Chemical Enhanced Oil Recovery
What is New, What Works, and Where Use It

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For more information about Chemical EOR research at CPGE, please visit:

http://cpge.utexas.edu/?q=IAP_ChemicalEOR

Research sponsors include:
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Chemical EOR

- Polymer flooding (PF)
- Surfactant-polymer (SP) flooding
- Alkali-surfactant-polymer (ASP) flooding
- Alkali-co-solvent-polymer (ACP) flooding
- Low tension gas flooding (LTG)
- Chemicals combined with heating
- Surfactant enhanced imbibition
- Polymer gels for blocking or diverting flow
- Polymers combined with low salinity
Why Chemical EOR?

• Chemical EOR is evolving and getting better with time due to innovations and experience
• The cost of chemicals has decreased by a factor of two relative to the price of crude oil while at the same time the quality of the chemicals has improved
• Hybrid processes have been developed and continue to improve:
  – Low tension gas flooding
  – Surfactants combined with heat
  – Polymers combined with smart water
  – Gravity stable surfactant floods
Where to Use It

• Favorable geology as indicated by good water flood performance, interwell tracers, single well tracers,....
• High porosity and permeability
• Oil viscosity
  – Up to 10,000 cp for PF/ACP
  – Up to 200 cp for SP/ASP
  – Even higher oil viscosity when combined with heating (hot water, electrical heating)
• Reservoir temperatures up to 250 °F
• Reservoir salinities up to 250,000 ppm TDS
## EOR Screening Criteria

<table>
<thead>
<tr>
<th>Property</th>
<th>CO2/ NGL/WAG</th>
<th>N2 WAG</th>
<th>Steam Drive</th>
<th>SAGD</th>
<th>Polymer</th>
<th>SP/ASP</th>
<th>ACP</th>
<th>Low Tension Gas</th>
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<td>Oil API</td>
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<td>&gt;40</td>
<td>&gt;8</td>
<td>&gt;6</td>
<td>&gt;12</td>
<td>&gt;12</td>
<td>12-25</td>
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<td>1000-10^6</td>
<td>&lt;10,000</td>
<td>&lt;200</td>
<td>20-1000</td>
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<tr>
<td>Salinity, ppm</td>
<td>--</td>
<td>--</td>
<td>--</td>
<td>--</td>
<td>&lt;250000</td>
<td>&lt;250000</td>
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<tr>
<td>Temp., °F</td>
<td>--</td>
<td>--</td>
<td>--</td>
<td>--</td>
<td>&lt;250</td>
<td>&lt;250</td>
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</tbody>
</table>
Polymer Flooding

The primary objective of polymer flooding is to provide better displacement and volumetric sweep efficiencies during a waterflood.
Example of Lower Remaining Oil Saturation of Polymerflood Compared to Waterflood

**Waterflood**

- $v_i = 13$ ft/day
- $\mu_w = 0.48$ cp
- $\mu_o = 80$ cp
- $S_{oi} = 0.87$
- $S_{or} = 0.38$

**Polymer flood**

- $v_i = 1.0$ ft/day
- $\mu_p = 17$ cp
- $S_{oi} = 0.85$
- $S_{or} = 0.26$

$\Delta S_{or} = -0.12$
Polymer Flooding Advances

• Quality of commercial hydrolyzed polyacrylamide (HPAM) polymers is much better resulting in high injectivity in both vertical and horizontal wells

• HPAM polymers are available with molecular weights up to at least 20 million

• Equipment and procedures for field preparation of high quality polymer solutions are now routine

• Water softening is now inexpensive (as low as US$ 0.15 per Bbl of seawater when done on a large scale) and enables the use of HPAM even at high temperature

• New polymers can be used in hard brine at high temperature
Polymer Flooding

- Increasing water viscosity by adding polymer to the water helps minimize the adverse effects of reservoir heterogeneity and will benefit almost all water floods even if the oil viscosity is low.

- The benefits are greatest when polymer is injected at high concentration for a long time e.g. more than one pore volume.

- Under favorable conditions, the polymer cost is in the range of $1 to $5 per Bbl of additional oil.
Surfactant Methods

• The main objective of SP/ASP/ACP flooding is to recover the oil remaining after water flooding by mobilizing oil trapped in pores due to capillary forces (residual oil saturation)

• The interfacial tension between the oil and water must be reduced by about 10,000 fold to mobilize all of the trapped oil in the swept zone

• Adding a high molecular weight polymer to the surfactant solution to increase its viscosity vastly improves the oil recovery
Example Oil Recovery of 100 cp Oil from Core

30% PV ASP Slug (0.3% surfactant); Surfactant retention=0.02 mg/g

Oil Cut or Cumulative Oil Recovered

Curves: UTCHEM
Points: Experiment

Cumulative Oil Recovered

Oil Cut

ASP slug diluted with polymer drive
New Surfactants and Co-solvents

• Several new classes of high-performance surfactants and co-solvents have been developed in recent years
• Wide range of molecular weights up to 4000
• Include inexpensive ethylene oxide and propylene oxide to improve salinity and hardness tolerance
• Carboxylates and sulfonates stable up to 250 °F
• Made from commercial feedstocks
• Use synergistic mixtures
• Cost about $2.50/lb of active surfactant
Low Surfactant Retention

• The amount of surfactant needed to recover oil is directly proportional to surfactant retention so lowering the surfactant retention is the key to low chemical cost per Bbl of additional oil

• Surfactant retention is caused by adsorption on the rock and phase trapping of viscous emulsions

• Phase trapping is often the largest contribution to surfactant retention

• Lower emulsion viscosity results in lower surfactant retention
Low Surfactant Retention

• Surfactant retention has been reduced by a factor of about 3 in recent years
• Alkali reduces surfactant retention a factor of about 2
• Surfactant retention in sandstones with high clay content has been reduced to values in the range of 0.02 to 0.11 mg/g rock and similar values have been measured in carbonate cores
• Good mobility control is essential to get such low retention
Conventional Co-solvent

- 30% oil; $\mu_o \approx 5.5 \text{ cP @ 25°C}$
- 0.5% TDA-13PO-SO4-, 0.5% C20-24 IOS
- 0% & 2% IBA
New Co-solvent

- 50% oil; $\mu_o=2.9$ cP @ 55°C
- 0.6% OA-45PO-10EO-SO4-; 0.4% C15-17 ABS
- 1% phenol-4EO
Surfactant Retention = 0.075 mg/g rock
Sandstone with 11.9 wt% clay, $\mu_{ME}/\mu_0 = 1.9$
Surfactant Retention = 0.11 mg/g rock
Sandstone with 11.9 wt% clay, $\mu_{ME}/\mu_o = 2.2$
Economic Significance of Reduced Retention

<table>
<thead>
<tr>
<th>Surfactant Retention (mg/g rock)</th>
<th>Surfactant Concentration (wt%)</th>
<th>Surfactant Cost ($/BBL Produced Oil)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.40 (1993)</td>
<td>1.78%</td>
<td>18.21</td>
</tr>
<tr>
<td>0.20 (2008)</td>
<td>0.88%</td>
<td>9.11</td>
</tr>
<tr>
<td>0.08 (2015)</td>
<td>0.36%</td>
<td>3.64</td>
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</tbody>
</table>

References

Assumptions
- Porosity: 20%
- Recovery Factor: 25% OOIP
- Size of Chemical Slug: 0.3 PV
- Surfactant to Co-solvent Ratio: 1
- Surfactant: $2.00 / lb
Live Oil Coreflood using new TSP Surfactant
(Oil Cut in ASP Field Pilot Nearly the Same as Coreflood)

Cum Oil Recovered (%), Oil cut (%)

Oil Saturation (%)

Pore Volumes

Cum Oil Recovery
Oil Cut
So

97.4%
1.01%
Take Home

• The combined impact of all of the new Chemical EOR and oilfield technology is a game changer
  – New and better chemicals at lower real cost
  – Increased performance at lower cost per Bbl oil
  – New hybrid methods for both light and heavy oil
  – Better models are available to design and predict field performance
  – Better enabling technologies e.g. horizontal wells

• But it’s still complex technology and geology still matters, and so do people
Mojdeh Delshad

Research Professor, Center for Petroleum and Geosystems Engineering, The University of Texas at Austin
Modeling Chemical EOR Methods
Our Mission Since 1977

- Mechanistic modeling of CEOR processes from *bench* to *pilot* to *field* scales

- Modeling geochemical reactions for more challenging fluid and reservoir conditions
  - Hard brine with EDTA, soft brine with sodium carbonate
  - Carbonate reservoirs
  - Low salinity waterflood

- Modeling hybrid methods
  - Wettability modification (surf. in fractured carbonates)
  - Low salinity or smart water (low salinity/ polymer)
  - Hot water (hot SP)
  - Foam (surf/foam)
  - Gas (low tension gas)
UTCHEM Applications

- Tracer tests (single well, interwell)
- Polymer flooding
  - Viscoelastic polymer
  - Polymer degradation mechanisms
  - Injectivity correction
- Surfactant/polymer flooding
- Alkaline/surfactant/polymer flooding
  - Geochemical reactive simulations
- Polymer/crosslinker (gel) for profile modification
- Wettability alteration with surfactants
- Low salinity waterflood
- Microbial EOR
  - Biological reactive simulations
  - Hot surfactant/polymer flood for heavy oil
    - Steam
    - Electrical heating
    - Hot water
  - Low tension gas flooding (SAG, ASG)
    - Foam options
    - Black oil option
Chemical EOR Methods for Heavy Oils
## Polymer Flooding of Offshore Viscous Oil with Strong Aquifer Support

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Model size</td>
<td>3805 ft x 3608 ft x 256.66 ft</td>
</tr>
<tr>
<td>No. of gridblocks</td>
<td>58 x 55 x 52</td>
</tr>
<tr>
<td>Reservoir temperature, °C</td>
<td>40</td>
</tr>
<tr>
<td>Oil viscosity, cp</td>
<td>1500</td>
</tr>
<tr>
<td>Average porosity</td>
<td>0.31612</td>
</tr>
<tr>
<td>Average reservoir perm. (md)</td>
<td>Kx = 18242, ky = 18242, kz = 10945</td>
</tr>
<tr>
<td>Reservoir brine TDS, ppm</td>
<td>52000</td>
</tr>
</tbody>
</table>
Injection Well Location Optimization

Inj. well

Producer

Water viscosity at 635 d
Oil Viscosity and Injector Location

![Graph showing oil recovery vs. injector location above WOC (ft).]

- **300 cp oil**
- **1520 cp oil**

**Graph Details:**
- X-axis: Injector Location Above WOC (ft)
- Y-axis: Oil Recovery (MM bbls)
- Two curves represent different oil viscosities:
  - Bent08, oil viscosity=1518cp
  - Bent10, oil viscosity=300 cp
Alkaline - CoSolvent - Polymer (ACP) New Technology

- Addition of co-solvent to AP leads to ACP
  - Low IFT & mobility control without synthetic surfactant
  - Breaks viscous and unstable emulsions
  - Effective only with oils that form soaps (active oil)

- Robust and less expensive than ASP
  - Co-solvents insensitive to geochemistry and temperature
  - Low adsorption
  - Lower microemulsion viscosity compared to ASP
ACP Lab Coreflood Recoveries

- Oil viscosity from 70 to 4800 cp
- Tertiary oil recoveries from 80 to 95% OOIP
ACP Pilot Project

- 0.5 PV polymer preflush
- 0.11 PV ACP slug
- 1 PV polymer

Initial Oil Saturation

Final Oil Saturation
Improve Displacement Efficiency using Viscoelastic Polymers
Residual Oil Saturation vs. Deborah Number

\[ S_{or} = S_{or}^h + \frac{(S_{or}^l - S_{or}^h)}{1 + TPP \times N_{De}} \]

- \( S_{or}^h \): residual oil saturation at high \( N_{De} \)
- \( S_{or}^l \): residual oil saturation at low \( N_{De} \)
- \( TPP \): fitting parameter
Sandpack Experiment with 250 cp Oil

- **Cum Oil Recovered (%)**
  - **Pore Volumes**
  - **Oil saturation**
  - **Oil Cut**

24% reduction in $S_{or}$

- **Water Flood**
- **Polymer Flood**

- **Cum Oil**

- **Oil Saturation (%)**
- **Cum Oil Recovered (%)**
- **Pore Volumes**

Accurate Polymer Injectivity Models

- Radial model with fine-grid (1 ft in r-direction) as true solution
- Coarse grid Cartesian model (77 ft x 77 ft)
Injectivity Correction Models

• Results are very close to radial simulations.

![Graph showing injectivity correction models](image)
Modeling Unstable Polymer Floods

$\mu_o = 100 \text{ cp}$

$\mu_o = 1000 \text{ cp}$ (base case)

$\mu_o = 10000 \text{ cp}$
Low-Tension Surfactant-Gas

- Similar to SP/ASP but **Gas** is used instead of **Polymer**
  - Reservoirs with **high-salinity/high-temperature**
  - No injectivity limitation with **tight formation/NFR/viscous oil**
  - Foam is an alternative mobility control
  - Foam can divert surfactants to matrix or low permeability zones
  - Mobilization of trapped oil

- Favorable for both **secondary & tertiary floods**

  **Surfactant-1**
  - IFT reduction
  - Wettability alteration

  **Surfactant-2**
  - Foaming to control mobility, increase sweep efficiency, divert surfactants
Simulation of SAG Coreflood

**Parameters**
- Maximum resistance factor, $RF_{max}$: 75
- Critical oil saturation, $S_o^*$: 0.3 (vol/vol)
- Critical surfactant concentration, $C_s$: 0.00085 (vol/vol)
- Gas shear thinning exponent, $\sigma$: 1.0
- Water saturation tolerance, $\varepsilon$: 0.01
- Reference gas velocity, $U_{g,Ref}$: 1.65 (ft/Day)
- Water saturation at critical capillary pressure, $S_w^*$: 0.25 (vol/vol)

Low trapping rel. perm properties are dominated
High trapping rel. perm properties are dominated
Foam properties are dominated
Gravity-Stable Surfactant (SGS) Floods

• No need for mobility control with either polymers or high pressure gas to reduce cost, complexity and uncertainty

• Using horizontal wells gives higher volumetric sweep efficiency and maximum critical velocity compared to vertical wells.

• Practical if there are no barriers to vertical flow and the vertical permeability is high.

• Some of the world’s largest oil reservoirs are high-temperature, moderate-permeability, light-oil reservoirs and thus good candidates.
SGS Coreflood in Fractured Carbonates

![Diagram showing recovery (% OOIP) vs. PV for surfactant and water floods, with LAB and Model annotations.]

- **Surfactant flood**
- **Water flood**
- **Surfactant flood**
- **Water flood**

**Recovery (% OOIP)**

- PV (Porosity Volume)

**SGS Experiment**
Permeability Distribution

Oil Saturation at 1.75 PV

Surfactant Conc. at 1.75 PV

Nx = 5, Ny = 5, Nz = 10
Correlation length = 0.01 ft
Mean value for permeability = 1000 md
Dykstra-Parsons coefficient = 0.975
Simulation of SGS Experiment
Effect of Grid Size
Recent Chemical EOR Field Projects
ASP Pilot in Mangala Field in India

- 27 API oil (19 cp)
- Excellent perm-por sand
- 62 C temperature

ASP formulation developed at UT
- 0.3% surfactant (TSP, IOS)
- 3% Na₂CO₃
- 3000 ppm FP3630 polymer

- 80% oil cut with performance similar to the corefloods
- No produced fluid issues (no emulsion etc.)
- Commercial polymer flood in progress
- Plan for larger ASP pilot in progress
ASP Single Well Tests in Challenging Carbonate Reservoir in Kuwait

- Thick, heterogeneous **Sabriyah Mauddud** with 1-100 mD and 80°C
- ASP Formulation
  - Sodium carbonate, 1.5 % surfactants (Carboxylate, 2xI0S)
- **SWTT #2** being **diverted around ASP** (top image)
- Perform **SWTT #2 in polymer** to stably displace ASP
  - $S_{orw} = 0.39$, $S_{orc} = 0.05$
  - 34 saturation units recovered
  - **89% recovery** of waterflood residual oil saturation
Q&A
Please enter your questions in the chat box on the left.

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Thank you!

Question? Comments? Please contact us!

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