Modeling Polymer Flooding, Surfactant Flooding and ASP (Alkaline, Surfactant, and Polymer) Flooding with ECLIPSE

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Charles A. (Chuck) Kossack

- Education
  - University of Michigan - BS Chemical Engineering, BS Math
  - Stanford University - MS, Ph.D. Chemical Engineering
- Research Engineer at ARCO - 12 Years
  - Developed reservoir simulators
  - Applied simulators

Charles A. (Chuck) Kossack

- Professor Norwegian Institute of Technology (now NTNU) – 4+ Years
  - Compositional Simulation
  - Scale-up Process
  - Simulating Horizontal Wells

Charles A. (Chuck) Kossack

- Independent Consultant – 5+ Years
  - Norsk Hydro - Oslo, Norway
  - AGIP - Milan, Italy
  - BEB - Hanover, Germany
- Schlumberger - 15+ Years
  - GeoQuest:ECLIPSE Support
  - Consulting with GeoQuest Reservoir Technologies- Holditch-Reservoir Technologies - Now SIS Training and Development

Charles A. (Chuck) Kossack

- Courses Taught
  - Applied Reservoir Simulation
  - Equation Of State and PVT Analysis
  - Compositional Simulation, Theory and Applications
  - Simulation of Naturally Fractured Reservoirs
  - Computer Aided History Matching Using SimOpt

Charles A. (Chuck) Kossack

- Courses Taught
  - Thermal Reservoir Simulation Using ECLIPSE
  - Integrated Reservoir Simulation
  - ECLIPSE Workflow Project Course
  - Simulation of In-situ Combustion and Chemical Reactions Using ECLIPSE
  - Simulation of Enhanced Oil Recovery Processes

Seminar Topics

- Simulation of Polymer Flooding With ECLIPSE
- Simulation of Surfactant Flooding With ECLIPSE
- Simulation of ASP Flooding With ECLIPSE

Disclaimer

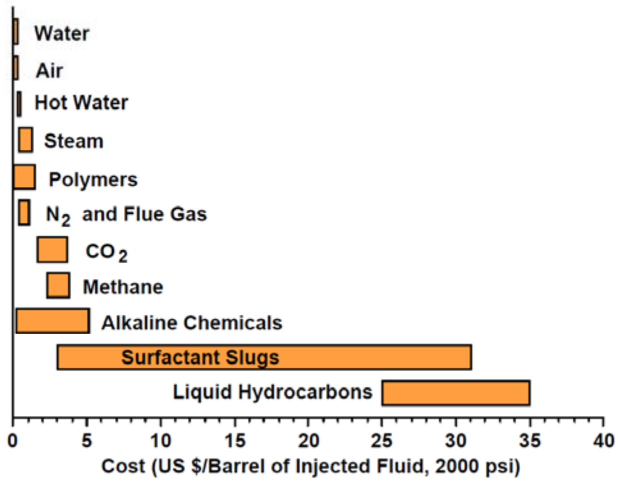
- Each one of these subject is complex and would require 3-5 day class to cover all details.
- 100's of keywords are involved.
- Only overview of theory and ECLIPSE models will be given here.

Copies

- Copy of this presentation
- And datasets used in examples
- Available – check with Professor Kleppe

Introduction

Cost of EOR Fluids



ECLIPSE Blackoil

Polymer
Surfactant
Alkaline
Foam
Solvent
Extensions (Salt models, Multi-partitioned tracers)

Sector Model for Demo Simulations

- Example simulations for all processes will be run in a heterogeneous sector model.
- Random heterogeneity in permeability and porosity will increase mixing and break down the injected slug of chemicals.

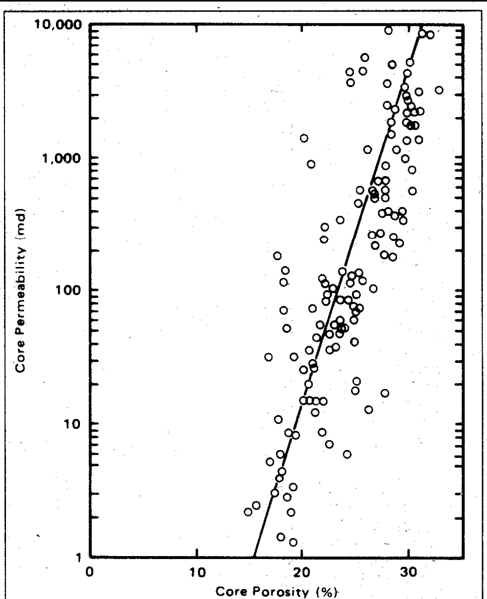


Fig. 4.12—Permeability/porosity correlation for cores from the Brent field.

Source of porosity-permeability correlation for heterogeneities of sector model grid.

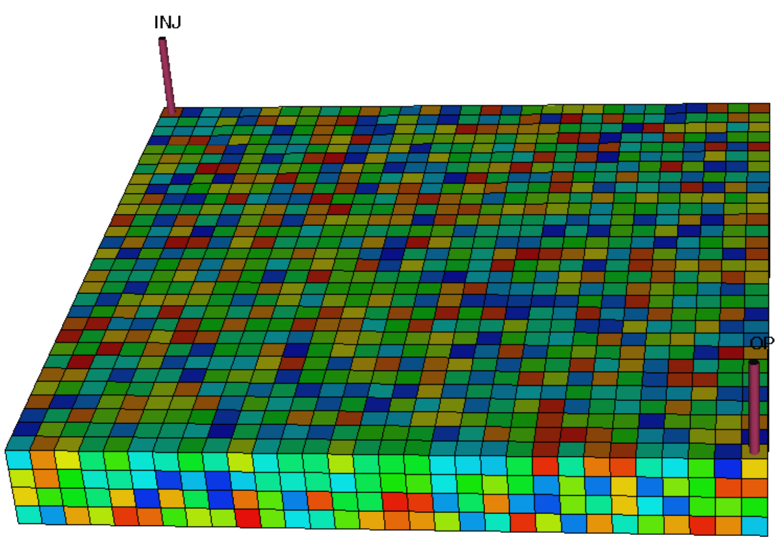
Stochastic porosity has uniform density in range

$$0.15 \leq \phi \leq 0.3$$

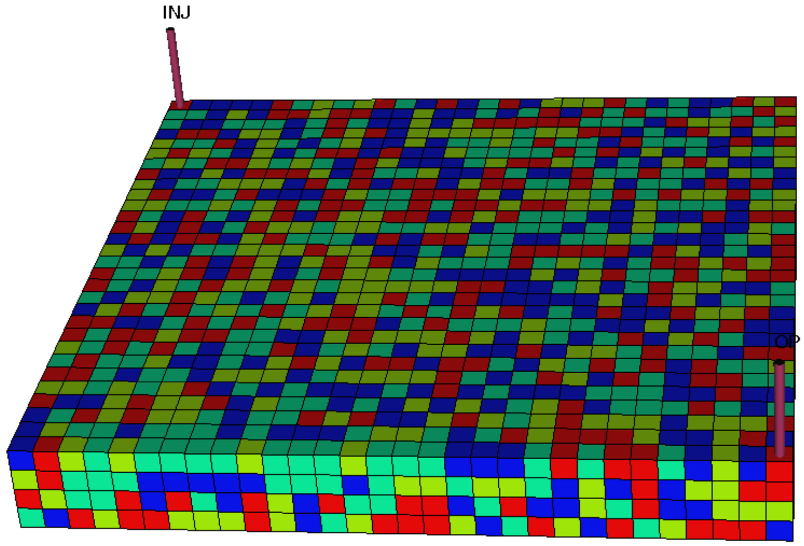
Grid

- 30 x 30 x 4 grid
- Some dataset in FIELD unit, some in METRIC units.
- Will usually compare Recovery Factors (RF) – FOE

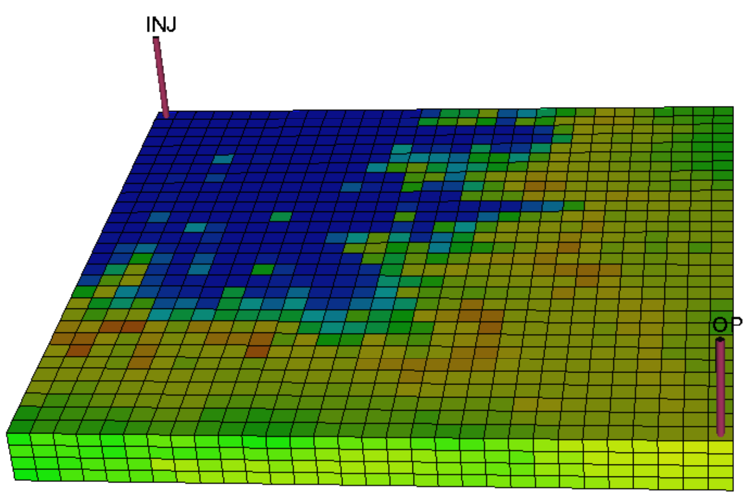
Porosity Values



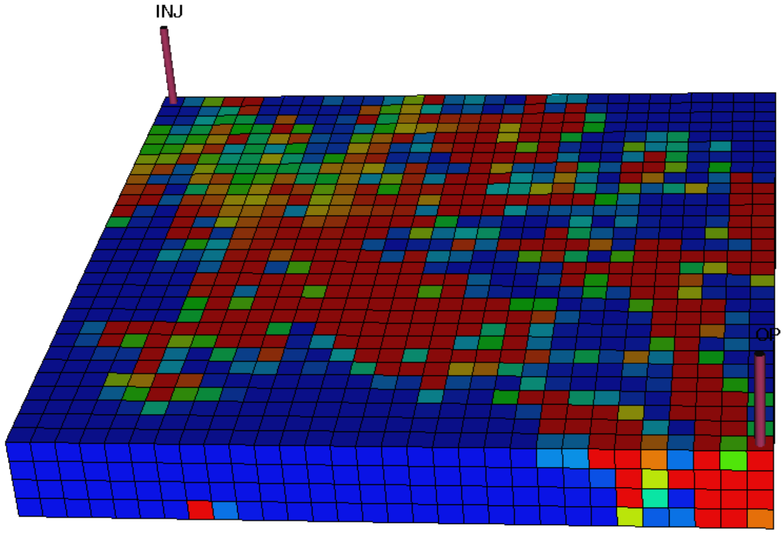
Permeability Values (Log Scale)



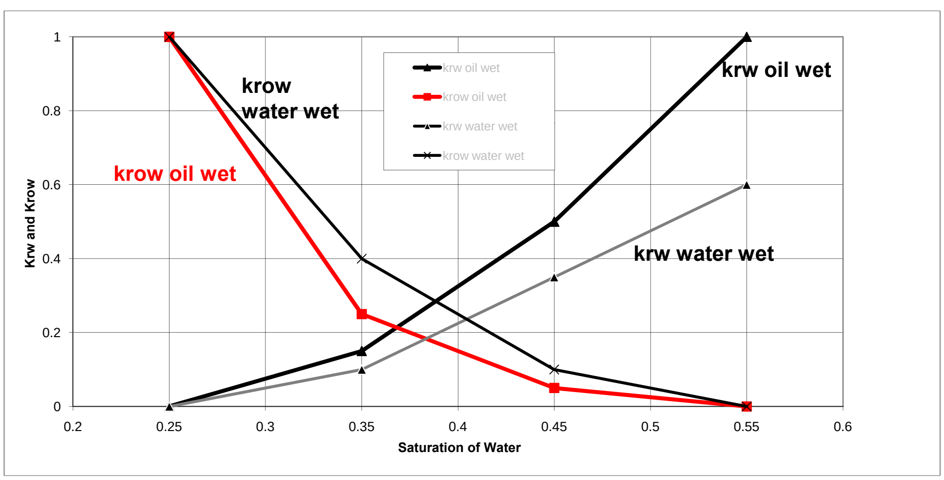
Oil Saturation at 40% of Surfactant Injection Case



Surfactant Adsorbed at End of Simulation



Water Wet and Oil Wet Rel Perms for Exercise Simulations



Initial Conditions

- Water flooded reservoir – S_{wi} = 0.55
- Unless otherwise specified
- Oil viscosity = 2 cP
- Water viscosity = 0.34 cP

Theoretical Discussion:
Langmuir Equation
Langmuir Isotherm
Langmuir Adsorption Equation

Langmuir Equation

- From surface chemistry – typical adsorption isotherm – called - Langmuir equation or Langmuir isotherm or Langmuir adsorption equation
- Relates the coverage or adsorption of molecules on a solid surface to gas pressure or concentration of a medium above the solid surface at a fixed temperature.
- Equation - developed by Irving Langmuir in 1916.

Langmuir Equation

$$\theta = \frac{\alpha \cdot P}{1 + \alpha \cdot P}$$

θ is percentage coverage of the surface

P is the gas pressure or concentration in a solution

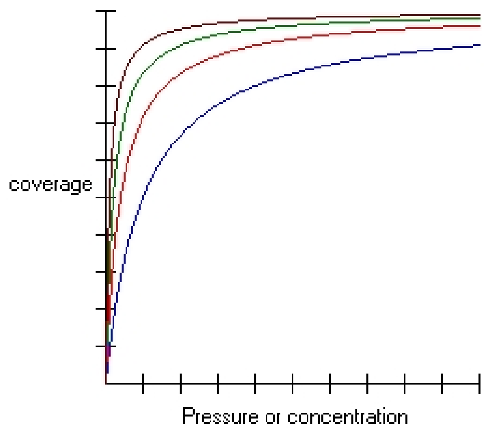
α is a constant

the Langmuir adsorption constant

increases with an increase in the strength of adsorption

and decreases with temperature

Langmuir Equation



Value of constant α increases from blue, red, green and brown

End of Introduction

Simulation of Polymer Flooding With ECLIPSE

Topics

- Introduction
- Principles of Polymer Flooding
- Polymer chemistry
- Polymer implementation in ECLIPSE
- How to use in ECLIPSE
- Example Simulation

Principles of Polymer Flooding

- Significant increases in recovery when compared to conventional water flooding projects
- Reduce the unfavorable effect of permeability variations
- Primary features for effectiveness
  - Reservoir heterogeneity
  - Mobility ratio of reservoir fluids

Polymers

$$M = \left(k_{rw} / \mu_w \right) / \left(k_{ro} / \mu_o \right)$$

- Water soluble polymers
  - Increase viscosity of displacing fluid
  - Improving mobility ratio
  - Increasing displacement efficiency
- To be useful polymer must be
  - Effective
  - Relatively cheap as they are used in high concentration

Polymer Chemistry

What are Polymers

- Smaller molecules (monomers) joining together and forming a repeating unit called a polymer

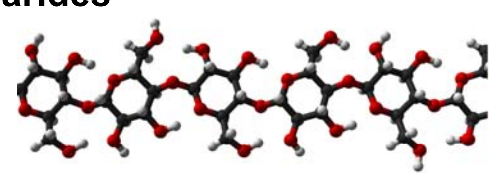
- Characteristics
  – High molecular weight
  – flexible

Polymer Examples

- Partially hydrolyzed polyacrylamide
- (HPAM)
- Xanthan gum (polysaccharide)
- Guar gum (polysaccharide)
- Carboxymethylcellulose (CMC)
- Hydroxyethylcellulose (HEC)
- Associating polymers

Polymers

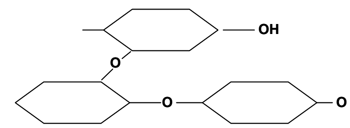
- Two polymers meet the criteria to be effective and to be economic are:
  - Polysaccharides



  - Polyacrylamides

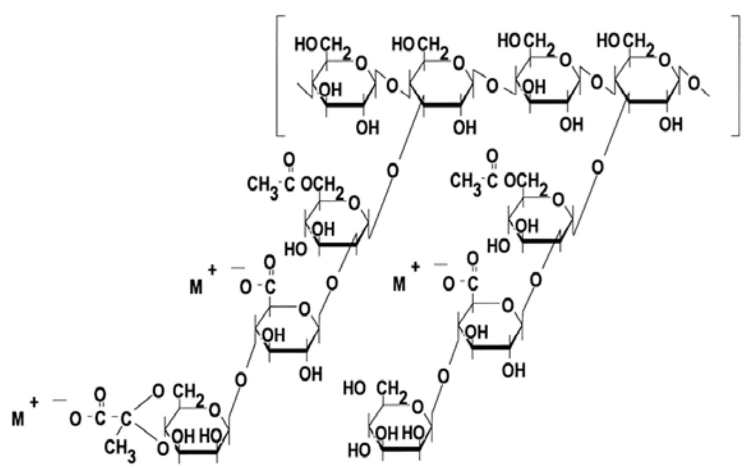
Polysaccharides

- Polymer chemical formula



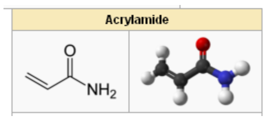
- It is a xanthan gum
- Not very flexible
- Molecular weight 5 million!
- Highly rigid
- Susceptible to bacterial action

Xanthan Gum Structure

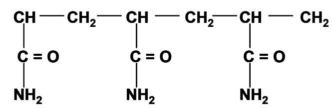


Acrylamide

- **Strictly named acrylic amide**
  - **Chemical formula C_3H_5NO**
  - **Monomer** $CH_2 = CH\text{-}C(=O)\text{-}NH_2$



  - **Polymer**



  - **White odorless crystalline solid soluble in water**

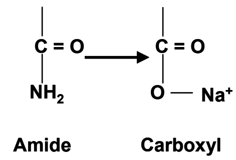
Polyacrylamide

- **Molecular weight 1 – 10 million**
  - **Typical molecular weight distribution**

- **Flexible molecule**
- **Long thin molecule**
  - **Susceptible to mechanical or shear breakage**
- **Immune to bacterial attack**

Hydrolysis of Polyacrylamide

- 0 – 30% hydrolysis achieved by treating with a strong base (eg. NaOH)



- Both hydrolyzed and unhydrolyzed are highly polar
- Great affinity for water but not oil

Displacement Mechanisms

- Polymers work by increasing effective viscosity of water, also reducing mobility

$$M = \frac{k_{rw}\mu_o}{k_{ro}\mu_w}$$

Displacement Mechanisms

- Term to Consider:
  - Rheology
  - Solvent
  - Molecular weight
  - Hydrolysis
  - Polymer concentration

To be discussed in the following slides

Rheology

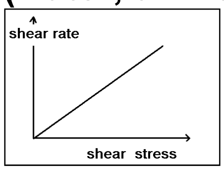
- Polymers are non-Newtonian fluids and do not strictly increase the viscosity of the water
- Newtonian fluids deform (flow) when subjected to shearing force
- Resistance to flow is a ratio shearing force to shear stress, called viscosity

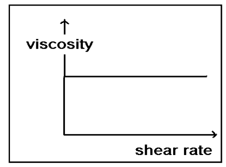
$$\mu = \frac{\tau}{\gamma}$$

μ viscosity
τ shear stress
γ shear rate

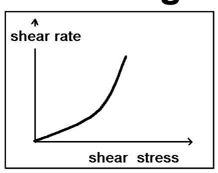
Rheology - Fluid Types

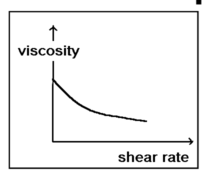
- Newtonian – viscosity remains constant (water, thin oils)





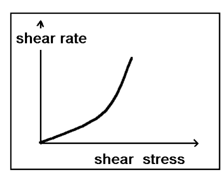
- Pseudoplastic – decreasing viscosity with increasing shear rate (emulsions polymers)





Rheology - Pseudoplastic Fluids

- As shearing rate increases, resistance to flow decreases
- Power law model



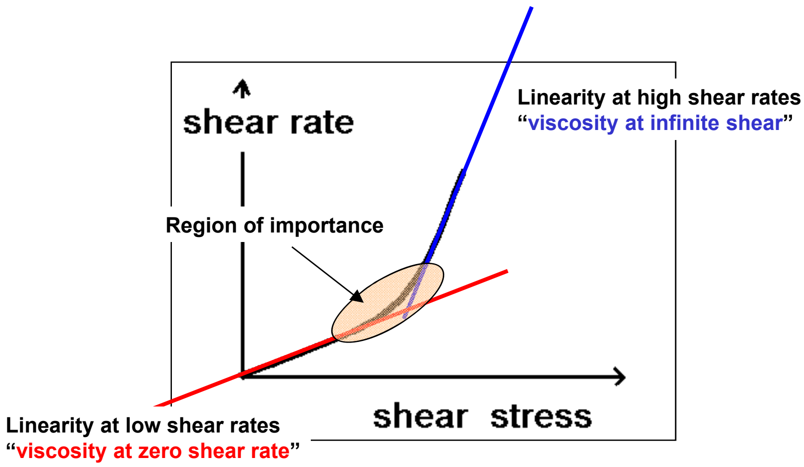
$$\mu = K\tau^n$$

n < 1 for pseudo plastic fluids

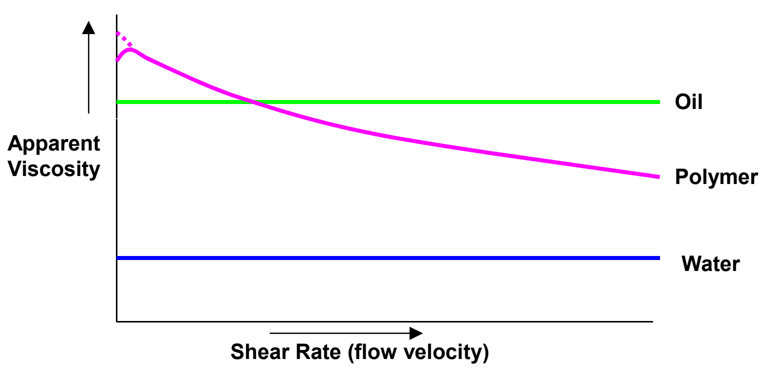
K and n used to define the flow behavior of the fluid

- Exhibits high viscosity at low flow rates and low viscosity at high flow rates

Rheology - Pseudoplastic Fluids



Rheology - Polymer Viscosities



Viscosity of polymers higher than that of water even at high flow rates

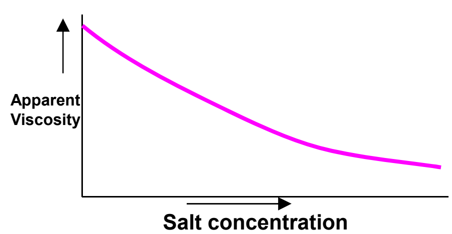
Solvents

Polymer can be visualized as a fibrous chain

- In a good solvent
  - Polymer chain extends to make good contact with solvent
  - Gives polymer gel like appearance
  - Polymer – polymer entanglement maximized
- In a poorer solvent
  - Minimized contact with solvent
  - Reduced entanglements
  - More rigid structure

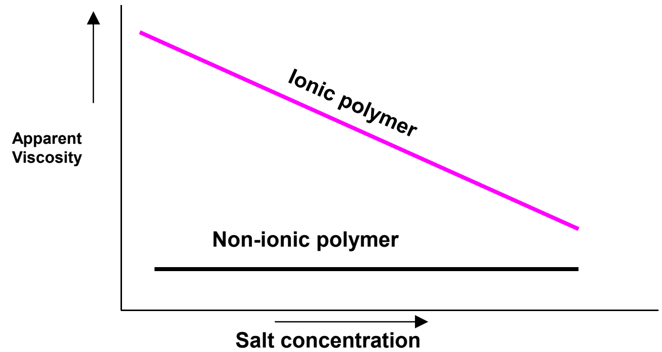
Solvent - Water

- Distilled water very good solvent
- However as salt is added the polar charge is neutralized and forces extending molecule are reduced



Solvent - Salt Concentration

- Viscosity reduction due to salt concentration more obvious in ionic polymers

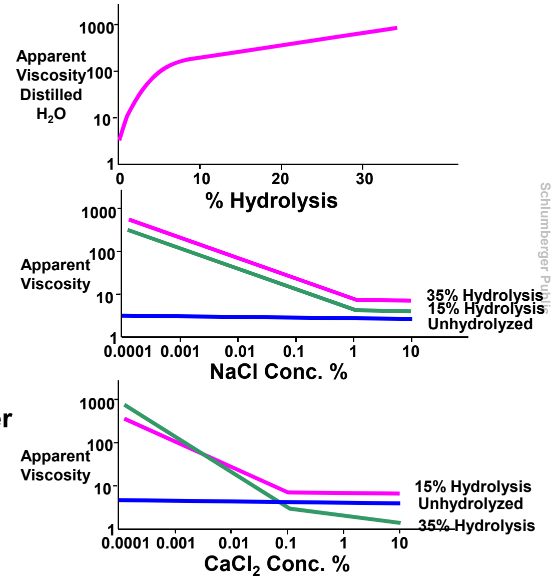


Molecular Weight

- Length of molecules and hence molecular weight is important
- As the molecules are of fibrous nature, extension and entanglement are important for viscosity increases

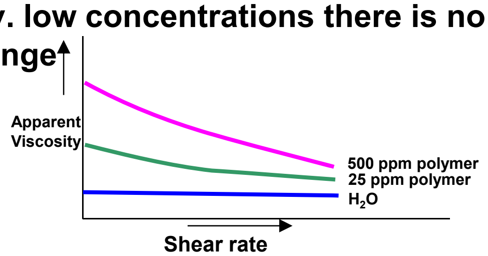
Hydrolysis

- Apparent viscosity increases with the degree of hydrolysis, however as salt is added effect is decreased
- $CaCl_2$ (calcium chloride), has a much greater effect than NaCl (sodium chloride) - divalent
- At $CaCl_2$ concentrations > 0.1 wt %, viscosity is less than unhydrolyzed polymer this is not observed with NaCl



Polymer Concentration

- Increase in viscosity due to polymer concentration is initially linear and then quadratic
  - Initially as concentration increases opportunity for molecular entanglement increases
  - At v. low concentrations there is no viscosity change



Further Complications!

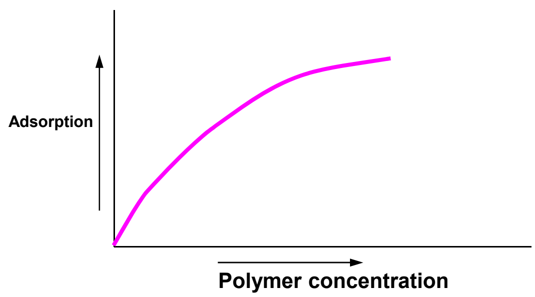
- Polymer retention and mobility reduction…
- As polymer is forced through formation there is a significant reduction in polymer concentration due to adsorption and plugging

Polymer Retention

- Reduced permeability caused by polymer retention
  - Polymer forced through cores shows reduction in concentration
  - The retention of the polymer in the pore spaces leads to permeability reduction

Polymer Adsorption

- **Adsorption increases with increasing polymer saturation**

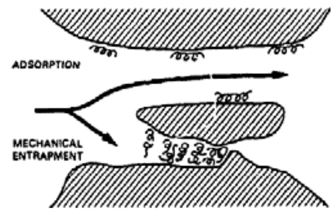


Inaccessible Pore Volume

- **Reduced adsorption caused by inaccessible pore volume**
- **Only brine passes through small pores, polymer bypasses**
- **Time of travel of polymer less than expected, velocity is higher, breakthrough sooner than brine**

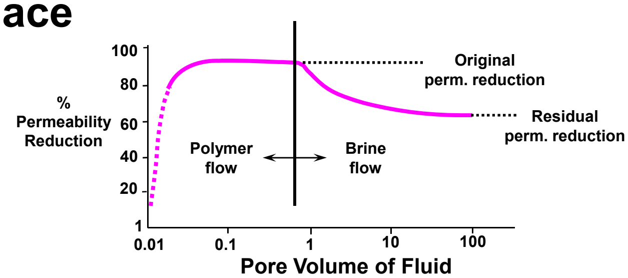
Entrapment

- Polymer trapped
  - Large pore openings at one end
  - Small pores at other
- Molecule shape
  - Elongated while flowing
  - Coiled when not flowing
- Entrapment is not plugging
  - Reduces ability of water to flow
  - Oil can still flow



Residual Resistance

- Adsorption and entrapment are only partially reversible
- Effect of polymer can be seen long after polymer injection has taken place



Shear Degradation

- Breakup of polymer chain as shear rate increases
  - Vicious shear is less than viscoelastic shear
- Presence of salts increases susceptibility to shear degradation

Selection of Reservoir for Polymer Injection

- Mobility poor (2 – 20)
  - >20 economics are likely to be poor
  - ~ 1 then little to be gained
- Significant permeability distribution
- Will help if high water cut due to
  - Water coning
  - High perm zone
  - High viscosity oil (up to 300 cP)

Parameters

- Reservoir temperature < 250-300 °F
- Reasonably high mobile oil S_o
- Not useful in fractured/vuggy reservoirs

Modifications for Polymers

- Modifications to the water equation required to account for polymers
  - Accumulation of polymer
  - Adsorption of polymer
  - Effect of brine

Polymer Equations

- **Water Equation**

$$\frac{d}{dt}\left(\frac{VS_w}{B_rB_w}\right)=\sum\left[\frac{Tk_{rw}}{B_w\mu_{w\,eff}R_k}\left(\delta P_w-\rho_w gD_z\right)\right]+Q_w$$

- **Polymer Equation**

Adsorption term

$$\frac{d}{dt}\left(\frac{V^*S_wC_p}{B_rB_w}\right)+\frac{d}{dt}\left(V\rho_rC_a\frac{1-\phi}{\phi}\right)=\sum\left[\frac{Tk_{rw}C_p}{B_w\mu_{p\,eff}R_k}\left(\delta P_w-\rho_w gD_z\right)\right]+Q_wC_p$$

$$S_w^*=S_w-S_{dpv}$$

Polymer concentration

- **Brine Equation**

Rock formation vol. factor

$$\frac{d}{dt}\left(\frac{VS_wC_n}{B_rB_w}\right)=\sum\left[\frac{Tk_{rw}C_n}{B_w\mu_{s\,eff}R_k}\left(\delta P_w-\rho_w gD_z\right)\right]+Q_wC_n$$

Nomenclature

S_{dpv}	denotes dead pore space in each grid cell
C_p^a	denotes the polymer adsorption concentration
ρ_r	denotes the mass density of the formation
ϕ	denotes the porosity
ρ_w	denotes the water density
$\sum$	denotes the sum over all neighbouring cells
R_k	denotes the relative permeability reduction factor for the aqueous phase due to polymer retention
μ_{aeff}	denotes the effective viscosity of the water (a=w), polymer (a=p) and salt (a=s).
D_z	is the cell center depth
B_r, B_w	are the rock and water formation volumes
T	the transmissibility
k_{rw}	is the water relative permeability
S_w	is the water saturation
V	is the block pore volume
Q_w	is the water production rate
P_w	is the water pressure
g	is the gravity acceleration

Numerical Stability

- Equations are solved implicitly
  - Removes problems that could be caused by large changes in aqueous properties over a time step
- IMPES solution algorithm cannot be used with the Polymer option

Fluid Viscosities

- Need to account for the viscosity change due to presence of:
  - Salt
  - Polymer
- Need to account for:
  - Physical dispersion at leading edge of the slug
  - Fingering effects at rear edge of slug
- Use Todd-Longstaff technique to calculate effective fluid viscosities

Aqueous Fluid Viscosities – Effective Polymer Viscosity

- Viscosity change due to polymers and salt
- Effective viscosity estimated using Todd – Longstaff technique

$$\mu_{p,eff} = \mu_m (C_p)^{\omega} \mu_p^{1-\omega}$$

Viscosity at max polymer concentration (injected polymer concentration)

Polymer concentration in solution

- Mixing parameter ω models degree of segregation between water and injected polymer

ω = 1 Polymer solution and water fully mixed

ω = 0 Polymer segregated from the water

Brine Option

- Effective polymer viscosity and partially mixed water viscosity terms hold
- Injection salt concentration required to calculate maximum polymer viscosity (μ_p)
- The effective salt component viscosity is set to effective water viscosity

Polymer Adsorption

- Treated as instantaneous effect
- Creates stripped water bank at leading edge
- Desorption may occur as slug passes
- User specified adsorption isotherm
- Tabulate (look up table) PLYADS
  - local polymer concentration in solution

    vs.
  - saturated concentration adsorbed by rock

PLYADS - Example

```
PLYADS
--polymer          polymer
--concentration    concentration
-- lb/stb          adsorbed by rock
--                 lb/lb
   0.0             0.00
   20.0            0.010
   70.0            0.010  /
```

Two Adsorption - Desorption Models

1. **Adsorption-Desorption - Each cell retraces adsorption isotherm as polymer concentration rises and falls**
2. **Adsorption-NO Desorption Adsorbed concentration on rock may not decrease with time**

Non-Newtonian Rheology – 2 Models

- **Model 1**
  - Shear thinning reduces the polymer viscosity at high flow rates
- **Model 2**
  - Hershel-Buckley used to model shear thinning and thickening, yield stress as a function of polymer concentration

PROPS keywords

Keyword	Description
PLYADS	Polymer adsorption isotherms.
ADSORP	Analytical adsorption isotherms with salinity and permeability dependence.
PLYMAX	Polymer/salt concentrations for mixing calculations.
PLYROCK	Specifies the polymer-rock properties.
PLYSHEAR	Polymer shear thinning data.
PLYVISC	Polymer solution viscosity function.
PLYVISCS	Polymer/salt solution viscosity function.
RPTPROPS	Controls output from the PROPS section. Mnemonics PLYVISC etc. output Polymer Flood model properties.
SALTNODE	Salt concentration nodes for polymer solution viscosity.
TLMIXPAR	Todd-Longstaff mixing parameter.

Injection Wells

- **WPOLYMER: Defines the polymer and salt injection streams**
- **Note: wells are not allowed to cross-flow when polymer flood model is used – gone in 2011.1**

Examples of Polymer Flooding Simulations

Case 1 – Field Units

- Polymer injection into our water flooded reservoir.
- Polymer concentration 10.5 lbs/stb
- Polymer solution viscosity = 3.4 cP

Oil Production Rate???

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Question to be Answered:

How does Polymer flooding compare to normal water flooding?

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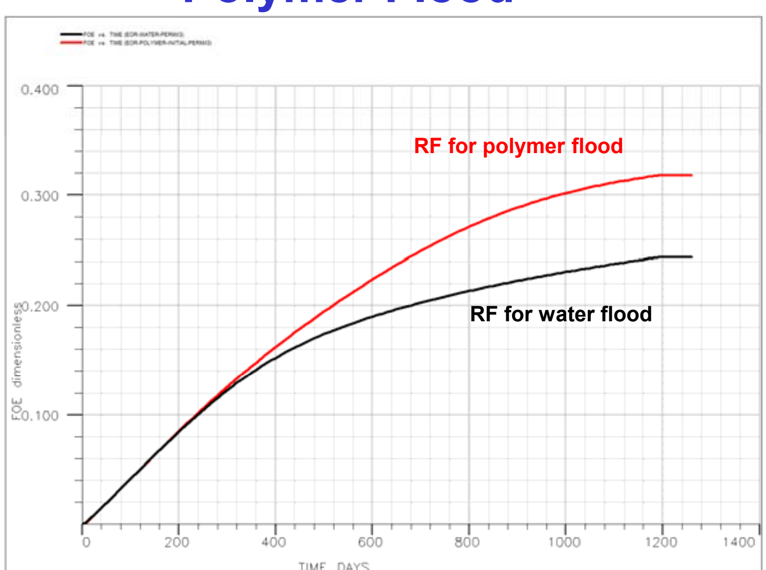
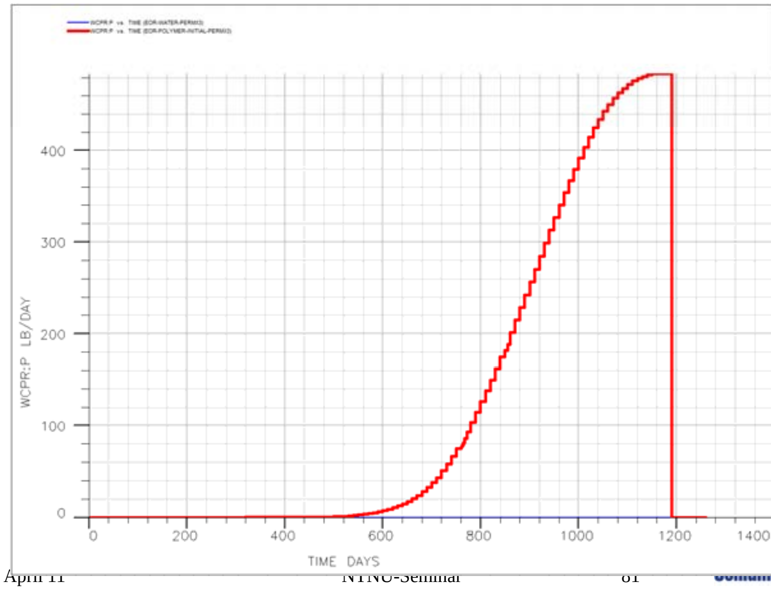
Case 2

- Switch to initial (prior to water flood) oil saturation reservoir.
- Case 2a: Inject water only – 2000 days
- Case 2b: Inject polymer for 360 days, inject water for 1640 days.
- Runs terminate when oil production rate < 30 stb/day
- Limited polymer adsorption

Comparison of Water Flood with Polymer Flood



Polymer Production Rate (lb/day)



Economics of Polymer Flooding

- Polymer cost = $2 / lb
- Polymer injected = 756,000 lbs
- Cost of polymer = $1.5 Million
- Incremental oil produced (incremental over water flood) = 35,000 Stb
- Income from oil production = $3.5 Million
- Profit = $2 Million = 11 Million NOK

End of Simulation of Polymer Flooding Lecture

Simulation of Surfactant Flooding With ECLIPSE

Surfactant Flooding

- Also goes by the names:
- Chemical Flooding
- Surfactant-Polymer Flooding
- ASP Flooding – Alkali-Surfactant-Polymer Flooding

Surfactants

- Surfactants are wetting agents that lower the surface tension of a liquid, allowing easier spreading, and lower the interfacial tension between two liquids.
- When the interfacial tension is reduced the residual oil decreases and the capillary pressure decreases.
- When the interfacial tension is reduced the capillary number N_{CA} increases – see next slide.

Capillary Number – N_{CA} or Ca

•Capillary number represents the relative effect of viscous forces versus surface tension acting across an interface between a liquid and a gas, or between two immiscible liquids.

•k = permeability

•Δp/L = pressure gradient along capillary

•v = velocity

•σ = interfacial tension between fluids

$$N_{CA} = \frac{k\Delta p}{L\sigma}$$

or

$$N_{CA} = \frac{\mu v}{\sigma}$$

Capillary Number

•Typical water flood capillary number are 10^{-7}

•For an effective surfactant flood – capillary number = 10^{-4} to 10^{-3}

•Interfacial tension reduction of 1000 to 10,000 necessary

EOR IN EARLY 1980'S

Field	Loudon	Big Muddy	Robinson
Company	Exxon, 1983	Conoco, 1981	Marathon, 1983
Surfactant Conc.	2 surfactants 2.3%	3%	10%
Pore Volume	0.3	0.1	0.3
Co-solvent	- - -	5% iso-butanol	0.6% hexanol
Salt	96% connate salinity	0.6%	2.5%
Polymer	0.1% xanthan	0.22% polyacrylamide	None
Recovery	68% RIOP	15% RIOP	19-21% ROIP

History of Surfactant Research and Applications

- Original Patent – 1929 De Groot – claiming water-soluble surfactants as an aid to improved oil recovery.
- 1962 – Gogarty and Olson of Marathon Oil Co. – patent based on field trial where used petroleum sulfonates along with a chemical slug containing hydrocarbons, water, electrolyte, and co-surfactants.

History of Surfactant Research and Applications

- There have been twenty-seven known Alkaline Surfactant Polymer, Surfactant Polymer or Alkaline Polymer projects around the world since 1980.
- They have taken place in Alberta, California, China, Colorado, Indonesia, Louisiana, Oklahoma, Venezuela, and Wyoming.
- Thousands of publications exist on Surfactant/Chemical Flooding

Past Surfactant Flooding – Reasons for Field Scale Failure

- Sensitivity to oil price
- Large up-front investment
- Unpredictable return on investment
- High surfactant concentration
- Salinity optimization required
- Optimum salinity shift in the formation
- Potential emulsion block
- Economic feasibility

COST OF CHEMICALS

	1980 Micellar	2008 (Oil Chem's surfactant /process)
Polymer	$3-4/lb	$1 – $1.8/lb
Surfactant[1]	$0.40-$0.60/lb	$0.80-$1.5/lb
Alkali[2]	$0.12/lb	$0.30 – $0.60/lb
Crude Oil	~ $12/bbl	$60-$140/bbl
Incr. Cost/bbl	$8 - > $15	$2 - $10

[1] Surfactant concentration has been reduced by 10 times as compared to 1980's

[2] Alkali has been reduced or in some cases is not needed at all

Source of Cost Data

- Oil Chem Technologies, Inc.
- 12822 Park One Drive
- Sugar Land, TX 77478
- www.oil-chem.com

Complex Process

- Surfactant flooding involves:
  - Multi-phase behavior
  - Adsorption
  - Salinity issues
  - Micelles
  - Surface tension
  - Relative permeability and capillary pressure changes
  - Viscosity changes
  - Wetability changes
  - Diffusion

Complex Process

- To understand all the details takes weeks or months
- And a knowledge of physical chemistry, etc.
- We will look at a few basic concepts
- Then look at ECLIPSE 100 Advanced Options implementation

Micellar/Polymer

- Most process are Micellar/Polymer – that is Surfactant solution in injected into the reservoir followed by a Polymer solution for mobility control
- We will initially look at just Surfactant flooding – since you have already seen Polymer flooding

Basic Idea

- Surfactants (surface active agent) can be added to injected water to decrease the residual oil saturation.
- n% PV slug of surfactant solution is injected into reservoir often followed by polymer mixture for mobility control.

Description of the Micellar/Polymer Process

- Most situations – tertiary displacement at the end of water flood.
- Oil saturation is S_{orw}.
- Specific volume – primary slug – of micellar solution is injected
- Volume of slug is 3% to 30% of flood pattern PV
- Micellar solution has very low IFT with residual crude oil – mobilizes the trapped oil – forms an oil bank – ahead of the slug

Description of the Micellar/Polymer Process

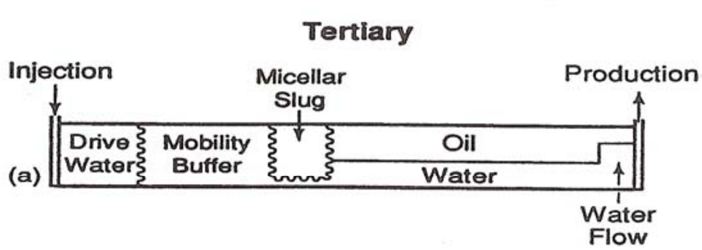
- Micellar slug – also low IFT with brine – displaces brine as well as oil
- Both oil and water flow in the oil bank
- Oil production occurs after oil bank breaks through

Description of the Micellar/Polymer Process

- Micellar/Polymer process – can be applied as secondary recovery process
- Micellar solution – designed so – favorable mobility displacement
- Potential to increase both volumetric sweep efficiency and microscopic displacement efficiency

Basic Idea

- Surfactant solution can be injected as tertiary recovery process.



Basic Idea

- Surfactants (surface active agent) can be added to injected water to decrease the residual oil saturation.
- If surfactant concentration is large enough – oil + water system can be single phase – surfactant is expensive so this is not a viable process.
- Low concentration of surfactant produces 3 phase mixture – oil + micro-emulsion + water – with low interfacial tension

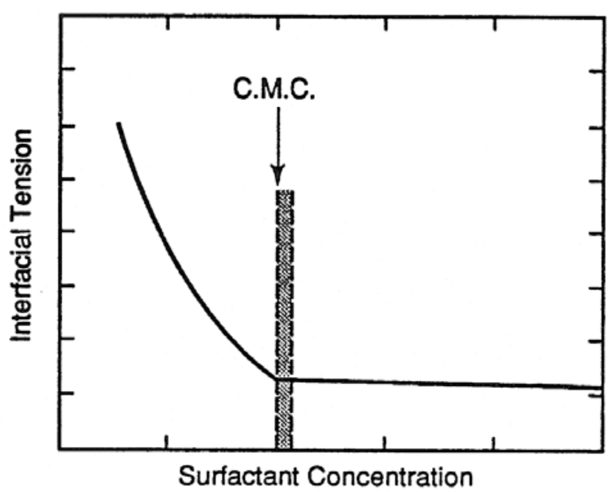
Typical Surfactant or Micellar Solution Compositions

Component	Volume %
Hydrocarbon	0 to 80
Water	10 to 95
Surfactant	<1 to 15
Cosurfactant	0 to 10
Electrolyte	<1 to 10

Basic Theory

- Surfactants reduce the interfacial tension between oil and water by adsorbing at the liquid-liquid interface.
- Examples of such aggregates are called vesicles and micelles.
- The concentration at which surfactants begin to form micelles is known as the critical micelle concentration or CMC.

IFT as a Function of Surfactant Concentration
CMC is critical micelle concentration

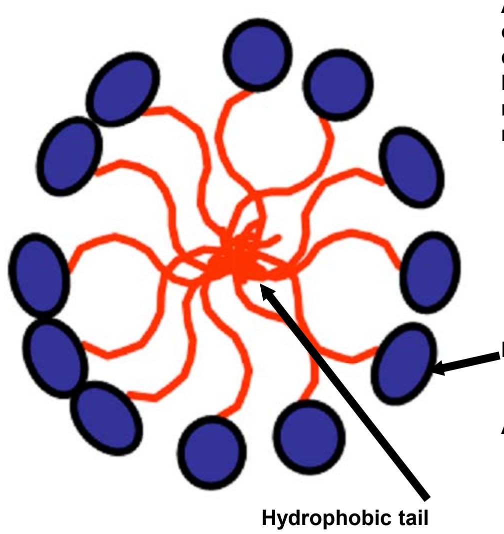


Basic Theory

•When micelles form in water, their tails (hydrocarbon portion – non polar) form a core that can encapsulate an oil droplet, and their (ionic/polar) heads form an outer shell that maintains favorable contact with water.

Micelle

A micelle - the lipophilic ends of the surfactant molecules dissolve in the oil, while the hydrophilic charged ends remain outside, shielding the rest of the hydrophobic micelle



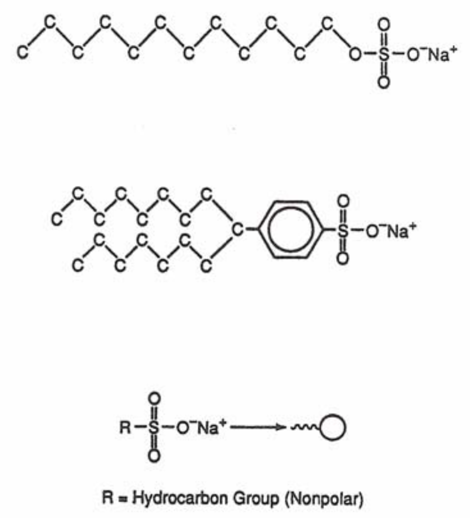


Fig. 7.6—Representative surfactant molecular structures: (a) sodium dodecyl sulfate, (b) Texas No. 1 sulfonate, and (c) commercial petroleum sulfonates. (Lake, *Enhanced Oil Recovery*, © 1988, p.356. Reprinted by permission of Prentice Hall, Upper Saddle River, New Jersey.)

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Idea Phase Behavior of Micro-emulsion on Ternary Diagram

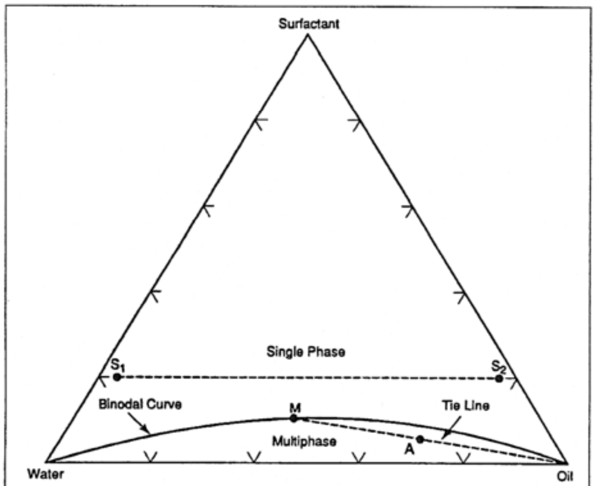

Fig. 7.15—Pseudoternary phase diagram for a micellar (micro-emulsion) solution.

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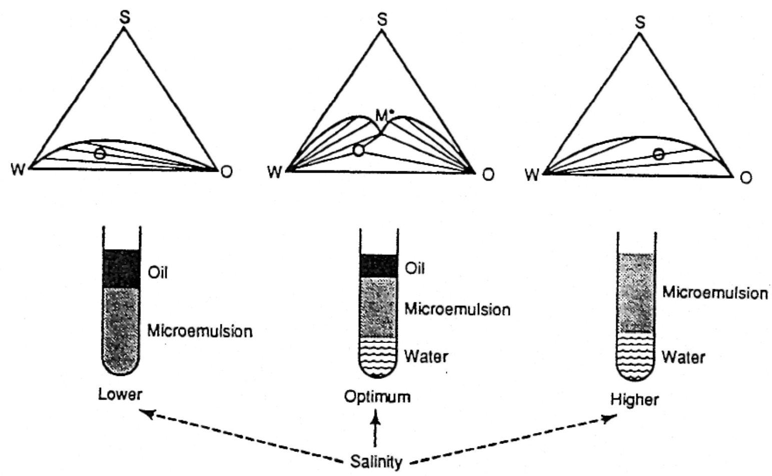
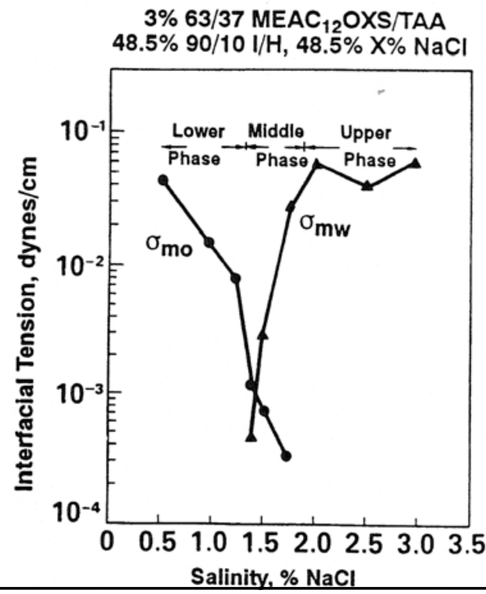
Effect of Salinity on Micro-emulsion Phase Behavior



Names of Surfactant Phase Behavior Systems

- (II –) system – oil is upper phase at low salinity (also called Upper Phase)
- (II +) system – brine is lower phase at high salinity (also called Lower Phase)
- (III) system – 3 phase system with oil + micro emulsion + brine at middle salinity (also called Middle Phase)

IFT as a Function of Salinity



Optimum is the 3 phase "Middle" system

Numerous Field Trials
3 Examples from Marathon, Exxon, and Conoco

TABLE 7.20—DATA ON SELECTED MICELLAR POLYMER FIELD APPLICATIONS

	Marathon	Exxon	Conoco
Reservoir name	Robinson (M-1 Project)	Weller Sand (Loudon field)[1]	Second Wall Creek (Big Muddy field)
Lithology	SS	SS	SS
Area in flood, acres	407	0.71	90
Pattern type	Five spot	Five spot (center well producer)	Five spot
Spacing, acres	2.5; 5.0	—	10
Tracer study	Yes	Yes	Yes
Permeability, md	103	67 to 189	56[2]
Porosity, %	18.9	19.5	≈20.0
Thickness, ft	0 to 60; average 27.8	8 to 28; average 15.6	65
Depth, ft	<1,000	1,400 to 1,600	3,100
Temperature, °F	72	78	115
Crude Oil			
Viscosity, cp	5 to 6	5.0	5.0
API gravity, °API	36		
Geology	Stacked and isolated sand lenses; meandering river, migrating point bars.	Deltaic deposit, fine to very fine grain sand.	Highly jointed with low closure pressure.
Heterogeneity	Lorenz coefficient = 0.44	Significant thickness variation.	Fracture joint system; Dykstra-Parsons V_{DP} = 0.01
Tertiary or secondary flood	Tertiary	Tertiary	Tertiary
Oil saturation at start of flood (swept zone), % PV	40	24.1	32
Chemical slug			
Surfactant type	Crude oil sulfonate	$RO(C_3H_6O)_m(C_2H_4O)_n SO_3Na$[3]	Blend of synthetic sulfonates
Surfactant concentration (active), wt%	10[4]	2.3	3
Cosurfactant type	Hexanol	—	Isobutyl alcohol
Cosurfactant concentration	0.8 vol%[5]	—	5 wt%
Oil, wt%	7.5[6]	2.65; 250 white oil base[7]	—
Water, wt%	80[8]	96 of resident salinity	
Salts, wt%	2.5[9]	96 of resident salinity	0.6
Polymer in slug	No	Yes, biopolymer	Yes, polyacrylamide, 2,200 ppm
pH	6.5 to 7.5	5.2	
Other additives	citric acid, 500 ppm[10]	Formaldehyde, citric acid, 90 mg/L[11]	
Viscosity, cp	<40	28[12]	12[13]
Slug size, % PV	10	30	10.2
Formation water, mg/L	16,575	104,000	Brine preflush
Ca	166	2,840	
Mg	118	1,210	

	Marathon	Exxon	Conoco
Mobility-control buffer			
Polymer type	Polyacrylamide	Biopolymer	Polyacrylamide
Biocide	No	Yes; Formaldehyde; 90 mg/L	
Polymer concentration, ppm	1,156	40 cp[14]	1,400, 12 cp[13]
Slug size, % PV	11	100	18[15]
Polymer concentration, ppm	800		
Slug size, % PV	19		
Polymer concentration, ppm	625		
Slug size, % PV	32		
Polymer concentration, ppm	411		
Slug size, % PV	12		
Polymer concentration, ppm	200		
Slug size, % PV	11		
Polymer concentration, ppm	50		
Slug size, % PV	10		
Polymer concentration, ppm	0		
Slug size, % PV	35		
Salinity	—	70% of formation salinity	0.4 wt%
Date injection started	Feb. 1977	Aug. 1982	1980 (preflush) Jan. 1981 (chemical)
Tertiary oil recovery			
Date	Sept. 1983	Nov. 1983	14% of oil in place at start of project.
Oil recovery	See Fig. 7.106	68% of waterflood residual oil; see Figs. 7.107 and 7.108.	
Problems		Production of an emulsion.	Low matrix *k*; fractures at *p* less than hydrostatic *p*; lack of containment of injected fluids.
References	120 and 12	5, 17, and 124	121, 122, 125, and 126

[1]This is the second of two pilot tests in the Loudon field in which a high-salinity-tolerant surfactant was used.
[2]k_w = 1 to 2 md at ROS. Fracturing occurs at less than hydrostatic pressure, leading to larger effective permeability.
[3]R represents i-$C_{13}H_{27}$; m = 3 or 4; n = 2 or 4; mixture of two surfactants used.
[4]Target value reported; actual value 9.2 to 10.8.
[5]Cosurfactant added at field after chemical slug made up at refinery. Refinery chemical slug consisted of surfactant, oil, water, and salt; target value reported; actual value 0.4 to 1.0.
[6]Target value reported; actual value 5 to 15.
[7]Surfactant, 250 white oil base and biopolymer broth mixed with formation brine.
[8]Water contained 501 mg/L salts.
[9]Specified as inorganic salt.
[10]Citric acid added at field as chelating agent.
[11]Formaldehyde added as a biocide.
[12]Viscosity measured at a shear rate of 11 seconds $^{-1}$.
[13]Measured at 12 rev/min on Brookfield viscometer.
[14]Concentration not specified. Sufficient polymer added to make viscosity equal to 38 cp measured at 11 seconds $^{-1}$ shear rate.
[15]Polymer slug injection terminated earlier than planned because of low injectivities and production. Planned volume was 0.4 PV.

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ECLIPSE 100 Advanced Options Treatment of Surfactant Flooding

ECLIPSE Technical Description – Surfactant Flooding Chapter

- "The ECLIPSE Surfactant model does not aim to model the detailed chemistry of a surfactant process, but rather to model the important features of a surfactant flood on a full field basis."

Surfactant Flooding Overview

1. Inject surfactant water solution into reservoir
2. Surfactant concentration solved by conservation equation in the water phase.
3. Interfacial tension – table look-up as a function of surfactant concentration
4. Capillary number calculated as a function of interfacial tension
5. Oil and water phase relative permeability interpolated as function of capillary number

Surfactant Flooding Overview

6. Water-oil capillary pressure reduced as a function of interfacial tension (surfactant concentration)
7. Water viscosity changed as a function of surfactant concentration.
8. Surfactant adsorbs onto the reservoir rock.
9. Wettability of the rock changes as a function of amount of surfactant adsorbed.

Details of ECLIPSE Surfactant Model

Theory and equations

Brief Overview of Surfactant Keywords

PROPS Keywords

SURFST	Water-oil surface tension in the presence of surfactant	(Obligatory)
SURFVISC	Modified water viscosity	(Obligatory)
SURFCAPD	Capillary de-saturation data	(Obligatory)
SURFADS	Adsorption isotherm	(Optional)
SURFROCK	Rock properties and adsorption model indicator	(If SURFADS is present)

SURFADDW **Concentration of adsorbed surfactant versus the fraction of the oil-wet and water-wet saturation functions (Optional)**

Surfactant Conservation Equation

- **The distribution of injected surfactant is modeled by solving a conservation equation for surfactant within the water phase.**
- **The surfactant concentrations are updated fully-implicitly at the end of each time-step after the oil, water and gas flows have been computed.**

Surfactant Conservation Equation

- The surfactant is assumed to exist only in the water phase, and the input to the reservoir is specified as a concentration at a water injector.

Calculation of the Capillary Number

- The capillary number is a dimensionless group that measures the ratio of viscous forces to capillary forces.
- The capillary number is given by:

$$N_c = \frac{|K \cdot gradP|}{ST} C_{unit}$$

Calculation of the Capillary Number

- where
- K is the permeability
- P is the potential
- ST is the interfacial tension (see SURFST Keyword)
- C_{unit} is conversion factor
- |K grad P | is calculated as

$$|K \cdot gradP| = \sqrt{(K_x \cdot gradP_x)^2 + (K_y \cdot gradP_y)^2 + (K_z \cdot gradP_z)^2}$$

Example Calculations of Capillary Number

Typical water flood

metric units

K	grad P	Surface Tension	C_{unit}	Nc	Log10(Nc)
mD	bars/meters	N/m	9.87E-11		
500	5	1		2.47E-07	-6.61
		0.1		2.47E-06	-5.61
		0.01		2.47E-05	-4.61
		0.001		2.47E-04	-3.61
		0.0001		2.47E-03	-2.61

Effective Surfactant flood

Surface Tension Table

- The surface tension is a tabulated function of the surfactant concentration.

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Relative Permeability Model

- The Relative Permeability model is essentially a transition from immiscible relative permeability curves at low capillary number to miscible relative permeability curves at high capillary number.
- User supplies table that describes the transition as a function of $\log_{10}$ (capillary number).

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Capillary Pressure

- oil water capillary pressure

$$P_{cow} = P_{cow}(S_w)\frac{ST(C_{surf})}{ST(C_{surf}=0)}$$

where

$ST(C_{surf})$ is the surface tension at the current surfactant concentration

$ST(C_{surf}=0)$ is the surface tension at zero concentration

Water PVT Properties

- Surfactant modifies the viscosity of the pure water phase.
- Multiplies the viscosity entered with the PVTW Keyword

Treatment of Adsorption - SURFADS

- The adsorption of surfactant – instantaneous
- Quantity adsorbed - function of the surrounding surfactant concentration.
- User - supply an adsorption isotherm - function of surfactant concentration

Modeling the Change to Wettability

- This feature enables the modeling of changes to wettability of the rock due to the accumulation of surfactant on the rock (adsorption).
- It is activated by using the SURFACTW keyword (RUNSPEC)
- To use this option sets of both oil-wet and water-wet relative permeabilities must be input.
- An interpolation between these 2 sets of curves is a function of the concentration of adsorbed surfactant.

Exercise on Surfactant Flooding Simulations

Question to be Answered:

In a water flooded reservoir, how does a low adsorption surfactant's performance compare to a high adsorption surfactant?

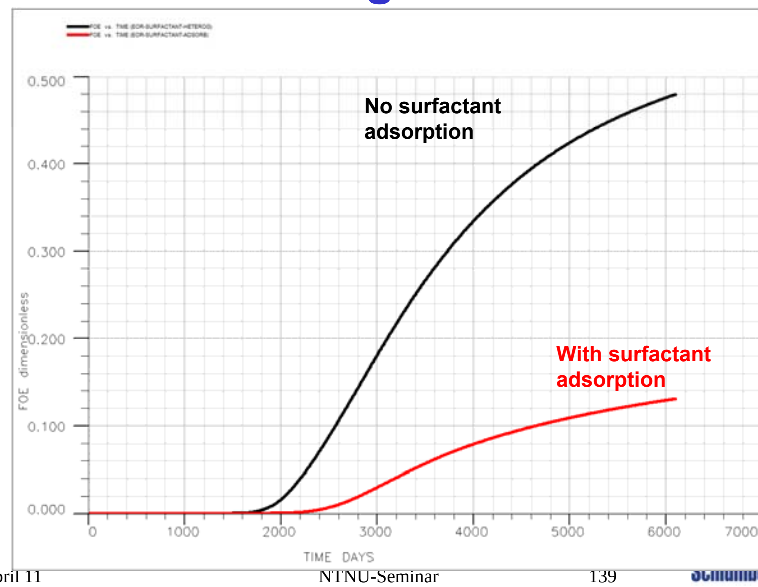
Surfactant Flooding Program – Metric Units

- Inject water 500 Sm^3/day -100 days – preflush
- Inject surfactant solution - 500 Sm^3/day – 10.5 kg/m^3 – 1000 days
- Inject water 500 Sm^3/day -5000 days

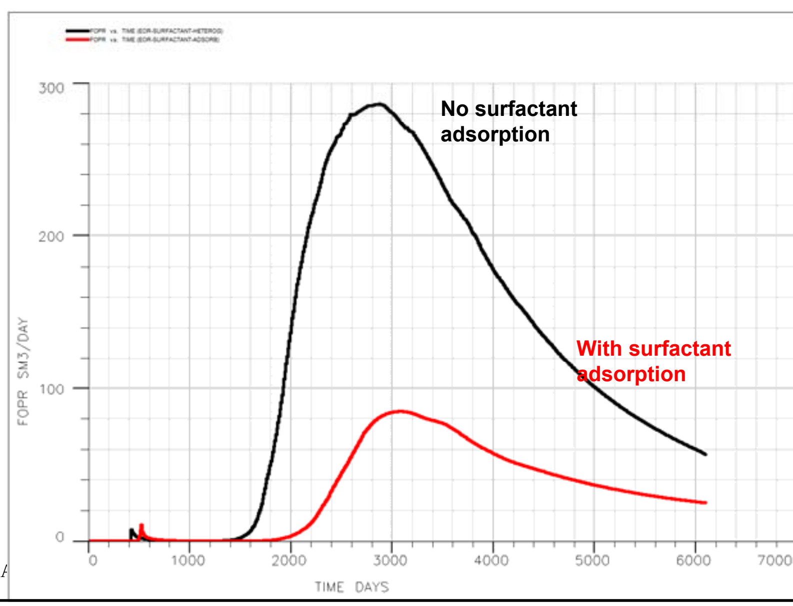
Surfactant Flooding Cases

- Case 1: No adsorption onto the rock
- Case 2: Normal adsorption onto the rock

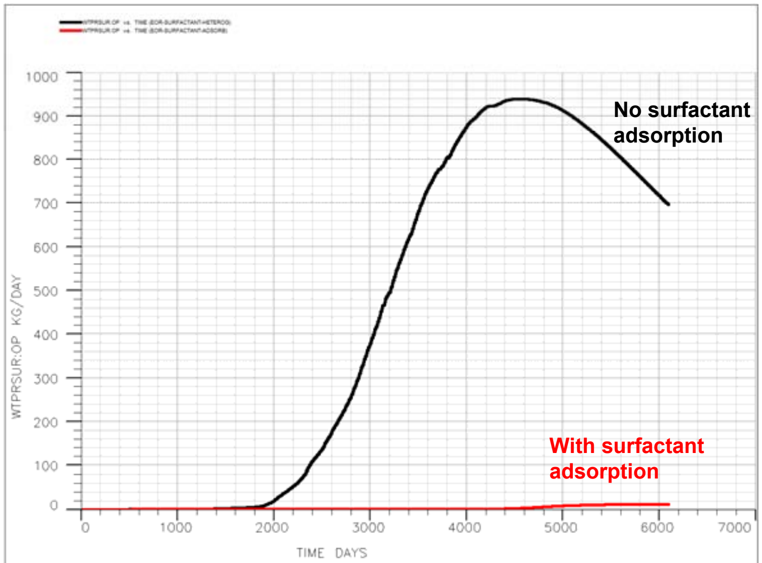
Comparison of RF – Surfactant Flooding Cases



Comparison of Surfactant Flooding Cases – Oil Production Rate



Comparison of Surfactant Flooding Cases – Surfactant Production Rate



Economics – Metric Units

- Surfactant cost = \$3.00 per kg
- Oil price = \$629 per m^3
- Surfactant injected = 5,096,000 kg
- Oil production (no adsorption) = 729,000 m^3
- Oil production (with adsorption) = 200,000 m^3

Economics

- Cost of injected surfactant = $15 Million
- Income from oil (no adsorption) = $458 Million
- Income from oil (with adsorption) = $125 Million
- Process makes money even with adsorption.

END of Simulation of Surfactant Flooding Lecture

Simulation of ASP (Alkaline-Surfactant-Polymer) Flooding with ECLIPSE

ASP Flooding

- Also goes by the name: Chemical Flooding
- ASP Flooding – Alkali-Surfactant-Polymer Flooding
- Starts with the injection of alkali agents to reduce interfacial tension (IFT) and residual oil saturation
- OR – injected combined slug of A+S+P

Links Between ASP Flooding and Surfactant Flooding and Polymer Flooding

- We have previously seen Surfactant Flooding and Polymer Flooding.
- The situation here is very similar – we will concentrate on the differences when we inject an alkali into the reservoir.

Definition of Alkali

- Alkali (from Arabic: Al-Qaly) is a basic, ionic salt of an alkali metal or alkaline earth metal element.
- Alkalis are best known for being bases that dissolve in water. Bases are compounds with a pH greater than 7.

Alkai

- Alkalis are all Arrhenius bases, which form hydroxide ions (OH^-) when dissolved in water.
- Common properties of alkaline aqueous solutions include:
  - Moderately-concentrated solutions (over 10^{-3} M) have a pH of 10 or greater. Concentrated solutions are caustic (causing chemical burns).
  - Alkaline solutions are slippery or soapy to the touch, due to the saponification of the fatty acids on the surface of the skin.

Basic Salts

- Most basic salts are alkali salts, of which common examples are:
  - sodium hydroxide (often called "caustic soda")
  - potassium hydroxide (commonly called "caustic potash")
  - lye (generic term, for either of the previous two, or even for a mixture)
  - calcium carbonate (sometimes called "free lime")
  - magnesium hydroxide is an example of an atypical alkali since it has low solubility in water.

ASP Flooding - Overview

- Synergistic chemical flooding process using alkali, surfactant, and polymer
- Synergistic = working together where different entities cooperate advantageously for a final outcome
- Oil recovery can be greatly improved by synergism of 2 or 3 chemicals together

ASP Flooding - Overview

- Quantity of expensive surfactant used – reduced 10 times
- Instead use cheaper alkali agent
- ASP flooding – used to recovery acid oil
- Typical alkali (NaOH or Na_2CO_3) is much cheaper that surfactant

ASP Flooding - Process

- ASP chemical slug combining high concentration of Alkali + low concentration of Surfactant + low concentration of Polymer is injected in to the reservoir
- Alternate Process – A + S injected followed by Polymer slug for mobility control.

ASP Flooding - Mechanisms

- Reducing interfacial tension (IFT)
  - Reaction between alkali and acid component in oil produce in-situ surfactant
  - Reduces the IFT and residual oil saturation
  - Surfactant further decreases IFT
  - Polymer increases slug (aqueous phase) viscosity for mobility control – enlarge sweeping volume

Typical ASP Flood - 1

- Chemicals used in the ASP flood are an alkali (NaOH or Na_2CO_3), a surfactant and a polymer.
- The alkali (1 to 2%) washes residual oil from the reservoir mainly by reducing interfacial tension between the oil and the water.

Typical ASP Flood - 2

- The surfactant (0.1 to 3 %) is mixed with the alkali and enhances the ability of the alkaline to lower interfacial tension.
- The polymer (1,000 to 100,000 ppm) injected after the AS slug is added to improve sweep efficiency.

Typical ASP Flood - 3

- The ASP chemical slug is injected first at approximately 30% pore volume.
- The polymer slug (approximately 25% pore volume) is injected next to push the ASP solution and maintain mobility control.
- Water is then injected to continue pushing the ASP and polymer slugs to the economic limit.

Typical ASP Flood - 4

- Wells are drilled at 5 acre spacing.
- Estimated ASP process oil recovery is 15 to 25 %.

ECLIPSE 100 Treatment of "The Alkaline Model"

Sections To Be Discussed -1

- Advanced ECLIPSE Options ASP Approximation
- Alkaline conservation equation
- Alkaline Concentrations Update
- Treatment of adsorption
- Treatment of desorption
- Alkaline effect on water-oil surface tension

Sections To Be Discussed - 2

- Alkaline effect on surfactant/polymer adsorption
- ASP Example

Advanced ECLIPSE Options ASP Approximation

The Alkaline Model –ECLIPSE Technical Description Chapter 3

•Alkaline flooding requires the injection of alkaline chemicals (lye or caustic solutions, that is high pH solutions) into a reservoir that react with petroleum acids to form in-situ surfactants that help release the oil from the rock by reducing interfacial tension, changing the rock surface wettability, and spontaneous emulsification.

The Alkaline Model –ECLIPSE Technical Description Chapter 3

•When used in conjunction with surfactant and polymer to perform an Alkaline-Surfactant-Polymer (ASP) flooding, the alkaline can reduce the adsorption of both surfactant and polymer on the rock surface, therefore enhancing the effectiveness of the surfactant and polymer drive.

The Alkaline Model –ECLIPSE Technical Description Chapter 3

- ECLIPSE provides a simplified model that does not take into account the in-situ surfactant creation and the phase behavior.
- The inject of only alkaline will not mobilize residual oil – one must inject the alkaline along with some surfactant to do an EOR flood.
- Once you inject some surfactant then the alkaline will help the surfactant reduce the IFT.

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RUNSPEC

OIL

WATER

POLYMER
SURFACT
ALKALINE

FIELD

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Alkaline Effect on Water-Oil Surface Tension

•Model the effect of alkaline on the water-oil surface tension as a combined effect with surfactant by modifying the water-oil surface tension as follows:

$$\sigma_{wo} = \sigma_{wo}(C_{surf})A_{st}(C_{alk})$$

where

$\sigma_{wo}(C_{surf})$ is surface tension as surfactant concentration and zero alkaline concentration (SURFST keyword)

$A_{st}(C_{alk})$ is the surface tension multiplier at alkaline concentration (ALSURFST keyword)

Alkaline Effect on Surfactant/Polymer Adsorption

•The alkaline can reduce the adsorption of both surfactant and polymer on the rock surface.

PROPS Section

Keyword	Description
ALSURFST	Tables of oil/water surface tension as a function of alkaline concentration Only if the surfactant option is activated
ALSURFAD	Tables of surfactant adsorption as a function of alkaline concentration Only if the surfactant option is activated
ALPOLADS	Table for polymer adsorption as a function of alkaline concentration Only if the polymer option is activated
ALKADS	Table for alkaline adsorption function as a function of alkaline concentration
ADSORP	Analytical adsorption isotherm (alternative to ALKADS).
ALKROCK	Alkaline-rock adsorption/desorption properties

Examples of ASP Flooding Simulations

Question to be Answered:

What is the importance of the Polymer in the ASP Slug Injection and in the drive water injection? Water Flooded Reservoir

ASP / AS Flood in Sector Model

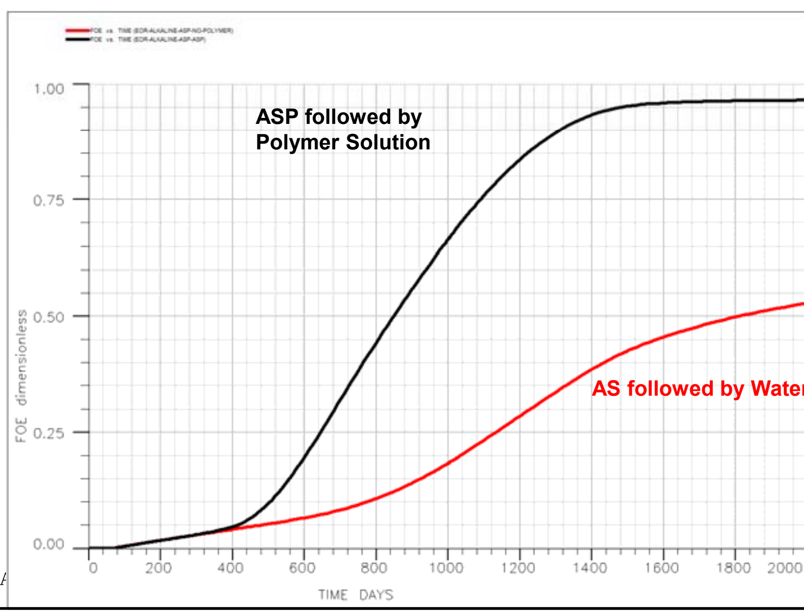
- Special designed solution of Alkaline +Surfactant + Polymer is created.
- Case 1: ASP injected for 1000 days followed by 1000 days of polymer injection (drive water) – for mobility control
- Case 2: AS (no P) injected for 1000 days followed by 1000 day of water injection only – no polymer in slug or drive water

Case 1: Our Injection Well Injects A+S+P

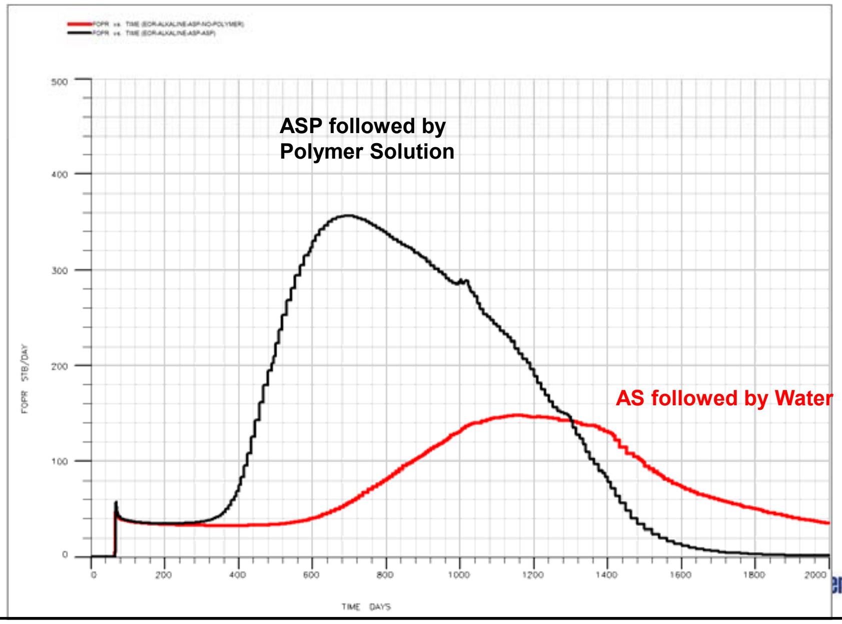
```
-- inject 1 wt % alkaline
WALKALIN
--well  alkaline injection
--name  concentration lb/stb
  I       3.5 /
/
-- inject 3 wt % surfactant
WSURFACT
--well  surfactant injection
--name  concentration lb/stb
  I       10.5 /
/

-- inject 3 wt % polymer
WPOLYMER
--well  polymer injection     Salt
--name  concentration lb/stb  concentrations
   I      10.5            0.0 /
 /
```

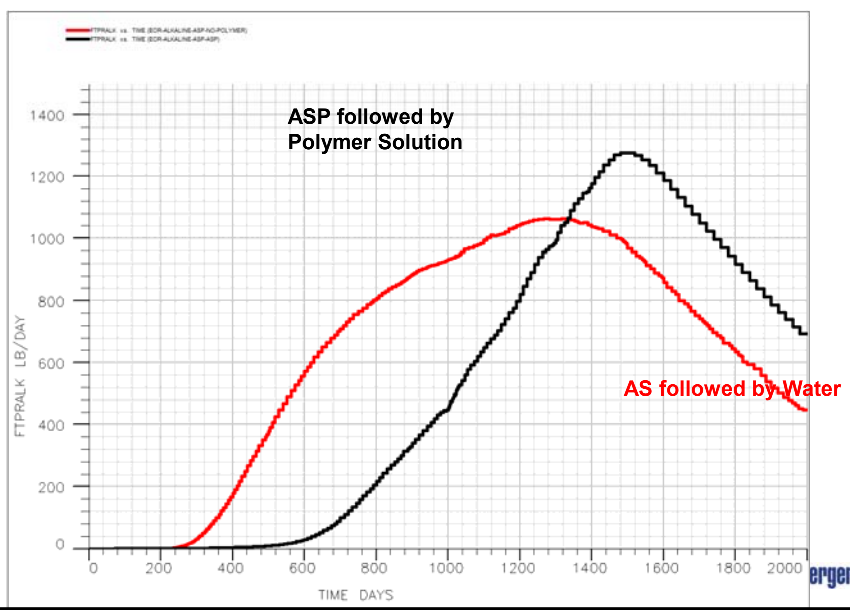

FOE (RF) for ASP / AS Flood Simulation



Oil Production Rate



Production of Alkaline



Economics

- Polymer cost = $21 Million
- Oil Production (Polymer case) = 272,000 stb
- Oil Production (no Polymer case) = 148,000 stb
- Incremental income from injecting polymer = $12 Million
- Need to find cheaper polymer!!!

Question to be Answered:

What is the effect of the Alkaline in the ASP Flood?
Water Flooded Reservoir

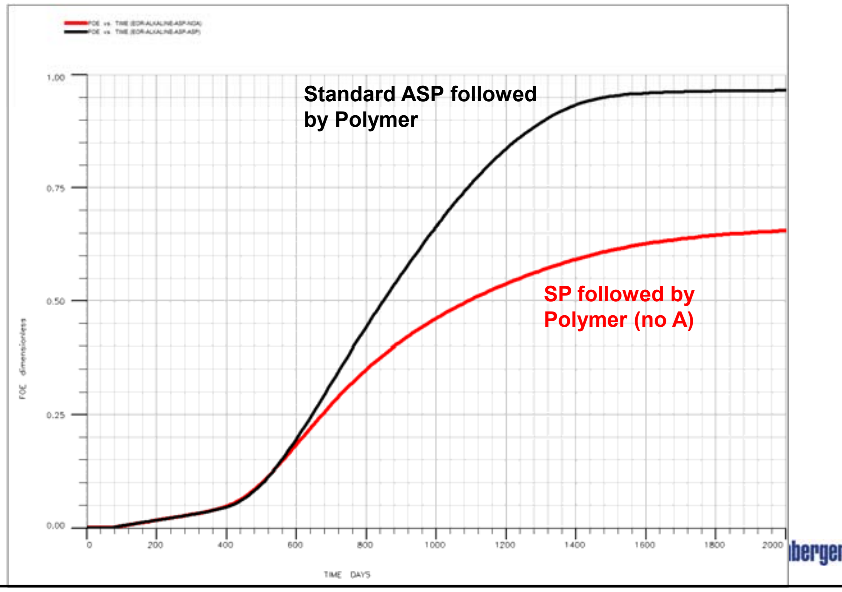
What do we know about Alkaline in an ASP Flood.

- The presents of Alkaline lowers the water-oil IFT an additional amount.
- As Alkaline adsorbs on the rock, it reduces the adsorption of both surfactant and polymer on the rock.

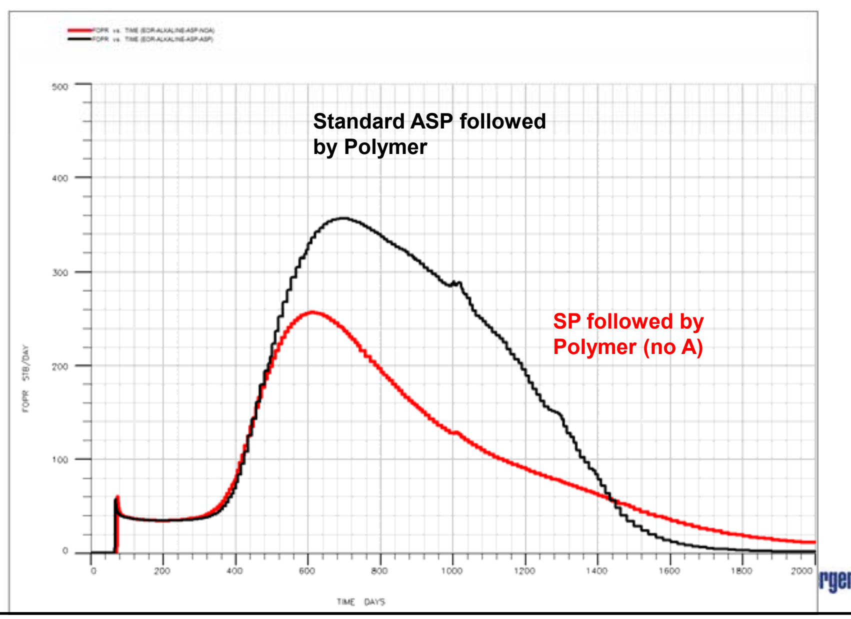
ASP / SP Cases

- Case 1: Standard ASP flood – 1000 days of ASP injection followed by 1000 days of polymer + drive water injection.
- Case 2: SP flood (no Alkaline) – 1000 days of SP injection followed by 1000 days of polymer + drive water injection.

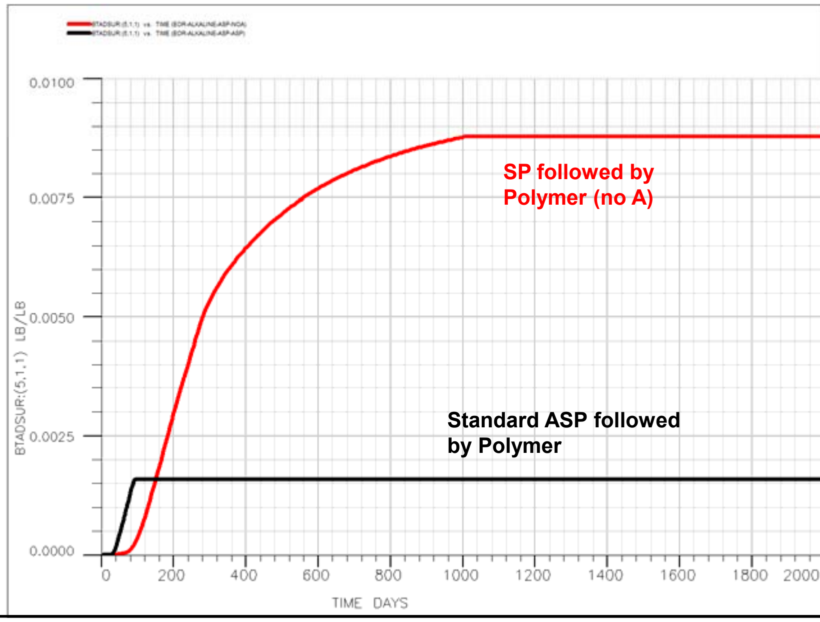
FOE Comparison



Oil Production Rate



Surfactant Adsorbed in Block (5,1,1)



Economics

- Cost of Alkaline = 0.30 / lb
- Amount of Alkaline injected in Case 1 = 1,750,000 lbs
- Cost of injected Alkaline = $525,000
- Incremental oil produced Case 1 (with Alkaline injection) = 88,000 stb
- Net profit (Case 1) = $8.3 Million
- Injection of Alkaline – positive effect

END of ASP Flooding Simulation Lecture

Questions?