

# Workshop: Minnelusa I

Day 3

8:10 – 9:10 am

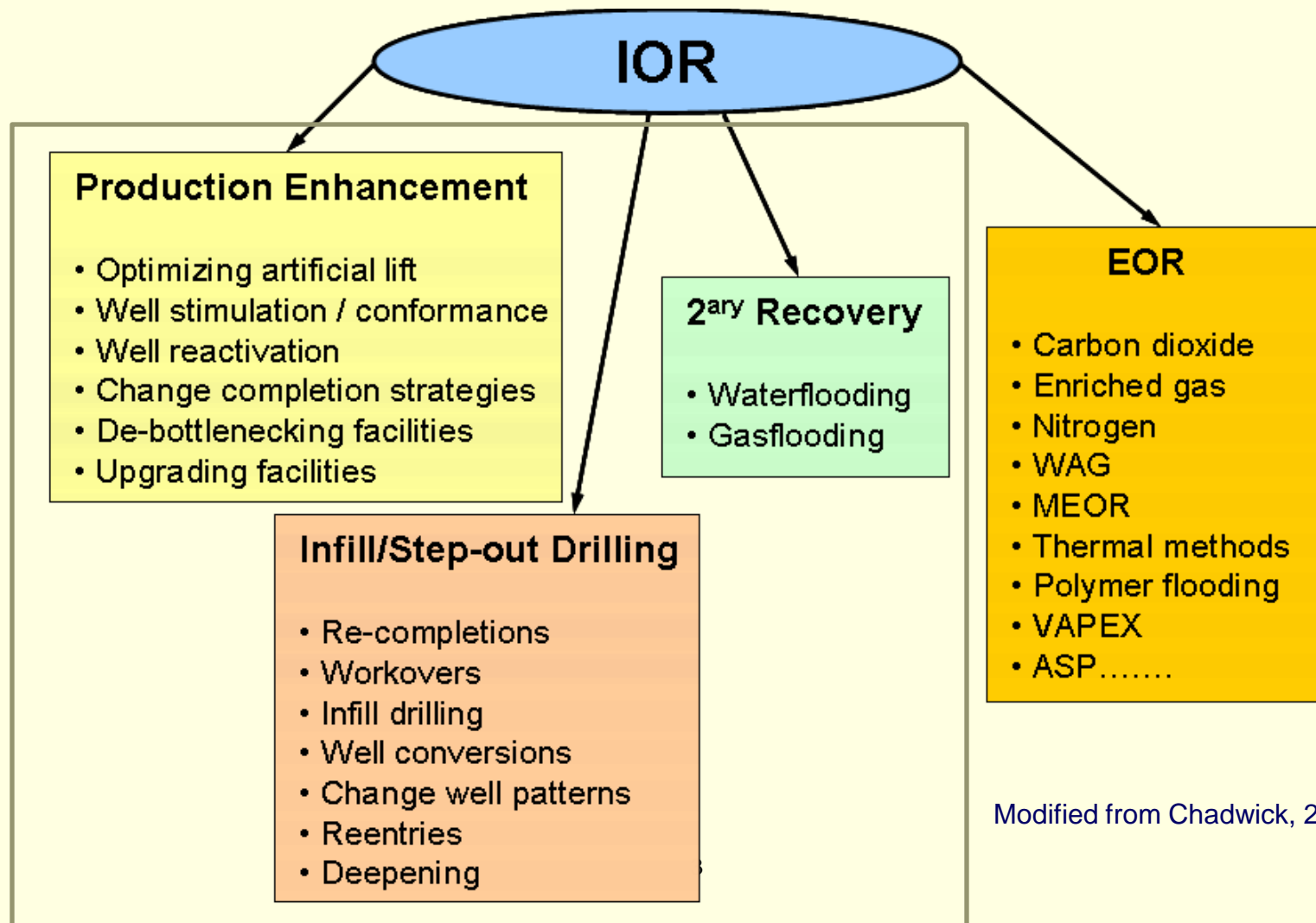
Minnelusa IOR/EOR options and feasibility

# Outline

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- Introduction
  - IOR and EOR
  - Traditional EOR targets
  - Workflow and need for screening
- Traditional screening & advanced methods
- Gas methods
- Chemical methods
- Issues specific to Minnelusa reservoirs
- Summary

# IOR and EOR



# Recovery Efficiency

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$$E_R = E_D \times E_V$$

- $E_R$ : overall recovery efficiency
- $E_D$ : displacement efficiency or microscopic
- $E_V$ : volumetric sweep efficiency

# Mobility Ratio

Mobility

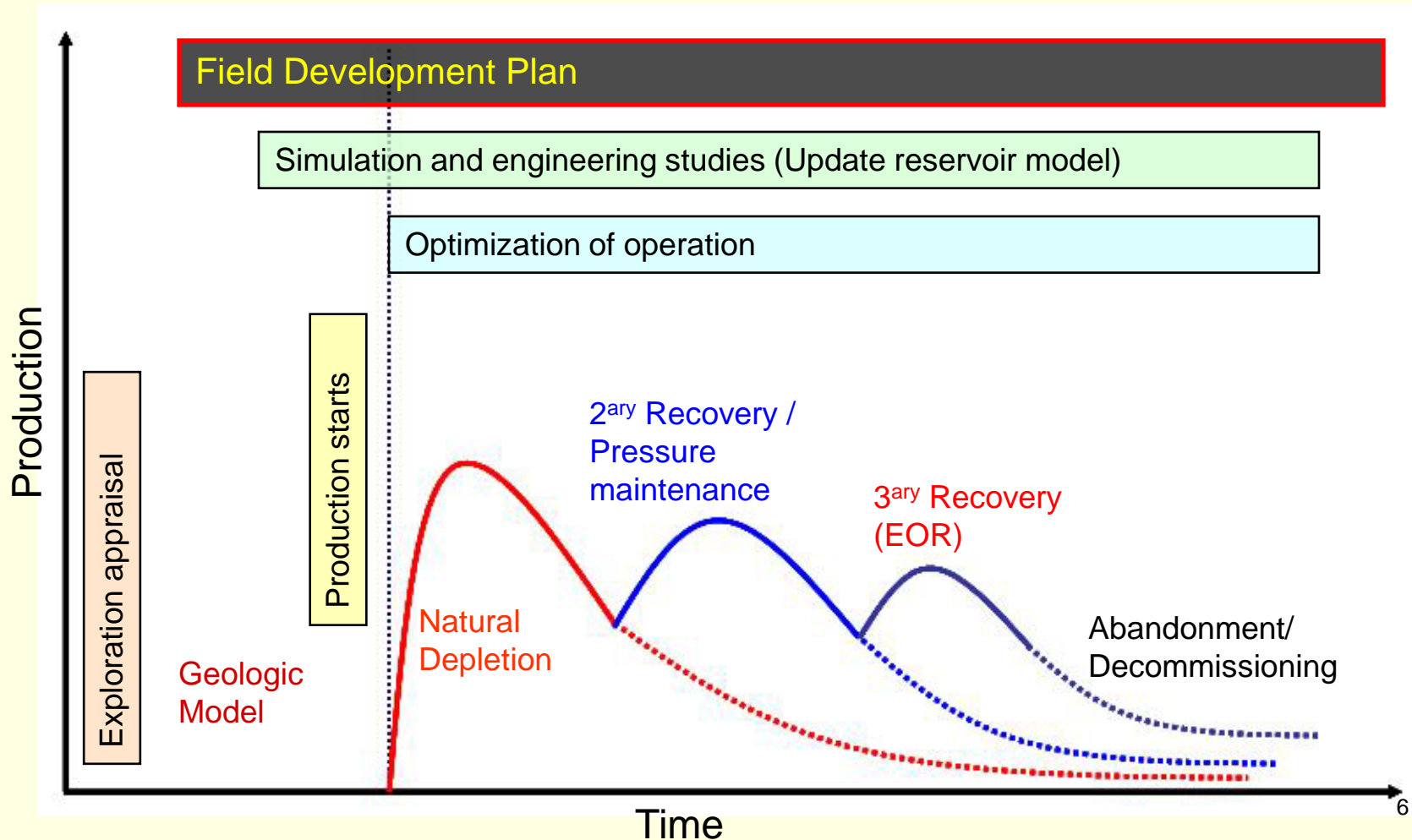
$$\lambda_o = \frac{k_o}{\mu_o}; \quad \lambda_w = \frac{k_w}{\mu_w}; \quad \lambda_g = \frac{k_g}{\mu_g}$$

Mobility Ratio

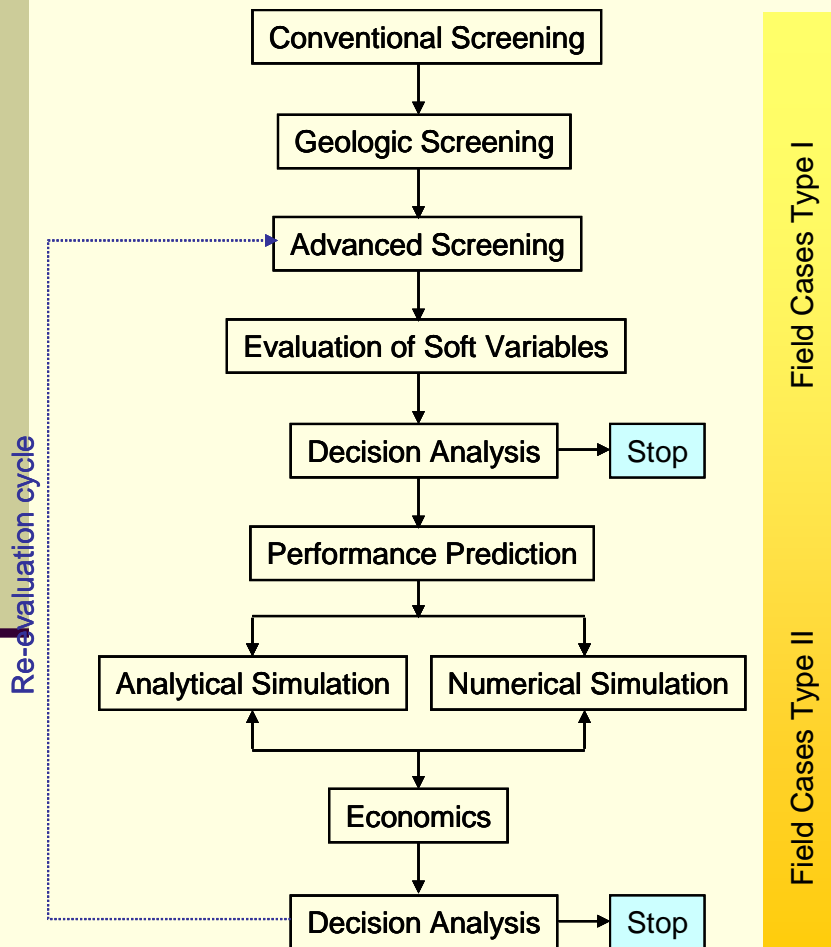
$$M \equiv \frac{\lambda_D}{\lambda_d} \quad \longrightarrow \quad M_{w,o} = \frac{(\lambda_w)_{S_{or}}}{(\lambda_d)_{S_{wc}}} = \frac{k_{rw}(S_{or})/\mu_w}{k_{ro}(S_{wc})/\mu_o}$$

*Similarly for other phase ratios*

# Traditional Phases of Field Production



# A Possible Workflow (for success?)



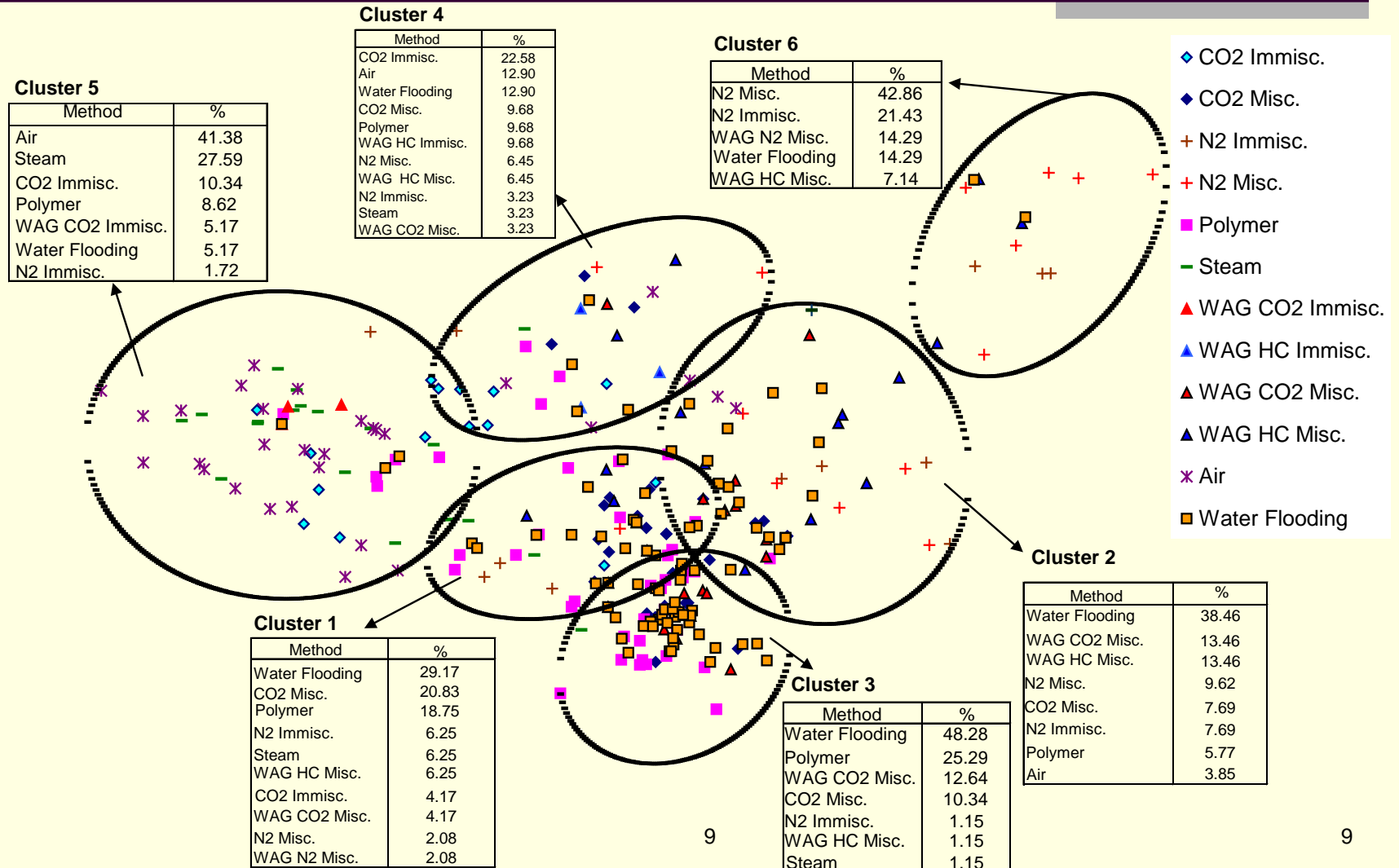
- Frame the problem adequately
- Avoid excessive and often unnecessary reiteration of analysis that leads nowhere
- Realize when simpler is better or new data are necessary
- Manage soft issues, before they become hard lessons
- Understand that a bad outcome does not qualify a decision

# Lookup Table Screening Criteria

Detail Table	EOR Method	Oil Properties			Reservoir Characteristics					
		Gravity (°API)	Viscosity (cp)	Composition	Oil Saturation	Formation Type	Net Thickness (ft)	Average Permeability (md)	Depth (ft)	Temperature (°F)
Gas Injection Methods (Miscible)										
1	Nitrogen and flue gas	>35↑48 ↑	<0.4↓0.2 ↓	High percent of C1 to C7	>40 ↑75 ↑	Sandstone or Carbonate	Thin unless dipping	NC	>6,000	NC
2	Hydrocarbon	>23 ↑41 ↑	<3↓0.5 ↓	High percent of C2 to C7	>30↑80 ↑	Sandstone or Carbonate	Thin unless dipping	NC	>4,000	NC
3	CO2	>22 ↑36 ↑	<10↓1.5 ↓	High percent of C5 to C12	>20↑5 ↑	Sandstone or Carbonate	Wide Range	NC	>2,500	NC
1-3	Immiscible gases	>12	<600	NC	>35↑70 ↑	NC	NC if dipping or good Kv	NC	>1,800	NC
Enhanced Waterflooding										
4	Micellar Polymer, ASP, and Alkaline flooding	>20 ↑35 ↑	<35↓13 ↓	Light intermediate, organic acids	>35↑53↑	Sandstone preferred	NC	>10↑450↑	>9,000↓ 3,250	>200↓80
5	Polymer Flooding	>15	<150, >10	NC	>50↑80↑	Sandstone preferred	NC	>10↑800↑	<9,000	>200↓1400
Thermal/Mechanical										
6	Combustion	>10 ↑16	<5,000 ↓1,200	Some asphaltic components	>50↑72↑	High φ sand /Sandstone	>10	>50	>11,500↓ 3,500	>100↑135
7	Steam	>8 to 13.5	<200,000 ↓4,700	NC	>40↑66↑	High φ sand /Sandstone	>20	>200↑2,450 ↑	>4,500↓ 1,500	NC
-	Surface Mining	7 to 11	Zero cold flow	NC	>8wt% sand	Mineable tar sand	>10	NC	>3:1 overburden to sand	NC



# Advanced Screening Criteria



# EOR Gas Methods

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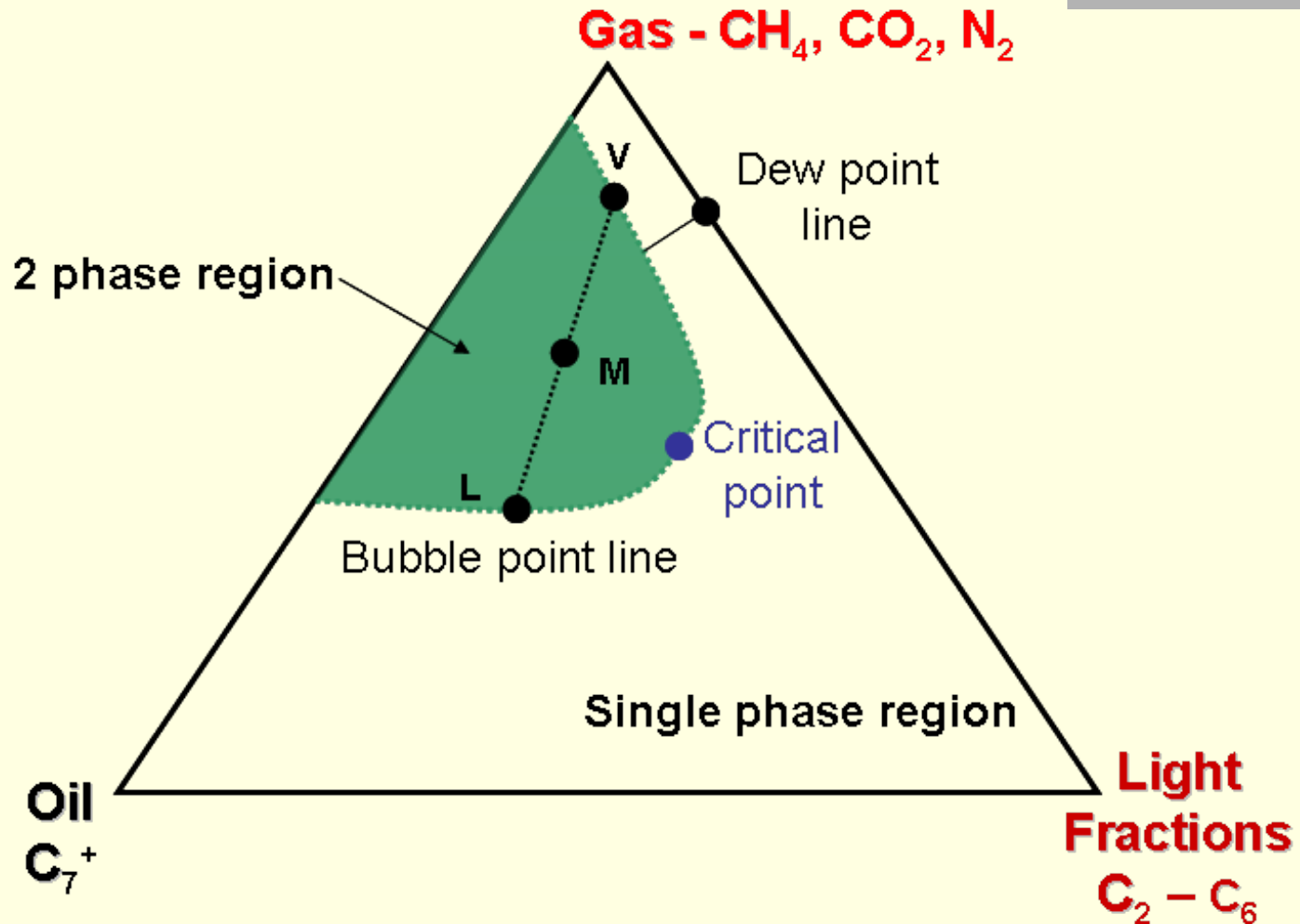
Gas injection methods can be classified as:

- Miscible processes
- Immiscible processes

Miscibility of two fluids occurs at either first contact or multiple contacts (condensing and vaporizing gas drives).

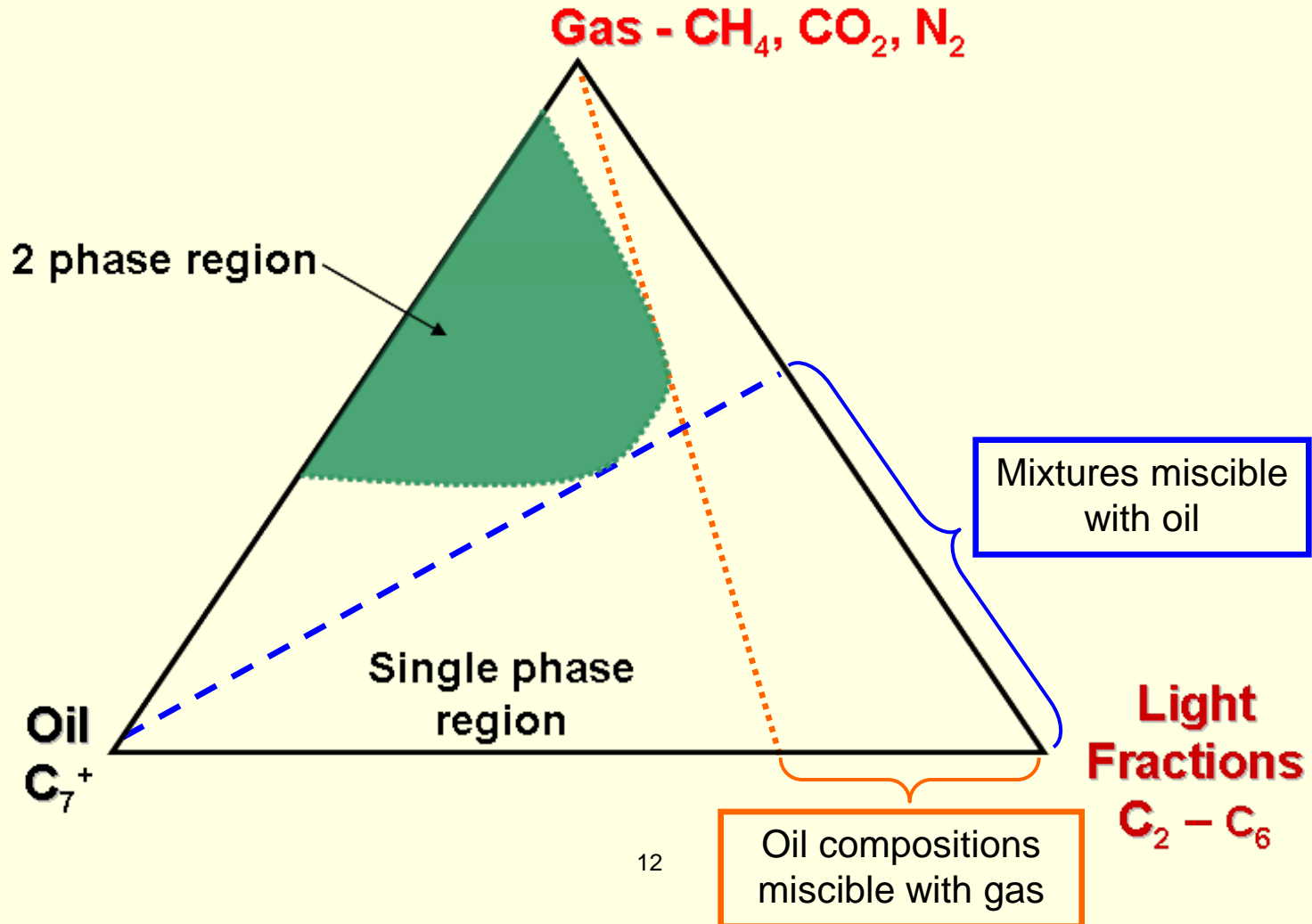
Generally, gas injection processes in heavy and medium crude oil reservoirs ( $< 25$  °API) are immiscible. However, miscibility in medium crude oils can be achieved in deep, high temperature, high pressure reservoirs.

# Phase Behavior in Gas EOR

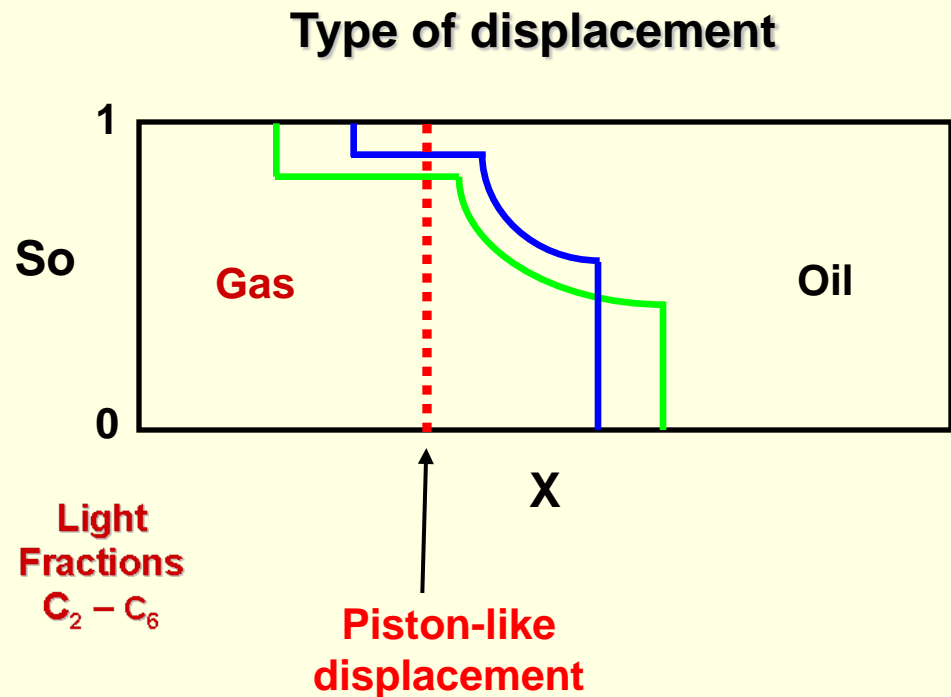
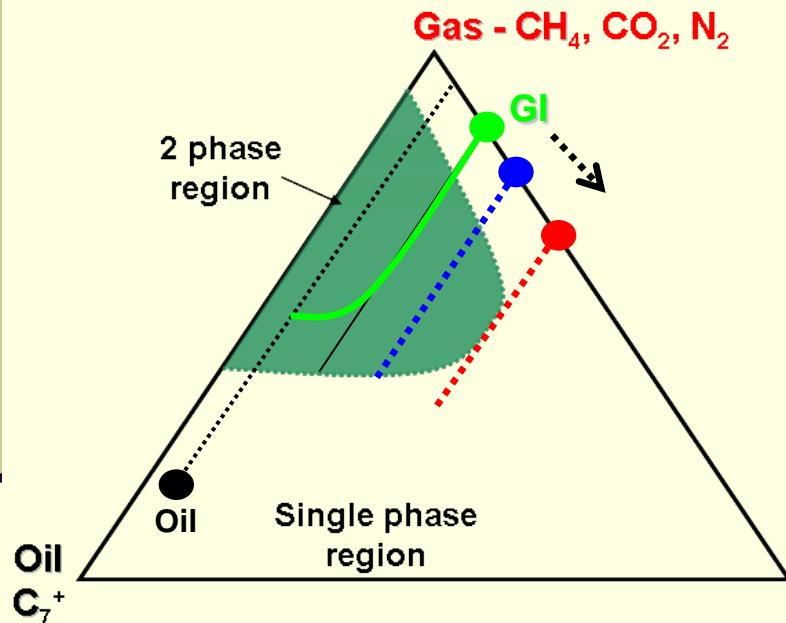


Ternary diagram for three-component mixture

# First Contact Miscibility



# Multiple Contact Miscibility: Condensing Gas Drive (continued)



# Basic Screening Criteria

Major criteria for immiscible and miscible gas injection (*SPE-88716*; *SPE-35385*)

	<b>Immiscible Gas injection</b>	<b>Miscible HC Injection</b>	<b>Miscible CO<sub>2</sub></b>	<b>Miscible N<sub>2</sub></b>
<b>Depth (m)</b>	> 200	> 1200	> 600	> 1800
<b>Oil Saturation (%)</b>	> 50	> 30	> 25	> 35
<b>Oil Gravity (°API)</b>	> 13	> 24	> 22	> 35
<b>Oil Viscosity @ Pb (mPa.s)</b>	< 600	< 5	< 10	< 2
<b>Crude Oil composition</b>	NC	High % of light hydrocarbons (C <sub>2</sub> to C <sub>7</sub> )	High % of light hydrocarbons (C <sub>5</sub> to C <sub>12</sub> )	High % of light hydrocarbons (C <sub>1</sub> to C <sub>7</sub> )

NC = Not critical

1 mPa.s = 1 cp

# Geologic Screening Criteria: Clastic Reservoirs (continued)

		LATERAL HETEROGENEITY		
		LOW	MODERATE	HIGH
VERTICAL HETEROGENEITY	LOW	Wave-dominated delta Barrier core Barrier shore face Sand-rich strand plain <b>(7) / [2]</b>	Delta-front mouth bars Proximal delta front (accretionary) Tidal Deposits Mud-rich strand plain <b>(2)</b>	Meander belts* Fluvially dominated delta* Back Barrier* <b>(2)</b>
	MODERATE	Eolian Wave-modified delta (distal) <b>(1) / [1]</b>	Shelf barriers Alluvial Fans Fan Delta Lacustrine delta Distal delta front <b>(3) / [1]</b>	Braided stream Tide-dominated delta <b>(3) / [2]</b>
	HIGH	Basin-flooring turbidites <b>[1]</b>	Coarse-grained meander belt Braid delta	Back barrier** Fluvially dominated delta** Fine-grained meander belt** Submarine fans** <b>(6)</b>

\* Single units \*\*Stacked Systems

Tyler and Finley clastic heterogeneity matrix showing depositional systems of 24 successful **(Blue)** and 7 failed **[Red]** CO<sub>2</sub> injection projects

# Screening Criteria of CO<sub>2</sub> Floods

## Main Screening Criteria (SPE-35385)

Properties <sup>α</sup>	Miscible-Floods <sup>α</sup>	Immiscible-Floods <sup>α</sup>
Porosity·(%) <sup>α</sup>	Not-critical <sup>α</sup>	
Permeability·(md) <sup>α</sup>	Not-critical <sup>α</sup>	
Depth·(ft) <sup>α</sup>	>·2,800 <sup>α</sup>	>·1,800 <sup>α</sup>
Temperature·(°F) <sup>α</sup>	Not-critical <sup>α</sup>	
Net-thickness·(ft) <sup>α</sup>	Wide-range <sup>α</sup>	
Oil-gravity·(°API) <sup>α</sup>	>·22 <sup>α</sup>	>·13 <sup>α</sup>
Oil-Composition <sup>α</sup>	High·C <sub>5</sub> -C <sub>12</sub> ·(Especially·for·misc·floods) <sup>α</sup>	
Oil-saturation·(%PV) <sup>α</sup>	>·20%·(Higher·the·better,·generally·>·50%) <sup>α</sup>	
Formation-type <sup>α</sup>	Carbonate·or·Sandstone <sup>α</sup>	

## Main reservoir properties of CO<sub>2</sub> floods (SPE-94682)

Reservoir-property <sup>α</sup>	Carbonate-reservoirs <sup>α</sup>	Sandstone-reservoirs <sup>α</sup>
Porosity·(%) <sup>α</sup>	6·-·25 <sup>α</sup>	9·-·29 <sup>α</sup>
Permeability·(md) <sup>α</sup>	1.5·-·170 <sup>α</sup>	10·-·1000 <sup>α</sup>
Depth·(ft) <sup>α</sup>	1,950·-·14,000 <sup>α</sup>	2,050·-·15,600 <sup>α</sup>
Temperature·(°F) <sup>α</sup>	90·-·245 <sup>α</sup>	75·-·305 <sup>α</sup>
Net-pay·(ft) <sup>α</sup>	22·-·325 <sup>α</sup>	21·-·224 <sup>α</sup>
Pay-ratio <sup>α</sup>	0.10·-·0.89 <sup>α</sup>	0.23·-·0.83 <sup>α</sup>
Oil-gravity·(°API) <sup>α</sup>	28·-·44 <sup>α</sup>	17·-·43 <sup>α</sup>
Oil-viscosity·(cp) <sup>α</sup>	0.4·-·6.0 <sup>α</sup>	0.2·-·3.1 <sup>α</sup>



# Quick Rules of Thumb

- Reservoirs with good water flood response are best candidates for CO<sub>2</sub>.
- Recovery factor using miscible CO<sub>2</sub> is 8%–11% OOIP. Immiscible CO<sub>2</sub> is 4%–6% (50% of miscible).
- MMP equals initial bubble point pressure.
- CO<sub>2</sub> requirement is 7–8 Mcf/barrel plus 3–5 Mcf/barrel recycled.
- Water injection required to fill gas voidage and increase reservoir pressure above MMP.
- WAG is alternative but 10 Mcf/barrel still required (**Most common development of CO<sub>2</sub> floods**).
- Top down CO<sub>2</sub> injection alternative is effective but requires more capital investment for higher CO<sub>2</sub> volume (WAG Tapered).

# Unfavorable Reservoir Characteristics for Empirical Screening

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- High concentrations of vertical fractures
- Very high, or very low, permeability
- Vertical segregation or fracture channeling (WAG injection strategies preferred in these cases)
- Thick reservoirs with no layered horizontal permeability barriers
- Reservoirs with poor connectivity
- Well spacing >80 acres (4,047 m<sup>2</sup>)
- Poor material balance during water flood (high water loss out of zone, water influx, or high water cut during primary production)
- Asphaltene precipitation in the presence of CO<sub>2</sub>

# Chemical Methods: Polymer+Surfactant+Alkali

# Overview

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EOR chemical methods have been considered for a wide range of crude oil (14° API – 35° API) reservoirs.

During the last decades, chemical EOR methods have declined in the public record, except in China and Russia where chemical methods contribute to the total oil production (*Debons, 2002; Mack, 2005; Surguchev et al., 2005*).

Chemical flooding is sensitive to oil prices and highly influenced by chemical additive costs, in comparison with the cost of gas and thermal EOR projects.

# Overview (continued)

Of 433 international pilot projects or field wide chemical floods well documented in the literature, only 79 projects have been conducted in reservoirs other than sandstone formations (*Surguchev et al., 2005*).

Chemical Method <sup>(1)</sup>	Reservoir Lithology		
	Sandstone	Carbonate	Other <sup>(2)</sup>
Alkaline (A)	22	-	-
Polymer (P) <sup>(3)</sup>	267	64	9
Micellar Polymer (SP)	38	6	-
S, AP, AS & ASP	27	-	-

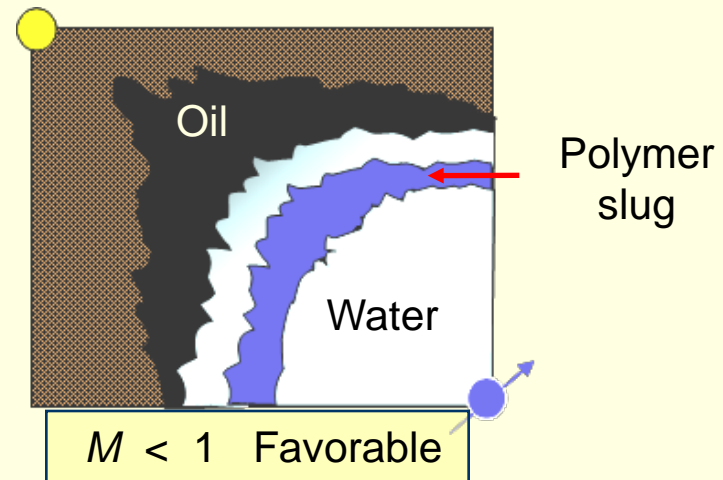
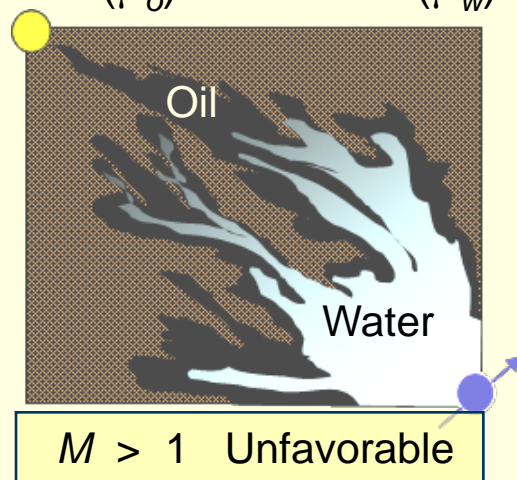
- (1) Does not include well stimulation with surfactants or well conformance (gels or foam treatments).
- (2) Includes chalk, diatomite, and turbiditic reservoirs.
- (3) Does not include biopolymer floods.

# Mobility Ratio

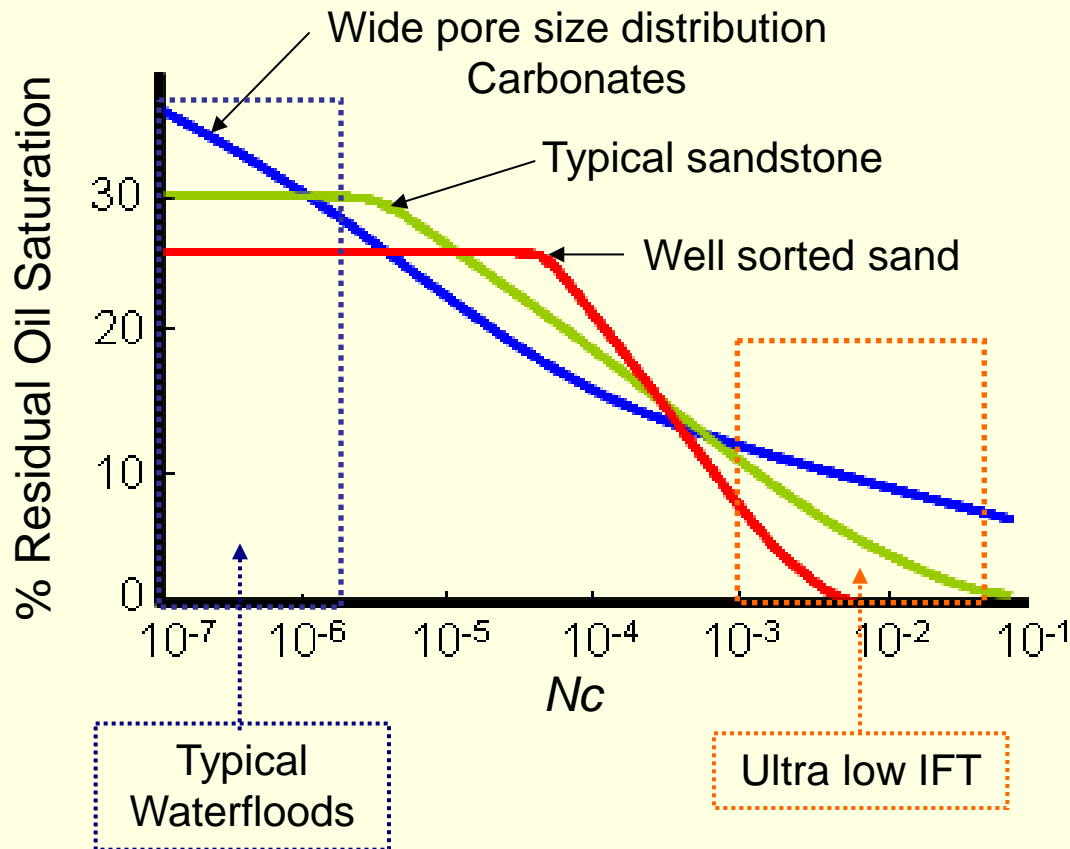
For a waterflood where piston-like flow is assumed, with only water flowing behind the front and only oil flowing ahead of the front,  $M$  can be defined as:

$$M = \frac{\text{Mobility of the Displacing Fluid}}{\text{Mobility of the Displaced Fluid}} = \left( \frac{k_{rw}}{\mu_w} \right)_{Sor} \left( \frac{\mu_o}{k_{ro}} \right)_{Swi}$$

Relative permeabilities ( $k_{rw}$  and  $k_{ro}$ ) are measured at residual oil saturation ( $Sor$ ) and immobile water saturation ( $Swi$ ), respectively;  $\mu$  represent the viscosity of oil ( $\mu_o$ ) and water ( $\mu_w$ ). The rule of thumb:



# Capillary Number



$$N_c = \frac{\mu_w v}{\sigma_{ow}}$$

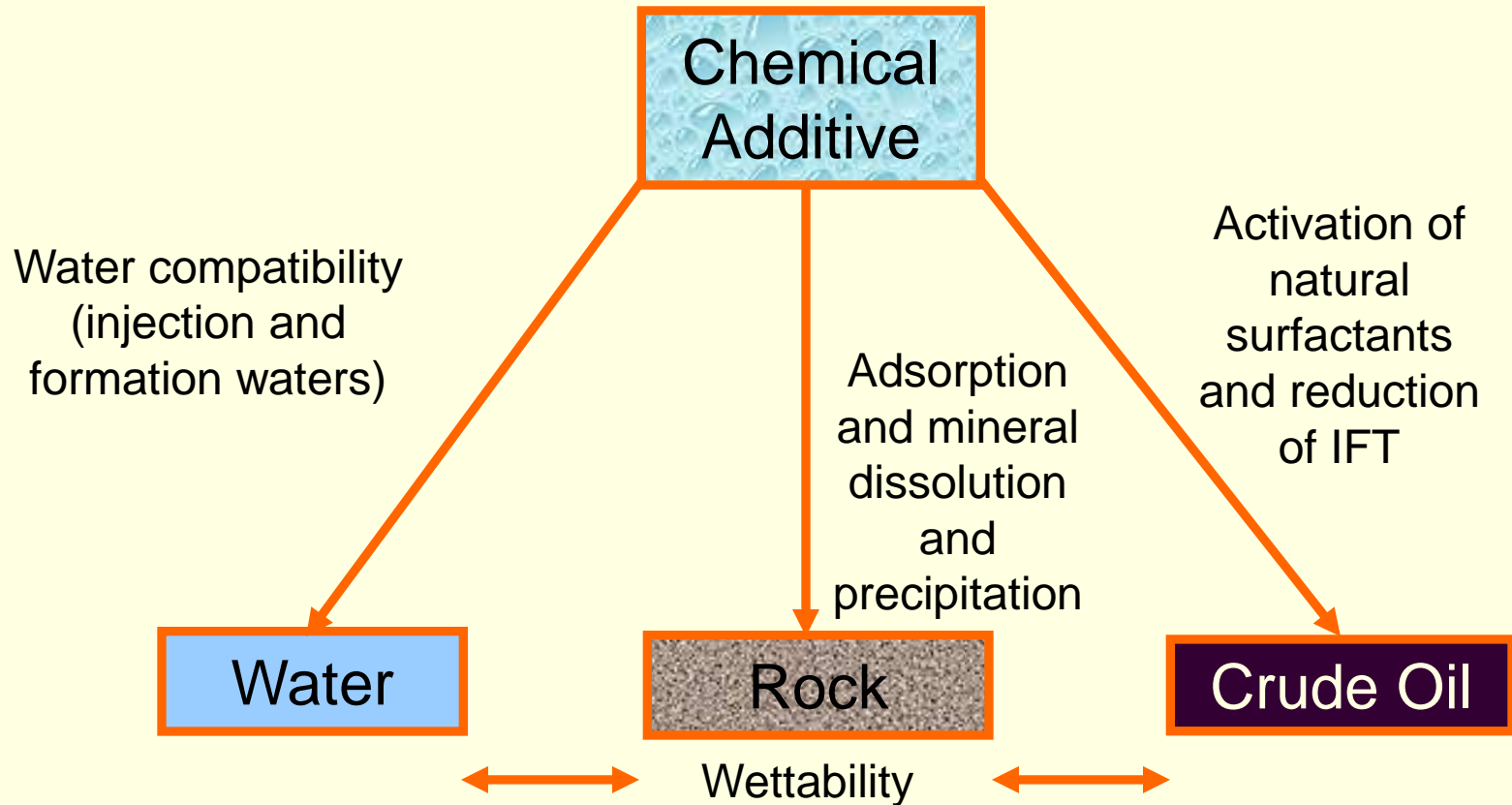
$v$  = velocity

$\mu_w$  = viscosity of water

$\sigma_{ow}$  = Interfacial tension (IFT)  
between the displaced and  
displacing fluids

# Basic Fluid-Fluid and Fluid-Rock Interactions in Chemical Methods

Scheme representing basic types of interactions during chemical flooding







# Polymer, Alkali & Surfactant

# Overview (Polymers)

Summary of major characteristics and results of U.S polymer floods (Manning et al., 1983; Needham and Doe, 1987; SPE-20234; Manrique et al., 2004).

	<b>273 Projects (Sandstone &amp; Carbonates)</b>	<b>26 Projects (Carbonates) <sup>(a)</sup></b>
Conc. (ppm)	50 to 3700	50 to 1000
Amount of polymer used (lb/acre-ft)	19 to 150	12 to 56
Oil recovered (b/lb polymer injected)	0 to 3.74	0 to 2.82
Recovery (% OOIP)	0 to 23	0 to 13

(a) 11 Field projects and 15 pilots

# Depositional Systems Where Successful Polymer Floods Have Been Tested

		LATERAL HETEROGENEITY		
		LOW	MODERATE	HIGH
VERTICAL HETEROGENEITY	LOW	Wave-dominated delta Barrier core Barrier shore face Sand-rich strand plain	Delta-front mouth bars Proximal delta front (accretionary) Tidal Deposits Mud-rich strand plain	Meander belts* Fluvially dominated delta* Back Barrier*
	MODERATE	Eolian Wave modified delta (distal)	Shelf barriers Alluvial Fans Fan Delta Lacustrine delta Distal delta front	Braided stream Tide-dominated delta
	HIGH	Basin-flooring turbidites	Coarse-grained meander belt Braid delta	Back barrier** Fluvially dominated delta** Fine-grained meander belt** Submarine fans**

\* Single units \*\*Stacked Systems

(Finley and Tyler, 1991; SPE-75148)

# Polymer Adsorption / Retention

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Polymer may be lost in the reservoir due to

- Adsorption
  - Chemical adsorption (bonding) onto rock surface, especially clays (usually an irreversible process)
  - Affected by formation water salinity
  - Adsorption generally is lower in intermediate to oil wet reservoirs
- Retention of polymer in narrow pore throats
- Adsorbed polymer may reduce permeability
- Residual Resistance Factor (RRF) at a given adsorption may depend on polymer type, salinity, permeability and shear rate

# Example of Water Compatibility: Alkaline Solution and Injection Water

Alkali

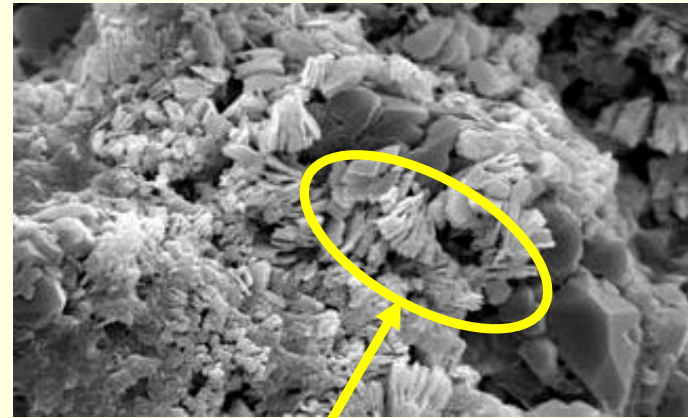
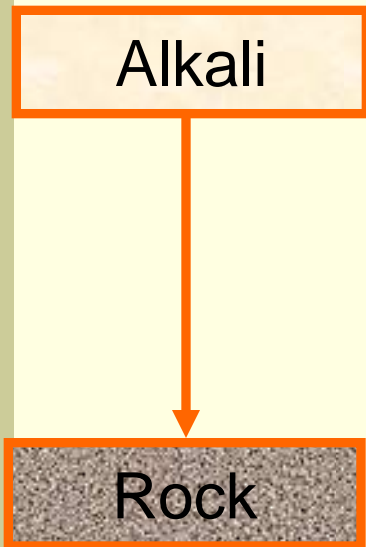
$\text{Na}_2\text{CO}_3$        $\text{NaOH}$        $\text{Na}_2\text{SiO}_3$   
 5000 ppm   10.000 ppm   5000 ppm   10.000 ppm   5000 ppm   10.000 ppm



Injection Water

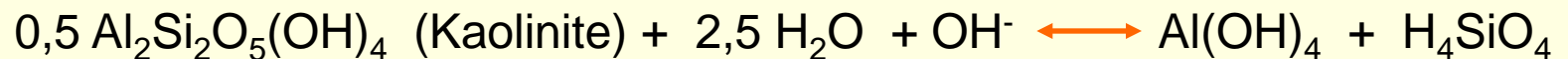
Alkali (5000 ppm)	Ca (ppm)		Mg (ppm)	
	Initial	Final	Initial	Final
$\text{Na}_2\text{CO}_3$				
NaOH	49	< 1	149	< 0,5
$\text{Na}_2\text{SiO}_3$				

# Example of Water – Rock Interaction in Alkaline Flooding



Kaolinite

Aluminosilicate dissolution:



Cationic Exchange:



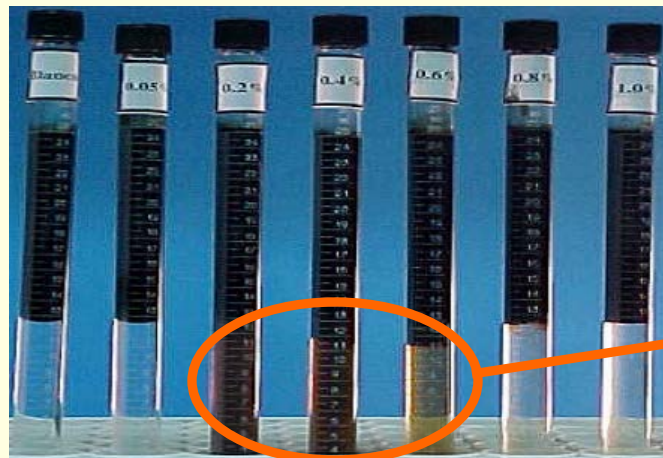
# Example: Alkali–Medium Crude Oil Interactions

Alkali



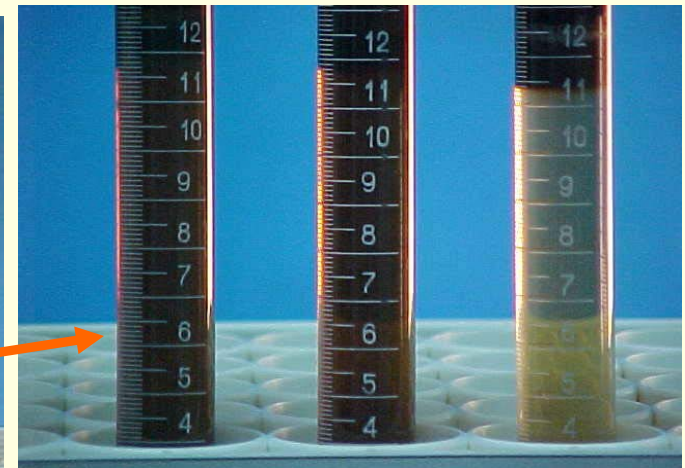
Crude Oil

24 °API Crude Oil



0 0.05 0.2 0.4 0.6 0.8 1.0

Alkali concentration (%)

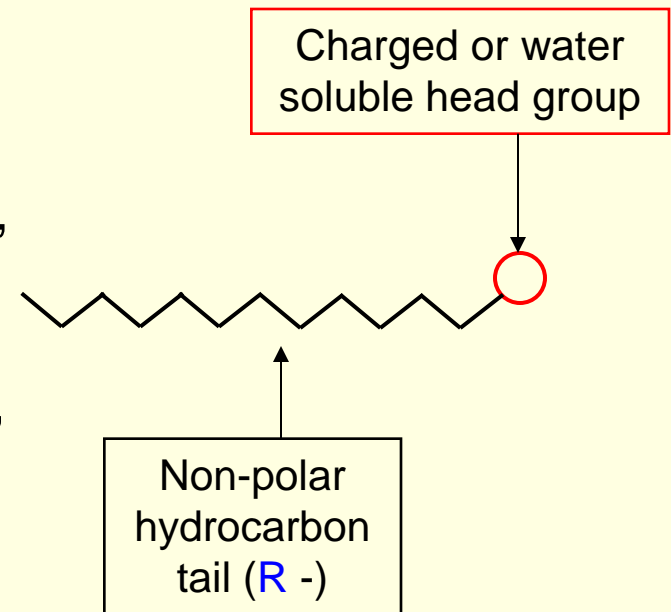


Indicative of spontaneous emulsification and IFT reduction

# Basic Principles

- Surfactants or surface active agents are chemical compounds that adsorb on or concentrate at a surface or fluid/fluid interface when present at low concentration in a system.
- Surfactants can alter interfacial properties significantly, and in particular, they decrease Interfacial Tension (IFT).
- Surfactants can be classified as anionic, cationic, and nonionic. Anionic and nonionic surfactants have been used in EOR processes.

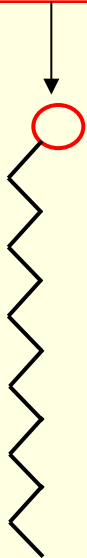
## Schematic of a surfactant molecule





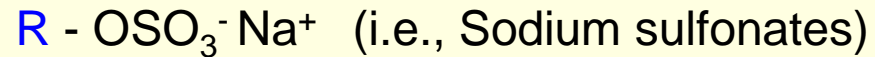
# Examples of Type of Surfactants

Charged or water soluble head group

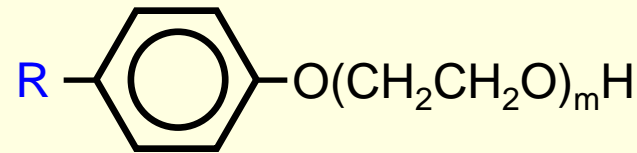


Non-polar hydrocarbon tail (R -)

Anionic

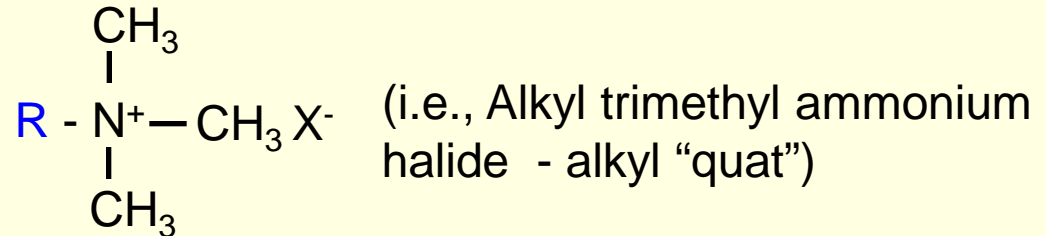


Nonionic (Does not ionize)

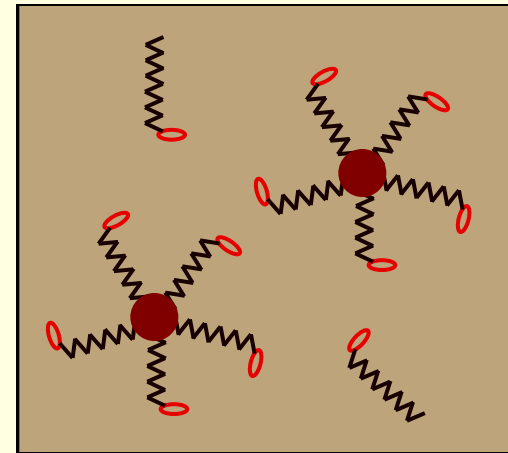
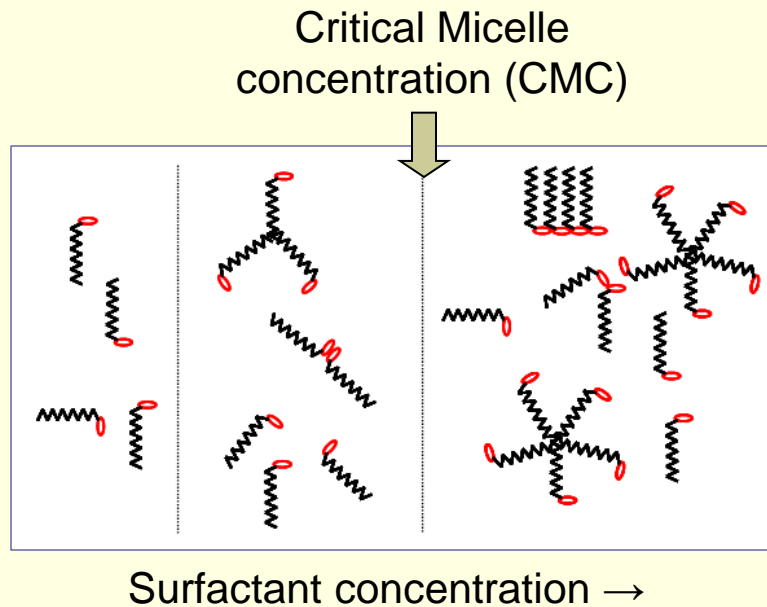


(i.e.: Ethoxylated Octylphenol,  $m = 2 - 100$ )

Cationic

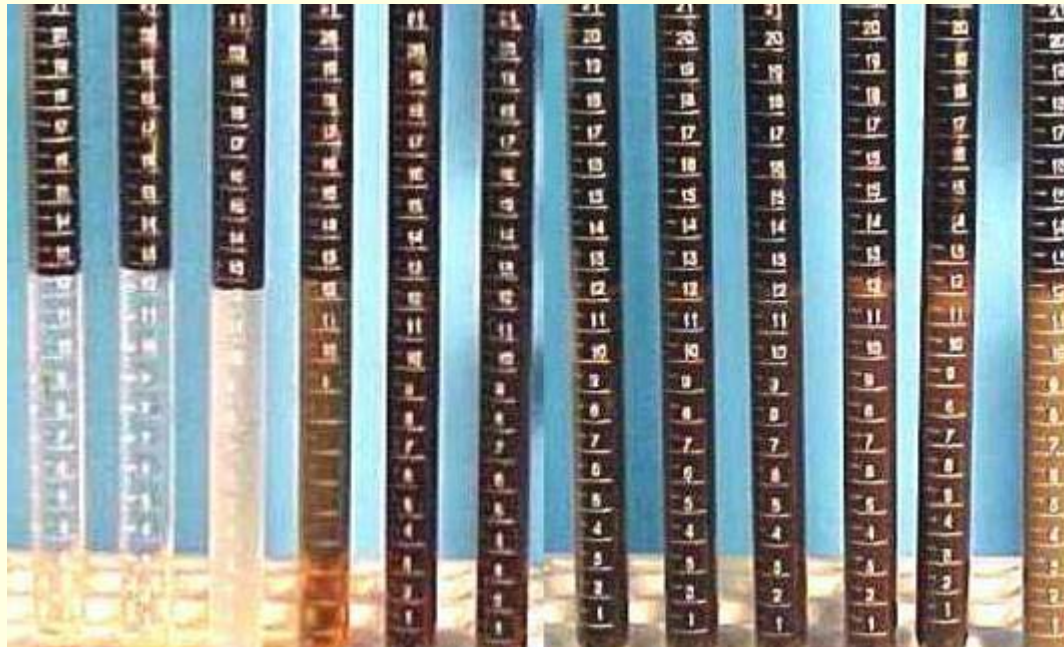


# Formation of Micelles and Oil Solubilization in Micelles



Oil solubilization in a surfactant solution

# Spontaneous Emulsification in Surfactant Solutions

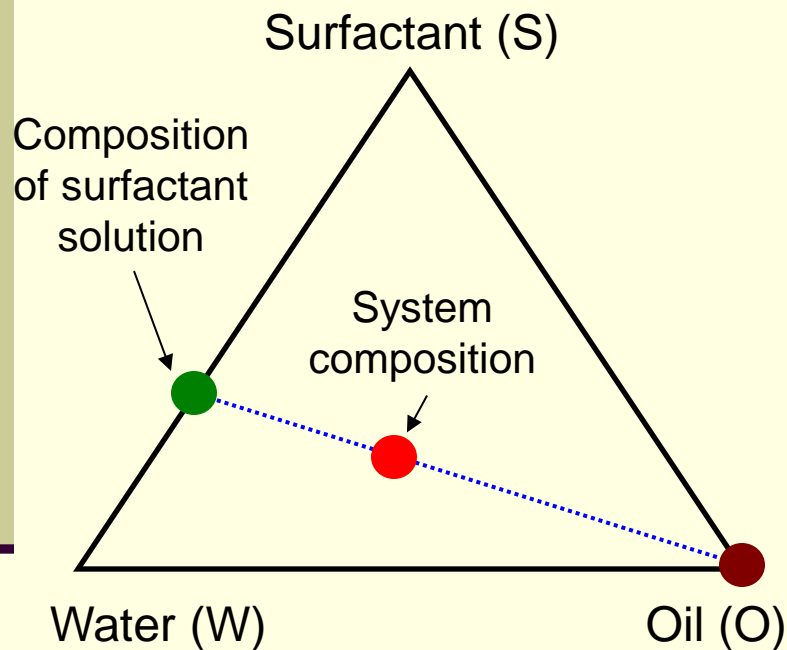


0 0.05 0.2 0.4 0.6 0.8 1.0 1.2 1.4 1.6 1.8 2.0

Surfactant concentration (%)

Example of spontaneous emulsification of a 24° API gravity crude oil and a commercial surfactant (synthetic petroleum sulfonate) solution dissolved in injection water after 60 days at reservoir temperature (60° C).

# Surfactant Phase Behavior



Surfactant solution in contact with oil

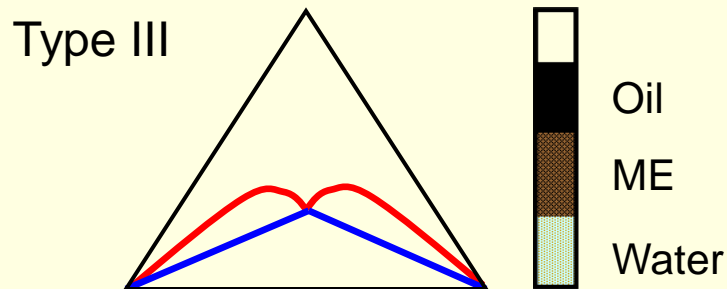
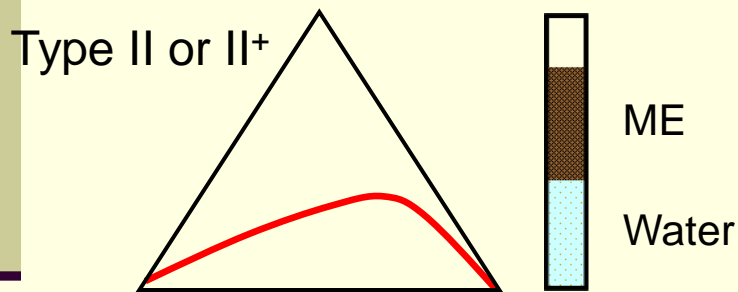
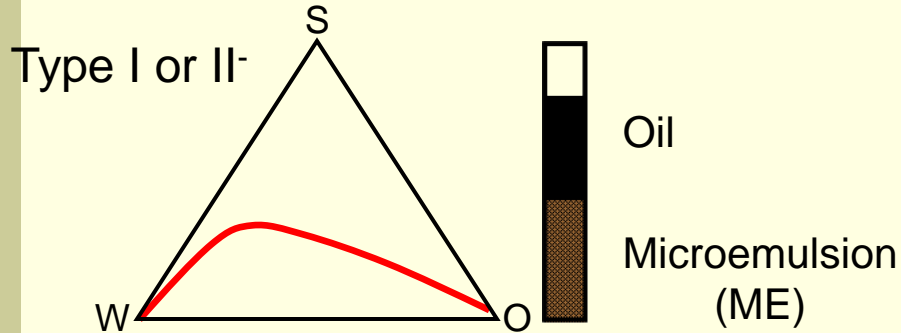
There are multiple possibilities for how this system composition can break into different phases:

Type I or II<sup>-</sup> phase behavior. Occurs when surfactant is more soluble in water than oil (i.e., Low salinity).

Type II or II<sup>+</sup> phase behavior. Occurs when surfactants are more soluble in oil than water (i.e., High salinity).

Type III phase behavior. Occurs when solubility of surfactants in oil and water are comparable.

# Surfactant Phase Behavior (continued)



To obtain better additional oil recoveries, the following order of phase behavior is preferred:

Type III > Type II<sup>-</sup> > Type II<sup>+</sup> > Type II

# Issues specific to Minnelusa

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- Gas methods have major constraints:
  - Large enough oil pool → Capital Expenditure
  - Miscible vs. immiscible → RF → ROI
  - Access to injection gas → Pipeline, Portable?
  
- What about Minnelusa sands?

Most reservoirs do not meet the threshold of ROIP to produce ROI, unless portable units can be justified (N<sub>2</sub>) or cheap NG is available

# Issues specific to Minnelusa (Cont)

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- Chemical methods critical constraints:
  - Reservoir characterization → Conformance, Location of ROIP, etc.
  - Water source → Fresh vs. produced
  - Rock-fluid interaction → Adsorption, CEC, etc.
  
- What about Minnelusa sands?

When Foxhill water is available, water is not a major issue. Characterization and anhydrite must be carefully dealt with.

# Summary

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- IOR and EOR opportunities are available in Minnelusa sands
- Gas methods might be available, but hardly justified, except in the largest fields or where cheap injectant is available
- Chemical methods have been applied in these reservoirs and conditions favor this type of methods in Minnelusa reservoirs
- Thermal methods are probably marginal, except in shallow reservoirs and heavier oils