SIMULATION OF LAB-SCALE HOMOGENOUS FRACTURED BLOCKS

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ABSTRACT

In this paper, we simulate dynamic imbibition on a small scale homogenous fractured block. The purpose is to seek optimum conditions under which the oil recovery is maximal. In order to do this, we consider a base case simulation and then we dosensitivity analyses on several parameters. The injections are all continuous. Various chemical solutions are injected. These include: water, polymer, surfactant, alkali, and different combinations of them. For convenience of simulation, although this is not physically correct, alkali represents the wettability modifying agent, while the surfactant is the agent that lowers the IFT to ultra-low values. Therefore, a simulation labeled AS indicates that the injected chemical solution lowers the IFT to ultra low values as well as alters the wettability from mixed-wet to water-wet. On the other hand, a simulation labeled ASP does the above task as well as making the chemical solution viscous (polymer). The recovery curves are compared for each sensitivity analysis and appropriate profiles are demonstrated in order to understand the results.

KEYWORDS: Chemical-enhanced , ASP flood, Surfactant, Static ,Dynamic .Imbibition Test.

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1. BASE-CASE MODEL DESCRIPTION AND SIMULATION RESULTS

The base case model in this paper is shown in Figure .1. The figure shows the porosity distribution. The blue represents the fracture and the pink represents the matrix. The red arrow shows the injection direction. This is a 1 ft by 0.25 ft by 0.07 ft horizontal fractured block modeled with UTCHEM. There are 31 gridblocks in the X direction, 11 gridblocks in the Y direction and 3 gridblocks in the Z direction. The fractures are modeled as discrete fractures. There are two parallel fractures along the X axis. There are also four parallel fractures along the Y axis, perpendicular to the direction of the injection/production. As shown in the figure, one of these four fractures contains the injection well; two are in the middle and the last one contains the production well. The height of this fractured block is small in order to minimize the effect of gravity. The top, bottom and sides of the block are sealed. The block matrix is homogenous and has a permeability of 30 md. The fractures are also homogenous. The block physical properties for the base case are listed in Table .1.

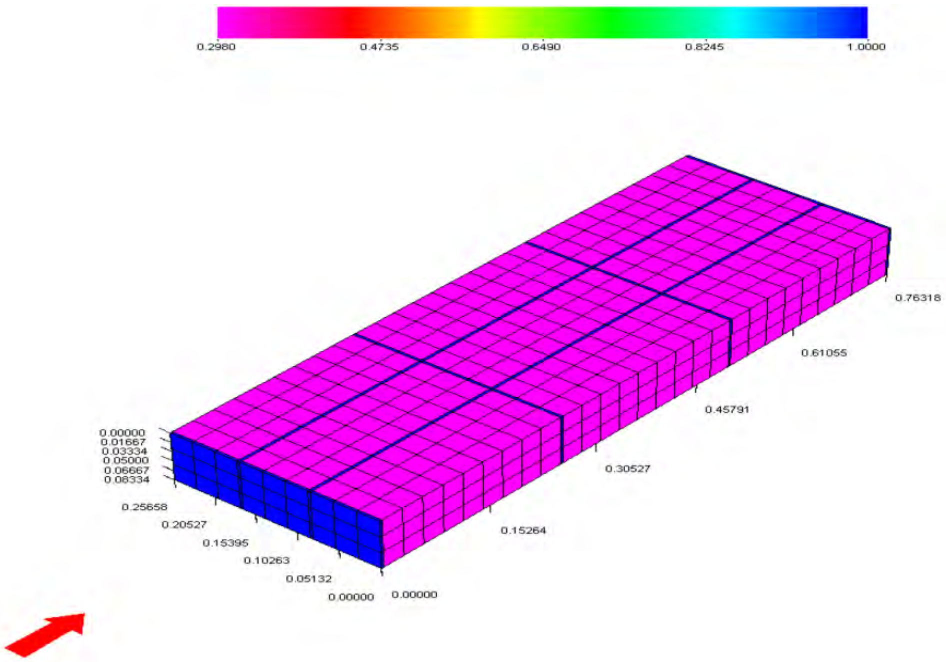

Figure .1 - Reservoir model for the static versus dynamic simulations

Block Length	1 ft
Block Width	0.25 ft
Block thickness	0.07 ft
Matrix size	0.02778 ft by 0.02778 ft by 0.02778 ft
Fracture spacing	0.25 ft in X and 0.0833 ft in Y direction
Aperture	0.003281 ft
Matrix porosity	0.298
Matrix permeability	34 md
Fracture porosity	1
Fracture permeability	2000 md
Total Fracture Porosity	5%
Block dip angle	0

Table .1 - Physical properties for the static versus dynamic simulations

The initial water saturation is 0.14 in the matrix and 0.99 in the fracture. There is a 1 psi pressure drop between the wells. Initially the matrix is mixed-wet. The capillary pressure in the fracture is always zero. The capillary pressure for the matrix is calculated using the Brook-Corey model. In current paper, in all cases where surfactant is involved, surfactant forms a type III microemulsion with oil. Alkali, when present, changes the wettability with a constant value of ω = 0.5. This is an approximation, but it has been found to be convenient to match the experimental data. The Initial condition parameters together with rock and fluid properties for the base case study are listed in Table .2.

Number of phases in the reservoir	Up to 3; water, oil, and microemulsion
Residual water saturation in matrix at low capillary number	0.1
Residual water saturation in fracture at low capillary number	0.05
Initial water saturation in matrix	0.86
Initial water saturation in fracture	0.99
Residual oil saturation in matrix at low capillary number	0.4
Residual oil saturation in fracture at low capillary number	0.35
Initial oil saturation in matrix	0.14
Initial oil saturation in fracture	0.01
Residual microemulsion saturation in matrix at low capillary number	0.1
Residual microemulsion saturation in fracture at low capillary number	0.05
Endpoint relative permeability of microemulsion at low capillary number	0.3 for matrix, 0.4 for fracture
Relative permeability exponent of aqueous phase at low capillary number	2 for matrix, 1.5 for fracture
Relative permeability exponent of oil phase at low capillary number	3 for matrix, 1.8 for fracture
Relative permeability exponent of microemulsion phase at low capillary number	2 for matrix, 1.5 for fracture
Endpoint relative permeability of all phases at high capillary number	1
Relative permeability exponent of all phasea at high capillary number	1
Matrix positive capillary Pressure Endpoint	0.1
Matrix negative capillary Pressure Endpoint	-0.15
Matrix capillary pressure parameter EPC0	3
Matrix critical water saturation SSTAR (transition saturation from Pc+ to Pc-)	0.41
Molecular diffusion coefficients of all components	0
Dispersivity of all phases	0
Surfactant adsorption parameters	AD31: 1.5, AD32: 0.15, B3D:1000
Cation Exchange	N/A
Water viscosity	1 cp
Oil viscosity	10.5 cp
Microemulsion viscosity parameters (These parameters produce an average viscosity of around 20cp)	ALPHAV1 = 2.5 ALPHAV2 = 2.45 ALPHSV3-5 = 0
CMC	0.0005
Lower type III salinity	0.77
Higher type III salinity	1.15
Initial reservoir salinity	0.82

Table .2 - Rock and Fluid Properties for the static versus dynamic simulations

The word "altered", wherever seen in this table, represents the value of the same parameter in a completely water-wet condition.

The injection in the base case includes 5 different scenarios, namely: water only (W), surfactant only (S), alkaline only (A), alkaline-surfactant (AS), and alkaline-surfactant-polymer (ASP). The injection and production wells are vertical, constrained to constant The initial water saturation is 0.14 in the matrix and 0.99 in the fracture. There is a 1 psi word "altered", wherever seen in this table, represents the value of the same parameter in pressures and completed in the leftmost and rightmost fractures, respectively. The well data for the base case study are listed in Table .3.

Number of Injectors	1
Number of producers	1
Distance between injector and producer	1 ft
Perforation layers of injector	All layers
Perforation layers of producer	All layers
Producer BHP	14.7 psi
Injector BHP	14.8 psi & 15.7 psi
Constraint on injector or producer	unlimited injection or production rates
Injected surfactant concentration, if any	2%
Injected alkali concentration	0
Injected polymer concentration	0
Injected salinity	0.94 (inducing phase III microemulsion)

Table .3 - Well Properties for the static versus dynamic simulations

This model contains 1023 grid blocks, 298 of which are fracture grid blocks. The total simulation time is 9 days. The UTCHEM solves the equations using the IMPES technique. The simulation parameters for the base case are listed in Table .4.

Total number of grid blocks	1023
Total number of fracture grid blocks	294
Method of solution	IMPES
Simulation time	9 days - around 2 pore volumes

Table .4 - Simulation Parameters for the static versus dynamic simulations

The base case simulation results are depicted in Figure .2.

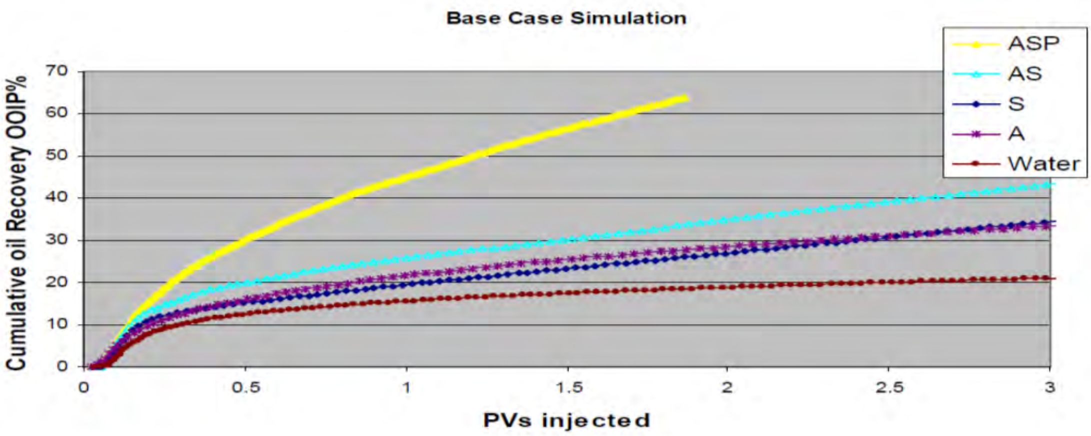

Figure .2 - Base case simulation results

As we can see, AS flooding has a higher and faster oil recovery than A or S alone. However, the behavior of S flooding relative to A flooding is not that simple. Initially curve S starts off faster than curve A, then curve A catches the curve S at around 0.25 pore volumes and stays above it until the S curve catches up finally at 2.5 pore volumes and outperforms it afterwards. capillary pressure as it progresses through the fracture. On the other hand, the water flood recovery is shown to be the poorest. Finally, ASP performs better than all other injection scenarios. The first conclusion from these results is that a viscous chemical recovers more oil than the same chemical solution that is not viscous. In other terms, ASP performs better than AS. Another conclusion is that AS (or ASP) acts better than A, or S alone. Therefore, a chemical solution that alters the wettability as well as reduces the IFT to ultra low values produces more oil at a given pore volumes of the injected fluid.

2. SENSITIVITY ON PRESSURE GRADIENT/INJECTION RATE

To test the effect of pressure gradient or injection rate, all the injection scenarios discussed were tested with a low pressure drop of 0.1 psi/ft, thereby reducing the effect of viscous forces and favoring for effect of capillarity. This is done to examine if the order of increasing oil recovery, observed in the case of 1 psi/ft, still holds.

Those parameters that differ in this simulation from the base case simulation are listed in Table .5.

Pressure gradient	0.1 psi/ft
Chemicals injected	W, S, A, AS, ASP

Table .5 - Sensitivity on pressure drop

The simulation results are demonstrated in Figure .3.

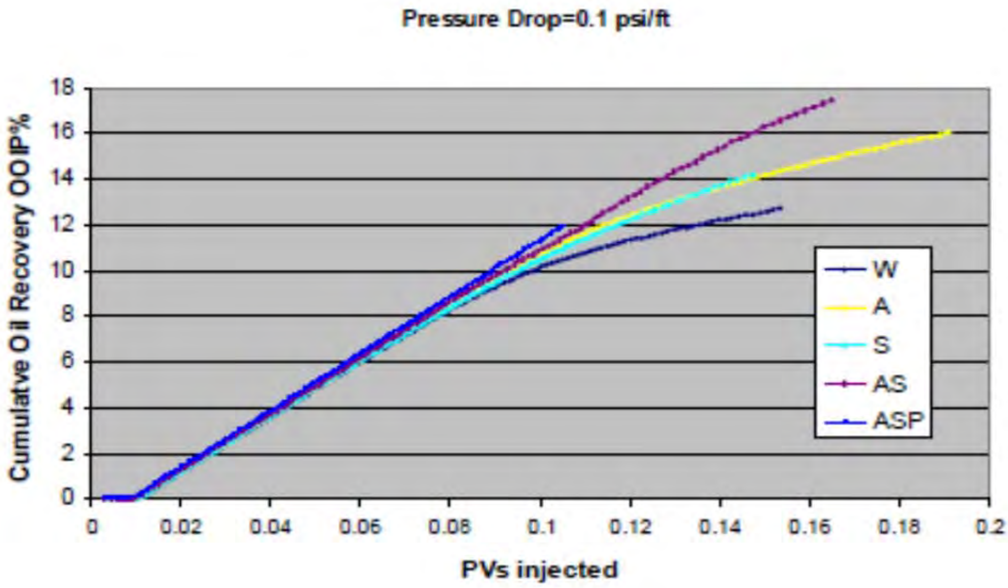

Figure .3 - Sensitivity on pressure gradient

As we can see, AS flooding has a higher and faster oil recovery than A or S alone. However, the behavior of S flooding and A flooding almost look the same up to 0.2 pore volumes which is the total injection time for this simulation. Here the water flood recovery is shown to be the poorest again.

Finally ASP performs better than all other cases. The main conclusion from this sensitivity study is that a viscous chemical recovers more oil than the same chemical solution that is not viscous irrespective of the pressure gradient. In other terms, AS (or ASP) acts better than A or S alone, even for a very low pressure gradient. Therefore, a chemical solution that alters the wettability as well as reduces the IFT to ultra low values produces more oil at a given pore volumes of the injected fluid.[1-3]

3. SENSITIVITY ON DIFFUSION COEFFICIENT

To understand if the diffusion coefficient of the chemical plays an important role here, a sensitivity study has been done. For the sake of this study, we temporarily put the polymer aside and compare the recoveries of the AS, A and S flooding at a nominal diffusion coefficient value and at high and low injection rates. The reason is that adding the polymer does not change the relative behavior of the recovery curves if they happen to be the same as in the base case simulation. Those parameters that differ in this simulation from the base case simulation are listed in Table .6.

Surfactant diffusion coefficient in water/Microemulsion	10^{-6} ft^2/day
Alkali diffusion coefficient in water/Microemulsion	10^{-6} ft^2/day
Pressure gradient	1 psi/ft & 0.1 psi/ft
Chemicals injected	AS, S, A

Table .6 - Sensitivity on diffusion parameter

The simulation results for 1 psi/ft and 0.1 psi/ft pressure drop cases are shown in Figures .4 and .5,

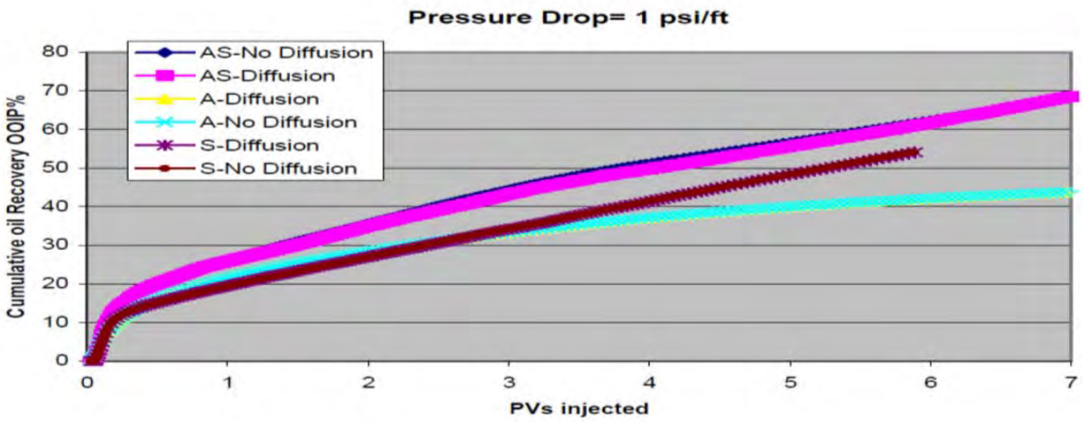

Figure .4- Sensitivity on Diffusion Coefficient, Pressure Drop =1 psi/ft

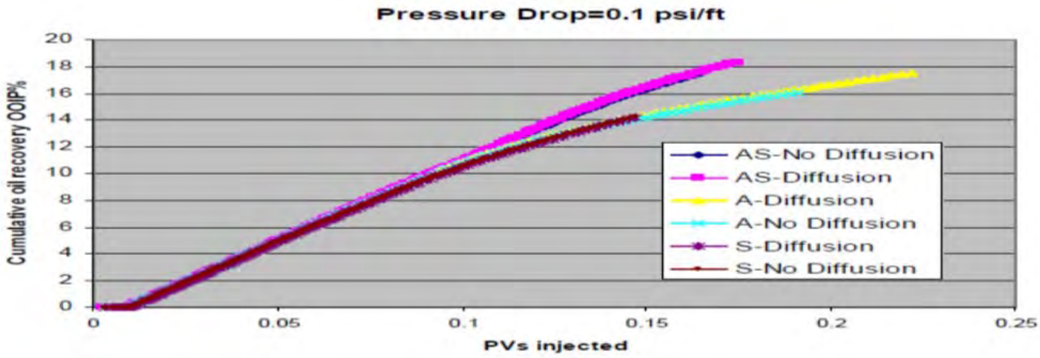

Figure .5- Sensitivity on Diffusion Coefficient, Pressure Drop =0.1 psi/ft respectively. We observe that diffusion does not make a significant difference in Figure .3; neither does it in Figure .4. A direct conclusion is that viscous forces make the effect of diffusion negligible and this is true even in the case of a low pressure drop. Of course, as others have done, it is possible to exaggerate the effect of diffusion by assigning a large value to the diffusion coefficient parameter in models, but then it will not be realistic.[4-5]

4. SENSITIVITY ON CAPILLARY PRESSURE PARAMETERS

We know that the matrix capillary pressure has a significant effect on oil recovery from fractured reservoirs. To understand this effect, we simulate 3 different cases including:
One case with zero capillary pressure endpoint, one with low capillary pressure endpoint and the last one with high capillary pressure endpoint (These are all for matrix. The fracture capillary pressure is always zero). The parameters for this sensitivity study are listed in Table.7.

Positive capillary pressure endpoint	0, 0.3
Negative capillary pressure endpoint	0, -0.45
Chemicals injected	AS, A, S

Table .7 - Sensitivity on capillary pressure

For each case, we simulate 3 injection scenarios, namely A, S, and AS.
The simulation results for surfactant flooding, alkaline flooding and alkaline-surfactant flooding are depicted in Figures .6, .7 and .8, respectively.

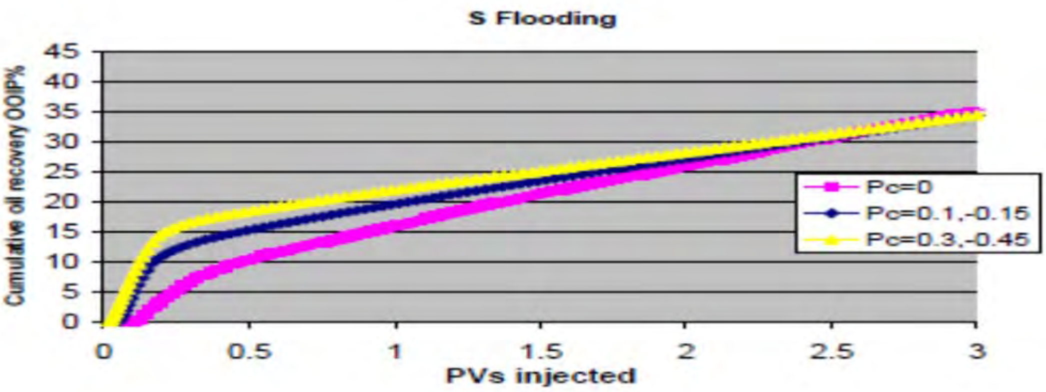

Figure.6 - Sensitivity on Capillary pressure endpoints - Surfactant flooding

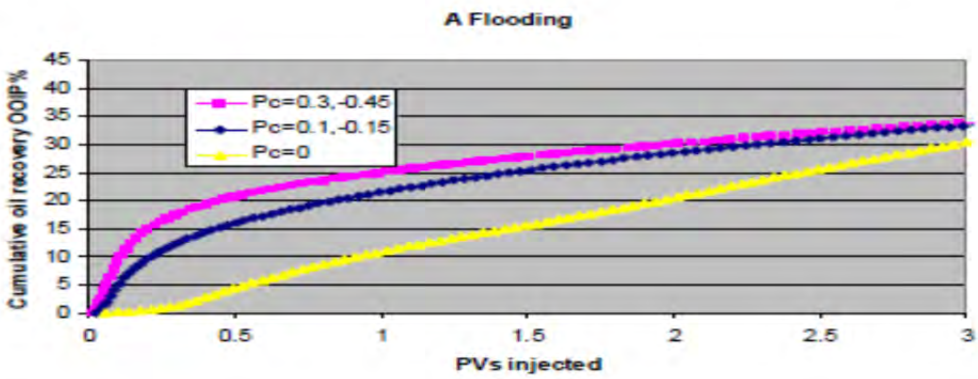

Figure .7 - Sensitivity on Capillary pressure endpoints - Alkaline flooding

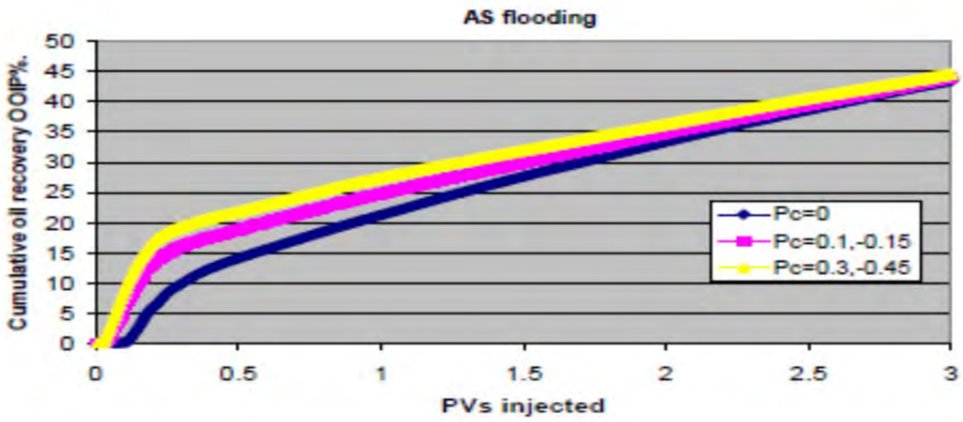

Figure .8 - Sensitivity on Capillary pressure endpoints; Alkaline-Surfactant flooding

Three conclusions can be drawn from these figures. First, increasing the capillary pressure endpoints enhances the oil recovery rate in all three cases. This is more pronounced in the case of alkaline flooding (Figure .7). Second, the effect of capillary pressure on recovery curve diminished after some time; all recovery curves collapse on each other after almost 3 pore volumes. This is consistent with the fact that capillary pressure goes to zero if the critical saturation in a block is reached or if the surfactant concentration has exceeded the CMC in that block. Third, no matter how high the capillary pressure is, injecting an alkaline- surfactant solution produces more oil and produces it faster than injecting the alkali alone or surfactant alone. This can be seen by comparing Figure .8 with Figure .6 and .7. AS flooding results in a recovery of around 45% after 3 pore volumes, while those of A or S flooding do not exceed 35% at the same pore volumes.

5. SENSITIVITY ON MICROEMULSION VISCOSITY

Microemulsion viscosity plays an important role in recovery from fractured reservoirs. This idea is further tested in this section by performing sensitivity simulations on microemulsion viscosity parameters ALPHAV1 and ALPHAV2. We know that increasing these parameters directly increases increase the microemulsion phase viscosity .

Therefore, we investigate whether increasing the microemulsion viscosity enhances or reduces the oil recovery. The new ALPHAV1 and ALPHAV2 values are listed in Table .8.

Microemulsion viscosity parameters	ALPHAV1 = 1 , 5 ALPHAV2 = 1 , 5 ALPHSV3-5 = 0
Chemicals injected	S, AS

Table .8 - Sensitivity on microemulsion viscosity

The simulation results for surfactant flooding and alkaline-surfactant flooding are shown in Figures .9 and .10.

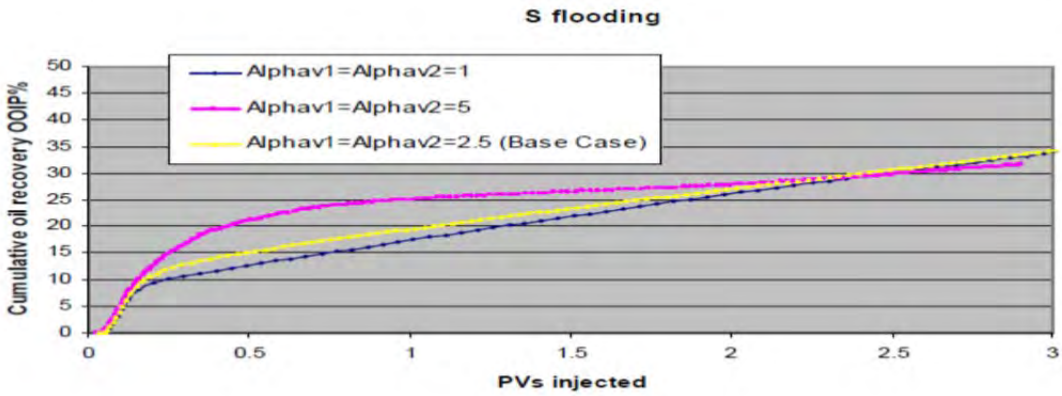

Figure .9 - Sensitivity on microemulsion viscosity - Surfactant flooding

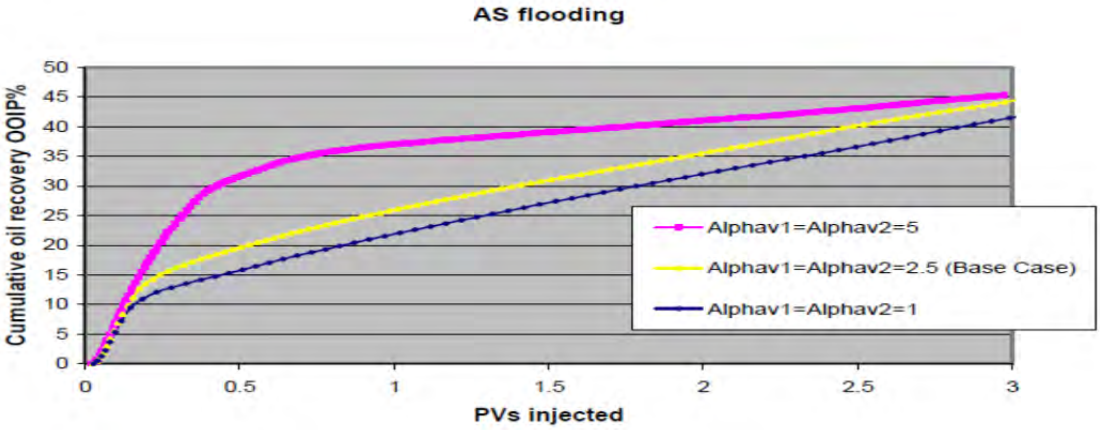

Figure .10 - Sensitivity on microemulsion viscosity - Alkaline surfactant flooding

The effect of increasing the ALPHAV1 and ALPHAV2 values is the same in both figures. In both cases therefore, increasing the microemulsion viscosity enhances the oil recovery versus pore volumes of the injected fluid. The reason is that the existence of microemulsion (mainly in fracture) produces the same effect as the polymer does. Hence, the more viscous the microemulsion, the better the sweep efficiency will be when flooding the fractured reservoirs.[6]

6. SENSITIVITY ON POLYMER PERMEABILITY REDUCTION FACTOR

In order to investigate the effect of polymer permeability reduction factor, we simulated five cases with different permeability reduction factors (CRK). These values can be found in Table.9. The injection is surfactant-polymer here. We want to know whether a higher CRK translates into a higher oil recovery or vice versa.

The simulation results are demonstrated in Figure .11. The recovery consistently increases as the CRK value is raised. For the case of CRK=0.25, the recovery approaches to 50% after 0.7 pore volumes of injection. We should keep in mind that the recovery curves are drawn versus pore volumes, not time. The reason for the observed behavior is that as polymer enters the fracture, it reduces its permeability and therefore the permeability contrast between the fracture and the matrix reduces. An equivalent interpretation is that the effective mobility of the injected fluid reduces as the CRK value is increased and this, in turn, results in a better sweep.

CRK	0, 0.05, 0.18, 0.25
Chemicals injected	SP

Table .9 - Sensitivity on polymer permeability reduction factor

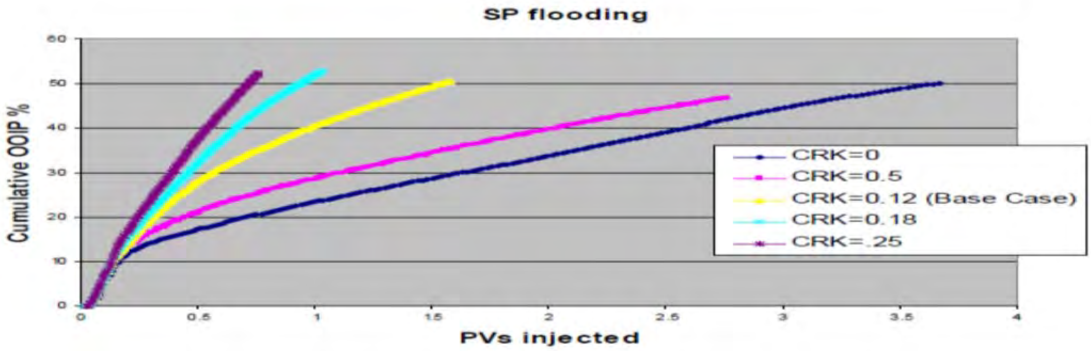

Figure .11 - Sensitivity on polymer permeability reduction factor

7. CONCLUSIONS TO LAB-SCALE SIMULATION FINDINGS

Small-scale simulations indicate that no matter how high the capillary pressure or how low the pressure gradient is, ASP flooding outperforms the other injection scenarios. In other terms, lowering the IFT to ultra values and switching the wettability at the same time produces the best result. Diffusion is also shown to have an insignificant effect on the recovery curve. The simulations show that even a small viscous gradient is more effective than diffusion or capillarity and that lowering the IFT and killing the capillary pressure does not necessarily translate into a lower or slower oil recovery. Polymer is shown to enhance the oil recovery by decreasing the permeability contrast and increasing the sweep. The conclusion to these simulations is that injecting a chemical solution that is viscous, lowers the IFT, and changes the wettability to water-wet is most beneficial.

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