Chemical Flooding for Oil Production

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***Abstract*—The enhanced oil recovery phase of oil reservoirs production usually comes after the water/gas injection (secondary recovery) phase. The main objective of EOR application is to mobilize the remaining oil through enhancing the oil displacement and volumetric sweep efficiency. The oil displacement efficiency enhances by reducing the oil viscosity and/or by reducing the interfacial tension, while the volumetric sweep efficiency improves by developing a favorable mobility ratio between the displacing fluid and the remaining oil. It is important to identify remaining oil and the production mechanisms that are necessary to improve oil recovery prior to implementing an EOR phase. Chemical enhanced oil recovery is one of the major EOR methods that reduces the residue al oil saturation by lowering water-oil interfacial tension (surfactant/alkaline) and increases the volumetric sweep efficiency by reducing the water-oil mobility ratio (polymer). In this research, the basic mechanisms of different chemical methods have been discussed including the interactions of different chemicals with the reservoir rocks and fluids. In addition, an up-to-date status of chemical flooding at the laboratory scale, pilot projects and field applications have been reported.**

Keywords—chemical flooding, reservoir, EOR, production, recovery

I. INTRODUCTION

A. *Chemical Flooding*

The chemical flooding is a general term for the processes that inject surfactant contained chemical solutions (or slugs) into the reservoir for enhancing the oil recovery.These processes aim at producing the trapped, residual oil after the water flooding. The micro emulsions, which are used to lower the Interfacial tension (IFT) between the displacing and displaced fluids, contain surfactant,hydrocarbon and water. Surfactant The surfactant and/or an alkali are used in the injected chemical solution to reduce the IFT between the oil and water in the reservoir . Polymers may also be employed to improve the mobility ratio, and consequently, the displacement sweep efficiency. A tremendous amount of work has beenpublished in the area of chemical flooding for enhancing the oil recovery. It is beyond the scope of this article to provide a review of all the published works.

Micellar polymer and alkaline flooding are regarded as the two major chemical flooding processes. Micellar flooding (also known as micro emulsion flooding or surfactant flooding) is a process in which a surfactant slug is injected into the formation followed by a larger slug of water containing polymer.
The traditional injection scheme for a surfactant-based chemical flooding process includes injecting a preflush, a chemical solution, a mobility buffer, and finally, a driving fluid, which displaces the chemicals and the developed oil bank towards producer. It should however be noted that the modern surfactants have made it possible to design formulations for the injected chemical solution without the need for a preflush. [1]

B. *EOR*

The Average oil recovery after the primary recovery phase is about 5–20% of the original oil in place (OOIP) and can be increased by applying the secondary recovery phase up to 40%. Usually, the EOR application stage will be after the secondary recovery when the main challenge is not the reservoir pressure only, but also the reservoir fluids relative mobility compared to the injected fluids during the secondary recovery phase[1-2]. There are different EOR methods such as thermal recovery, miscible Gas Injection, Chemical flooding and Microbial EOR [1-2].
The feasibility study and design for EOR projects require integrated work between different disciplines such as reservoir

engineers, petroleum geologists, petrophysits, geomodellers, chemical engineers, and production engineers whom are responsible to start with the screening phase of the different EOR methods and come up with the shortlisted one in order to go for the next step which is lab testing phase that requires PVT/core labs capable to implement the various EOR lab tests, then, analyze the lab scale results to be coupled with the reservoir simulation model in order to estimate the incremental recovery for the different EOR methods under study. For any EOR project, the initial stage is the screening criteria in order to identify the best EOR application for the candidate reservoirs in terms of incremental recovery that will be added and the economics of the project [1-3].

For any EOR project, the initial stage is the screening criteria in order to identify the best EOR application for the candidate reservoirs in terms of incremental recovery that will be added and the economics of the project. The screening criteria is based on both reservoir rock and fluids properties such as oil gravity, oil viscosity, oil composition, remaining oil saturation (target), formation type, reservoir thickness, depth, and temperature. In Table 1, a summary of screening criteria for the chemical EOR methods based on lab and applied field data.
So, in this chapter we are assuming that the screening criteria was done and it has been found that the chemical flooding is the optimum EOR method that can be applied for the reservoir under study [1].

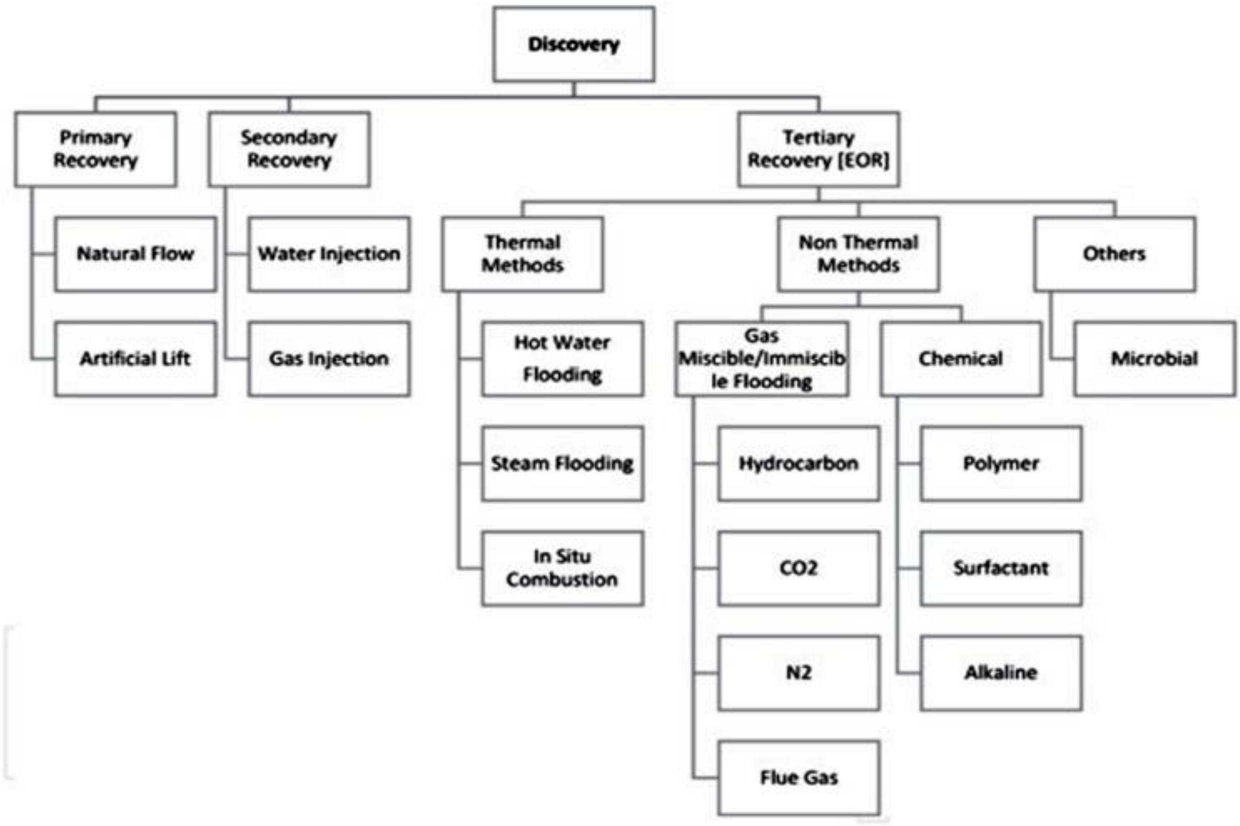


Figure I-1 Oil production mechanism

EOR Method	Oil Gravity (°API)	Viscosity (cP)	Oil Saturation (%)	Formation Type	Reservoir Thickness (ft)	Average Permeability (mD)	Depth (ft)	Temperature (°F)
Polymer Flooding	> 15	<150 & >10	>50	Sandstone is preferred	NC	>10	<9000	>200
Micellar/Polymer, ASP, and Alkaline flooding	> 20	<35	>35	Sandstone is preferred	NC	>10	>9000	>200

Table I-1 A Summary of screening criteria for the chemical EOR methods

So we can say the enhanced oil recovery is generally considered as the third, or last, phase of useful oil production, sometimes called tertiary production. The first, or primary, phase of oil production begins with the discovery of an oilfield using the natural stored energy to move the oil to the wells by expansion of volatile componentsand/or pumping of individual wells to assist the natural drive.

When this energy is depleted, production declines and a secondary phase of oilproduction begins when supplemental energy is added to the reservoir by injection of water. As the water to oil production ratio of the field approaches economic limit ofoperation, when the net profit diminishes because the difference between the value of the produced oil

and the cost of water treatment and injection becomes too narrow, thetertiary period of production begins. Since this last period in the history of the field commences with the introduction of chemical and thermal energy to enhance the production of oil, it has been labeled as enhanced oil recovery (EOR).

Actually, EOR may be initiated at any time during the history of an oil reservoir whenit becomes obvious that some type of chemical or thermal energy must be used to stimulate production. The combined total oil production by primary and secondary methods is generally less than 40% of the original oil in place. Thus, the potential targetfor EOR is greater than the reserves that can be produced by conventional methods. Before initiating EOR, the operator must start from status quo and obtain as much information as possible about the reservoir and its oil saturation.

This body of information furnishes the rational basis for prediction of recoverable oil reserves by various proven techniques for EOR. The EOR procedures involve the injection of chemical compounds dissolved in the injection water, miscible gas injection alternating with water injection, the injection of micellar solutions (micro emulsions composed of surfactants, alcohols, and crude oils), the injection of steam, and in-situ combustion. Perhaps the most critical datum for EOR is the existing oil saturation of the reservoir. The investor must weigh the estimated recoverable oil by EOR against the total cost of implementing these newer, or developing, technologies.

The choice of the process also is dependent upon the amount of oil in place as well as other considerations such as depth, oil viscosity, etc. Consequently, numerous new logging methods have been developed recently as well as other methods, such as the single well tracer, for the accurate deter mention of reservoir oil saturation.

The general procedure for chemical EOR, using the specific case of the alkaline polymer technique. In general, the introduction of chemicals to a petroleum reservoir is preceded by a preflush (the injection of a low-salinity orcontrolled tapered salinity water) to place a compatible aqueous buffer of fluid betweenthe highly saline reservoir brine and the chemical solutions, which may be adversely affected by the dissolved salts. Chemical additives are detergent-type compounds (frequently petroleum sulfates), organie polymers (to increase sweep efficiency in a heterogeneous reservoir), and micellar solutions.

The alkaline or other chemical solution is injected after the reservoir conditioning preflush, as illustrated in Fig. 2-1. Injection of the chemical solutions is followed by theinjection of a polymer solution (usually a polyacrylamide or a polysaccharide) to in- crease fluid viscosity, to aid in displacement of the chemicals through the reservoir and to minimize loss due to dilution and channeling. Finally, the salinity of the injected water following injection of the polymer is gradually increased to the normal concentration of the oilfield fluids.

Another EOR technique utilizes the injection of gas for pressure maintenance and oil displacement by miscible or solution drive [1].

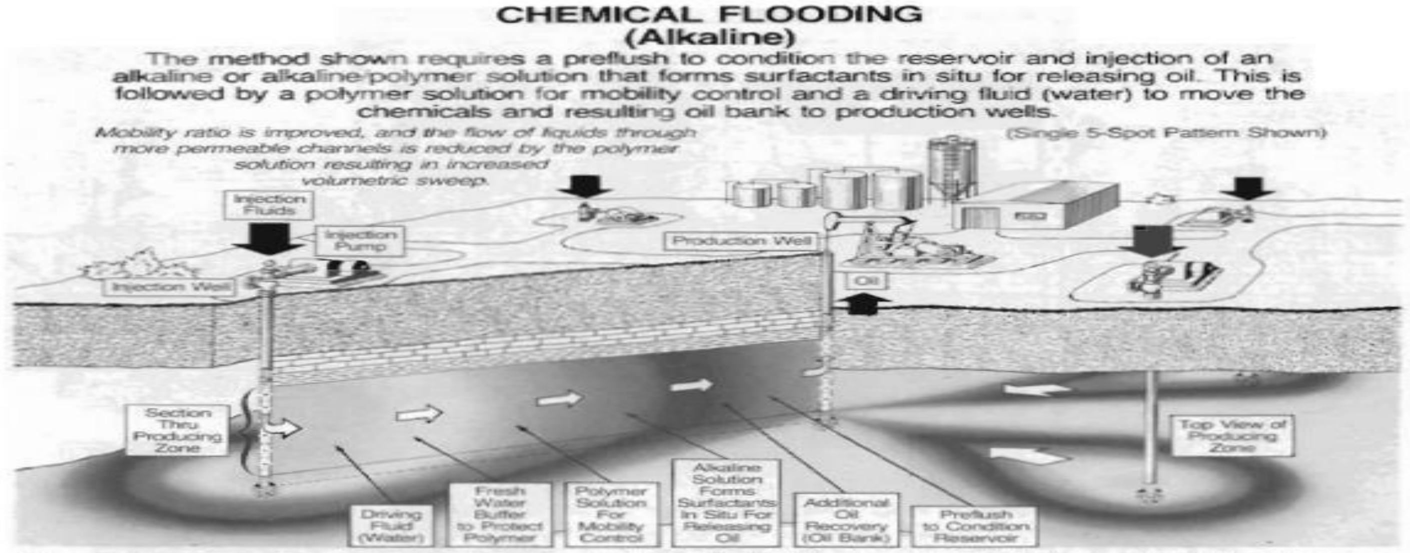


Figure I-2 Schematic diagram of chemical flooding (alkaline)

II. LITERATURE REVIEW

A. Mechanism of Polymer Flooding

Polymer flooding is an isothermal EOR process originated to relieve the issue coupled with conventional water flood depletion as a consequence of unfavorable mobility ratio.

Polymer flooding is a process of adding polymer to the water of a water flood, in order to decrease its mobility. Adding a polymer leads to an increase in viscosity, as well as to a decrease in aqueous phase permeability and a lower mobility ratio. The remaining oil saturation decreases, due to the increased efficiency of the water flood, even if the irreducible oil saturation is not affected by this technique. Schematic of polymer flooding mechanism is shown in Figure (II-1) Because oil and water are immiscible fluids, none of them can completely sweep the other under reservoir conditions [4].

Oil is remaining behind in the porous media after water flood either water bypassed oil, or the oil got trapped due to capillary pressure. In order to resweeps the remaining oil, the interfacial tension between oil and water phases should be reduced to a certain lowered value. This can be done by adding a Surfactant to the displacing fluid. However, producing remaining oil by this strategy is the goal of low tension surfactant flooding Polymer flooding could neither lower the interfacial tension to adequately low value nor sufficiently rises the viscous to capillary pressure more economically balance between water and oil phases in the displacement process, without which the remaining oil cannot be displaced. Therefore, the aim of polymer flooding is to produce that percentage of oil that left behind upon water flood but does not include remaining oil Even though polymer flooding cannot lower the remaining oil saturation, it’s still a practical method way to attain the So more economically.

According to Needham and Doe (1987), high oil recovery obtained from polymer flooding over that of a conventional mean could be achieved through the effects of polymer on fractional flow, through more efficient oil displacement in the swept zone, and by lowering water-oil mobility ratio.

In order to completely understand the mechanism of polymer flooding, it is very important to review some key concepts related to polymer flooding, such as mobility ratio, fractional flow, displacement efficiency, volumetric sweep efficiency, and resistance factor [4].

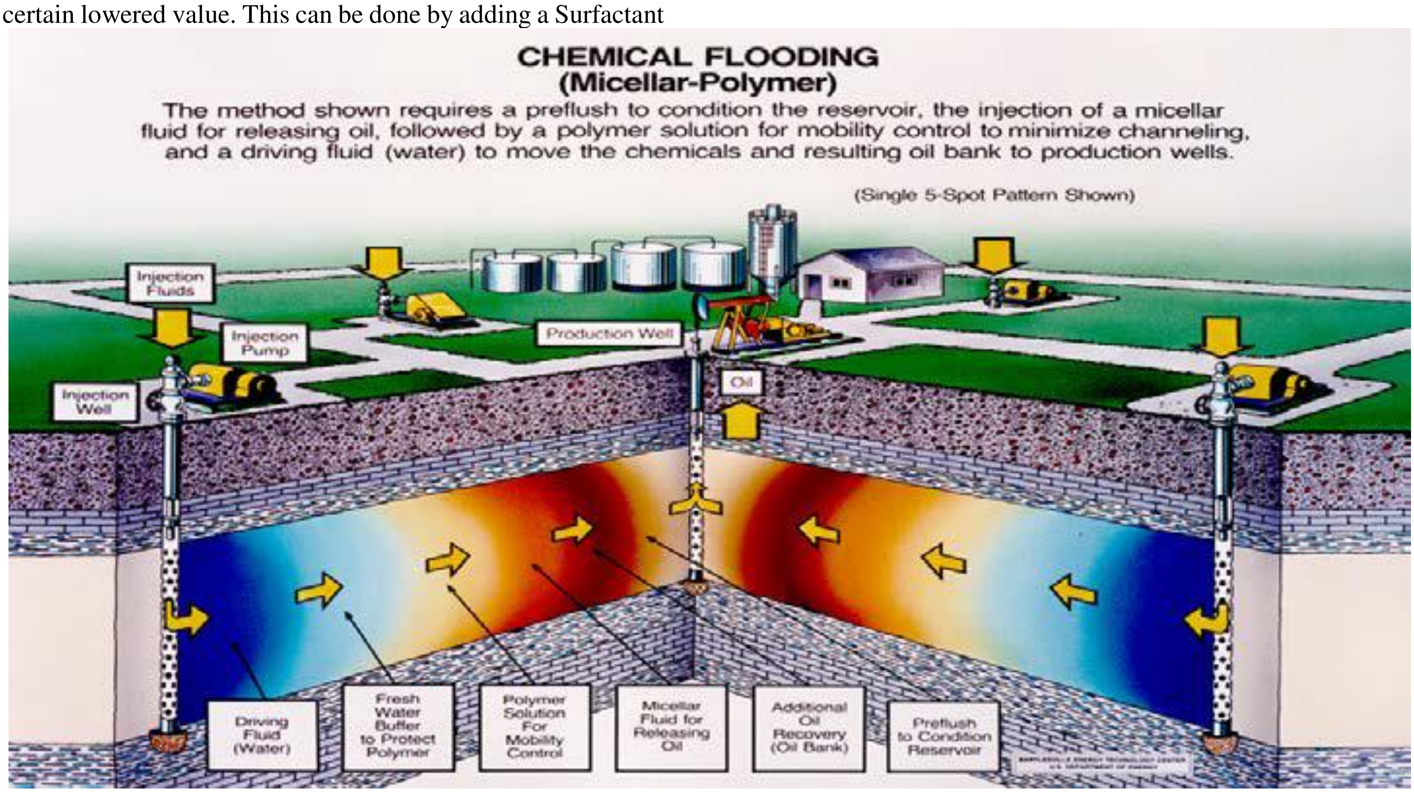


Figure II-1 Polymer flooding mechanism (Lindley, 2001)

B. Mobility Ratio

Mobility ratio, M, is the faction of mobility of injecting fluid to the to the mobility of the displaced fluid. It is defined as follows:

$M = \lambda w/\lambda o=(Kw/\mu w)/(ko/\mu o)$

λw is the mobility of water phase, displacing fluid and λo is the mobility of oil phase, displaced.

μo and μw are the viscosities of oil and water respectively. Ko and Kw are the effective permeabilities of oil and water phases respectively. If a mobility ratio is greater than one, water is more mobile than oil. In this case, water fingers through the oil zone causing early breakthrough. As a result, low displacement efficiency would take place. On the other hand, if the mobility ratio is equal to or less than one, it would delay breakthrough time due to what is called favorable motility ratio. This is where adding polymer play its role. As discussed earlier, one of the advantages of polymer flooding is lowering mobility ratio which would improves sweep efficiency and oil displacement over waterflooding. Figure (II-2) demonstrates how mobility ratio improves oil recovery [4].

As demonstrated in Figure (II-2) (a), The Buckley-Leverett theory of immiscible displacement anticipates that at unfavorable motility ratios the displacing fluid arrival the producing well faster due to its lower viscosity resulting breakthrough with period of two-phase production.

laboratory experiments to study the performance of waterflood under unfavorable mobility ratios [4].

They summarized that the sweep was controlled by viscous fingering, with movable water dramatically lowering the oil recovery, and they highly recommended lowering the mobility ratio by adding polymer would enhance oil sweep and recovery efficiency significantly. When polymer is added to the displacing fluid, the mobility ratio would be effectively lowered and resulting in more piston-like displacement and higher sweep efficiency. This scenario is depicted in Figure. (II-2) (b).

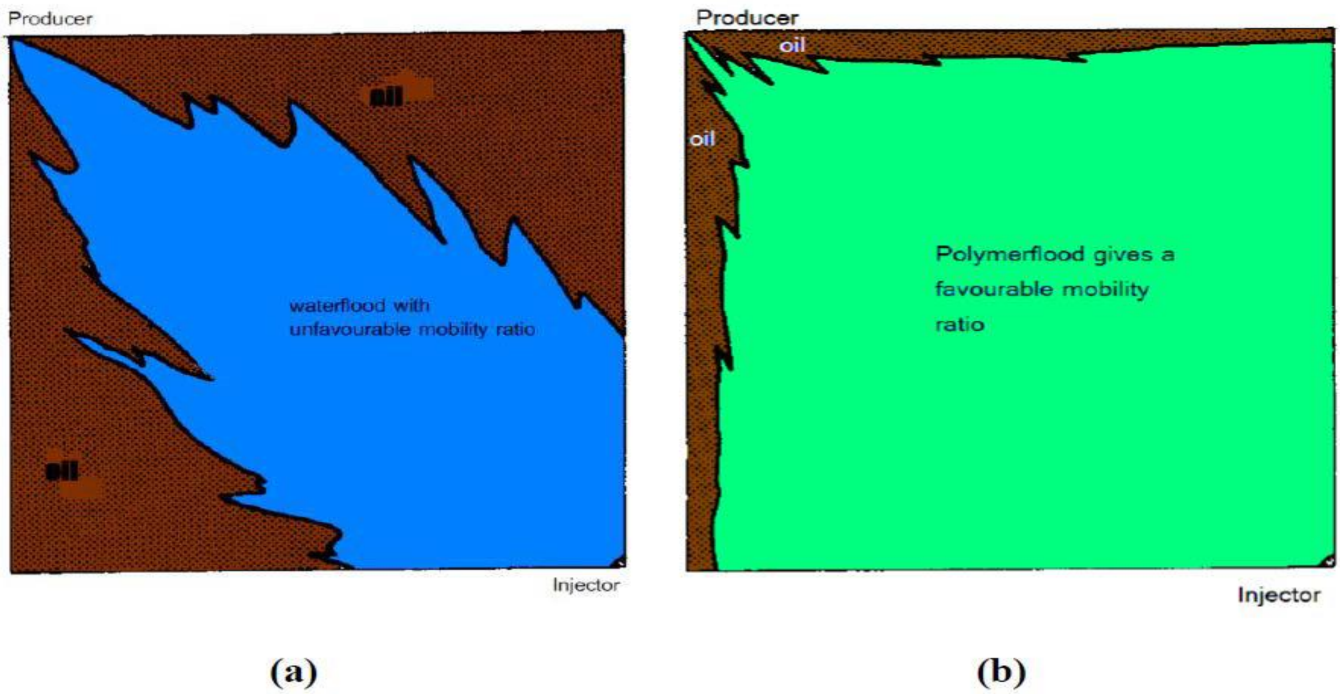


Figure II-2 Favorable and unfavorable mobility ratio influences on sweep efficiency

C. *Fractional Flow*

Fractional flow is another key concept related with polymer flooding. In two-phase immiscible flow, the mobility ratio does not stay constant. It changes as the saturation of flowing phase changes.

The fractional flow equations for water and oil as they flow with one another through a reservoir are written as follows:

$$f_w = \frac{q_w}{q_w + q_o} = \frac{1}{1 + \frac{k_{ro}\mu_w}{k_{rw}\mu_o}} = \frac{1}{1 + \frac{1}{M}}$$

$$f_o = \frac{q_o}{q_w + q_o} = \frac{1}{1 + \frac{k_{rw}\mu_o}{k_{rw}\mu_o}}$$

As explained earlier, adding polymer to the displacing water, would increase water viscosity, µw, and lower the relative permeability to water. This can be explained more through the denominator in Equation is the value of denominator increases, the fractional flow of water decreases, which will enhance the oil recovery efficiency [4].

D. *Resistance Factor*

The resistance factor is a term that represents the resistance in the flow of polymer solution due to the decrease in the number of flow paths by polymer retention. For example, a resistance factor of 10 times means that it is 10 times harder for polymer solution to flow through porous media than plain water. While water has a viscosity of 1 cp in the standard conditions, polymer solution has an apparent viscosity higher than the actual viscosity measured in viscometer. Resistance factor provide a good estimation of the apparent viscosity of polymer solution Resistance factor, Rf, is defined as the fraction of mobility of water to the mobility of a polymer solution . Whereas the residual resistance factor, Rrf, is the ratio of the permeability of water before the filtration of a polymer solution to that of after a polymer solution.

$$R_{rf} = \frac{k_w(initial)}{k_w(after\ polymer\ flood)}$$

$$Rf = (kw/\mu w)/(kp/\mu p)$$

The residual resistance factor measures the ability of the polymer to absorb into the pores throats till partly block the porous medium. This provides a sing that resistance factor has a significant effect on the permeability of the porous medium. According to studies by several authors, the permeability depends on resistance factor and that has been proved through correlations. This influence is a required phenomenon in flooding processes as it shows the advantages of the polymer flood [4].

E. Sweep Efficiency

Sweep efficiency is an important factor that, in coupling with mobility ratio, determines the success of a flooding process. The total efficiency factor, E, symbolize the ratio of initial oil in place at the start of a secondary or tertiary displacement process, that can be produced [4] .

E = ED.EAS.EVS

Figure(II-3) represents all three efficiencies. Where:

ED: displacement efficiency

EAS: Aerial sweep efficiency

EVS: vertical sweep efficiency

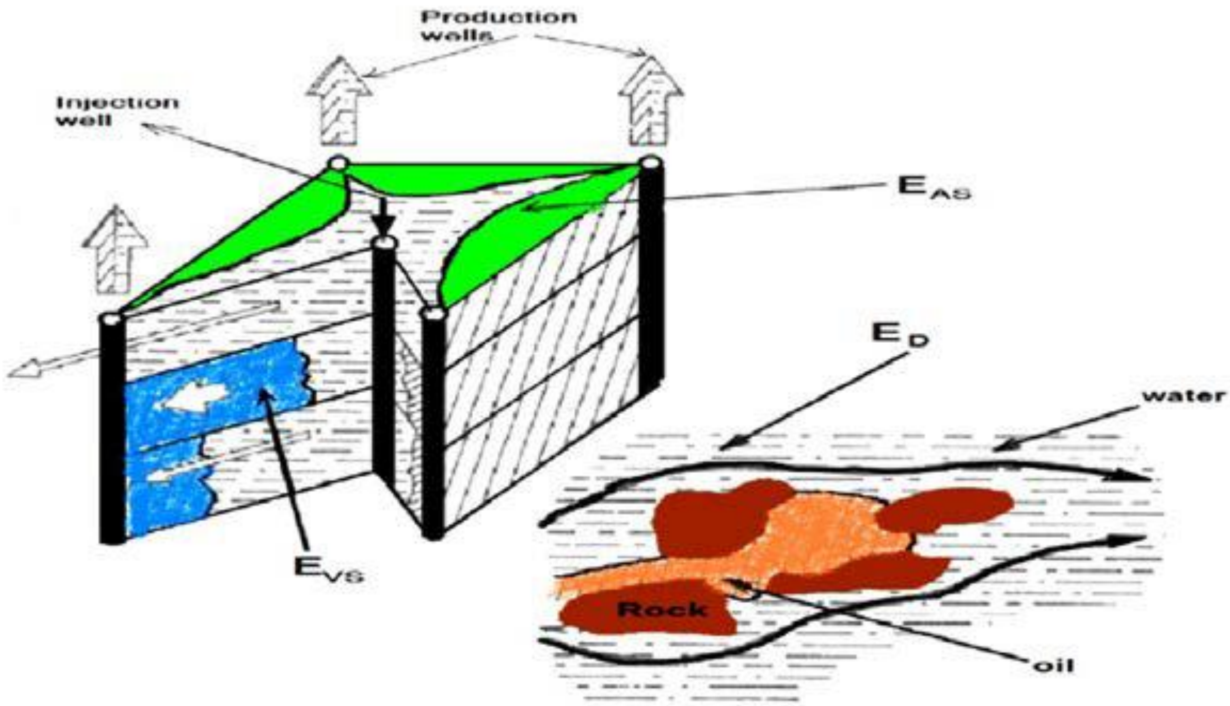


Figure II-3 Sweep efficiencies

1. Displacement Efficiency (ED)

Displacement efficiency, known as microscopic sweep efficiency, is defined as the ratio of the portion of oil displaced from the swept zone by the injected fluid. In waterflooding and polymer flooding operations, ED is calculated using water saturation (Sw) behind the front at the time of breakthrough and initial water saturation (Swi) [4].

ED = (Sw−Swi)/(1−Swi)

2. Volumetric Sweep Efficiency (Ev)

Volumetric sweep efficiency is the ratio of total reservoir volume that is swept by the displacing fluids (water or polymer). Volumetric Sweep Efficiency is the total of the aerial sweep efficiency and vertical sweep efficiency

EA = EAS + EVS

Aerial Sweep Efficiency (EAS)

It is defined as the fraction of the area swept to total area that is contacted by the displacing fluid. It is function of time, volume injected, well pattern, and mobility ratio. It increases steadily from the start of water flood till the breakthrough, and then it continues to increase with slow rate.

Figure (II-4) demonstrates the aerial sweep efficiencies at three different periods of a waterflood operation.

The aerial sweep efficiency equations at different stages of a waterflood operation can be written as following :

$$E_{ASi} = \frac{A_i}{Area\ ABCD} \qquad E_{ASb} = \frac{A_b}{Area\ ABCD} \qquad E_{ASa} = \frac{A_a}{Area\ ABCD}$$

Vertical (or invasion) Sweep Efficiency (EVS)

It is defined as the ratio of vertical height swept to the total vertical pay zone height. It is functional of the vertical heterogeneity which include different permeability, strata, drains and fractures of the reservoir. These factors prevent the uniform movement of the front and are mischievous to sweep . In many situation, vertical sweep efficiency dominates the efficiency of a waterflood more than any other factors [4].

One of the major kind of Heterogeneity is where high permeability strata be next to much lower permeability layers. This kind of heterogeneity causes an early water breakthrough and consequently poor vertical sweep efficiency. The purpose of polymer in flooding process is to lower the mobility ratio to favorable value, which enhances the vertical sweep because of viscous cross-flow influences .

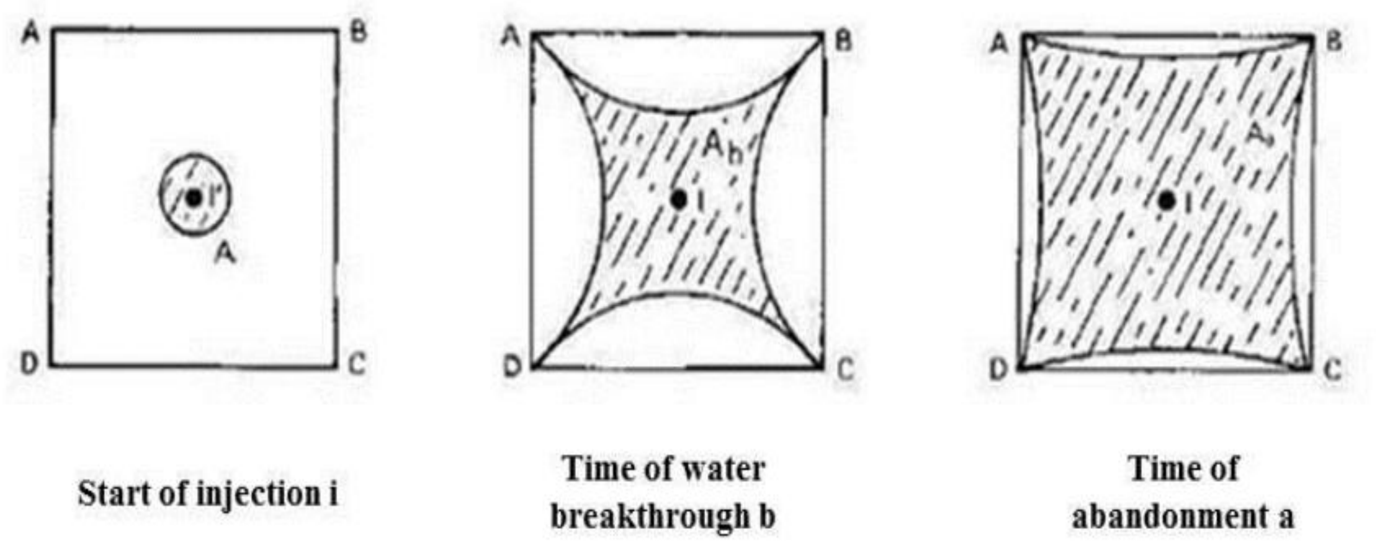


Figure II-4 Aerial sweep efficiency for a five-spot pattern waterflood operation

F. *Selection of an EOR Process and Polymer Screening Criteria*

All the strategies explained have limitations in application. These restrictions have been obtained partly from theory, partly from laboratory experiments, and partly from field experiences. Prospect screening composes of the following:

1. Evaluating available information about the reservoir, oil, rock, water, geology, and previous performance.

2. Supplementing available information with certain brief laboratory screening tests.

3. Selecting those processes that are potentially applicable and eliminating those that definitely are not.

A potential reservoir for one or more enhanced oil recovery processes should not be rejected because it does not fulfill one or two criteria. Each prospect should be studied on its own eligibility by analyzing the many reservoir operational and economic variables.

Screening is the prime footstep in the enhanced oil recovery application series. The next stage would be a further estimation of potential processes if more than one fulfills the screening criteria. Following steps could compose a pilot test design, pilot test application, pilot test evaluation, and a commercial project.

Table (II-1) presents screening criteria based upon oil properties for application of different enhanced oil recovery strategies. The criteria compose the gravity, viscosity, and saturation of the oil [4].

Process	Gravity (°API)	Viscosity (cp)	Composition	Oil Saturation
Water flooding	> 25	< 30	N.C.	>10% PV mobile oil
Hydrocarbon	> 35	< 10	High % of C_2–C_7	> 30% PV
Nitrogen and Flue gas	> 24 Nitrogen > 35 Flue Gas	< 10	High % of C_1–C_7	> 30% PV
Carbon dioxide	> 26	< 15	High % of C_5–C_{12}	> 20% PV
Surfactant/ Polymer	> 25	< 30	Light to intermediate desired	> 30% PV
Polymer	> 25	< 150	N.C.	> 10% PV mobile oil

Table II-1 Screening criteria for Enhanced Oil Recovery processes based on oil properties

Alkaline	13–35	< 200	Some organic acids	Above waterflood residual
Combustion	< 40 (10–25) normally	< 1,000	Some asphaltic components	> 40%–50% PV
Steam flooding	< 25	< 20	N.C.	> 40%–50% PV

Note: PV = Pore Volume; N.C. = Not Critical.

Table II-2 Screening criteria for Enhanced Oil Recovery processes based on oil properties

Steam flooding is mainly used to viscous oils in massive, high permeability sandstones or unconsolidated sands. It is restricted to shallow formations due to heat losses from the wellbore. Heat is also transferred to the adjacent formations once steam contacts the oil-bearing formation. Therefore, adequately high steam injection rates are required to offset for heat losses. The minimum miscibility pressure for effective CO_2 flooding ranges widely. The required pressure can be 1,200 psi for high gravity oil (more than 30 °API) at lower temperatures to more than 4,500 psi for heavy crudes at higher temperatures.

To satisfy this requirement, the reservoir has to be deep enough to achieve the minimum miscibility pressure. For an example, the minimum miscibility pressure for West Texas CO_2 floods is around 1,500 psi at depths of more than 2,000 ft. On the other hand, more than 4,500 ft. deep reservoirs are needed for effective NO and high-pressure hydrocarbon miscible floods.

Table (II-3) presents screening criteria based upon reservoir characteristics for application of the various enhanced oil recovery processes. The criteria include formation type, net thickness, average permeability, depth, and temperature [4].

Process	Formation Type	Net Thick. (ft)	Average Perm. (mD)	Depth (ft)	Temp. (°F)
Waterflooding	Sandstone or carbonate	N.C.	N.C.	N.C.	N.C.
Hydrocarbon	Sandstone or carbonate	Thin unless dipping	N.C.	>2,000 ()	N.C.
Nitrogen and Flue gas	Sandstone or carbonate	Thin unless dipping	N.C.	> 4,500	N.C.
Carbon dioxide	Sandstone or carbonate	Thin unless dipping	N.C.	> 2,000	N.C.

Note: N.C. = Not Critical.

Table II-3 Screening criteria for Enhanced Oil Recovery processes based on reservoir properties.

Polymer	Sandstone preferred; carbonate possible	N.C.	> 10 (normally)	< 9,000	< 200
Alkaline	Sandstone preferred	N.C.	> 20	< 9,000	< 200
Combustion	Sand or sandstone with high porosity	> 10	> 100	> 500	> 150 preferred
Steam flooding	Sand or sandstone with high porosity	> 20	> 200	300–5,000	N.C.

Note: N.C. = Not Critical.

Table II-4 Screening criteria for Enhanced Oil Recovery processes based on reservoir properties.

Thermal floods are mainly used with heavy viscous oils. Steam floods are used for oil with gravity less than 25 °API, viscosity more than 20 cp, and oil saturation more than 40% PV. Higher viscosity with less than 100 cp may be applied for combustion floods. Hydrocarbon, nitrogen, carbon dioxide, and surfactant floods are usable to higher oil gravities and lower oil saturation than that for steam floods. Evaluating of those operations that are possibly applicable for enhanced oil recovery methods is a substantial step, as a result excluding those that absolutely are not [4].

A candidate reservoir for one or more enhanced oil recovery methods should not be rejected because it does not match with one or two standards. Each prospect should be estimated on its own eligibility by analyzing several oilfield operational and economic variables Figure (II-5) shows a proposal from Kaminsky et al. who organized a process for EOR application analysis and development.

After a decision to go ahead and apply polymer flooding, all possible EOR polymers should be evaluated and screened. Because not all polymers are applicable for every oilfield, it is very necessary to perform a detailed feasibility study before choosing a polymer for the given reservoir conditions. In Figure (II-6) detailed Screening parameters for polymers are shown[4].

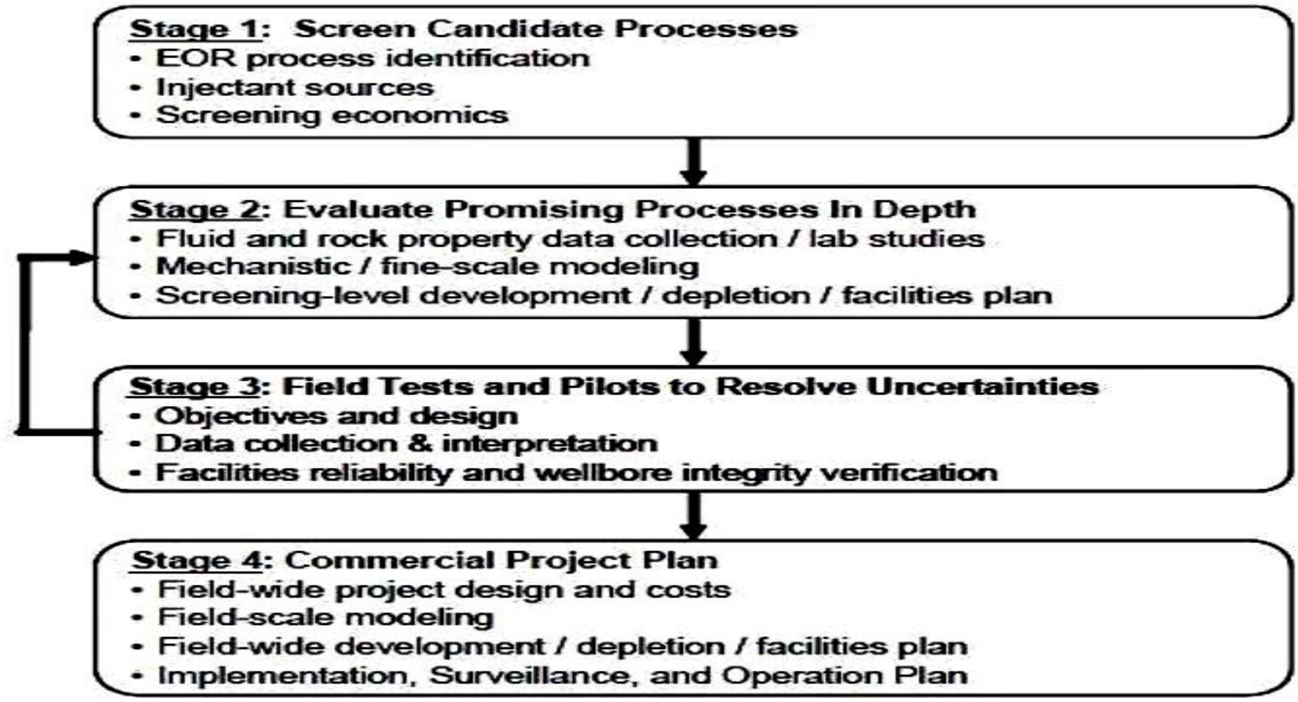


Figure II-5 Organized process for EOR application analysis and development (Kamisnky et al., 2007)

Polymer screening is the prime step in a polymer flooding project. Once the first screening is achieved, a detailed project evolution is performed. In 2007, Kaminsky et al concluded an organized process for polymer flood evaluation and development and it is shown in Figure.(II-6)

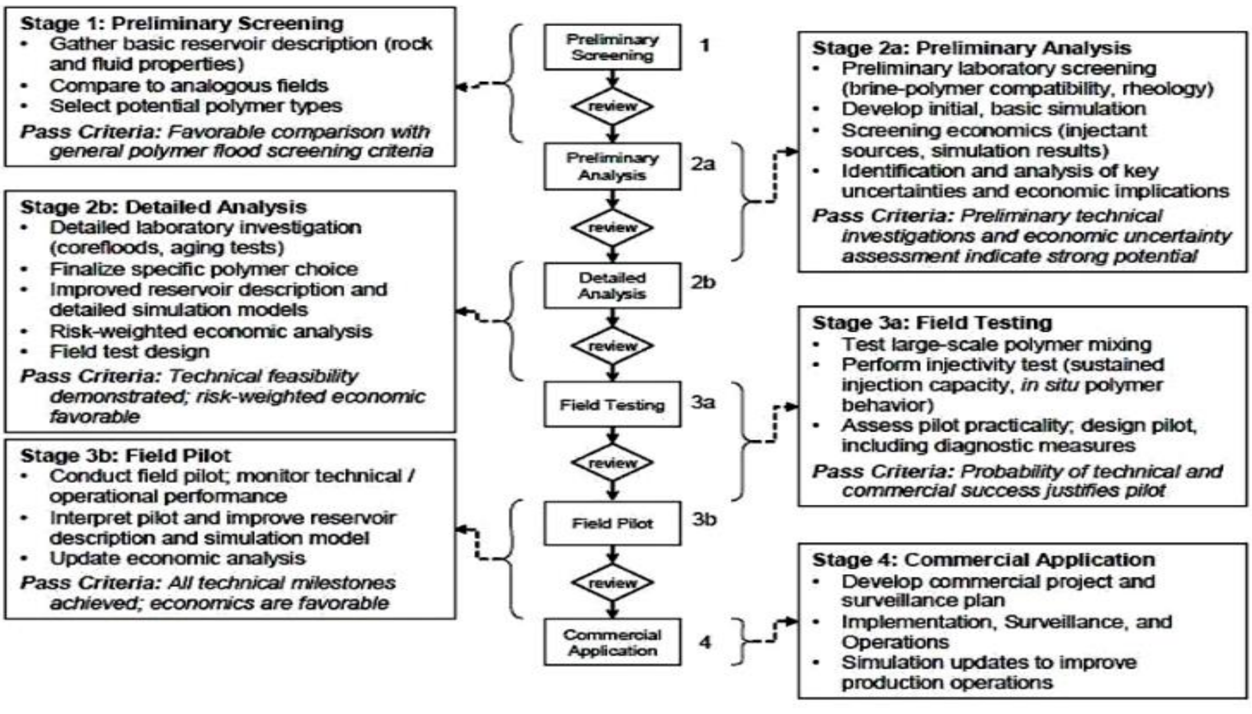


Figure II-6 Polymer project evaluation and development steps

III. FLOOD PATTERNS

A. *Introduction*

The frontal advance theory assumes that flow between injections and producing wells is linear (all flow paths are straight lines) and that 100 percent of the reservoir pore volume is contacted by injected water. Although this behavior may be approximated in some elongated reservoirs, ideal linear flow would be possible only if fluids could be injected into, and produced from, the entire reservoir cross section rather than through the limited area of a wellbore. This problem is complicated further by the fact that most fields are developed, and water flooded, using some regular well pattern. Looking at these fields areally, both injection and production take place at points. If the patterns are symmetrical, the shortest travel path and the largest pressure gradient will occur along a straight line between producers and injectors. Accordingly, the injected water which travels along this streamline will reach the producing wells first. Water traveling along longer streamlines will not have reached the producing well at the time of breakthrough and, consequently, part of the reservoir will not have been contacted by water at that time. That fraction of a water flood pattern which has been contacted by water at a given time during a flood is referred to as the pattern sweep efficiency, Ep or areal sweep efficiency, Technically, pattern sweep efficiency should be used when referring to field applications, and areal weep efficiency should only be used when referring to the results of model studies; practically, however, most engineers use the term areal sweep efficiency for all situations.

In general, areal sweep efficiency will depend upon the mobility ratio, the geometric configuration of the flood pattern, reservoir heterogeneities and the amount of water injected into the pattern area.

Also it known as injection pattern, the particular arrangement of production and injection wells.

The injection pattern for an individual field or part of a field is based on the location of existing wells, reservoir size and shape, cost of new wells and the recovery increase associated with various injection patterns. The flood pattern can be altered during the life of a field to change the direction of flow in a reservoir with the intent of contacting upswept oil.

It is common to reduce the pattern size by infill drilling, which improves oil recovery by increasing reservoir continuity between injectors and producers. Common injection patterns are direct line drive, staggered line drive, two-spot, three-spot, four-spot, five-spot, seven-spot and nine-spot. Normally, the two-spot and three-spot patterns are used for pilot testing purposes. The patterns are called normal or regular when they include only one production well per pattern.

Patterns are described as inverted when they include only one injection well per pattern [5].

B. *Basic Flood Patterns*

Although many older fields were developed using an irregular well spacing, a better understanding of reservoir mechanics and conservation principles in recent years has resulted in relatively uniform well spacing and drilling patterns. At the time a water flood begins, a field is generally completely developed. Since infill wells are expensive to drill and equip, we will generally have to work with the well patterns that exist. Accordingly, field should be developed on a pattern that will be suitable for subsequent enhanced recovery operations.

For this reason, a basic understanding of the commonly used flood patterns is needed [5].

1. Direct line drive

As noted previously, the only way to achieve 100 percent areal sweep at the time of breakthrough would be to inject fluid over an entire vertical plane. This is not physically possible but can be approached somewhat with a pattern where the producing and injection wells directly offset each other. The sweep efficiency of this pattern, depicted by Fig. (III-1), improves as the d/a ratio increases, where d is the distance between adjacent rows of producers and injectors, and a is the distance between adjacent wells in a row. The relationship between (d/a) and areal sweep efficiency is presented in Fig. (III-2) for a unity mobility ratio. It should also be noted that the ratio of producers to injectors is unity for this pattern [5].

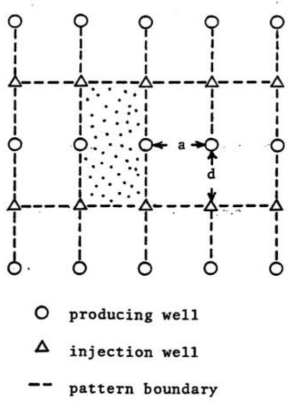
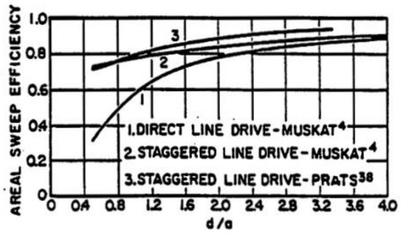


Figure 0-1 Direct line drive



: Flooding efficiency of direct line (1) and staggered line drive (2 and 3) well networks as a function of d/a. Mobility ratio = 1 (Ref. 1).

Figure 0-2 Flooding efficiency of direct line

2. Staggered line drive

As shown by Fig. (III-3), the staggered line drive is simply a modification of the direct line drive where rows of producing and injection wells are moved in such a manner that wells in alternate rows are displaced one-half the inter-well distance [5].

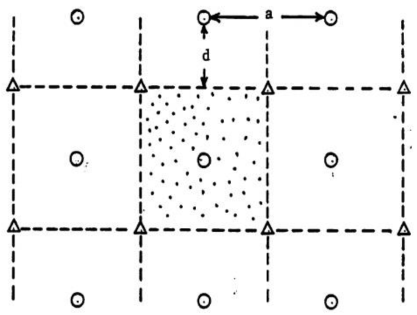


Figure 0-3 Staggred line

3. Five-Spot

The five-spot pattern, depicted by Fig. (III-4), is a special case of the staggered line drive where the d/a ratio is 0.5. This is the most commonly used flooding pattern resulting primarily from the regular well spacing required, or at least used, in most areas. Note that the drilling pattern required to have a five-spot is square, and that the ratio of producers to injectors is unity. The five-spot is a highly conductive pattern since the shortest flow path is a straight line between the injector and producer. Also, the pattern gives good sweep behavior. The square drilling pattern which yields the five spot is also flexible enough that other flood patterns can be generated simply by rearranging the position of the injection and production well like the nine-spot [5].

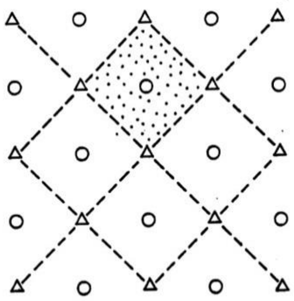


Figure 0-4 Five Spot

4. Nine-Spot

This pattern, illustrated by Fig. (III-5), can be developed from a square drilling pattern. The injection well placement for this pattern leads to an injection-production well ratio of three. This type of system is very useful if a high injection capacity is needed due to low permeability or similar problems. The inverted nine-spot is probably used more than the normal nine-spot. In this case, producing wells outnumber injection wells by a factor of three. The inverted pattern is useful where fluid injectivity is high [5].

One of the major advantages of the nine spot is flexibility. Directional movement of water and premature breakthrough in certain wells can necessitate major conversions in flooding patterns. Some patterns are very difficult and expensive, to convert, and may require extensive infill drilling. The inverted nine-spot, however, can be revised to result in a 1:1 injector-producer ratio pattern, either five-spot or line drive, with minimum effort.

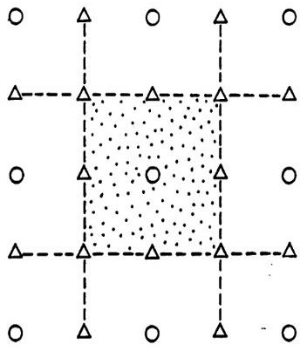


Figure 0-5 Nine Spot

This pattern, depicted by Fig (III-6), has two injection wells per producer and has merit where injectivity is low. Very seldom, however, will a field that is already developed have this pattern.
The pattern required is an equilateral triangle, or can be considered a staggered line pattern with a d/a ratio of 0.866. If a field is not developed on this pattern, too many infill wells are generally required to make the pattern feasible.
An inverted seven-spot is also used occasionally. This pattern, also termed a four a pot, has two producers per injector [5].

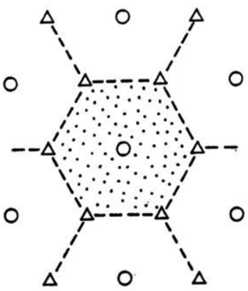


Figure 0-6 Seven Spot

IV. CLASSIFICATION OF CHEMICAL FLOODING

The chemical flooding EOR can be categorized into the Following :

1. Polymer flooding.
2. Surfactant flooding.
3. Surfactant-polymer flooding.
4. Alkaline flooding.
5. Alkaline-surfactant-polymer flooding.

A. *Polymer flooding*

In concept, a water-soluble polymer is used to reduce the mobility ratio of water-oil by increasing the water viscosity which improves the volumetric sweep efficiency. The mechanism of polymer flooding is to increase the water viscosity and also to reduce the permeability of the rock to water, in other words, to reduce the water-oil mobility ratio close to unity or less [1-6].

Over the past years, polymer floods projects have been applied over a wide range of conditions:

- Reservoir temperatures [46–235] °F.
- Average reservoir permeability [0.6–15,000] mD.
- Oil viscosity [0.01–1494] cP.
- Net pay thickness [4–432] ft.
- Remaining oil at start-up [36–97] % of OOIP.

Polymers have been used in oil production in three modes; as near-well treatments to improve the performance of water injectors or watered out producers by blocking off high conductivity zones, agents that may be cross-linked in situ to plug high conductivity zones at depth in the reservoir and agents to lower water mobility or water-oil mobility ratio. Polymer flooding is suited for reservoirs where normal water floods fail due to one of the two reasons: High Heterogeneity and High oil water mobility ratio which is targeting the oil in areas of the reservoir that have not been contacted efficiently [1-7].

The main economic limitation is the cost of polymers is. For example, if the cost of acrylamide/acrylate copolymers and xanthan polymers were substantially lower and higher polymer concentrations with larger polymer flood bank sizes could be granted in a given application. It would improve oil-recovery efficiencies, wider ranges of potential applications, and higher profits. Polymer flooding is showing promising results, specifically, if flooding projects are started at high remaining oil saturations. Polymer flooding has been conducted in sandstone and carbonate reservoirs, and oil-wet, water-wet, and mixed-wettability reservoirs [1-8].

1. Mechanism

The main effect of the polymer is the enhancement of the water-oil mobility ratio to be unity or less, the mobility is calculated from the following equation: [6]

$$M_o = \frac{K_w}{K_o} * \frac{\mu_o}{\mu_w} = \frac{K_{rw}}{K_{ro}} * \frac{\mu_o}{\mu_w}$$

where

Mw−o : the water − oil mobility ratio
Mw : the water mobility
Mo : the oil mobility
Kw : the effective permeability to water, mD
Ko : the effective mobility to oil, mD
μo : the oil viscosity, cP
μw : the water viscosity, cP
Krw : the relative permeability to water
Kro : the relative permeability to water

As per this equation, it is clear that in order to drive the mobility ration to be unity or less, the water viscosity is increased by adding the water-soluble polymers to the injected water as shown in Figure (IV-1), when the displacing fluid (water) viscosity is lower than the oil, the recovery efficiency decreases as the remaining oil after this flooding is about 45% of the OOIP at 0.1 viscosity ratio. On the other hand, once the viscosity ratio reached to 1 (polymer added to water) the remaining oil after the flooding will be reduced to 20% of the OOIP. As summary, the highest viscosity ratio is the highest oil recovery [9].

2. Polymer flooding advantages

The advantages of polymer flooding could be summarized as following: [10]

1. Applicable over a wide range of conditions.
2. A reduction in the quantity of water required to reduce the oil saturation to its residual value in the swept portion of the reservoir.
3. An increase in the areal and vertical coverage in the reservoir due to a reduced water flood mobility ratio
4. Diverting the injected from swept zones.
5. Promising for heavy oil application.
6. Cost-effective.

3. Polymer flooding limitations

1. High oil viscosities require a higher polymer concentration.
2. Results are normally better if the polymer flood is started before the water oil ratio becomes excessively high.
3. Clays increase polymer adsorption.
4. Some heterogeneity is acceptable, but avoid extensive fractures.
5. Lower injectivity than with water can adversely affect oil production rates in the early stages of the polymer flood.
6. Xanthan gum polymers cost more, are subject to microbial degradation, and have a greater potential for wellbore plugging.

A summary statistical data for field projects of polymer flooding as shown in table (IV-1)

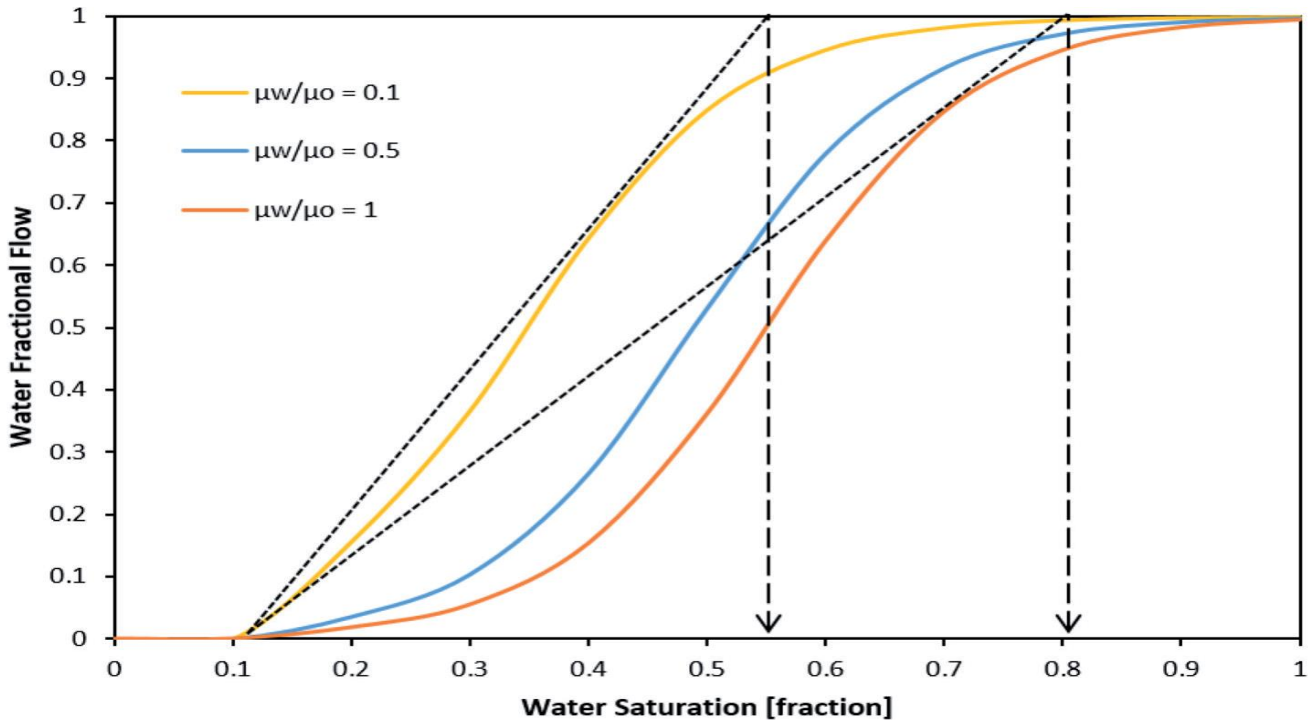


Figure 0-1 Effect of viscosity ratio on the fractional flow curve.

Parameter(s)	No. of Projects	Mean
Depth, ft	87	4000
Temperature, F	88	117
Permeability, mD	80	453
Oil Viscosity, cP	82	21.5
Polymer Concentration, ppm	48	279
Oil Recovery, % OOIP	20	4

Table 0-1 A summary of statistical data for field projects.

B. Surfactant flooding

Correctly designed surfactants can create micro emulsions at the interface between oil and water phases, which cause a reduction in the interfacial tension (IFT) that consequently will mobilize the residual oil which improving the oil recovery as shown in Figure (IV-2) This method of EOR is a challenging one by many factors such as rock adsorption of the surfactant and co-surfactant, and the chromatographic separation of the surfactant during the injection in the reservoir. The designed surfactants should be resistant and active at reservoir conditions which could by at higher pressure, temperature and water salinities [11].

In the surfactant flooding the phase behavior is the most important factor to make it successful. Currently, there is no EOS model to describe the phase behavior in these systems. Consequently, phase behavior studies should be observed experimentally which is challenging to mimic the reservoir conditions. Surfactant solutions are used to reduce the oil-water IFT, while the co-surfactants are mixed with these solutions in order to enhance the properties of the surfactant solutions. The co-surfactants added to the solutions are serving as an active agent or a promoter.

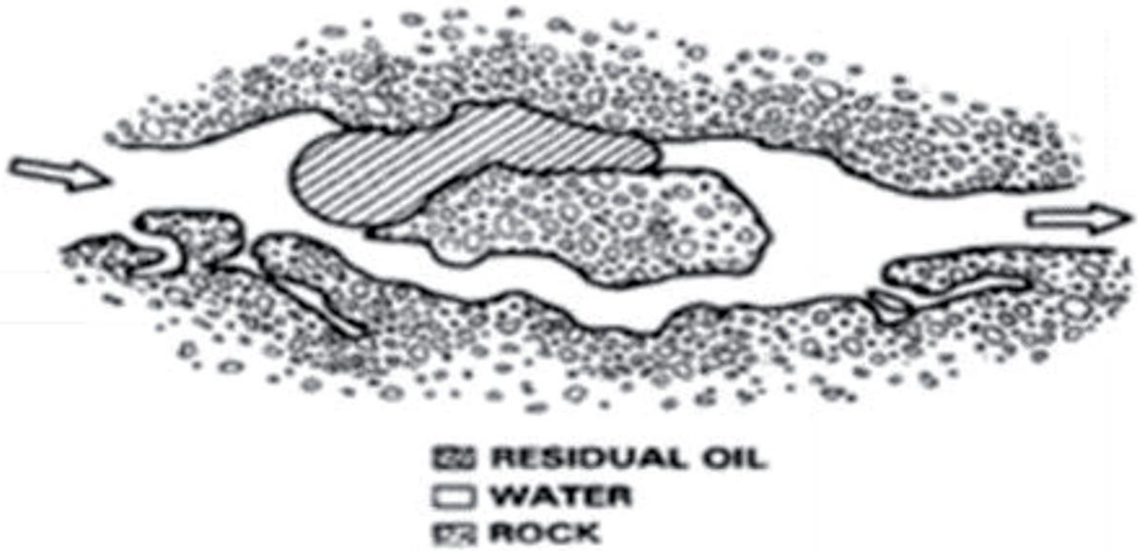


Figure 0-2 Principle of flooding

where residual oil is trapped in the reservoir, for the movement of oil through the narrow capillary pores, very low oil/water interfacial tension (IFT) is required in the mixed solution in order to enhance the surfactant effectiveness with respect to temperature and water salinity as it is well known that surfactant flooding is sensitive to reservoir temperature and salinity [6].

1. Mechanism

A surfactant is added to an aqueous fluid and co-surfactant is also added in order to prepare the surfactant solution and injected into the reservoirs as surfactant flooding reduces the interfacial tension between the oil and water phases and also alters the wettability of the reservoir rock in order to mobilize the residual oil trapped in the reservoir which improves the oil recovery as shown in Figure (IV-2)
The surfactant selection is a critical stage in designing the surfactant flooding projects as the Anionic surfactants preferred due to the following reasons:

1) Low adsorption at neutral to high pH on both sandstones and carbonates.
2) Can be tailored to a wide range of conditions
3) Widely available at low cost in special cases.
4) Sulfates for low temperature applications.
5) Sulfates for high temperature applications.
6) Cationics can be used as co-surfactants.

On the other hand, the Non-ionic surfactants have not performed as well for EOR as anionic surfactants. Sulfonated hydrocarbons such as alcohol propoxylate sulfate or alcohol propoxylate sulfonate are commonly used for Surfactant flooding.

2. Surfactant flooding advantages

The surfactant flooding has several advantages and some of them are listed below: [12]

1. Very effective in lab test [high oil recovery].
2. Surfactant modeling is relatively simple with only a few well-designed experiments needed to provide the most important simulation parameters.
3. Recent developments in surfactants solutions for EOR have effectively reduced the required surfactant concentration which lowering the chemical costs required.
4. Recently, new and effective surfactants are derived from plant resources such as sunflower oil, soy and corn oil. It is non-toxic, non-hazardous, and readily biodegradable.

3. The disadvantages of surfactant flooding

1. Complex and expensive system.
2. Possibility of chromatographic separation of chemicals.
3. High adsorption of surfactant.
4. Losing its effectiveness at higher pressure, temperature, and salinity.

C. Surfactant-polymer (SP) flooding

Surfactant-polymer flooding process is injecting a chemical slug that contains water, surfactant, electrolyte (salt), usually a co-surfactant (alcohol), followed by polymer-thickened water. In this process a surfactant is added to the polymer solution that has the affinity for both water and oil. The use of the micellar solution is to reduce the interfacial tension of the water-oil system in the reservoir in order to displace the residual oil.
SP flooding method was patented for Marathon Oil co. by Gogarty and Tosch known as Mara-flood. The injection profile of the method consists of injecting a pre-flush (to achieve the desired salinity environment), followed by micellar slug (surfactant, co-surfactant, electrolyte), and followed by polymer solution along with drive water. The micellar solution composition that ensures a gradual transition from the displacement water to the displaced oil without interface is as following: [1]

• Surfactant 10–15%.
• Water 20–60%.
• Oil 25–70%.
• Co-surfactant 3–4%.

Usually, the co-surfactant is alcohol which enhances the possibility for the micellar solution to include oil or water. This surfactant-polymer flooding reduces the oil-water IFT through the surfactant portion and reduces the mobility ratio through presence of polymer.

1. Mechanism

The micellar solution is prepared using inorganic salts (water-soluble electrolytes) in order to gain better viscosity control of the solution. A polymer slug is used to drive the micellar solution slug in order to get a mobility control. The injection process is shown in Figure (IV-3) The technique establishes low oil-water IFT and controls the mobility ratio which forming a considerable oil bank to be produced [11].

2. Surfactant-polymer flooding advantages

The SP flooding advantages are listed below:

• Interfacial tension reduction (improves displacement sweep efficiency).
• Mobility control (improves volumetric sweep efficiency).
• Reduce adsorption of expensive surfactants.

3. Surfactant-polymer flooding disadvantages

• Complex and expensive system.
• Possibility of chromatographic separation of chemicals.

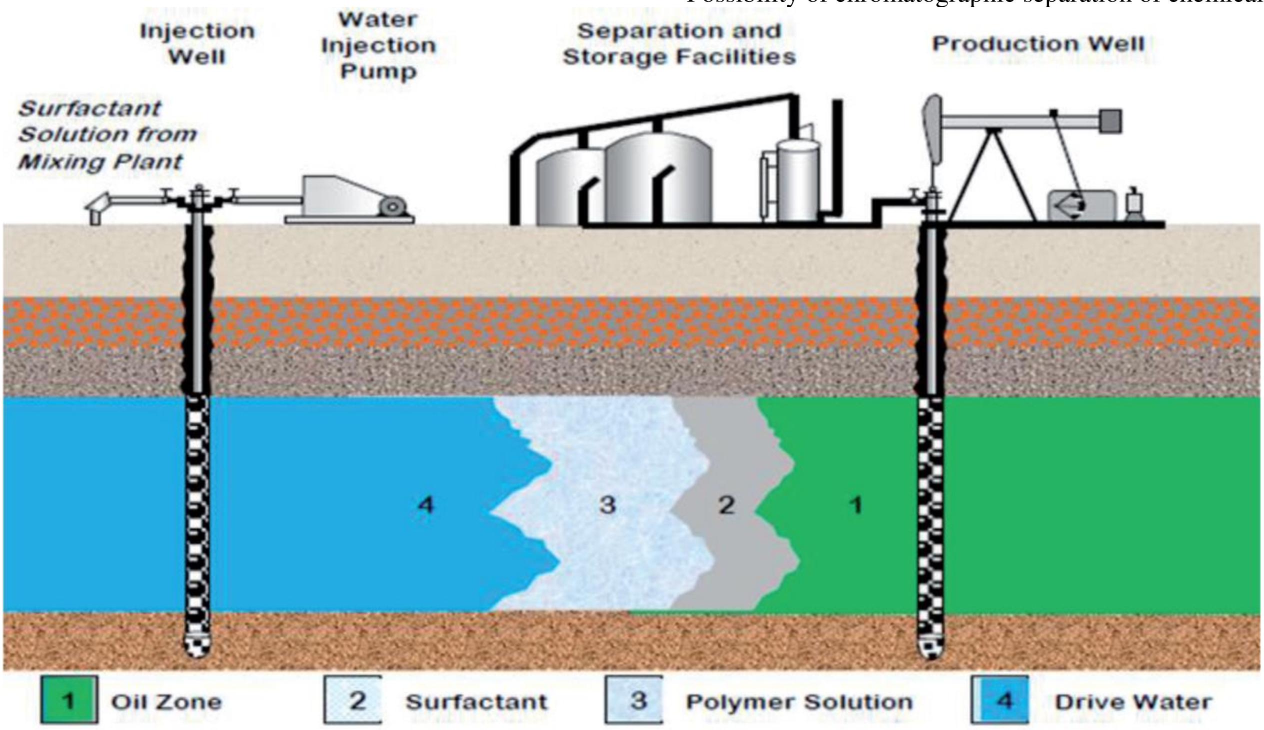


Figure 0-3 Surfactant-polymer injection process

• High adsorption of surfactant.
• Interactions between surfactant and polymer.
• Degradation of chemicals at high temperature.

D. Alkaline flooding

Alkaline flooding is one of the EOR methods in which alkaline agents are injected into the reservoir to produce in situ surfactants, so the alkaline flooding will eventually have the same effect of the surfactant flooding.

1. Mechanism

In the Alkaline flooding process, the alkaline agents such as sodium hydroxide solution is injecting into the reservoirs which react with the naturally occurring organic acids in the oil in order to produce surfactants or soaps at the oil-water interface. However, the alkaline agents are less expensive than the surfactant agents, the expected incremental oil recovery by alkaline flooding has not been confirmed by field results and still remains possibility as the process is mainly dependent on the mineral composition of the reservoir rock and its oil [11].

2. Alkaline flooding advantages

This EOR method has the same advantages of the surfactant flooding in addition to that its main advantage over the surfactant is the cost of the alkaline agents are cheap compared to the surfactant agents [1-12].

E. Alkaline-surfactant-polymer (ASP) flooding

Individual chemical flooding processes, alkaline flooding, surfactant flooding and polymer flooding, can be combined differently. The three-component combination, alkaline surfactant-polymer (ASP). The ASP method represents a cost-effective chemical EOR method that yielding high oil recovery (mostly for sandstone reservoirs). ASP flooding is utilizing the benefits of three flooding methods, where oil recovery was enhanced, by reducing IFT, improving mobility ratio, and improving microscopic displacement efficiency [1] The ASP projects in China shows that the incremental oil recovery over water-flooding is 18.9% on the average.

1. Mechanism

Alkaline injection reduces surfactant adsorption and the combination of soap and synthetic surfactant results in low interfacial tension (IFT) in a wider range of salinity. Soap and surfactant make emulsions stable through reduced IFT which improve the sweep efficiency. There is a competition of adsorption sites between polymer and surfactant. Therefore, addition of polymer reduces surfactant adsorption, or vice versa and improves the sweep efficiency of ASP solution [5].

2. Alkaline surfactant-polymer flooding advantages

Several advantages can be summarized as follows:

- Alkali is inexpensive, so it is cost reduction factor.
- Alkali reacts with acid in oil to form soap.
- Provide lower IFT in a wide salinity range.
- Soaps and surfactants produce emulsions that improve the sweep efficiency.
- Polymer and alkaline are reducing the surfactant adsorption.
- The polymer addition improves the sweep efficiency of the ASP solution.
- Carbonate formations are usually positively charged at neutral pH, which favors adsorption of anionic surfactants. However, when (Na_2CO_3) is present, carbonate surfaces (calcite, dolomite) become negatively charged and adsorption decreases several fold.
- High pH also improves micro-emulsion phase behavior.

3. The limitations and challenges for ASP flooding

- Severe scaling in the injection lines with strong emulsification of the produced fluid.
- Polymers are less effective under high water salinity conditions, as the high salt waters degrade the viscosity of polymers.
- Mobility control is critical.
- Laboratory tests must be done with crude and reservoir rock under reservoir conditions and are essential for each reservoir condition.

V. FIELD PROJECTS USING EOR

1. Field projects statistical data of some polymer flooding:

A summary statistical data for field projects of polymer flooding as shown in bellow: [1]

Parameters (s)	No. of projects	Mean
Depth, ft	**87**	**4000**
Temperature, F	**88**	**117**
Permeability, mD	**80**	**453**
Oil Viscosity, cP	**82**	**21.5**
Polymer Concentration, ppm	**48**	**279**
Oil Recovery, %OOIP	**20**	**4**

Table V-1 A summary of statistical data for field projects

2. Field projects of the surfactant flooding:

Many technically successful pilots have been done in addition to several small commercial projects have been completed and several more are in progress. Relatively, homogeneous reservoir formation is preferred. The presence of high amounts of clays, gypsum, or anhydrite is undesirable. For commercially available surfactants, formation-water chlorides should be less than 20,000 ppm and divalent ions (Ca^{++} and Mg^{++}) should be less than 500 ppm. The problems encountered with some of the old pilots are well understood and have been solved and the new generation surfactants will tolerate high salinity and high hardness so there is no practical limit for high salinity reservoirs [13].

3. Field project of the surfactant-polymer flooding:

Since 1990, polymer flood and SP flood have been applied in a few field pilots and expanded field tests [1].

4. Field project of the surfactant-polymer flooding:

There were several pilot tests worldwide such as in Russian Tpexozephoe Field, Hungarian H Field, Whittier Field in California, and North Gujarat Oil Field, India [1].

5. Field projects of the alkaline surfactant-polymer flooding:

There are large field trials that already implemented worldwide showing encouraging results. The following table (Table V-2) shows a summary for the ASP projects or underway since 1980 including the start-up date, oil gravity, Oil viscosity, implementation phase as secondary or tertiary, oil recovered in % of OOIP, and the chemical cost in USD/bbl. In Figure 3, the production results after applying the ASP flooding at the end of the water-flooding phase [14].

Surfactant Enhanced Water Floods

Alkaline Surfactant Polymer Projects Completed or Underway Since About 1980

Field	Owner	Techical	Region	Start	API	Oil Viscosity - cp	Type	Pore Volume Chemical	Oil Recovered % OOIP	Chemicals US Cost/bbl	
Adena	Babcock & Brown	Surtek	Colorado	2001	43	0.42	Tertiary	In progress		$2.45	Na2CO3
Cambridge	Barrett	Surtek	Wyoming	1993	20	25	Secondary	60.4%	28.07%	$2.42	Na2CO3
Cressford	Dome	Surtek	Alberta	1987			Secondary			$2.25	Alkali and Polymer Only
Daquing BS	Sinopec		China	1996	36	3	Tertiary	82.1%	23.00%	$7.88	NaOH - Biosurfactant
Daquing NW	Sinopec	Surtek	China	1995	36	3	Tertiary	65.0%	20.00%	$7.80	NaOH
Daquing PO	Sinopec	Surtek	China	1994	26	11.5	Tertiary	42.0%	22.00%	$5.51	Na2CO3
Daquing XV	Sinopec		China		36	3	Tertiary	48.0%	17.00%	$9.26	NaOH
Daquing XF	Sinopec		China	1995	36	3	Tertiary	55.0%	25.00%	$7.14	NaOH
Daquing Foam	Sinopec		China	1997	NA	NA	Tertiary	54.8%	22.32%	$8.01	ASPFoam Flood following WAG
Daquing Scale Up	Sinopec		China	??	Reported to be Shut In Due to QC Problems with Surfactant						
David		Surtek	Alberta	1985	23		Tertiary			$0.80	
Driscoll Creek	TRUE	Surtek	Wyoming	1998	Acrylamid converted to acrylate - water cut lowered						
Enigma	Citation	Surtek	Wyoming	2001	24	43	Secondary	In progress		$2.49	Na2CO3
Etzikom	Renaissance/Husky	Surtek	Alberta	Current	In progress - Information not released						
Gudong	CNPC	Shenli	China	1992	17.4	41.3	Tertiary	55.0%	26.51%	$3.92	
Isenhaur	Enron	Tiorco	Wyoming	1980	43.1	2.8	Secondary	57.7%	11.58%	$0.83	Alkali and Polymer Only
Karmay	CNPC	UT/NIPER	China	1995	30.3	52.6	Tertiary	60.0%	24.00%	$4.35	
Lagomar	PDVSA	Surtek	Venezuela	2000	24.8	14.7	Tertiary	45.0%	20.11%	$4.80	Single Well Test
Mellot Ranch	West	Surtek	Wyoming	2000	22	23	Tertiary	In progress		$2.51	NaOH
Minas I	Chevron	Chevron	Indonesia	1999	Micellar Polymer Failed when salinity of slug decreased						
Minas II	Texaco	Texaco	Indonesia	Current	Lignin II Surfactant - In progress - Information not released						
Sho Vel Tum	LeNorman	DOE	Oklahoma	1998	26.4	41.3	Tertiary	60.0%	16.22%	$6.40	Low Acid Number - Viscous
Bevery Hills	Stocker	Tiorco	California	Surfactant Injectivity Test							
Tanner	Citation	Surtek	Wyoming	2000	21	11	Secondary	In progress		$2.82	NaOH
West Kiehl	Barrett	Surtek	Wyoming	1987	24	17	Secondary	26.5%	20.68%	$2.13	
West Moorcroft	KSL	Tiorco	Wyoming	1991	22.3	20	Secondary	20.0%	15.00%	$1.46	Alkali and Polymer Only
White Castle	Shell	Shell	Louisiana	1987	29	2.8	Tertiary	26.9%	10.10%	$8.18	*No Polymer*

Table V-3 Field cases of ASP EOR.

VI. CONCLUSIONS

1. Chemical EOR technology is dramatically better than 30 years ago due to more experience, better understanding, better modeling, better enabling technologies and better chemicals at lower cost adjusted for inflation in its in the aforementioned methods, which are as follows:
   - Surfactants to lower the interfacial tension between the oil and water or change the wettability of the rock.
   - Water soluble polymers to increase the viscosity of the water.
   - Surfactants to generate foams or emulsions.
   - Polymer gels for blocking or diverting flow.
   - Alkaline chemicals such as sodium carbonate to react with crude oil to generate soap and increase pH.
2. Chemical EOR, especially ASP, is a complex technology requiring a high level of expertise and experience to successfully implement in the field.
3. At current oil prices, oil companies operating can make a high rate of return using chemical EOR methods.
4. Many of the mature oil fields appear to be suitable candidates for chemical flooding.
5. Many ASP floods made money even at $20/Bbl oil but were under designed for current oil prices.
6. Operators can both increase oil recovery and make more profit by using:
   - larger amounts of surfactant and polymer than used in projects designed in the 90s
   - better geological characterization
   - better reservoir modeling and engineering design
   - better well technologies

- better monitoring and control similar to what evolved over many decades with steam drives and CO2 floods.

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