Workshop: Minnelusa I

Day 3

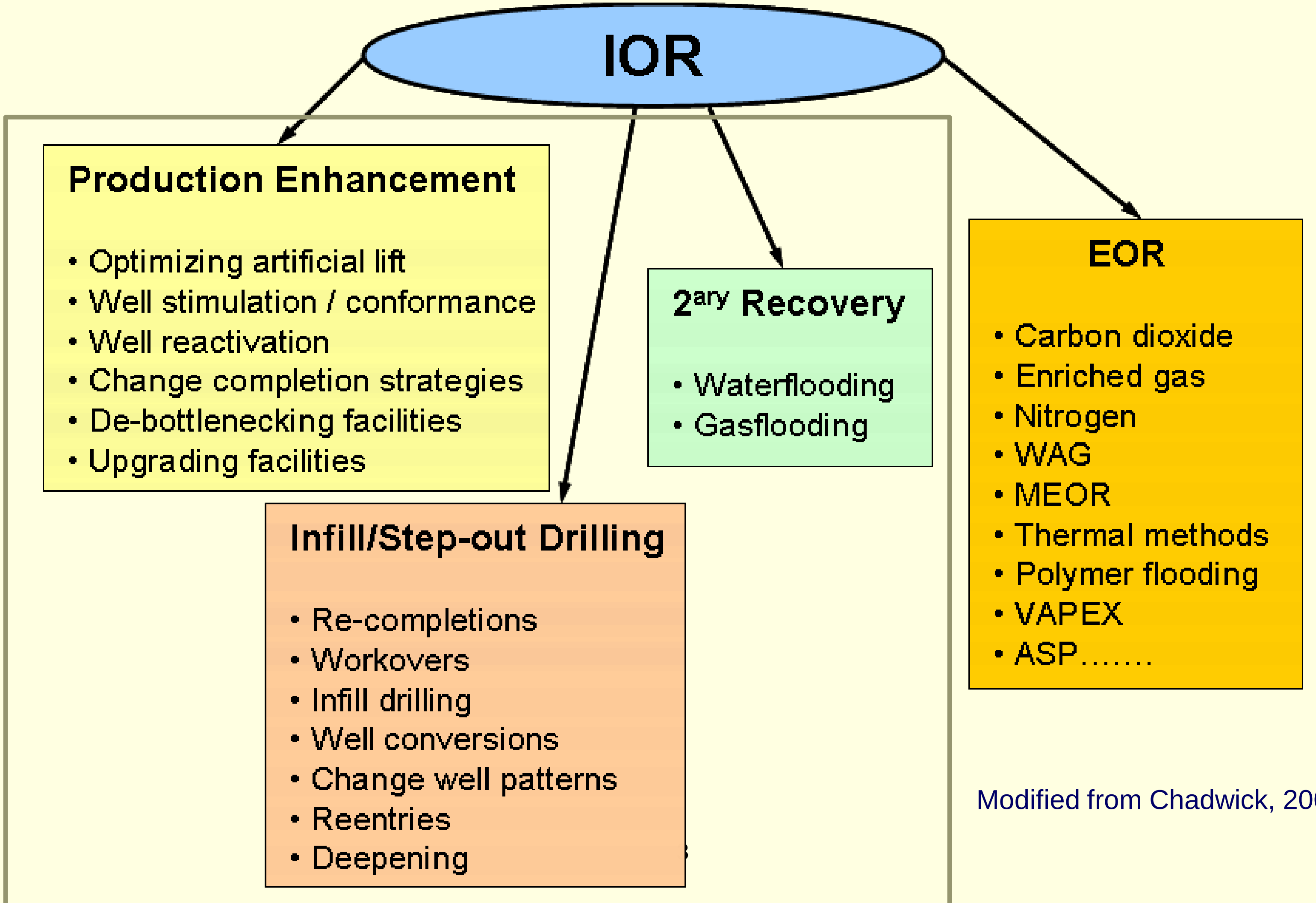
8:10 – 9:10 am

Minnelusa IOR/EOR options and feasibility

Outline

- 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



Modified from Chadwick, 2003

Recovery Efficiency

$$E_R = E_D \times E_V$$

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

Mobility Ratio

Mobility

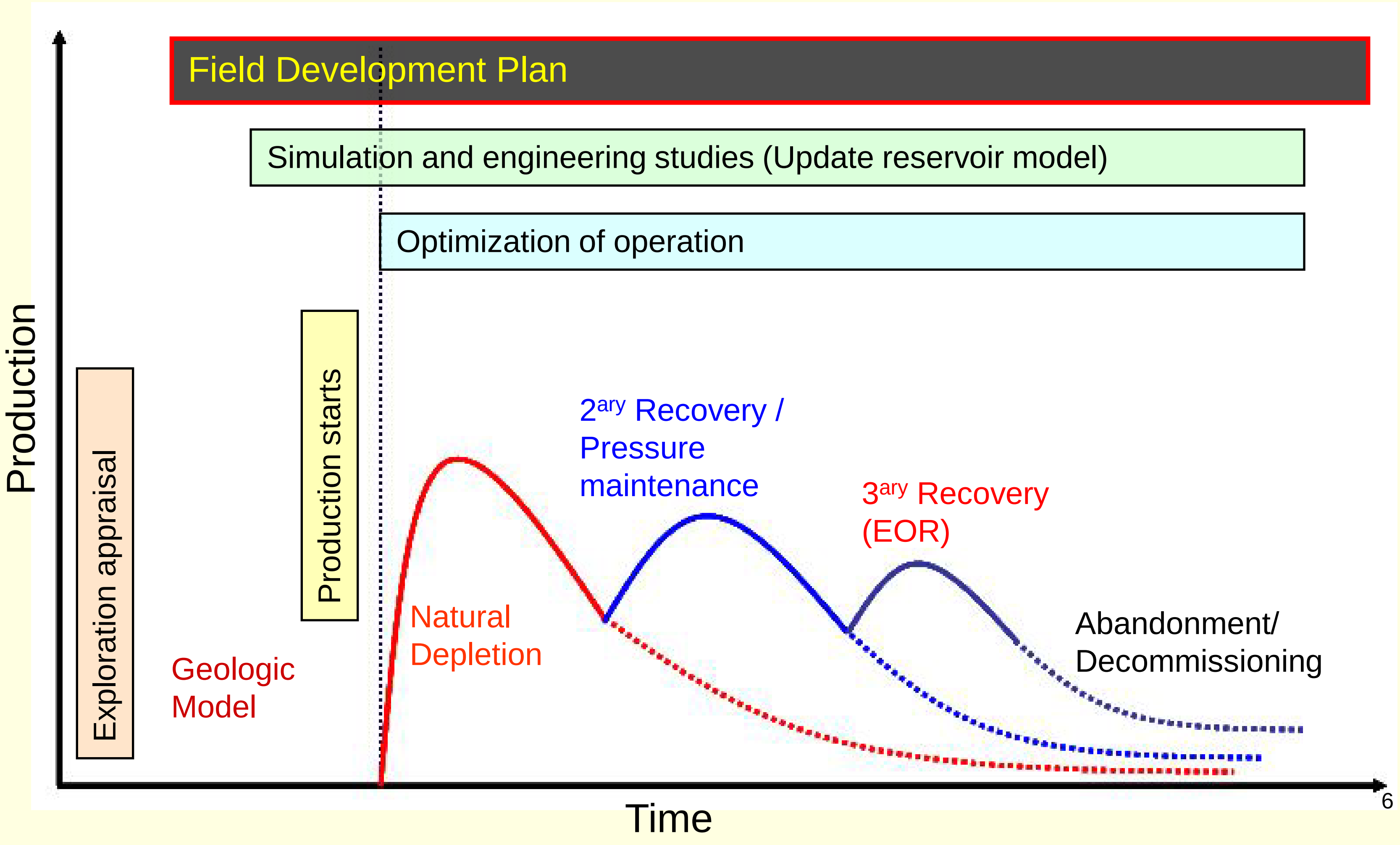
$$\lambda_o = {k_o}/{\mu_o}\;;\quad \lambda_w = {k_w}/{\mu_w}\;;\quad \lambda_g = {k_g}/{\mu_g}$$

Mobility Ratio

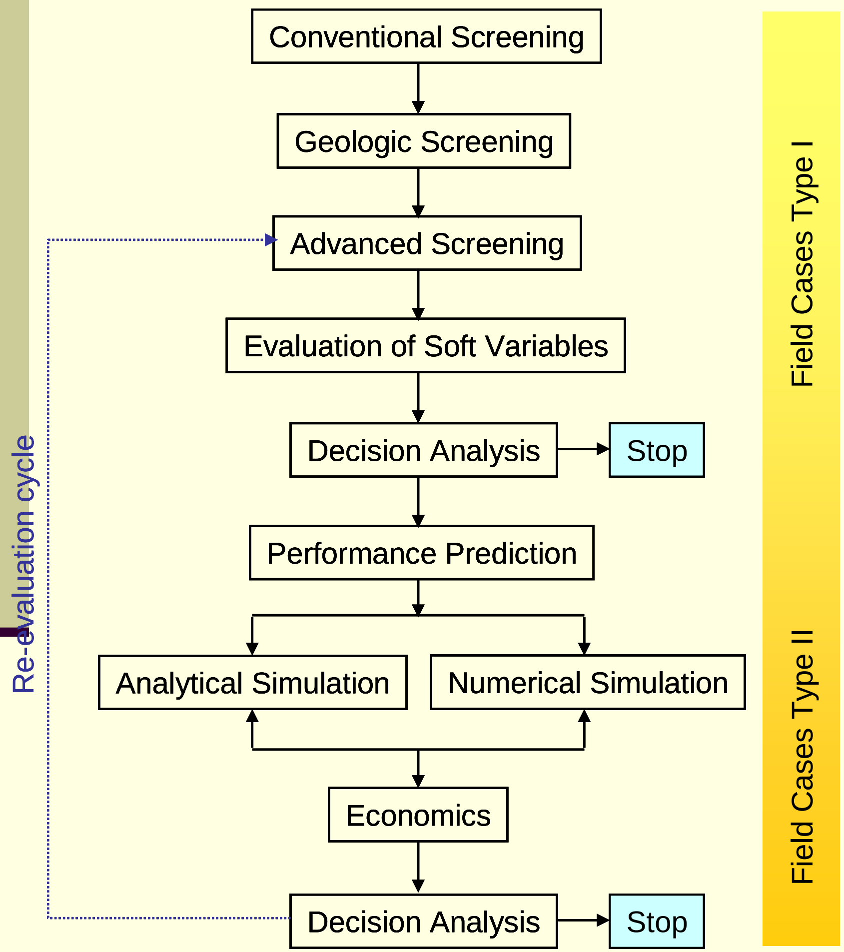
$$M \equiv \frac{\lambda_D}{\lambda_d} \Rightarrow M_{w,o} = \frac{(\lambda_w)_{S_{or}}}{(\lambda_d)_{S_{wc}}} = \frac{k_{rw}(S_{or})/\mu_w}{k_{ro}(S_{wc})/\mu_o}$$

Similarly for other phase ratios

Traditional Phases of Field Production



A Possible Workflow (for success?)

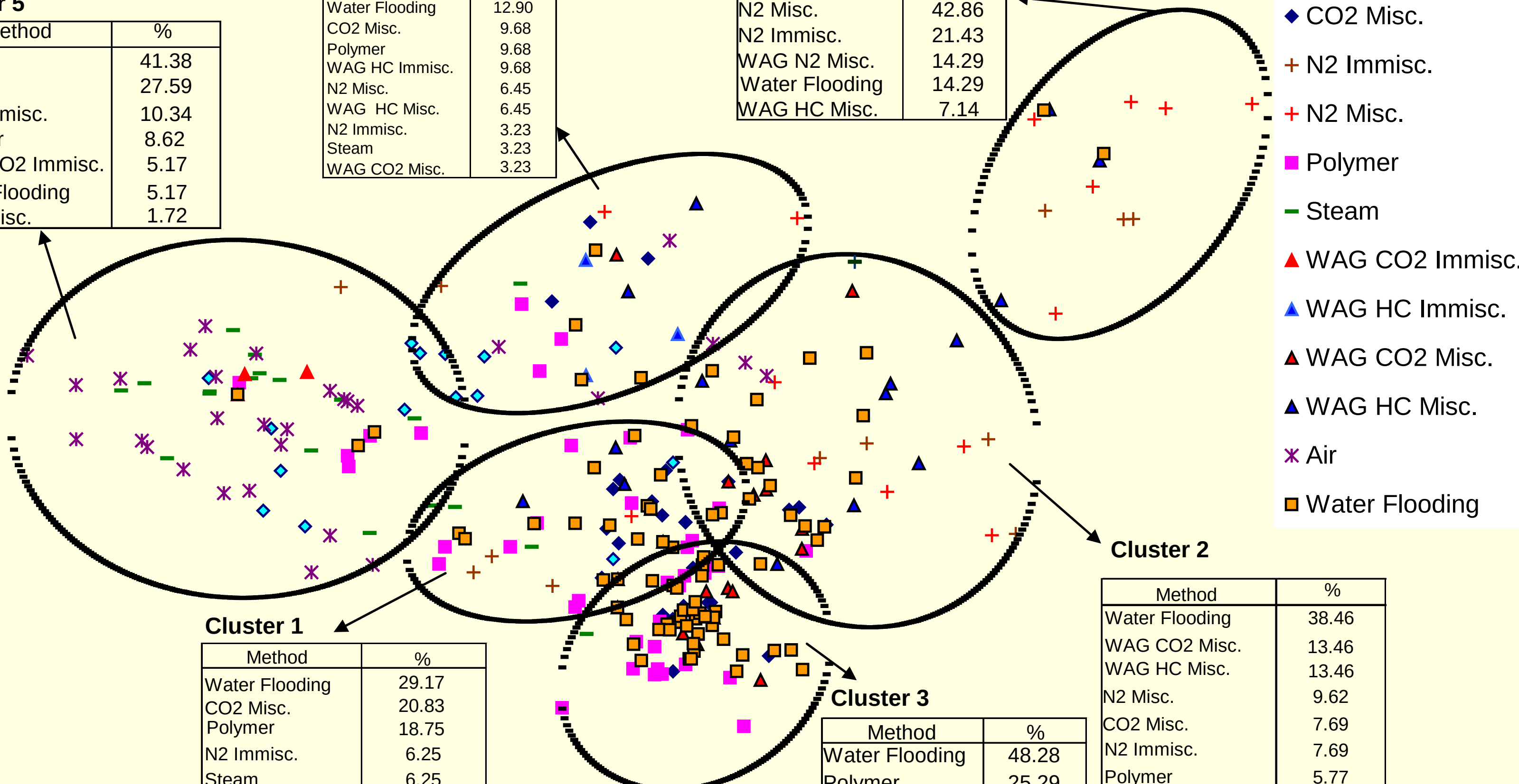


- **Frame the problem adequately**
- **Avoid excessive and often unnecessary reiteration of analysis that leads nowhere**
- **Realize when simpler is better or new data are necessary**
- **Manage soft issues, before they become hard lessons**
- **Understand that a bad outcome does not qualify a decision**

Lookup Table Screening Criteria

		Oil Properties			Reservoir Characteristics					
Detail Table	EOR Method	Gravity (ºAPI)	Viscosity (cp)	Composition	Oil Saturation	Formation Type	Net Thickness (ft)	Average Permeability (md)	Depth (ft)	Temperature (ºF)
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



Cluster 4

Method	%
CO2 Immisc.	22.58
Air	12.90
Water Flooding	12.90
CO2 Misc.	9.68
Polymer	9.68
WAG HC Immisc.	9.68
N2 Misc.	6.45
WAG HC Misc.	6.45
N2 Immisc.	3.23
Steam	3.23
WAG CO2 Misc.	3.23

Cluster 6

Method	%
N2 Misc.	42.86
N2 Immisc.	21.43
WAG N2 Misc.	14.29
Water Flooding	14.29
WAG HC Misc.	7.14

Cluster 5

Method	%
Air	41.38
Steam	27.59
CO2 Immisc.	10.34
Polymer	8.62
WAG CO2 Immisc.	5.17
Water Flooding	5.17
N2 Immisc.	1.72

Cluster 2

Method	%
Water Flooding	38.46
WAG CO2 Misc.	13.46
WAG HC Misc.	13.46
N2 Misc.	9.62
CO2 Misc.	7.69
N2 Immisc.	7.69
Polymer	5.77
Air	3.85

Cluster 1

Method	%
Water Flooding	29.17
CO2 Misc.	20.83
Polymer	18.75
N2 Immisc.	6.25
Steam	6.25
WAG HC Misc.	6.25
CO2 Immisc.	4.17
WAG CO2 Misc.	4.17
N2 Misc.	2.08
WAG N2 Misc.	2.08

Cluster 3

Method	%
Water Flooding	48.28
Polymer	25.29
WAG CO2 Misc.	12.64
CO2 Misc.	10.34
N2 Immisc.	1.15
WAG HC Misc.	1.15
Steam	1.15

SPE-78332

EOR Gas Methods

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.

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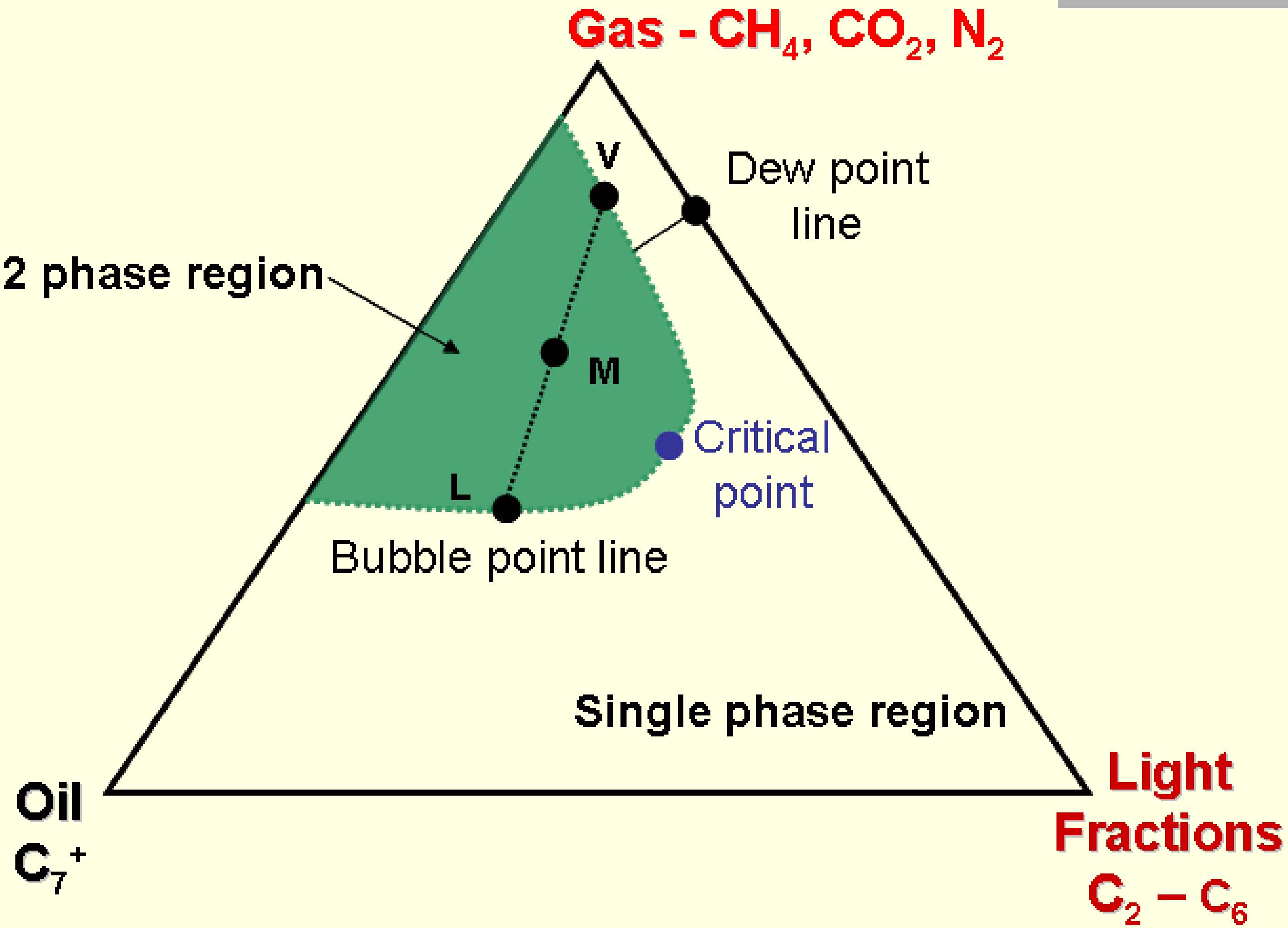
Phase Behavior in Gas EOR



Ternary diagram for three-component mixture

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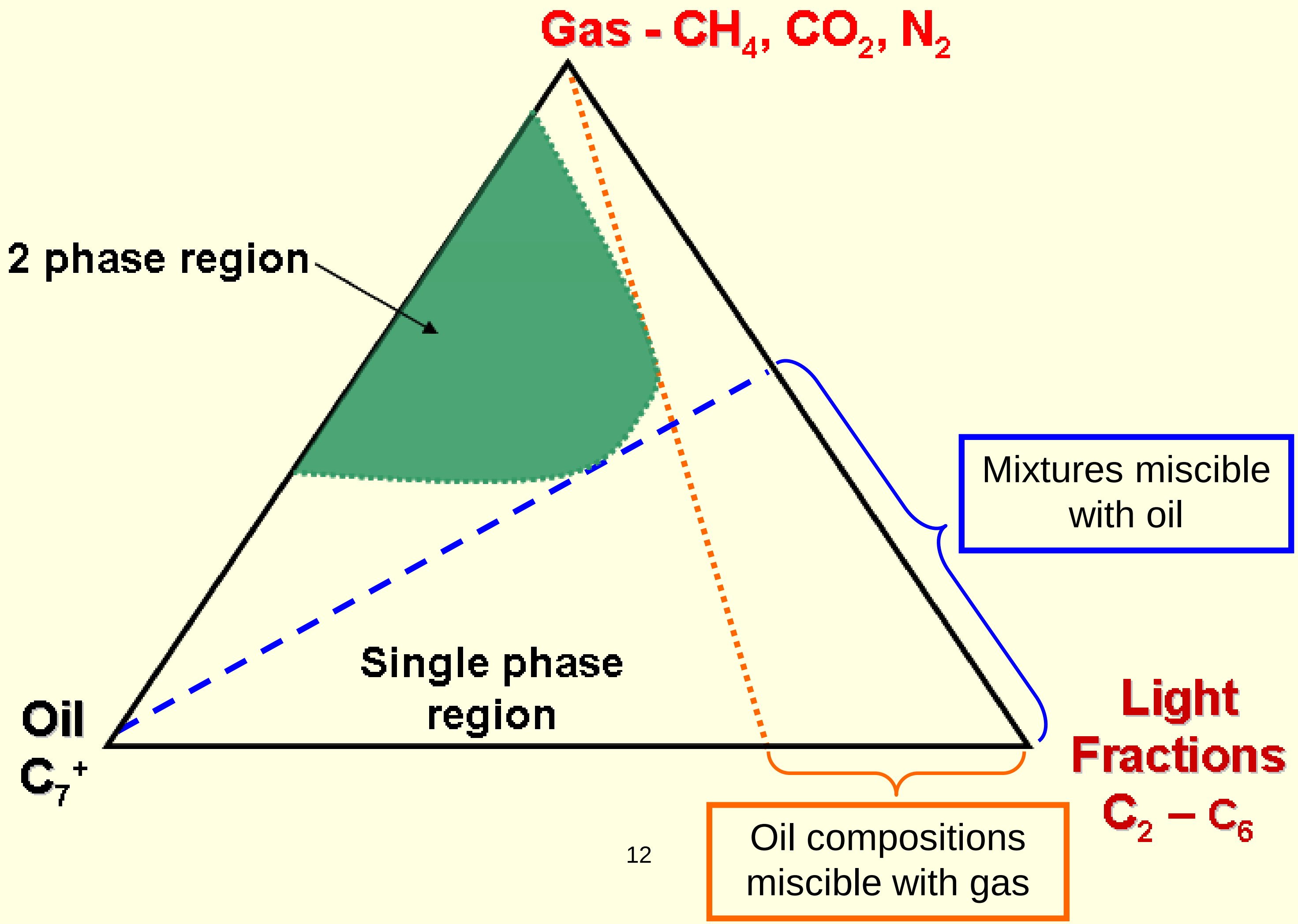
First Contact Miscibility



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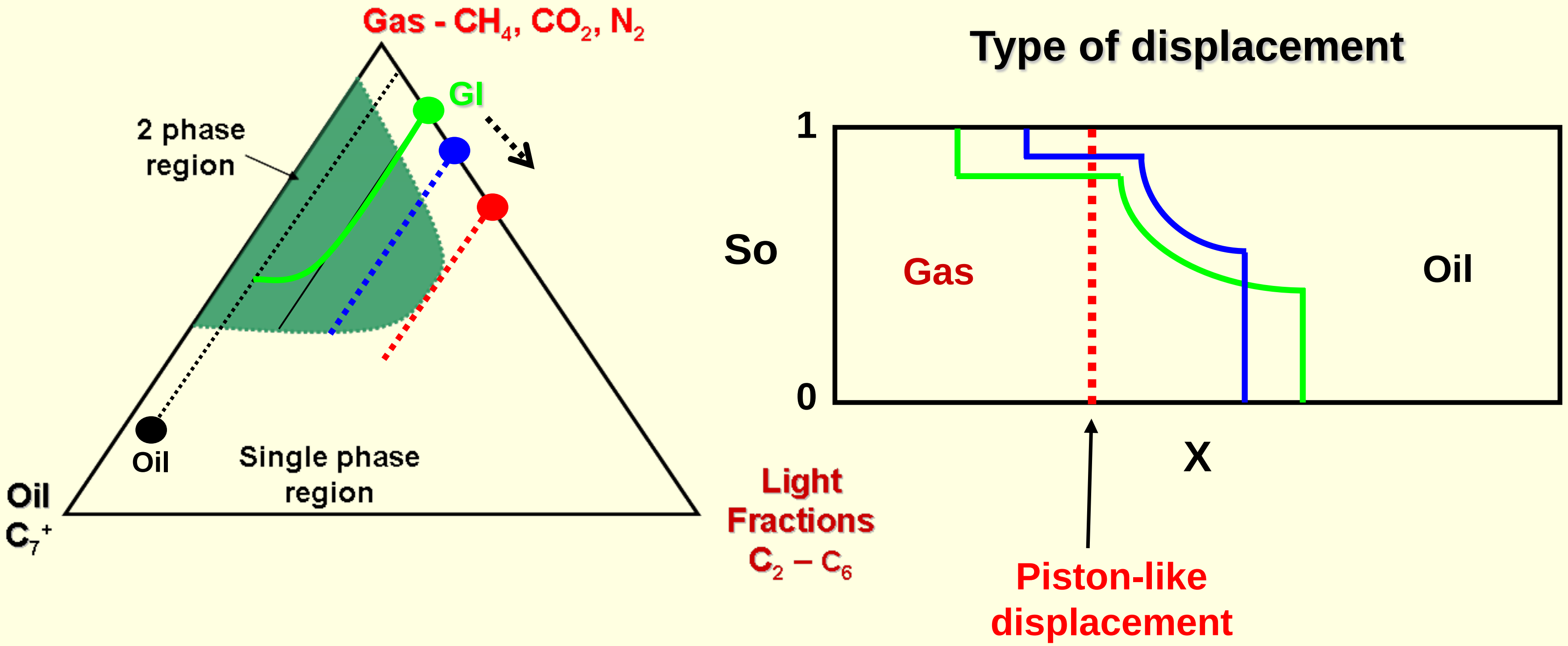
Multiple Contact Miscibility: Condensing Gas Drive (continued)



Basic Screening Criteria

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

	Immisicible Gas injection	**Miscible HC Injection**	**Miscible CO_2**	**Miscible N_2**
Depth (m)	> 200	> 1200	> 600	> 1800
Oil Saturation (%)	> 50	> 30	> 25	> 35
Oil Gravity (°API)	> 13	> 24	> 22	> 35
Oil Viscosity @ Pb (mPa.s)	< 600	< 5	< 10	< 2
Crude Oil composition	NC	High % of light hydrocarbons (C_2 to C_7)	High % of light hydrocarbons (C_5 to C_{12})	High % of light hydrocarbons (C_1 to C_7)

NC = Not critical
1 mPa.s = 1 cp

Geologic Screening Criteria: Clastic Reservoirs (continued)

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

* Single units   **Stacked Systems

Tyler and Finley clastic heterogeneity matrix showing depositional systems of 24 successful **(Blue)** and 7 failed **[Red]** CO_2 injection projects

Screening Criteria of CO_2 Floods

Main Screening Criteria (*SPE-35385*)

Properties	Miscible Floods	Immiscible Floods
Porosity (%)	Not critical	
Permeability (md)	Not critical	
Depth (ft)	> 2,800	> 1,800
Temperature (°F)	Not critical	
Net thickness (ft)	Wide range	
Oil gravity (°API)	> 22	> 13
Oil Composition	High C_5-C_{12} (Especially for misc. floods)	
Oil saturation (%PV)	> 20% (Higher the better, generally > 50%)	
Formation type	Carbonate or Sandstone	

Main reservoir properties of CO_2 floods (*SPE-94682*)

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

Quick Rules of Thumb

- Reservoirs with good water flood response are best candidates for CO_2.
- Recovery factor using miscible CO_2 is 8%–11% OOIP. Immiscible CO_2 is 4%–6% (50% of miscible).
- MMP equals initial bubble point pressure.
- CO_2 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_2 floods**).
- Top down CO_2 injection alternative is effective but requires more capital investment for higher CO_2 volume (WAG Tapered).

Unfavorable Reservoir Characteristics for Empirical Screening

- 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^2)
- 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_2

Chemical Methods: Polymer+Surfactant+Alkali

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Overview

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*).

	Reservoir Lithology		
Chemical Method[1]	Sandstone	Carbonate	Other[2]
Alkaline (A)	22	-	-
Polymer (P)[3]	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.

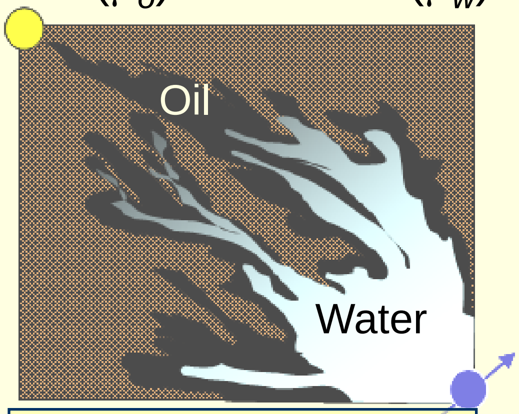
(3) Does not include biopolymer floods.

Mobility Ratio

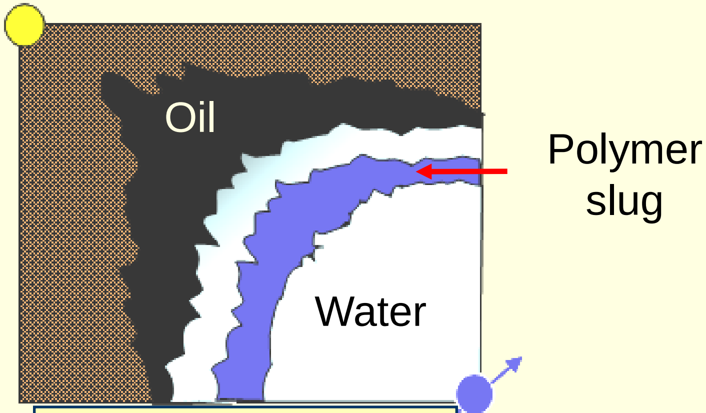
For a waterflood where piston-like flow is assumed, with only water flowing behind the front and only oil flowing ahead of the front, *M* can be defined as:

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

Relative permeabilities (k_{rw} and k_{ro}) are measured at residual oil saturation (*Sor*) and immobile water saturation (*Swi*), respectively; μ represent the viscosity of oil (μ_o) and water (μ_w). The rule of thumb:

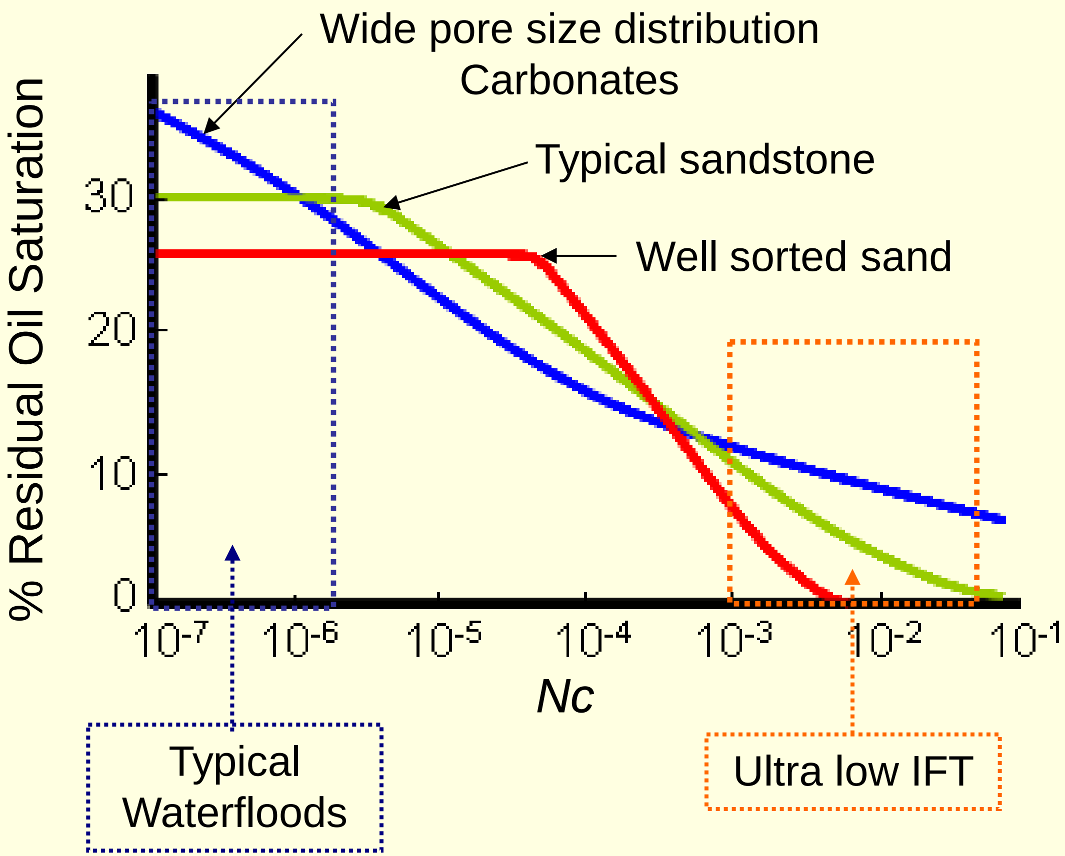


$M > 1$ Unfavorable



$M < 1$ Favorable

Capillary Number



$$Nc = \frac{\mu_w \nu}{\sigma_{ow}}$$

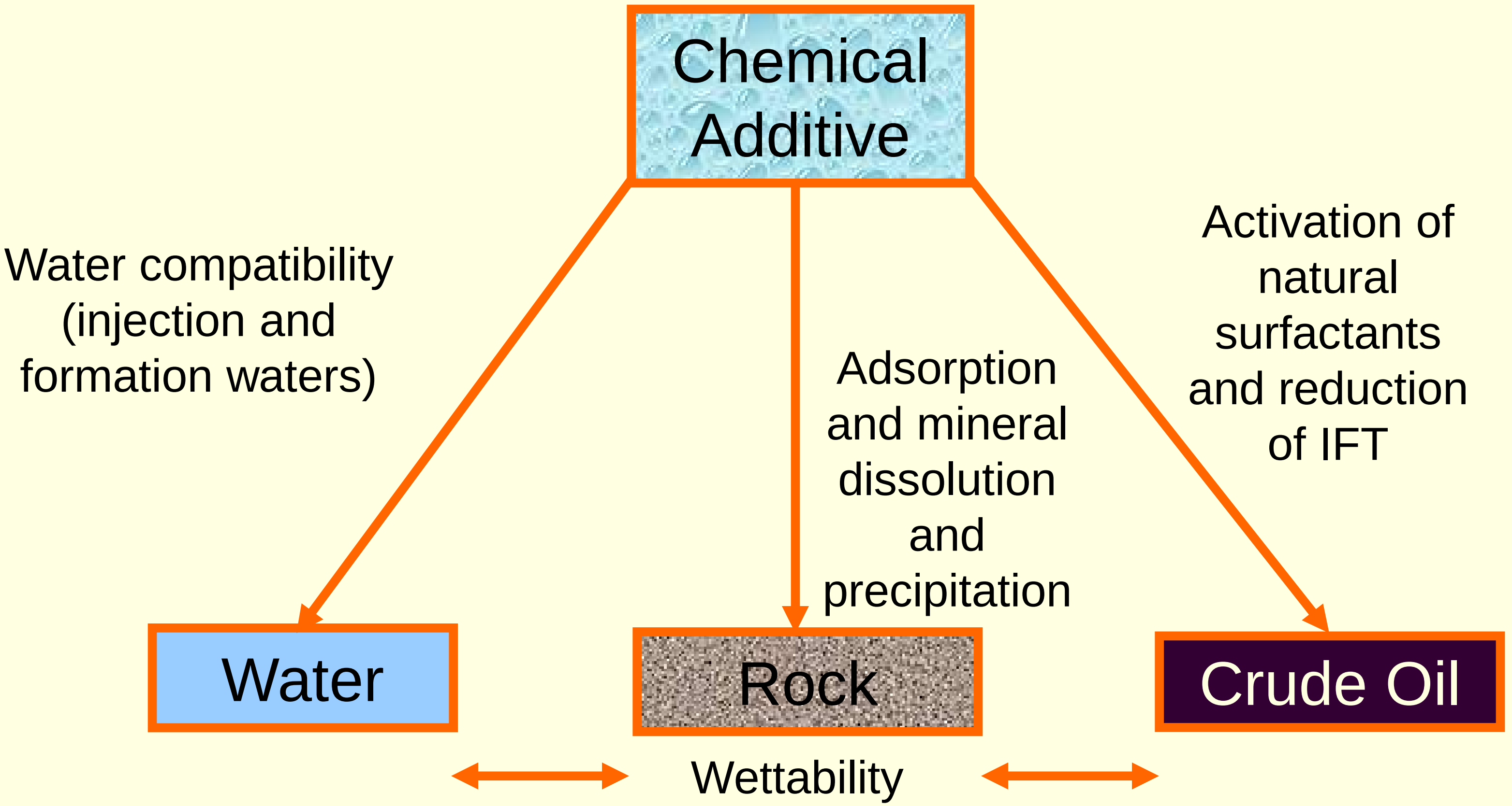
ν = velocity

μ_w = viscosity of water

σ_{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).

	273 Projects (Sandstone & Carbonates)	**26 Projects (Carbonates)** [(a)]
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

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

Injection Water

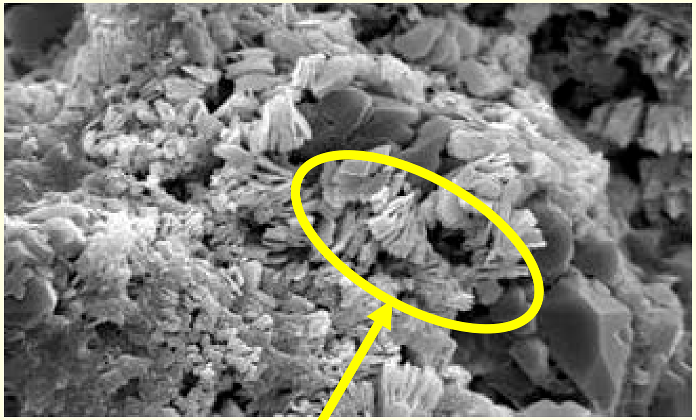
Na_2CO_3		NaOH		Na_2SiO_3	
5000 ppm	10.000 ppm	5000 ppm	10.000 ppm	5000 ppm	10.000 ppm

Alkali	Ca (ppm)		Mg (ppm)	
(5000 ppm)	Initial	Final	Initial	Final
Na_2CO_3 NaOH Na_2SiO_3	49	< 1	149	< 0,5

Example of Water – Rock Interaction in Alkaline Flooding

Alkali

Rock



Kaolinite

Aluminosilicate dissolution:

$$NaAlSi_3O_8 \text{ (Albite)} + 8H_2O \longleftrightarrow Al(OH)^-_4 + Na^+ + 3H_4SiO_4$$

$$0{,}5\ Al_2Si_2O_5(OH)_4 \text{ (Kaolinite)} + 2{,}5\ H_2O + OH^- \longleftrightarrow Al(OH)_4 + H_4SiO_4$$

Cationic Exchange:

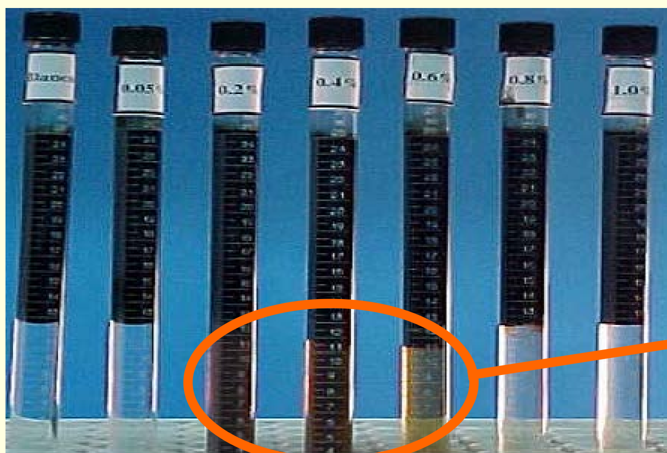
$$\text{Clay-H} + NaOH \longleftrightarrow \text{Clay-Na} + H_2O$$

Example: Alkali–Medium Crude Oil Interactions

Alkali

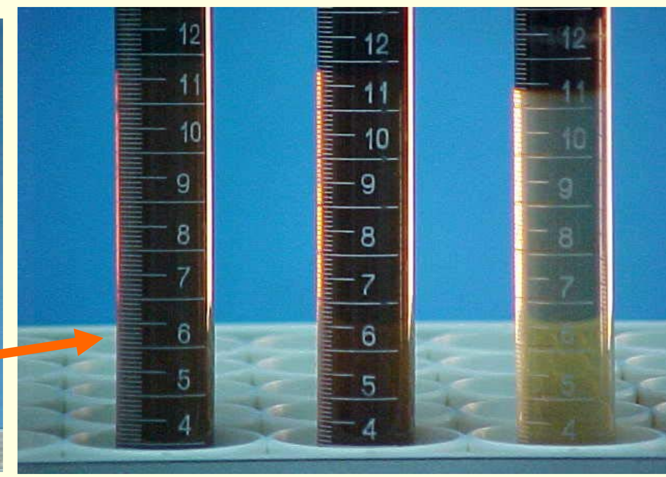
Crude Oil

24 °API Crude Oil



0 0.05 0.2 0.4 0.6 0.8 1.0

Alkali concentration (%)

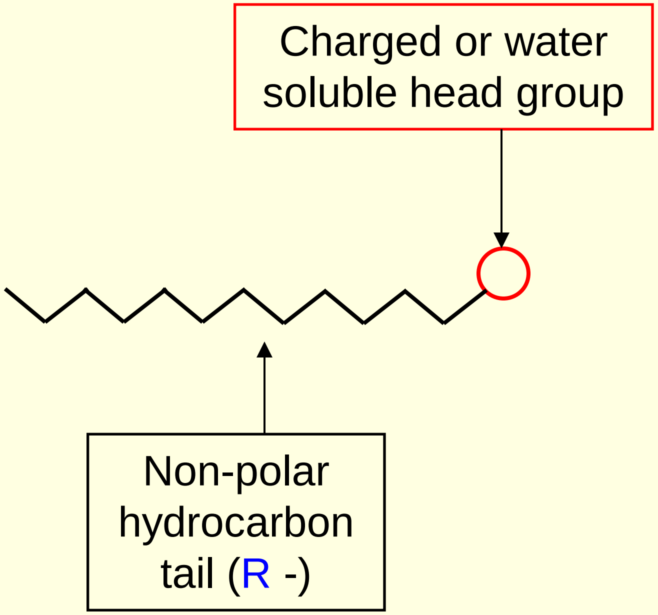


Indicative of spontaneous emulsification and IFT reduction

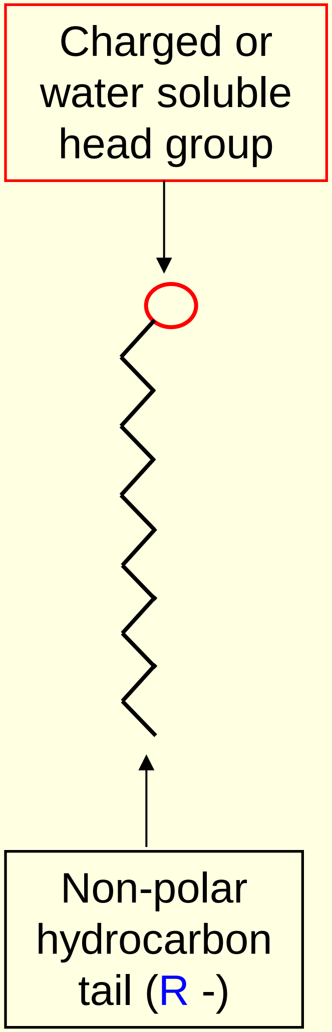
Basic Principles

- 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



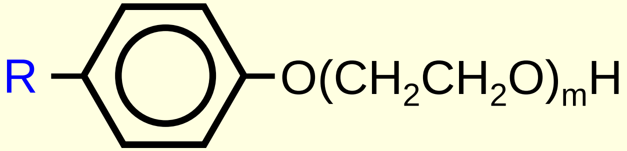
Examples of Type of Surfactants



Anionic

R - $OSO_3^- Na^+$ (i.e., Sodium sulfonates)

Nonionic (Does not ionize)



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

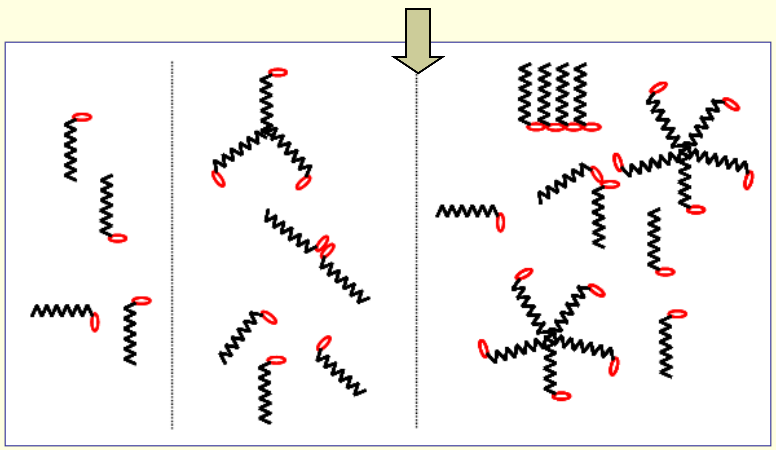
Cationic

$$R - N^{+}(CH_3)_3 \, X^{-}$$

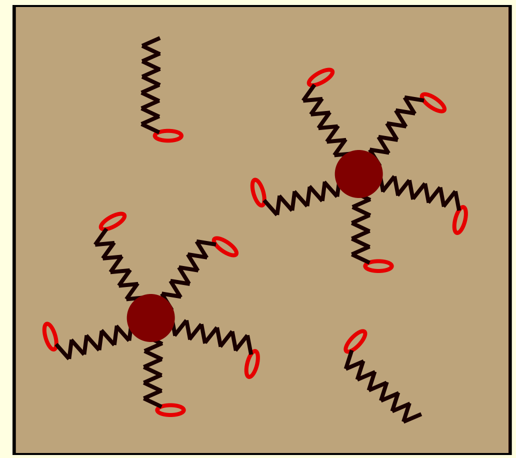
(i.e., Alkyl trimethyl ammonium halide - alkyl “quat”)

Formation of Micelles and Oil Solubilization in Micelles

Critical Micelle concentration (CMC)

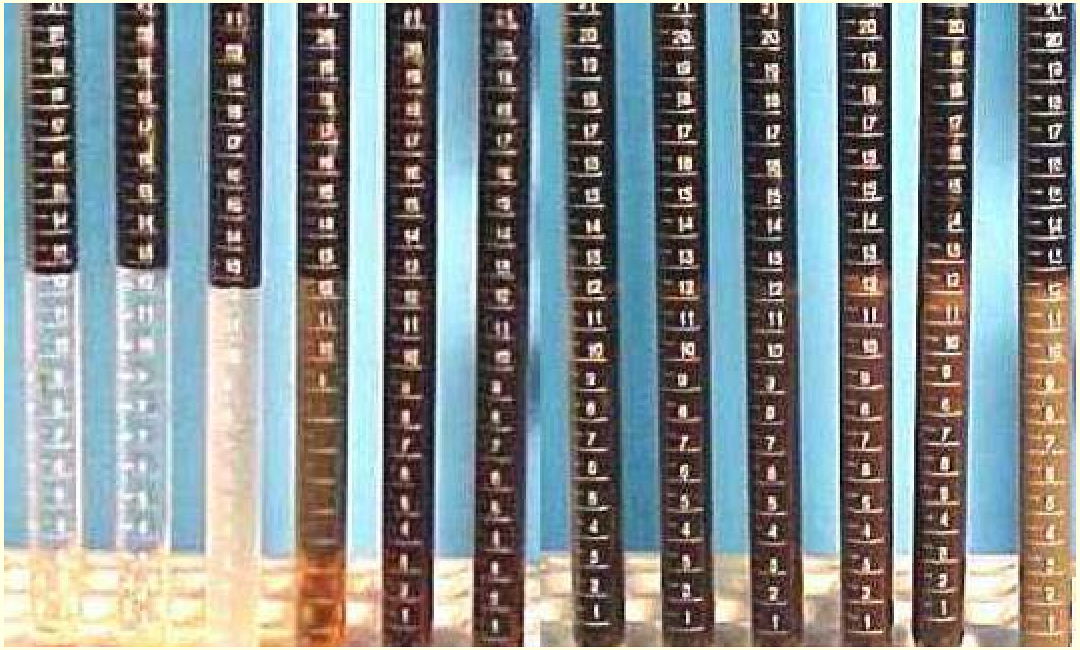


Surfactant concentration →



Oil solubilization in a surfactant solution

Spontaneous Emulsification in Surfactant Solutions

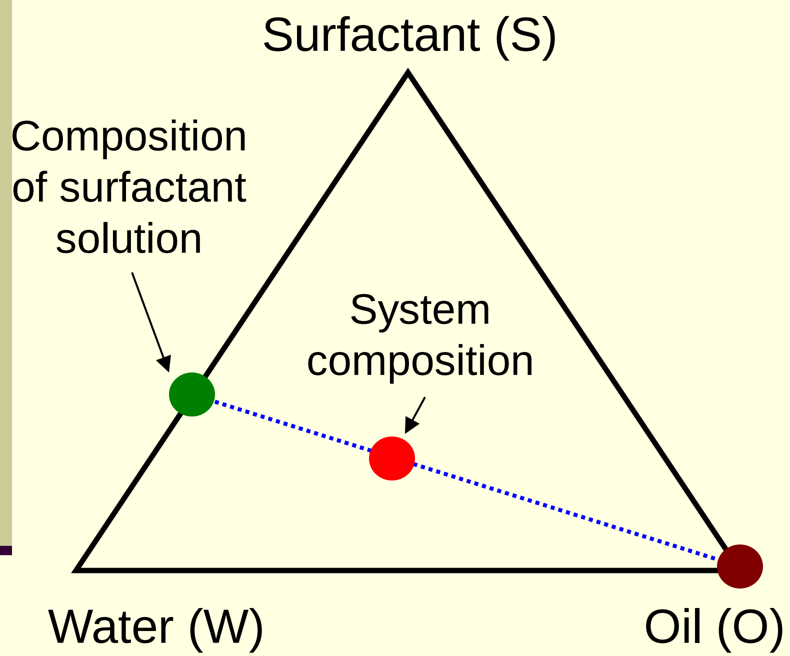


0 0.05 0.2 0.4 0.6 0.8 1.0 1.2 1.4 1.6 1.8 2.0

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

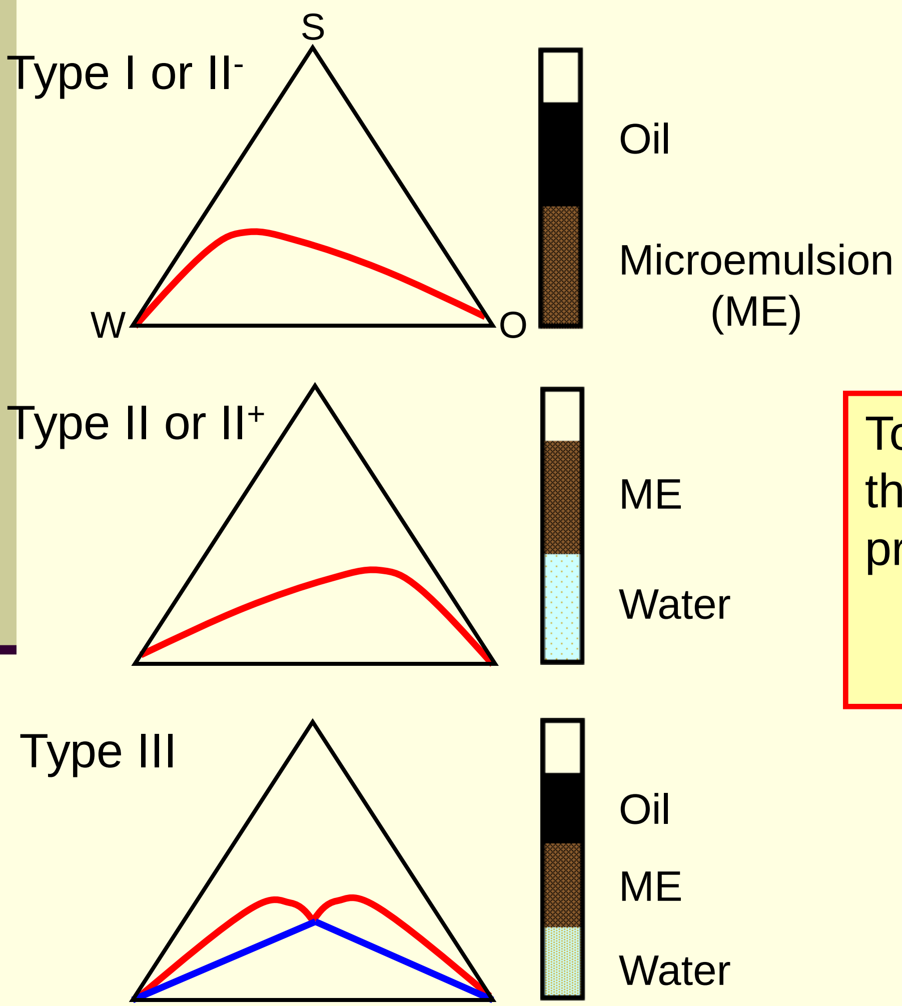
There are multiple possibilities for how this system composition can break into different phases:

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

Type II or II^+ 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$^-$ > Type II$^+$ > Type II

Issues specific to Minnelusa

- 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 (N2) or cheap NG is available

Issues specific to Minnelusa (Cont)

- <u>Chemical methods critical constraints:</u>
  - Reservoir characterization → Conformance, Location of ROIP, etc.
  - Water source → Fresh vs. produced
  - Rock-fluid interaction → Adsorption, CEC, etc.

- <u>What about Minnelusa sands?</u>

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

Summary

- 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