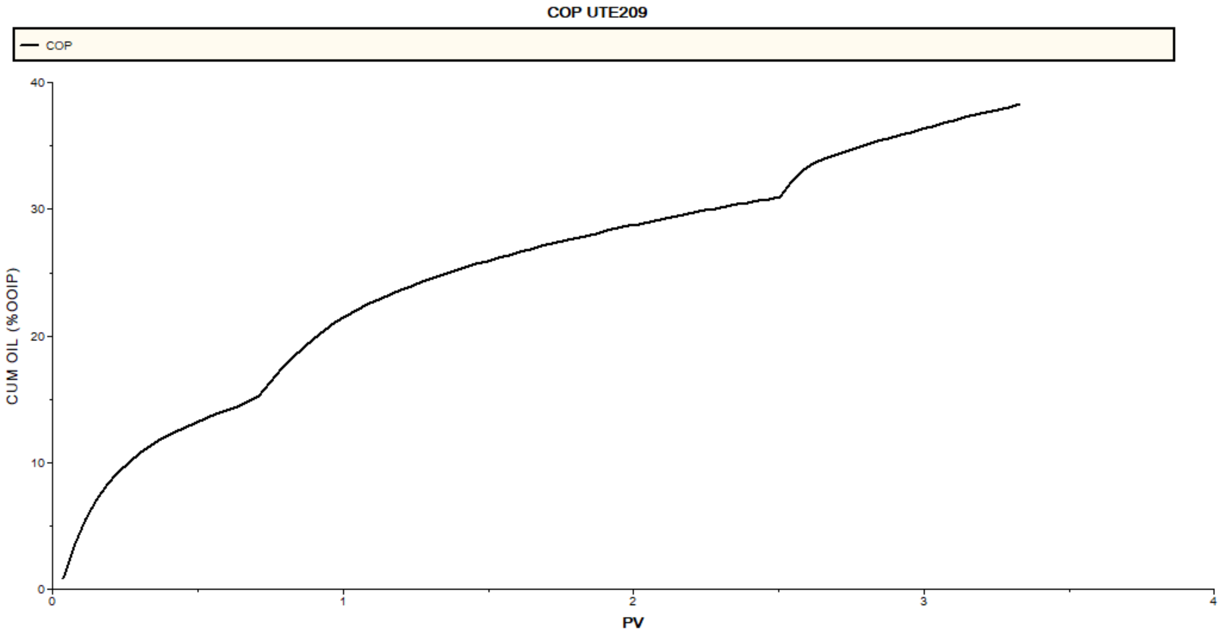

Figure 30. Oil recovery curve

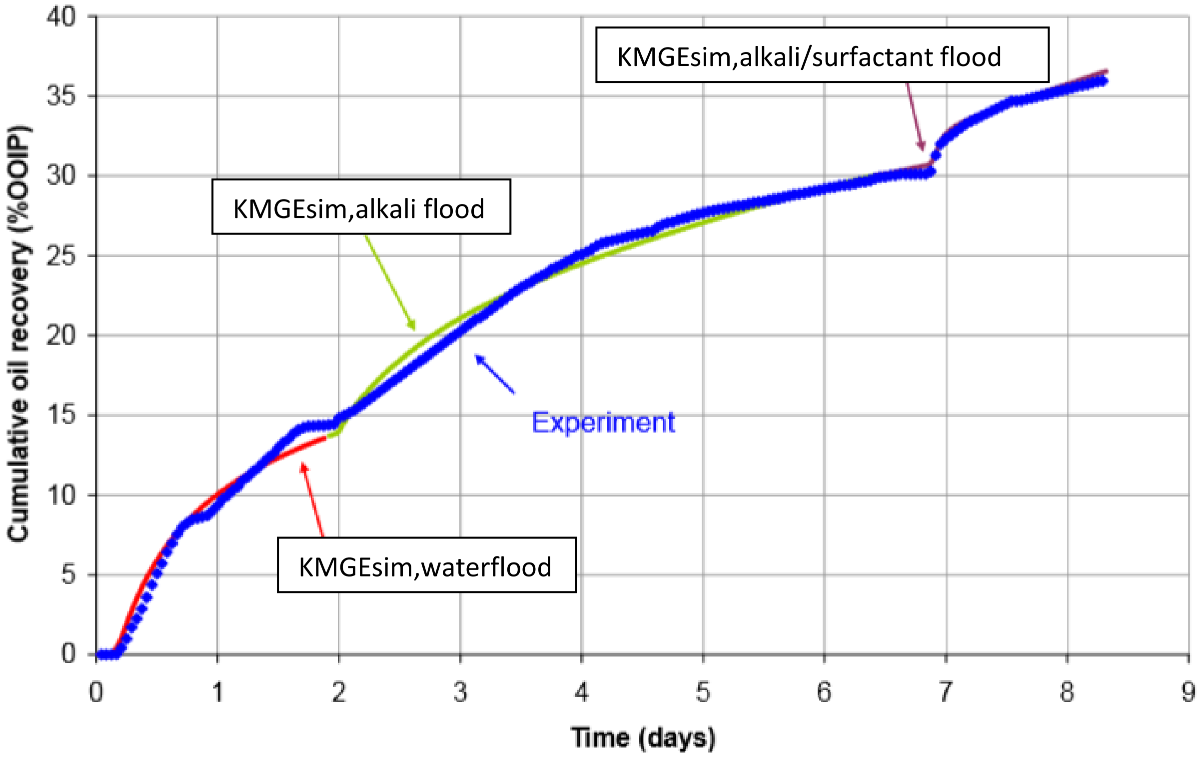

Figure 31. The quality of the match obtained for all three stages of the Fractured Block experiment.

4.6 Modeling the Fractured Block Experiment

The main expected assumptions for the simulation of the experiment are:

- In waterfloods, capillary pressure prevails in the stream. The primary mixed-water nature of the rocks creates both capillary pressure and favorable. The negative capillary pressure contains a large amount of fat on the matrix.
- At the next alkalinity input, the main humidification of the rock varies depending on the irrigation state of the water-wet, which causes a change in petrophysical properties such as relative conductivity and capillary pressure. Capillary pressure is positive, oil is displaced by capillary and viscous forces.
- When flooding alkali/surfactant, the IFT decreases to ultraviolet values, which causes the following changes in petrophysical properties:
  - ➢ Reduction of residual saturation with oil, water and microemulsion
  - ➢ The relative conductivity curves are straight for all three phases
  - ➢ reducing capillary pressure

Conclusions

1. Water, alkali and surfactant/alkali were sequentially pumped into the mixed wet-blasting carbonate block. The saturation of watering with high residual oil decreased dramatically with the introduction of sodium metabolate as an irrigation modifier.

2. Due to oil mobilization, residual interfacial attraction remaining after injection of surfactant solution and injection of alkalis is additionally reduced.

3. The practical results were successfully modeled by the flexibility change model using KMGEsim.

4. The combination of the very low phase stress of the surfactant solution and the change in the moisture of the sodium metaborate has great potential to produce a significant portion of the associated oil from mixed wet-split carbonates. The main recovery mechanisms are moisture change, phase stress reduction, oil emulsion, and mobilization.

5. The introduction of chemicals is very important before the critical saturation of water in the steppe is achieved. The reason is the absence of an important gradient for transferring chemicals to the matrix after leveling the binding forces with negative capillary forces.

6. Dynamic laboratory experiments and simulations are needed to assess chemical floods in naturally broken reservoirs.

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