Enhanced Oil Recovery (EOR)

R. Kharrat

Professor of Petroleum University
of Technology

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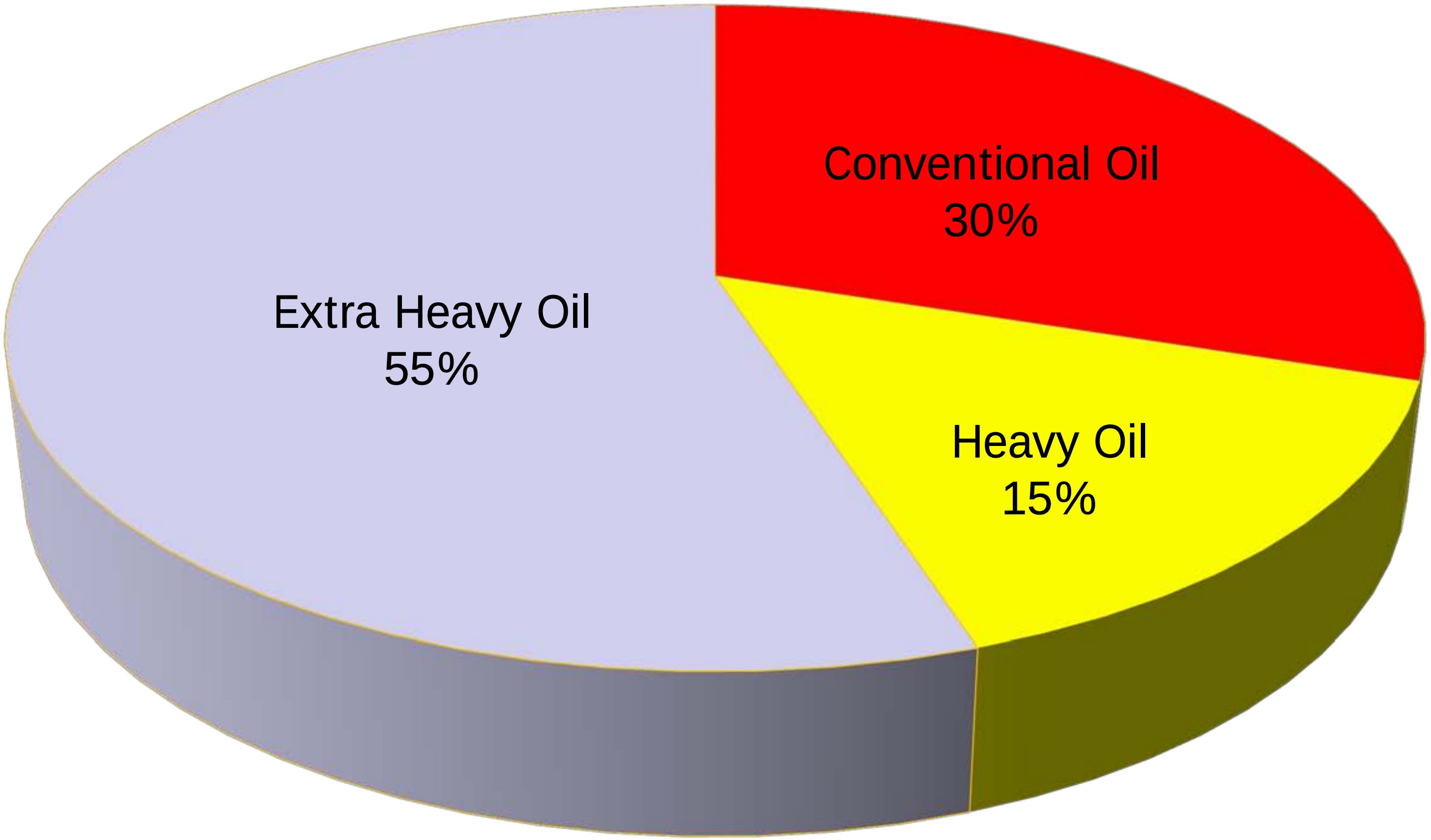
Chapter 1

Introduction

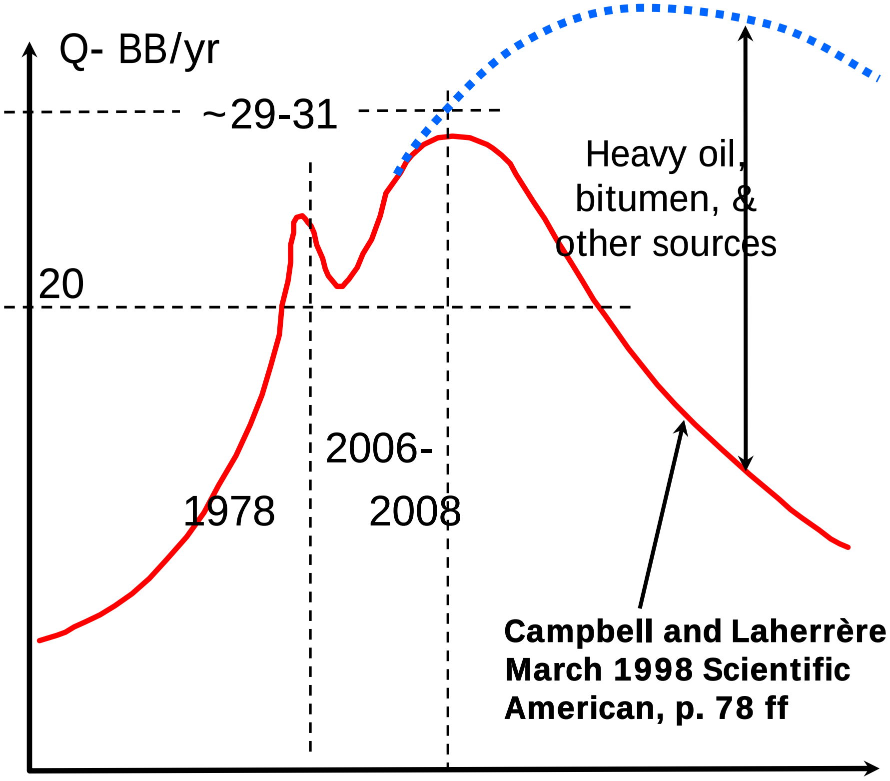
Distribution of Identified Petroleum Resources



Future of Conventional Oil

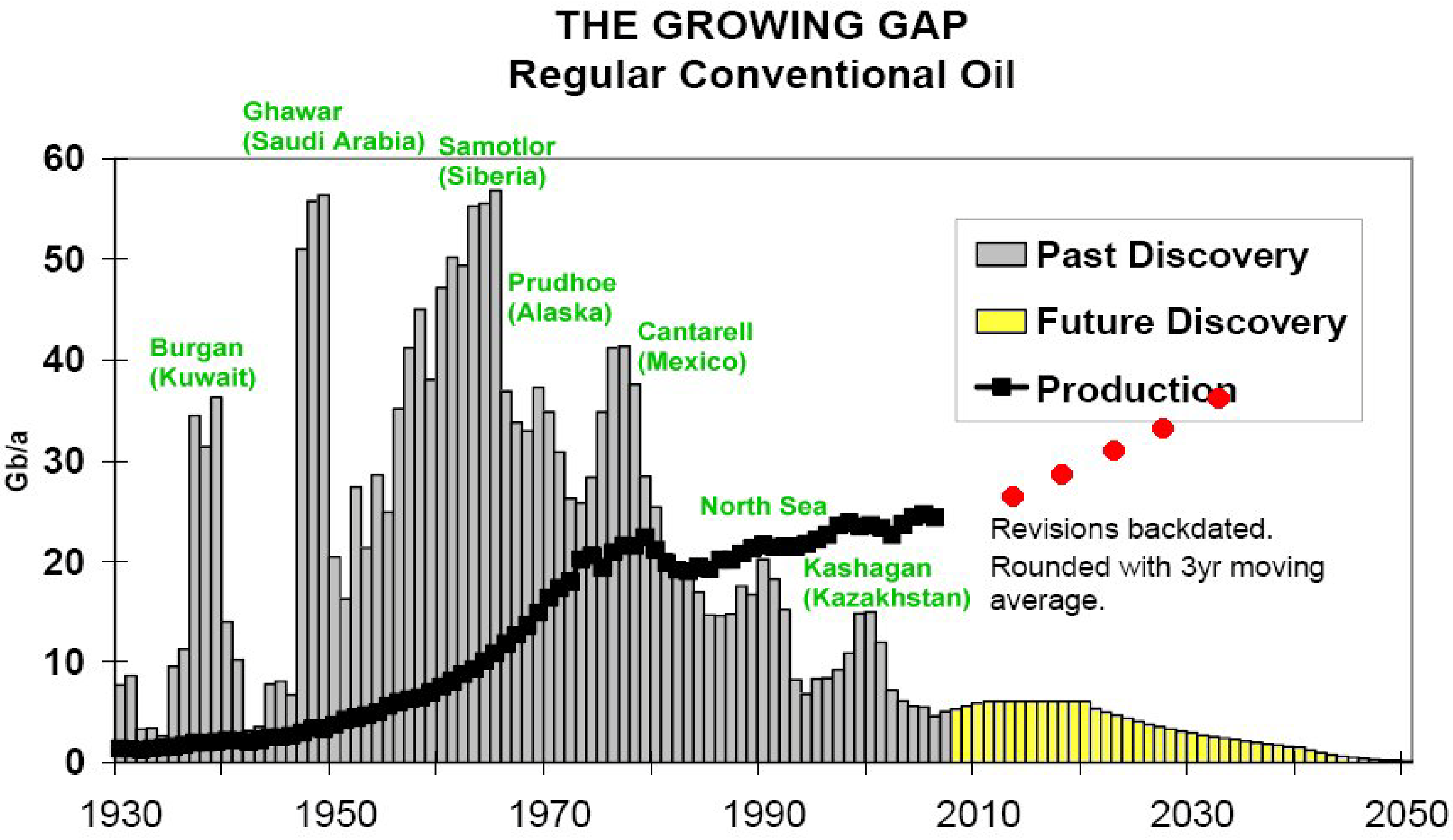
- Currently, 90% of production is from conventional oil
- Heavy oil and bitumen are growing rapidly
- About 70% of world reserves are heavy and extra heavy oil

Conventional Oil Prediction in Red
Total Need Prediction in Blue Dots

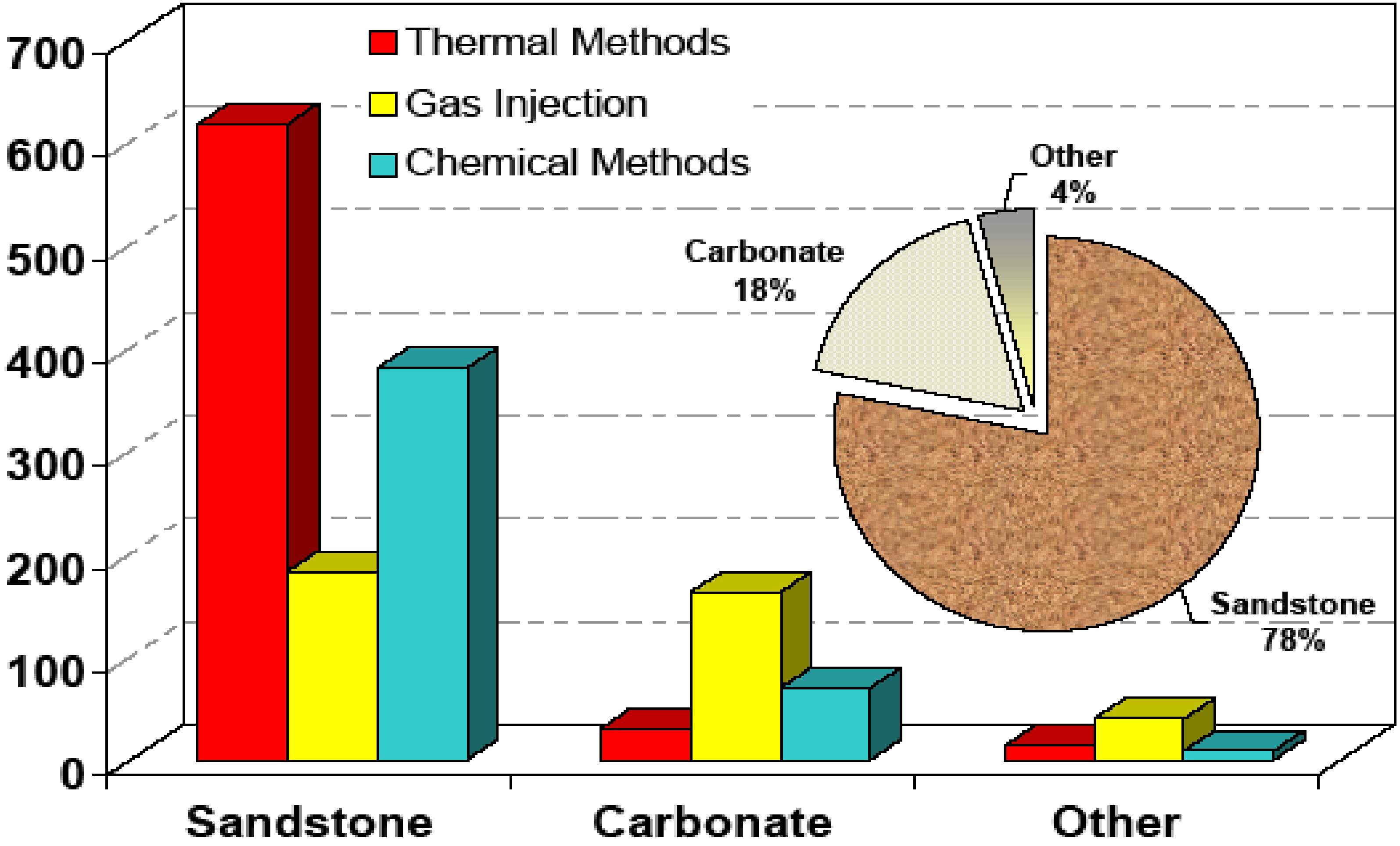


Campbell and Laherrère March 1998 Scientific American, p. 78 ff

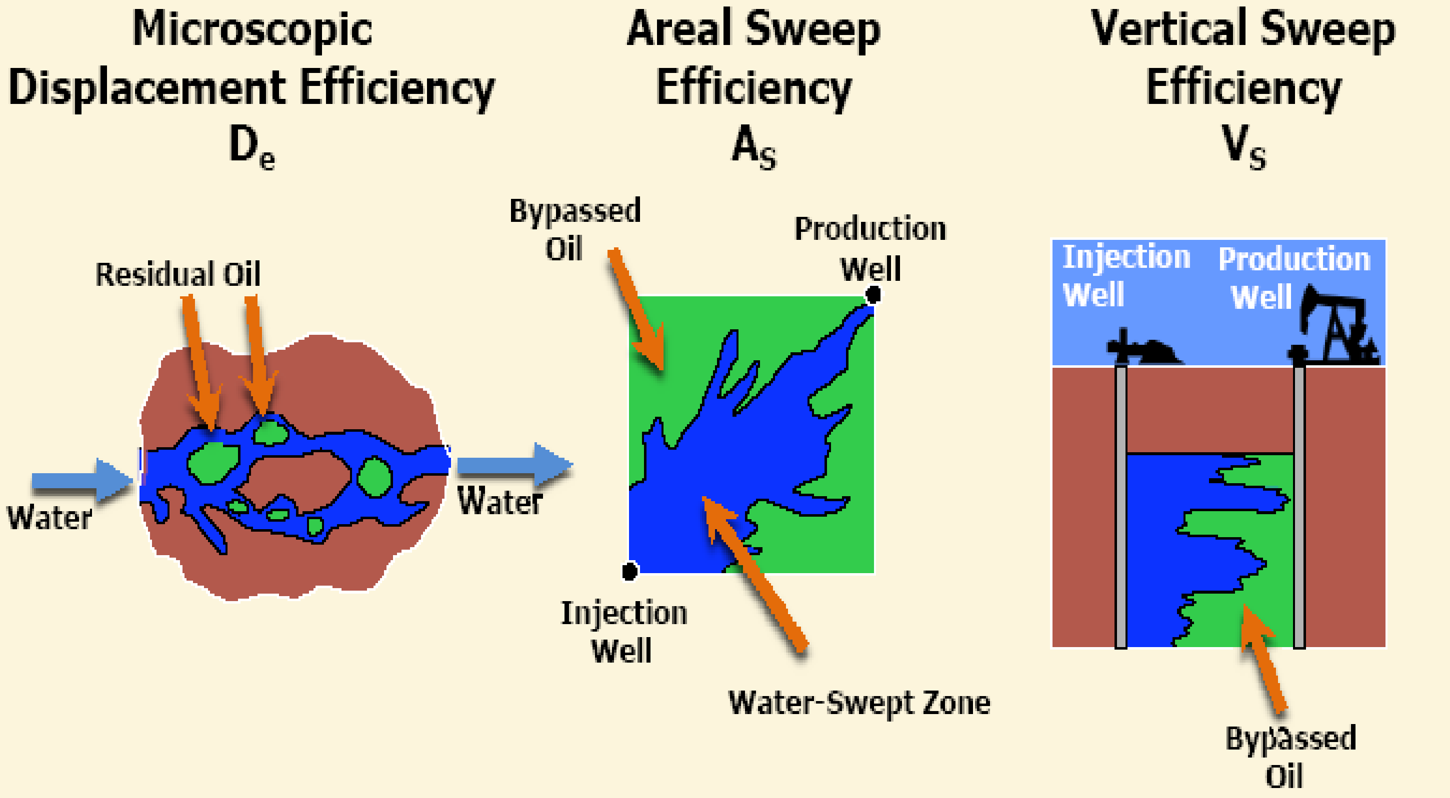
The Concept of Peak Oil



EOR methods by lithology (Based on a total of 1507 projects)



Why EOR



Microscopic Displacement Efficiency D_e

Areal Sweep Efficiency A_S

Vertical Sweep Efficiency V_S

Recovery Efficiency RE = $D_e \times A_s \times V_s$

A typical EOR project might have RE = .9 x .7 x .8 = .5, or 50% of the remaining in place.

Definition

- Primary
- Secondary
- Tertiary
- IOR
- EOR

Primary Recovery (around 20%)

Natural flow of energy of reservoir

- The primary recovery depends on the conditions encountered in the fields.
- Water Drive (70 to 80%)
- Solution gas drive (10 to 30%)
- Gas Cap Drive
- Gravity Drainage
- Fluid and Rock Expansion

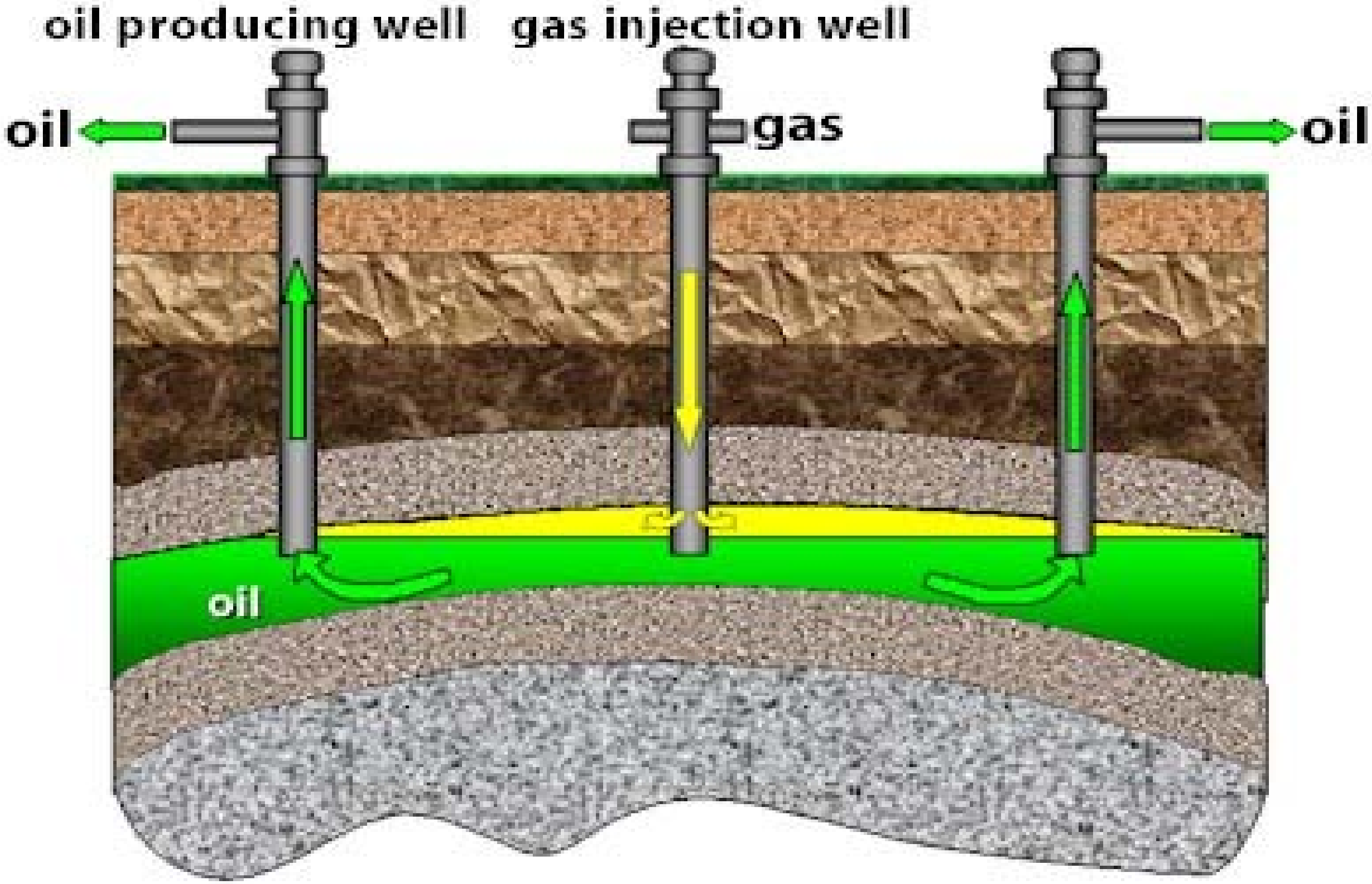
Primary Oil Recovery: Point to be considered

- Optimum Production Rate
- Maximum Recovery Factor
- Pressure decline under control
- Gas Injection
- Water Injection
- Production under stabilized conditions
- Monitoring WOR & GOR
- Reservoir Management

Secondary Recovery 15 TO 60%

- To produce more oil, the pressure in the reservoir must be maintained by injecting another fluid.
  - Water injection
  - Gas injection
- Small oil field:
  - Water into the aquifer
  - Gas into the gas cap
- Large field: Fluid injection must be distributed through the reservoir

Gas injection into the gas cap



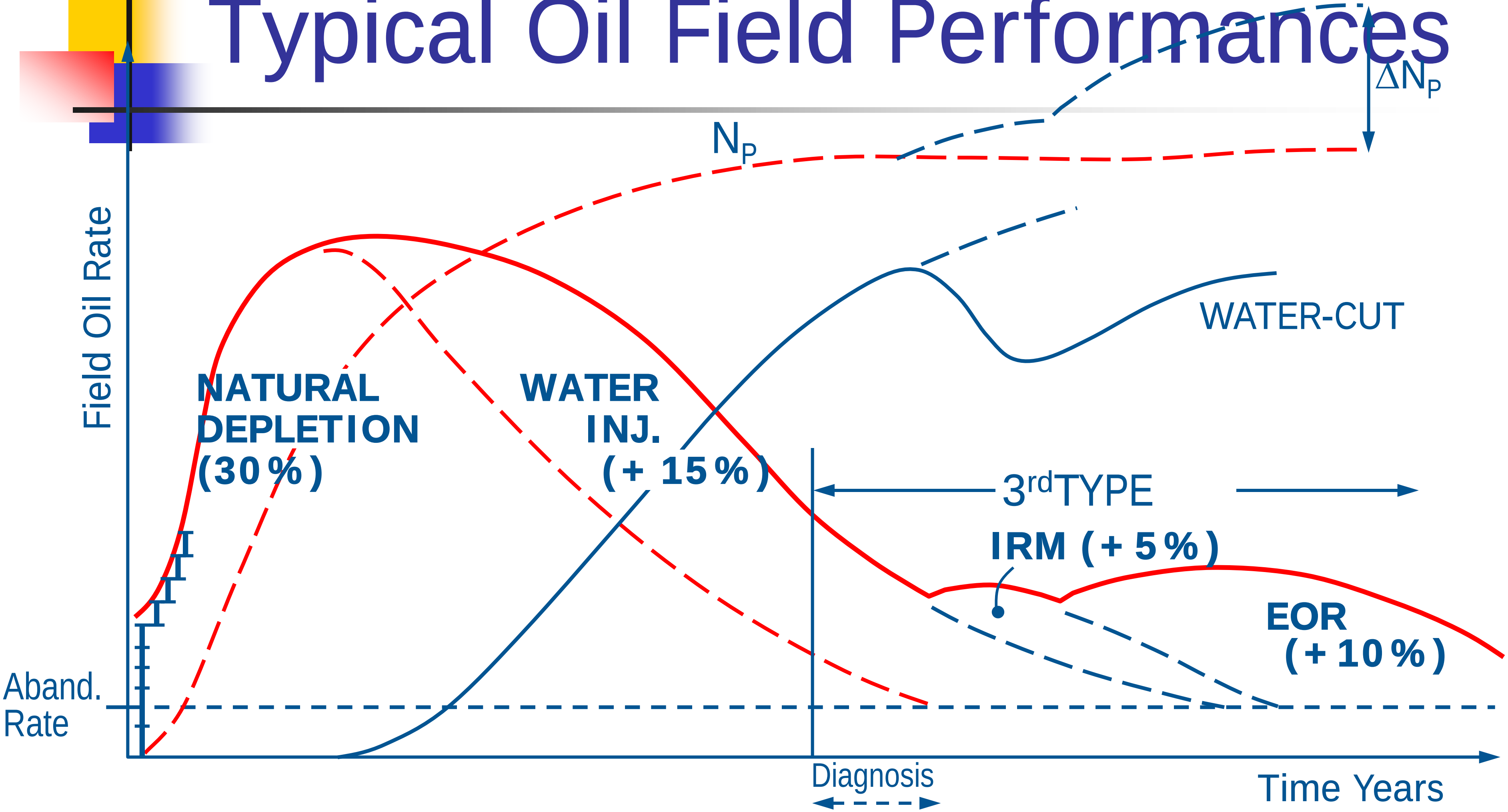
Tertiary Recovery

- Producing the oil that remain in the part of the reservoir already swept by the displacing.
  - Increasing the displacement efficiency

    (Part of the reservoir that was already swept in secondary recovery)
  - Increasing the sweep efficiency

    (producing oil that remains in the part of the reservoir not swept by displacing fluid)
  - Increasing both displacement and sweep efficiencies

Typical Oil Field Performances



Definition of EOR/IOR

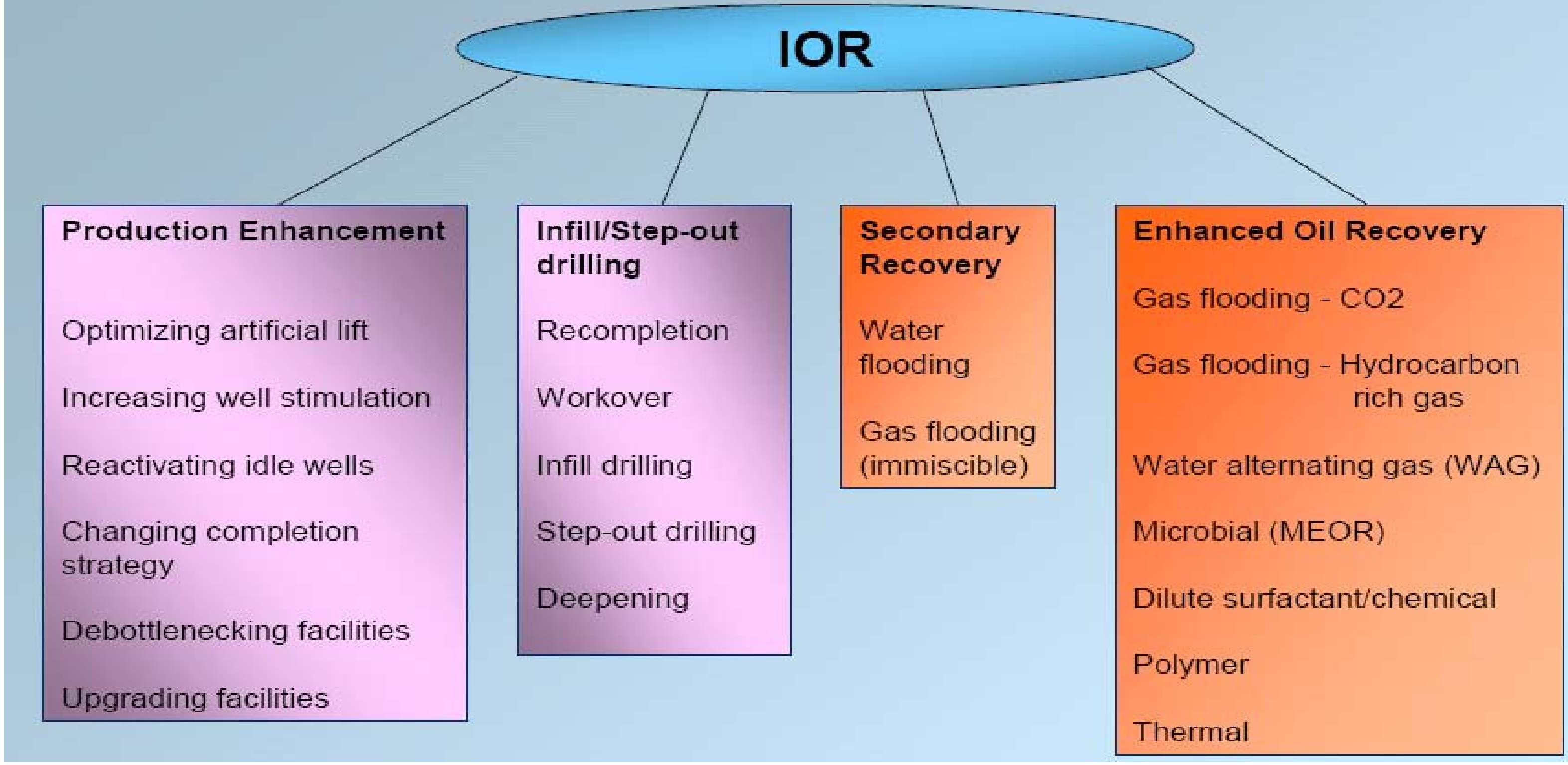
EOR refers to any method used to recover more oil from a reservoir than would be produced by primary recovery

IOR refers to any process which enhances the production or recovers more oil from a reservoir during the life of the reservoir

Improved & Enhanced Oil Recovery

- IOR: methods supplementing reservoir forces & energy
  - to increase ultimate recovery from a reservoir
    - pressure support
    - cycling
    - infill drilling in by-passed areas
    - artificial lift methods (gas-lift vs ESP)
  - includes EOR and/or tertiary methods
    - targeting oil remaining after conventional project

IOR Definition & Processes



IOR

Production Enhancement

- Optimizing artificial lift
- Increasing well stimulation
- Reactivating idle wells
- Changing completion strategy
- Debottlenecking facilities
- Upgrading facilities

Infill/Step-out drilling

- Recompletion
- Workover
- Infill drilling
- Step-out drilling
- Deepening

Secondary Recovery

- Water flooding
- Gas flooding (immiscible)

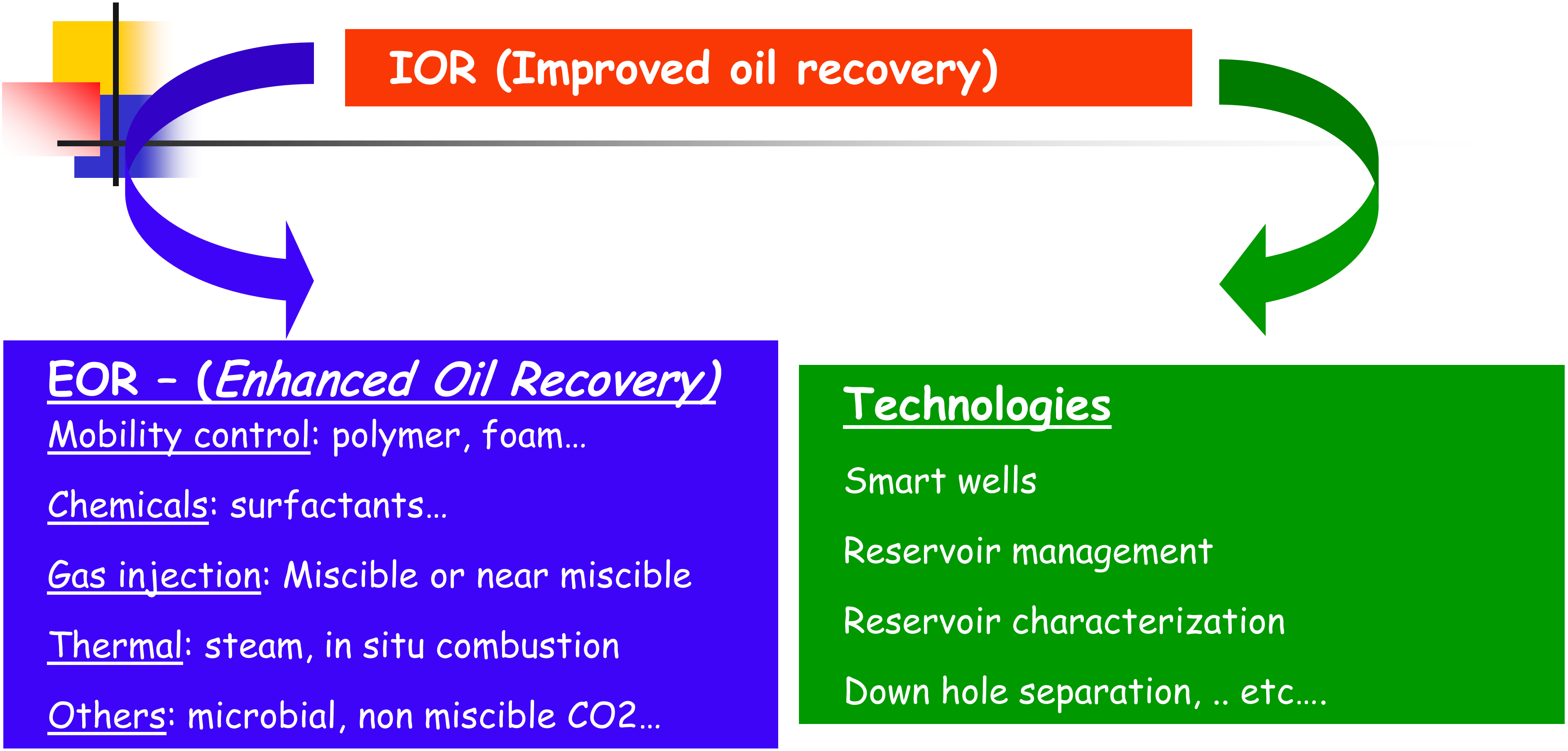
Enhanced Oil Recovery

- Gas flooding - CO2
- Gas flooding - Hydrocarbon rich gas
- Water alternating gas (WAG)
- Microbial (MEOR)
- Dilute surfactant/chemical
- Polymer
- Thermal

Improved & Enhanced Oil Recovery

- **EOR: “injecting anything that will increase the recovery attained by previous methods”**
  - **Improvement of displacement efficiency**
    - decreasing Sorw and/or Sorg
      - miscible or near miscible gas injection
      - chemical flood-surfactants
      - taking advantage of gravity forces
      - oil vaporization
  - **Improvement of volumetric sweep efficiency**
    - lowering mobility ratio by increasing m_w or m_g
      - polymers or foams
    - reducing viscosity
      - thermal flood

TERMINOLOGY



IOR (Improved oil recovery)

EOR – (*Enhanced Oil Recovery*)

Mobility control: polymer, foam…

Chemicals: surfactants…

Gas injection: Miscible or near miscible

Thermal: steam, in situ combustion

Others: microbial, non miscible CO2…

Technologies

Smart wells

Reservoir management

Reservoir characterization

Down hole separation, .. etc….

EOR will basically refer to the same methods/mechanisms

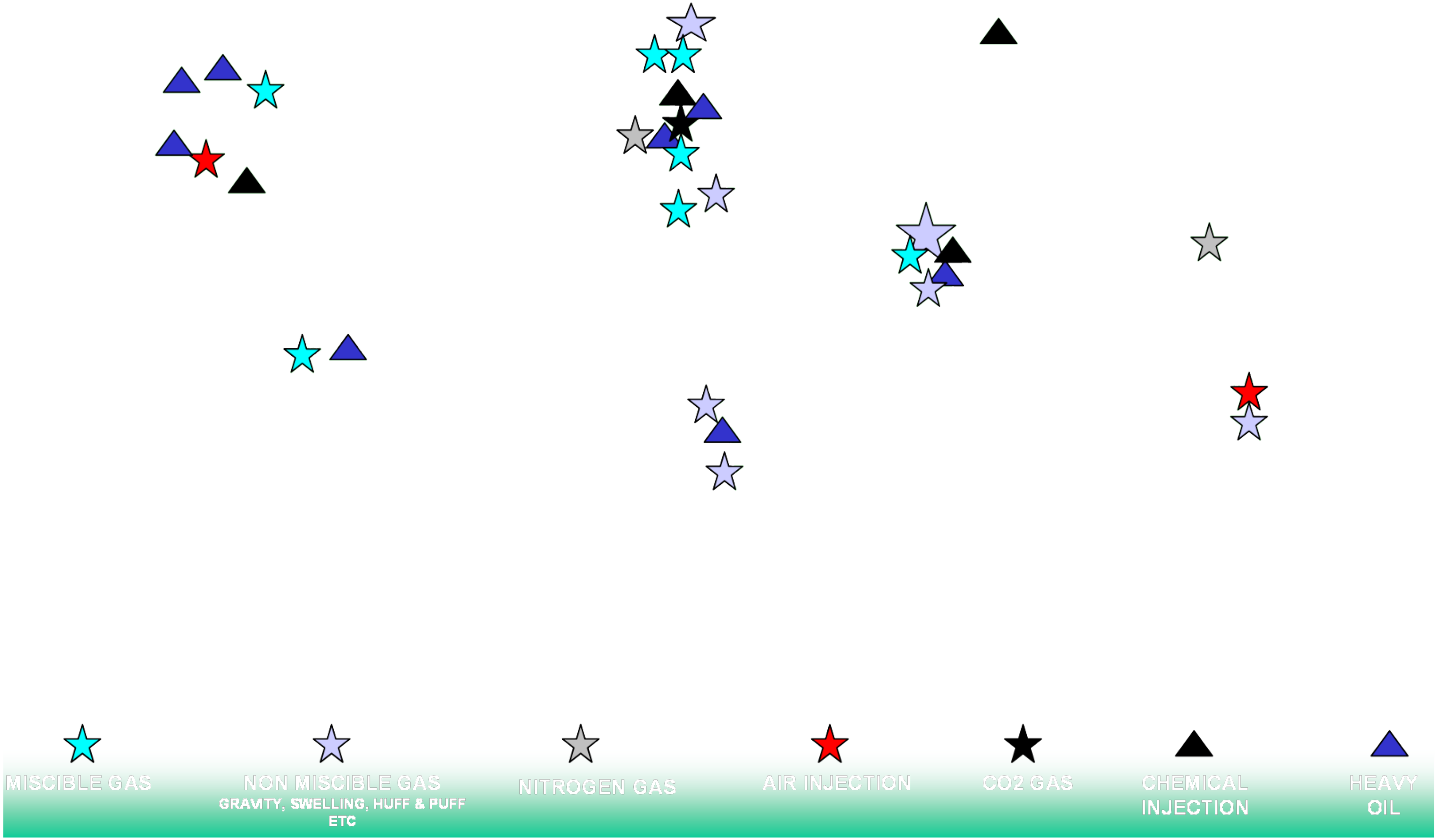
IOR technologies will change versus time with different standards across the world and among the various companies

The two scales of EOR

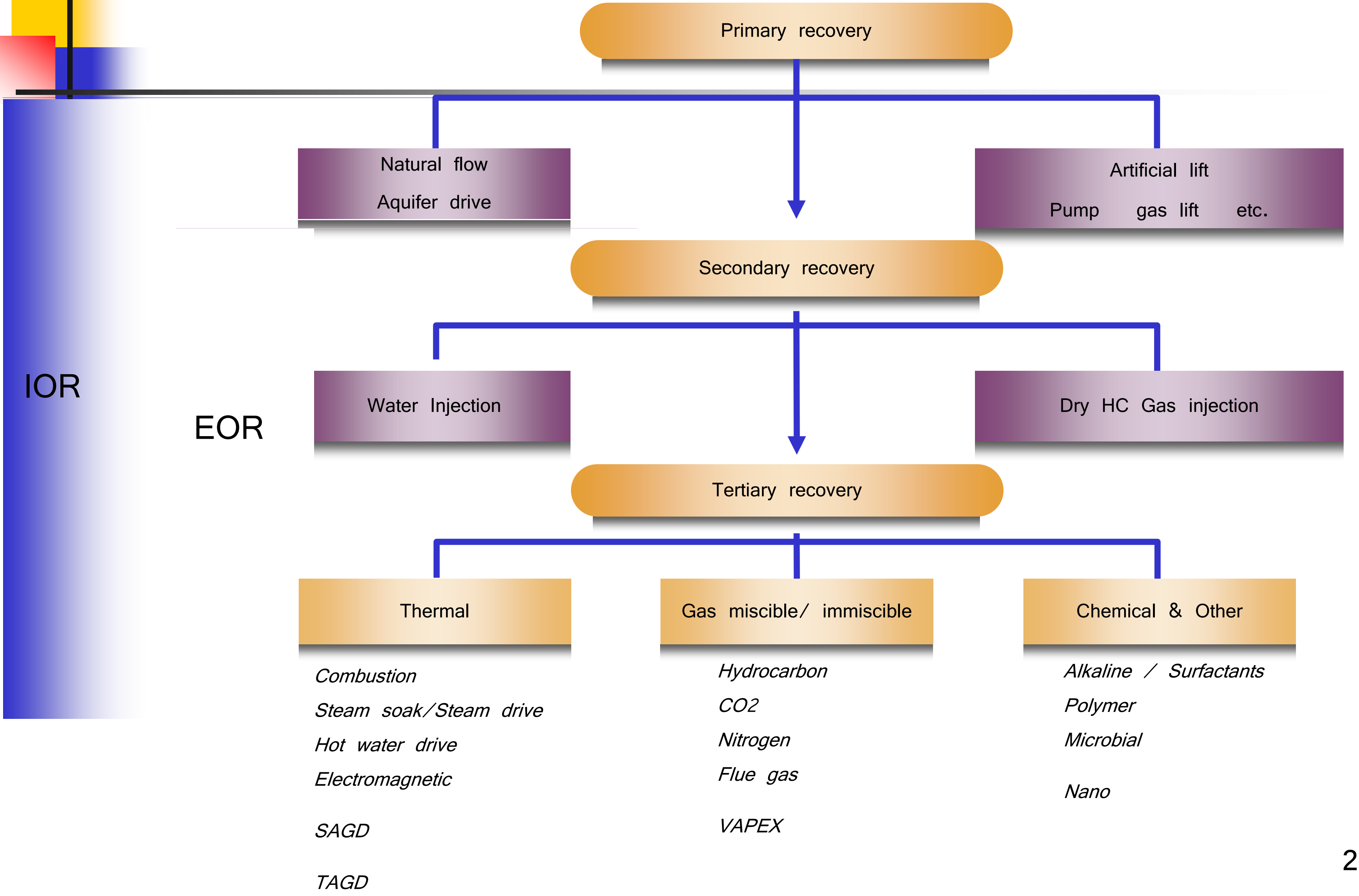
- **Microscopic scale**
  - what happens in the porous network
  - interaction between injected and in place fluids
  - ➔ requires calibration by lab experiments

- **Field scale: extrapolation of microscopic behavior seriously impacted by**
  - structural set-up
    - formation dip, existing updip…
  - geological heterogeneities
    - vertical barriers to flow, contrast in permeabilities
  - mechanistic upscaling may be required
  - ➔ pilot required to validate extrapolation of microscopic scale results

World Wide Experience in EOR



Definition of terms



IOR

EOR

Primary recovery

- Natural flow
  Aquifer drive
- Artificial lift
  Pump gas lift etc.

Secondary recovery

- Water Injection
- Dry HC Gas injection

Tertiary recovery

- Thermal
  - *Combustion*
  - *Steam soak/Steam drive*
  - *Hot water drive*
  - *Electromagnetic*
  - *SAGD*
  - *TAGD*
- Gas miscible/ immiscible
  - *Hydrocarbon*
  - *CO2*
  - *Nitrogen*
  - *Flue gas*
  - *VAPEX*
- Chemical & Other
  - *Alkaline / Surfactants*
  - *Polymer*
  - *Microbial*
  - *Nano*

Enhanced Oil Recovery (EOR) Processes

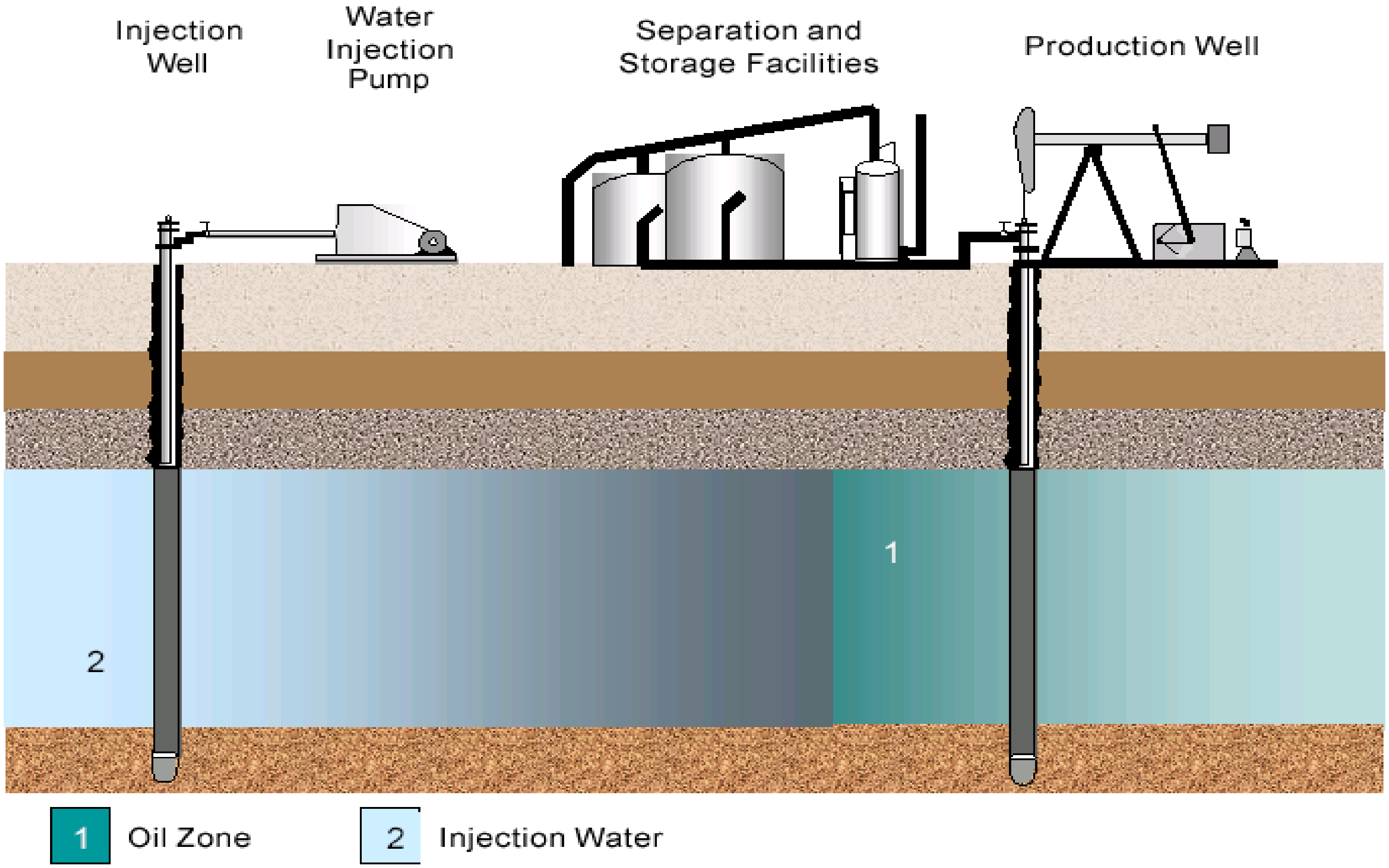
Enhanced oil recovery (EOR) processes include all methods that use external sources of energy and/or materials to recover oil that cannot be produced, economically by conventional means.

EOR methods include:

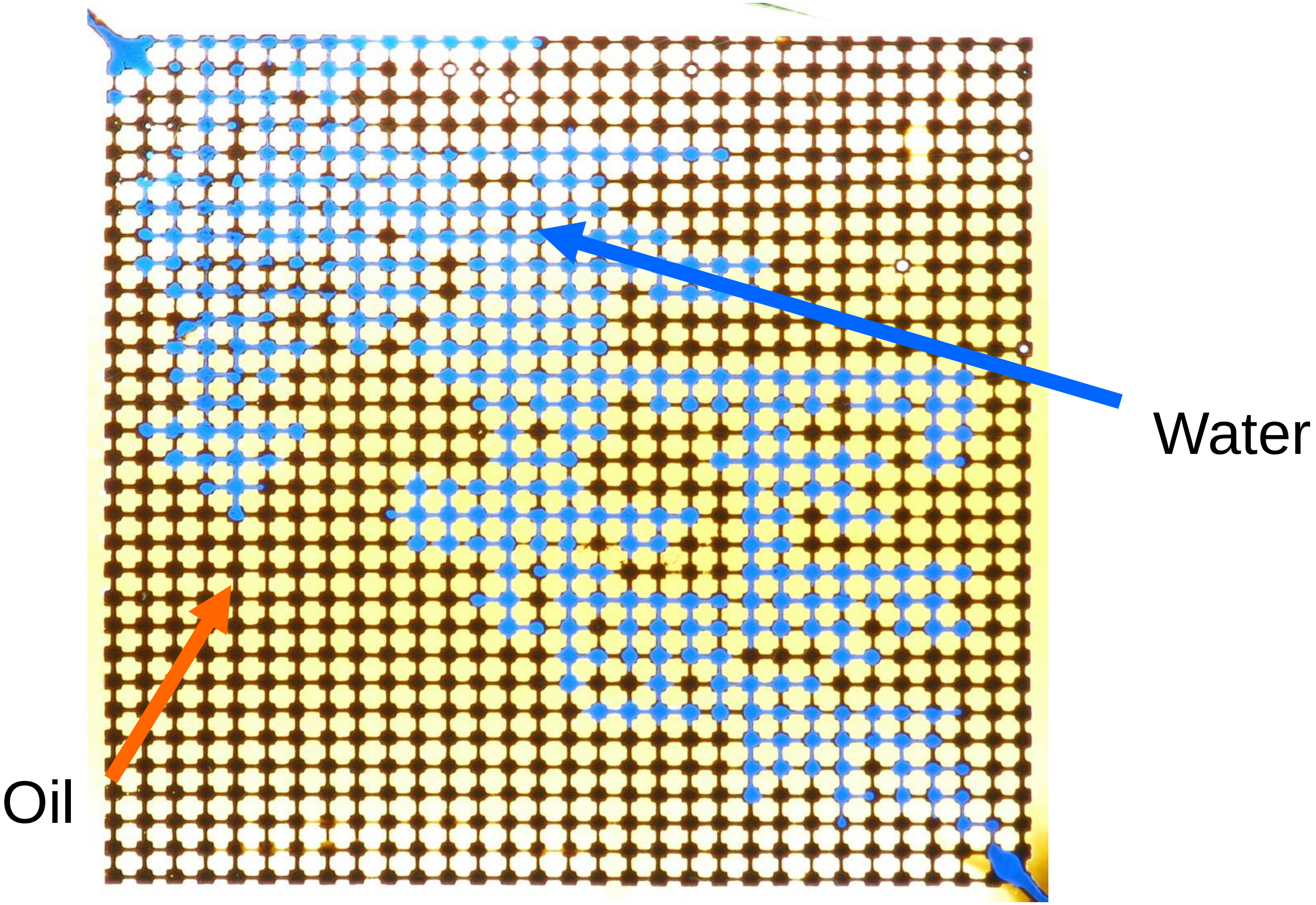
- **Water flooding**
- **Thermal methods**: steam stimulation, steam flooding, hot water drive, and in-situ combustion
- **Chemical methods**:polymer,surfactant,caustic,and miscellar /polymer flooding.
- **Miscible methods**: hydrocarbon gas,CO2,and nitrogen (flue gas and partial miscible/immiscible gas injection may also be considered)

Waterflood	**Thermal**	**Chemical**	**Miscible gas**
Maintains reservoir pressure &physically displaces oil with water moving through the reservoir from injector to producer.	Reduce Sorw by steam distillation and reduces oil viscosity.	Reduces Sorw by lowering water-oil interfacial tension, and increases volumetric sweep efficiency by reducing the water-oil mobility ratio.	Reduces Sorw by developing miscibility with the oil through a vaporizing or condensing gas drive process.

Water flooding



Water Flooding In 5-Spot Pattern



Description

Waterflooding consist of injecting water into the reservoir. It is the most post-primary recovery method. Water is injected in patterns or along the periphery of the reservoir.

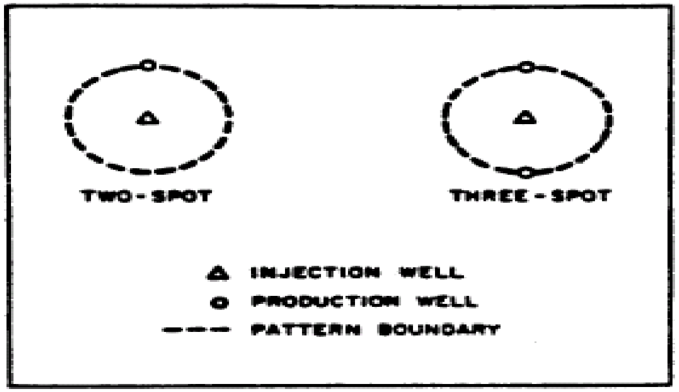
Mechanisms That Improve Recovery Efficiency

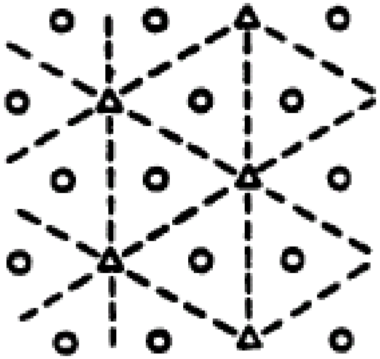
Water Drive
Increased Pressure

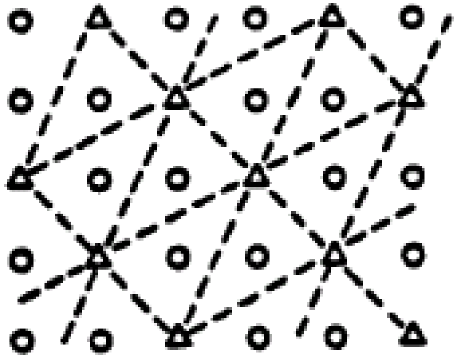
Limitations

High oil viscosities result in higher mobility ratios.
Some heterogeneity is acceptable, but avoid extensive fractures

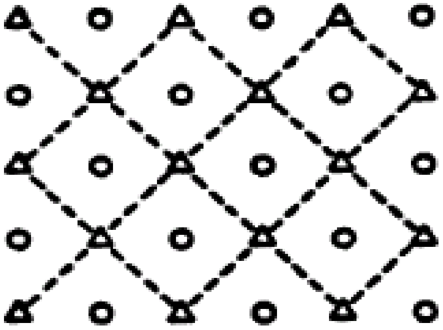
Flooding Patterns: A number of different injection/production well patterns have been used in reservoir displacement process



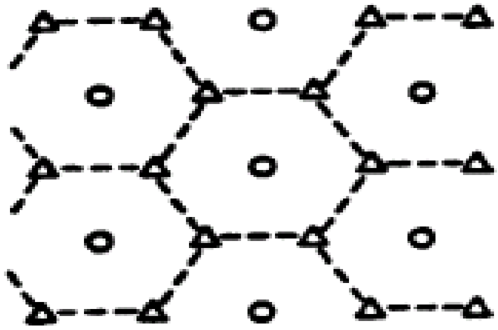

REGULAR FOUR-SPOT


SKEWED FOUR-SPOT

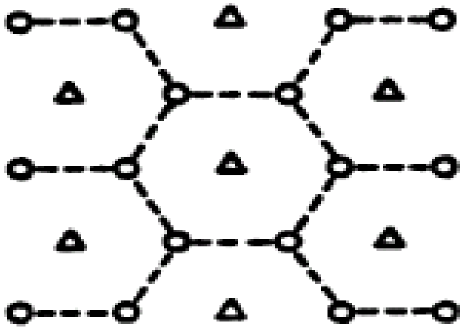
Flooding Patterns



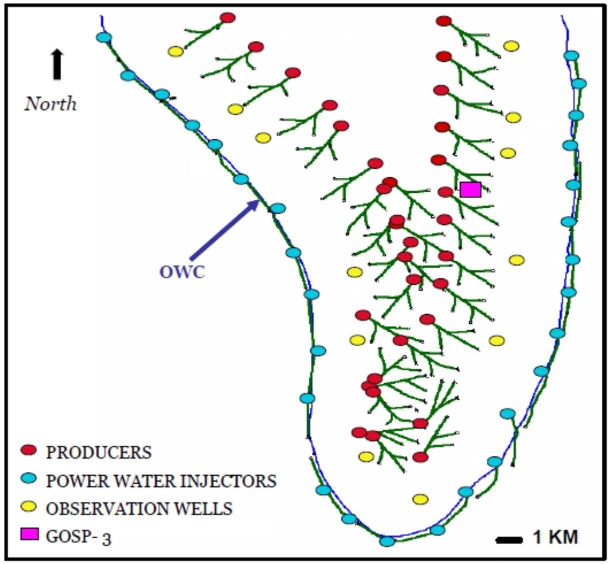
FIVE-SPOT



SEVEN-SPOT

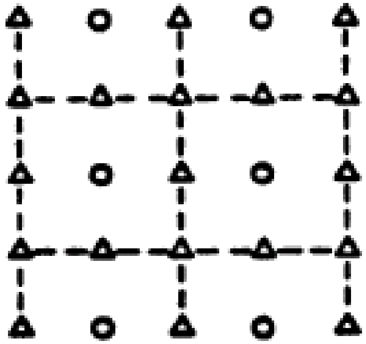


INVERTED SEVEN-SPOT

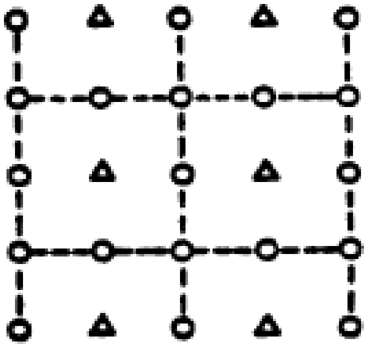


Haradh Increment-III Map

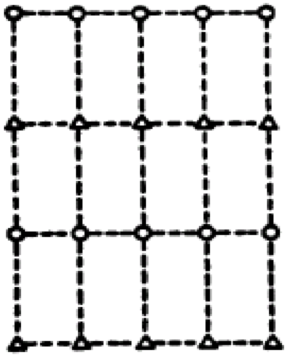
Flooding Patterns



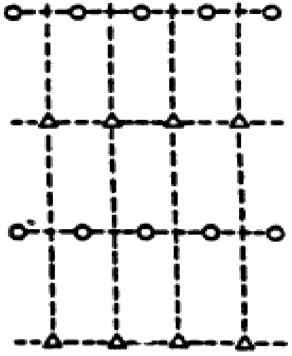
NORMAL NINE-SPOT



INVERTED NINE-SPOT



DIRECT LINE DRIVE



STAGGERED LINE DRIVE

Challenges

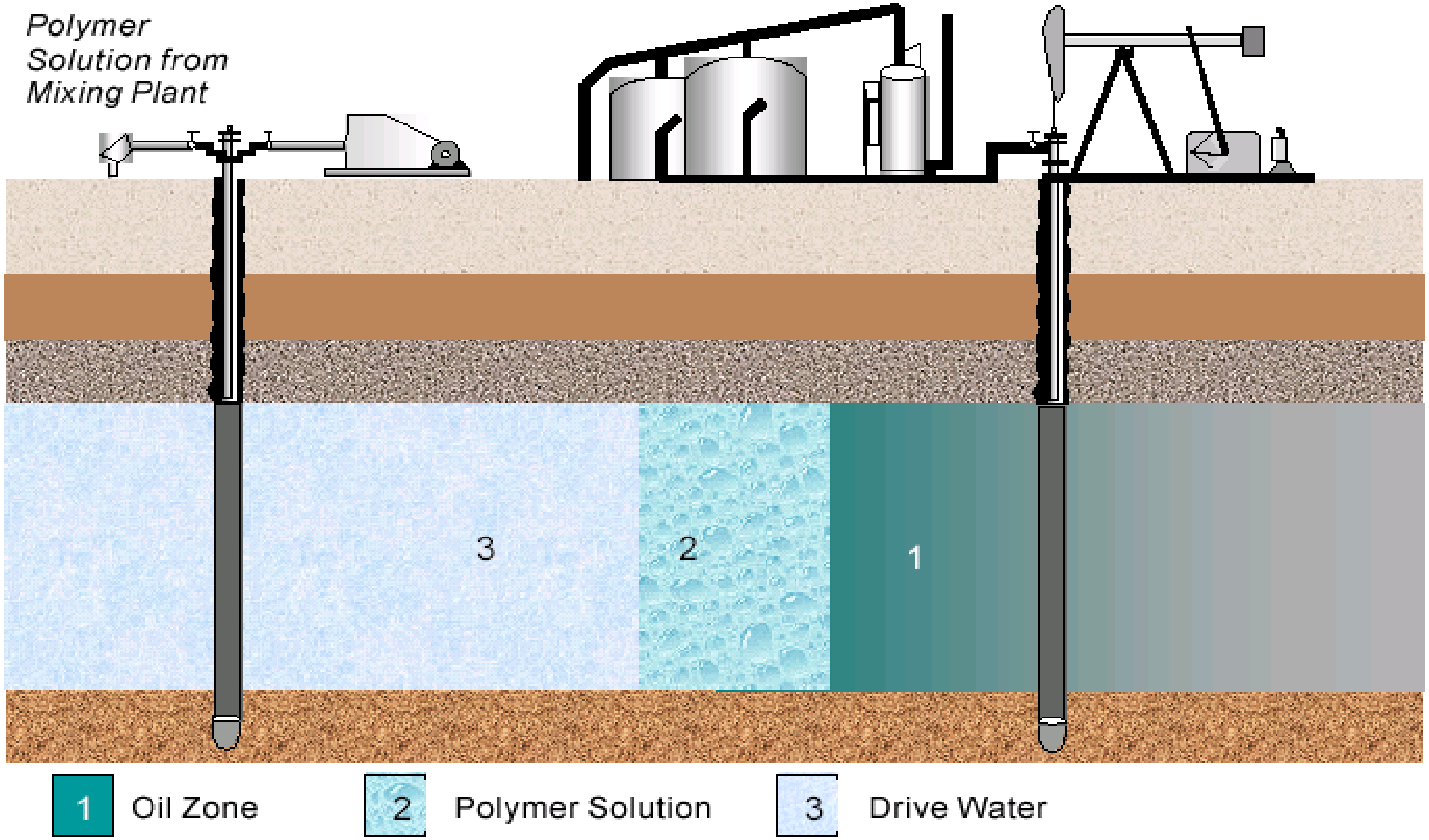
Compatibility between the injected water and the reservoir may cause formation damage.

Screening Parameters

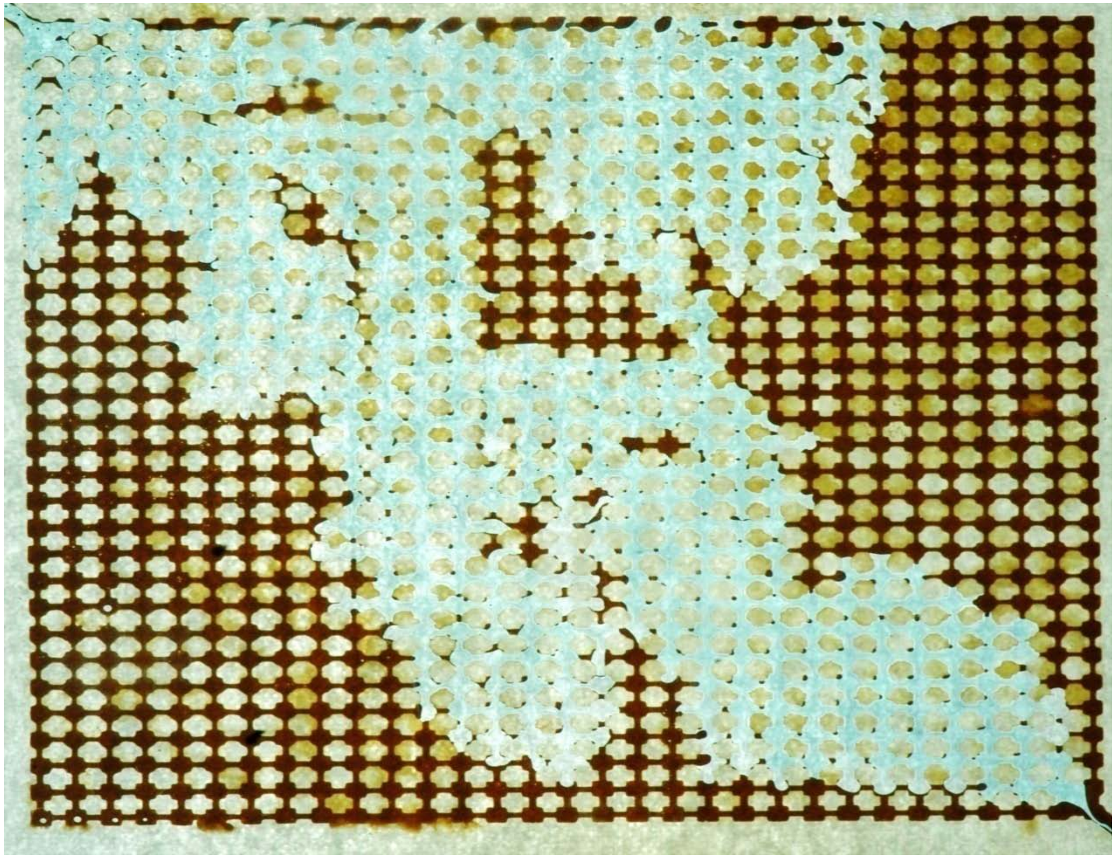
Gravity	>25 API	**Viscosity**	<30cp
Composition	not critical	**Oil saturation**	>10% mobile oil
Formation type	sandstone/carbonate	**Net thickness**	not critical
Average permeability	not critical	**Transmissibility**	not critical
Depth	not critical	**Temperature**	not critical

Note: *Most EOR screening values are approximations based on successful north American project.*

Chemical Flooding: Polymer Flooding



Polymer Flooding In 5-Spot Pattern



Description

Waterflooding consists of adding water soluble polymers to the water before it is injected into the reservoir.

Mechanisms That Improve Polymer augment Recovery Efficiency

Mobility control(improves volumetric sweep efficiency)

Limitations

- High oil viscosities require a higher polymer concentration.
- Results are normally better if the polymer flood is started before the water–oil ratio becomes excessively high.
- Clays increase polymer adsorption.
- Some heterogeneity is acceptable ,but avoid extensive fractures. if fractures are present, the crosslinked or gelled polymer techniques may be applicable.

Challenges

Lower injectivity than with water can adversely affect oil production rates in the early stages of the polymer flood. Acrylamide-type polymers loose viscosity due to shear degradation, or it increases in salinity and divalent ions.

Screening Parameters

Gravity	>18 API	**Viscosity**	<200cp
Composition	Not Critical	**Oil saturation**	>10% PV mobile oil
Formation type	sandstone /carbonate	**Net thickness**	not critical
Average permeability	>20md	**Transmissibility**	not critical
Depth	<9000ft	**Temperature**	<225^{o}F

Polymers Commonly used are Polyacrylamides & Polysaccharides

General Properties

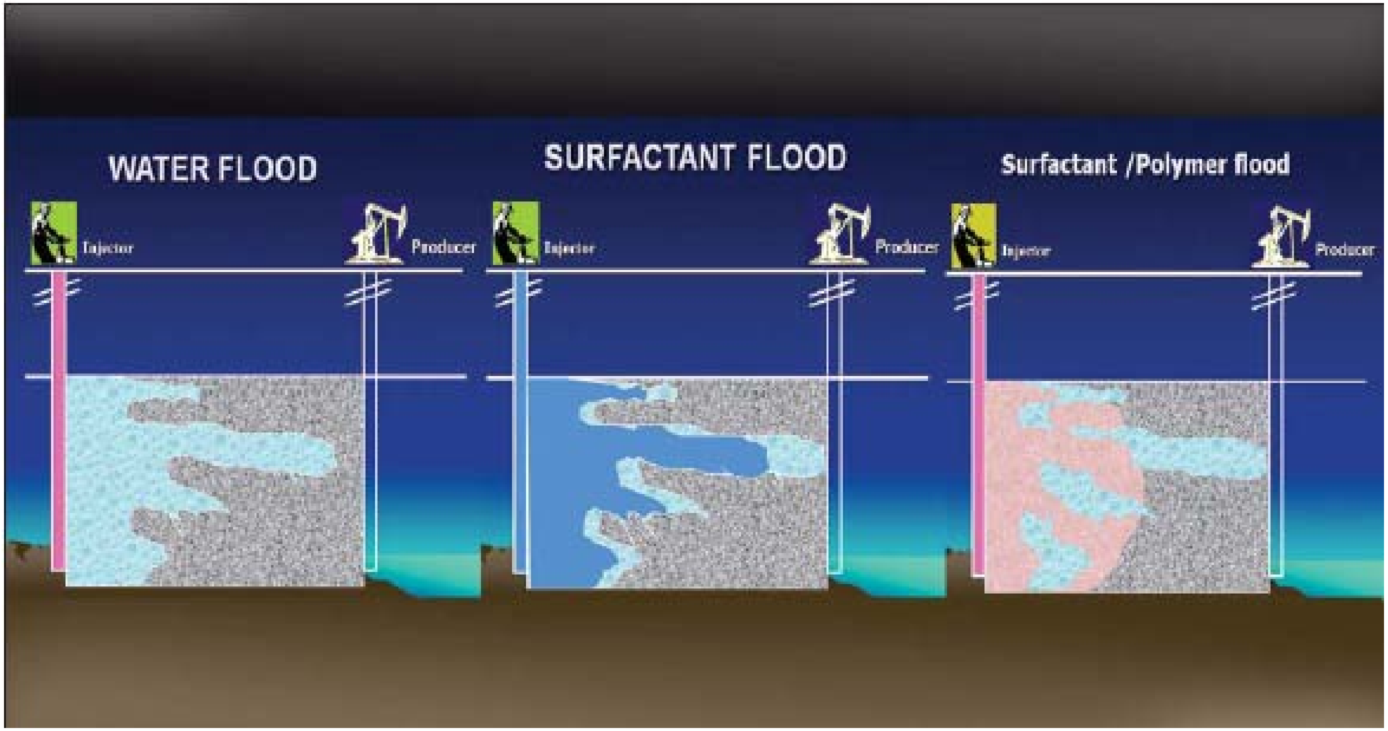
PA:

- Shear thinning
- Shear sensitive (degradable)
- High adsorption / retention
- Brine Sensitive
- Cheap

PS:

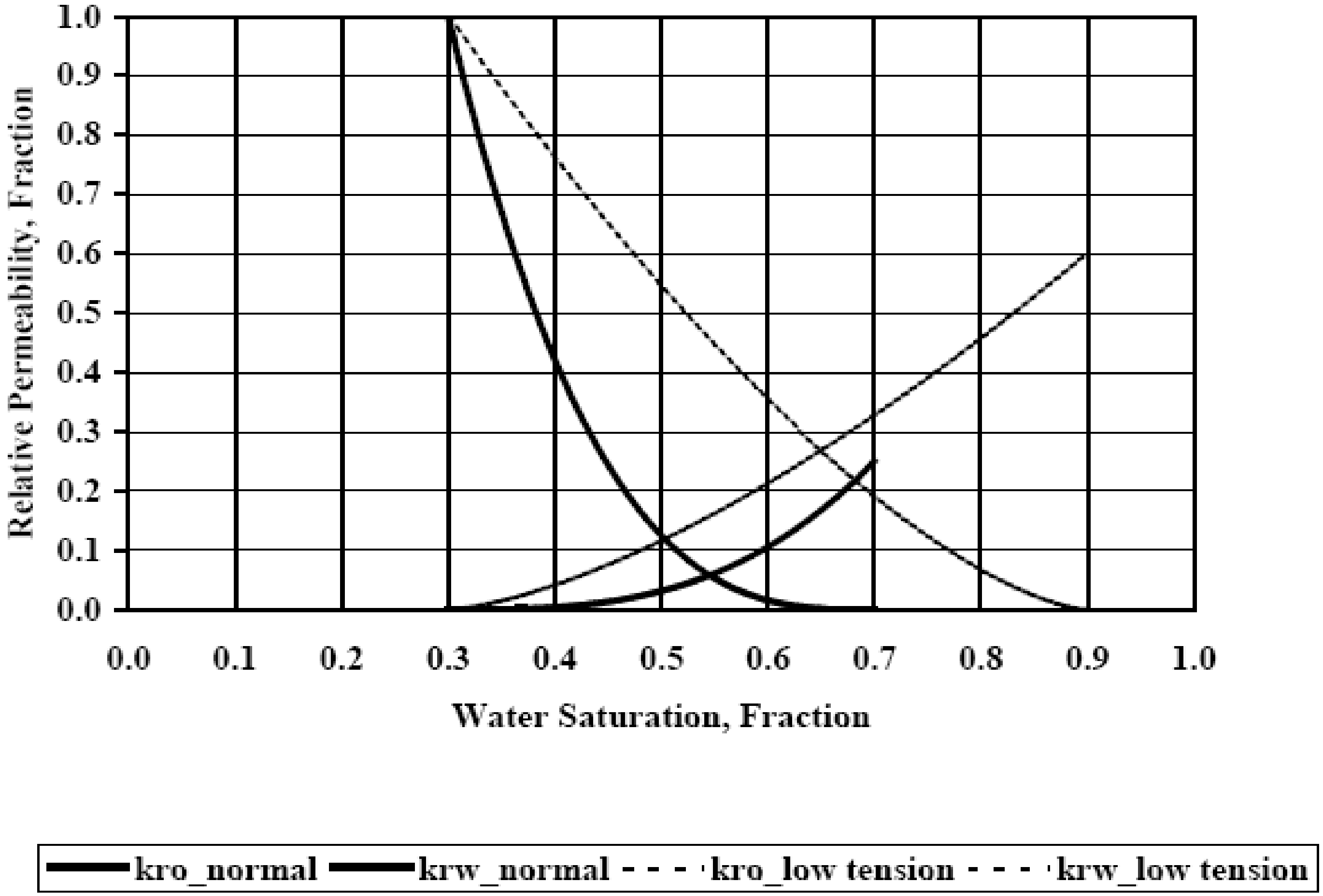
- Shear thinning
- Less shear Sensitive
- Less retention / adsorption
- Less sensitive to brine
- Sensitive to bacteria
- More expensive

Surfactant/Polymer Flooding

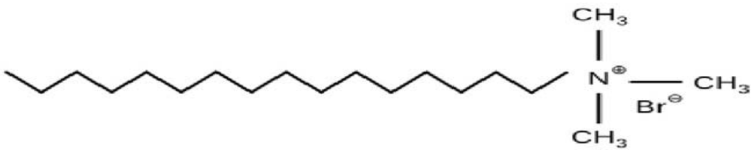
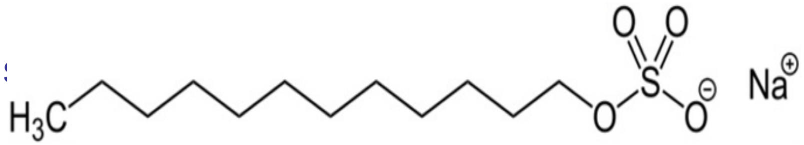
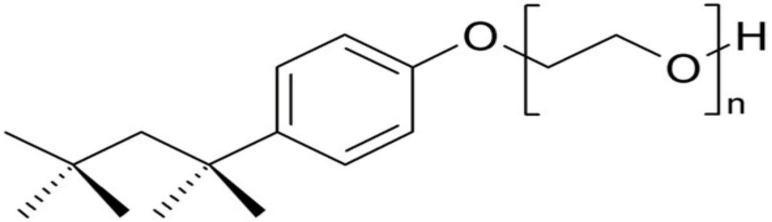


Surfactant Flooding in a Linear System

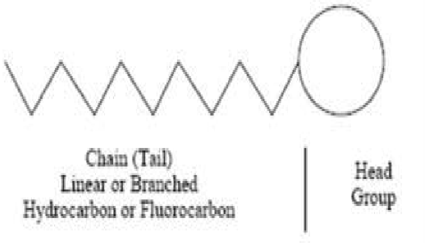
- The main EOR mechanism in a low-tension flood is the reduction in residual oil saturation (R.O.S.).
- The large reduction in IFT changes the fractional flow curve by changing the relative permeability curves.
    - Several changes occur in the relative permeability:
    - The R.O.S. decreases significantly.
    - The curvature of the relative permeability curves decreases.
    - The end-point water relative permeability increases.
- The change in relative permeability can only be determined experimentally.
- In the absence of experimental data, an approximate analysis is possible by simply shifting the residual oil saturation.
- Surfactant adsorption is an important consideration and must be determined experimentally.

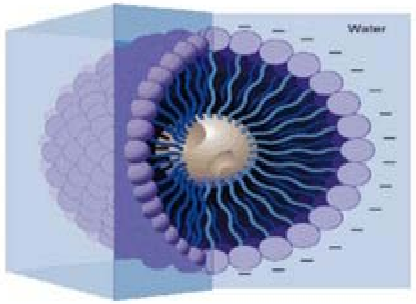

1.0
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0.0
Relative Permeability, Fraction
0.0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1.0
Water Saturation, Fraction
kro_normal
krw_normal
kro_low tension
krw_low tension

Schematic of Surfactant Structures

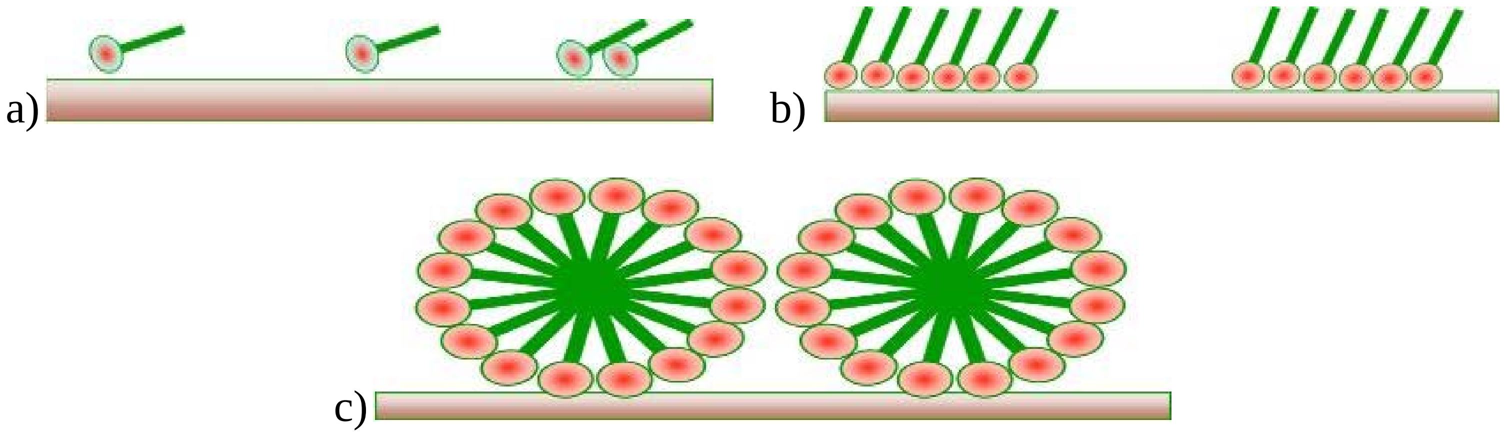
Surfactant	Structure
CTAB	
SDS	
Triton X-100	

molecular structure of the





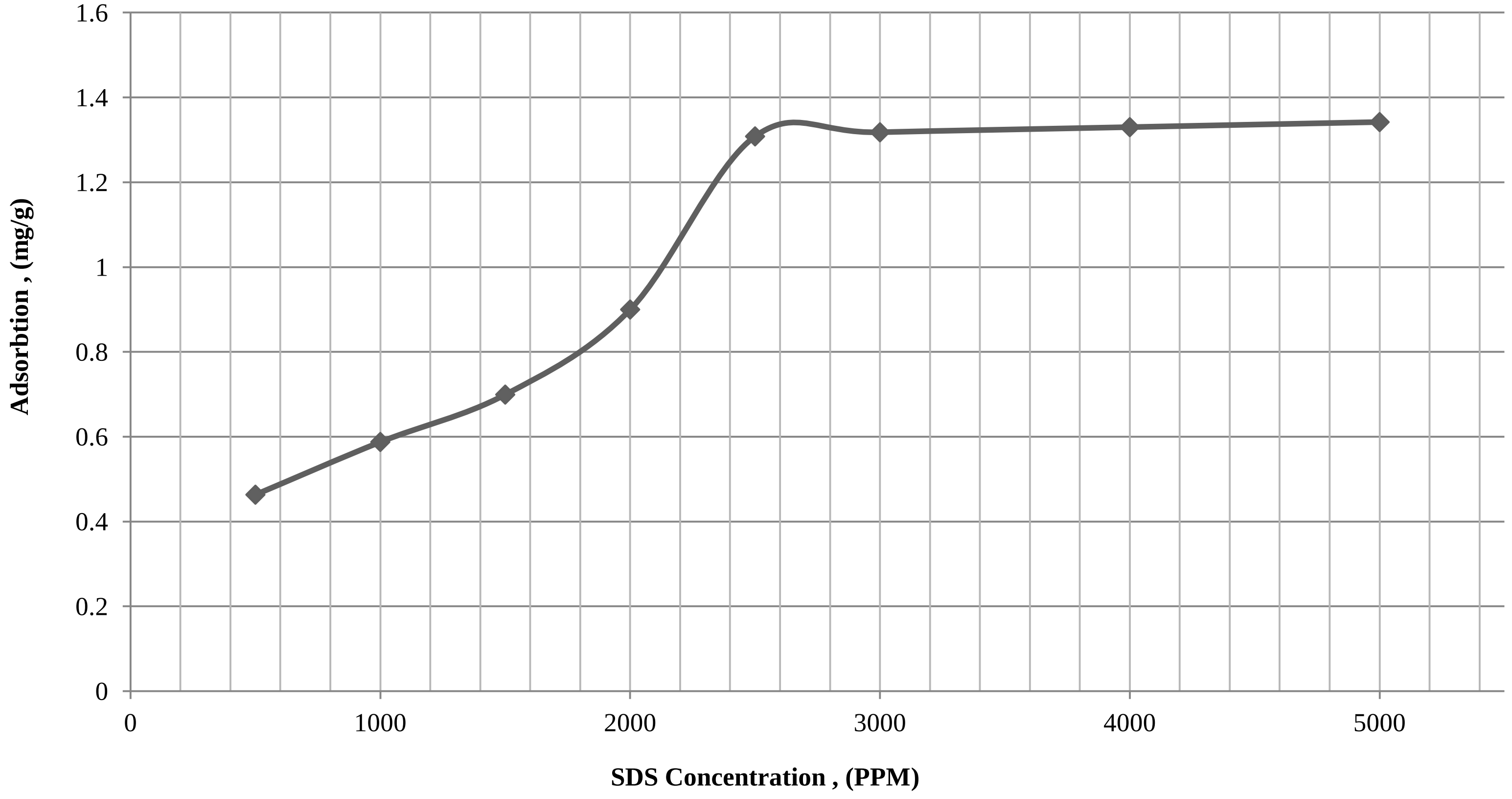
Schematic of the critical micelle concentration of a surfactant molecule drugs at three concentrations



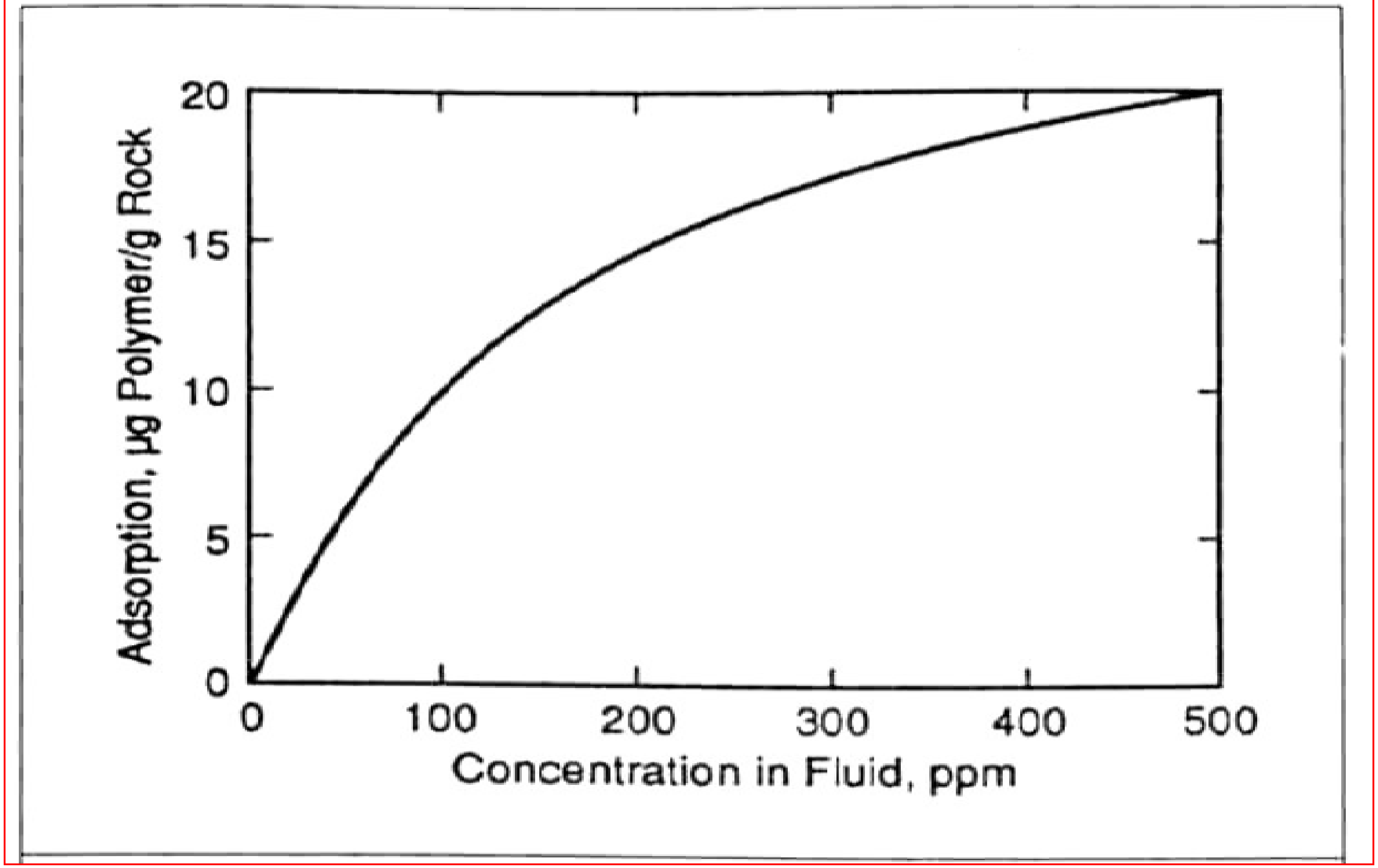
a) the critical concentration
b) the critical concentration range,
c) above the critical concentration.

Properties of some surfactants (all properties at 20°C).

Surfactant	Molar mass (g/m)	Solubility in water (g/mol)	Bulk Density (kg/m^3)	PH value	CMC (ppm)
Cetyl trimethyl ammonium Bromide	364.45	0.192	390	5 – 7	328
Sodium Dodecyl Sulfate	288.37	150	490-560	6-9	2307
Triton X-100	--	soluble	1070	5-8	1500


1.6
1.4
1.2
1
0.8
0.6
0.4
0.2
0
Adsorbtion , (mg/g)
0
1000
2000
3000
4000
5000
SDS Concentration , (PPM)

Typical adsorption isotherm of Polymer



Description

Surfactant/polymer flooding consists of injecting a slug that contains water surfactant, electrolyte (salt), usually a co-solvent (alcohol), and possibly a hydrocarbon (oil), followed by polymer-thickened water.

Mechanisms That Improve Recovery

Interfacial tension reduction (improves displacement sweep efficiency)
Mobility control

Limitations

An areal sweep of more than 50% for waterflood is desired.
Relatively homogeneous formation.
High amounts of anhydrite, gypsum, or clays are undesirable.
Available systems provide optimum behavior within a narrow set of conditions.
Water chlorides should be <20000 ppm and divalent ions<500ppm

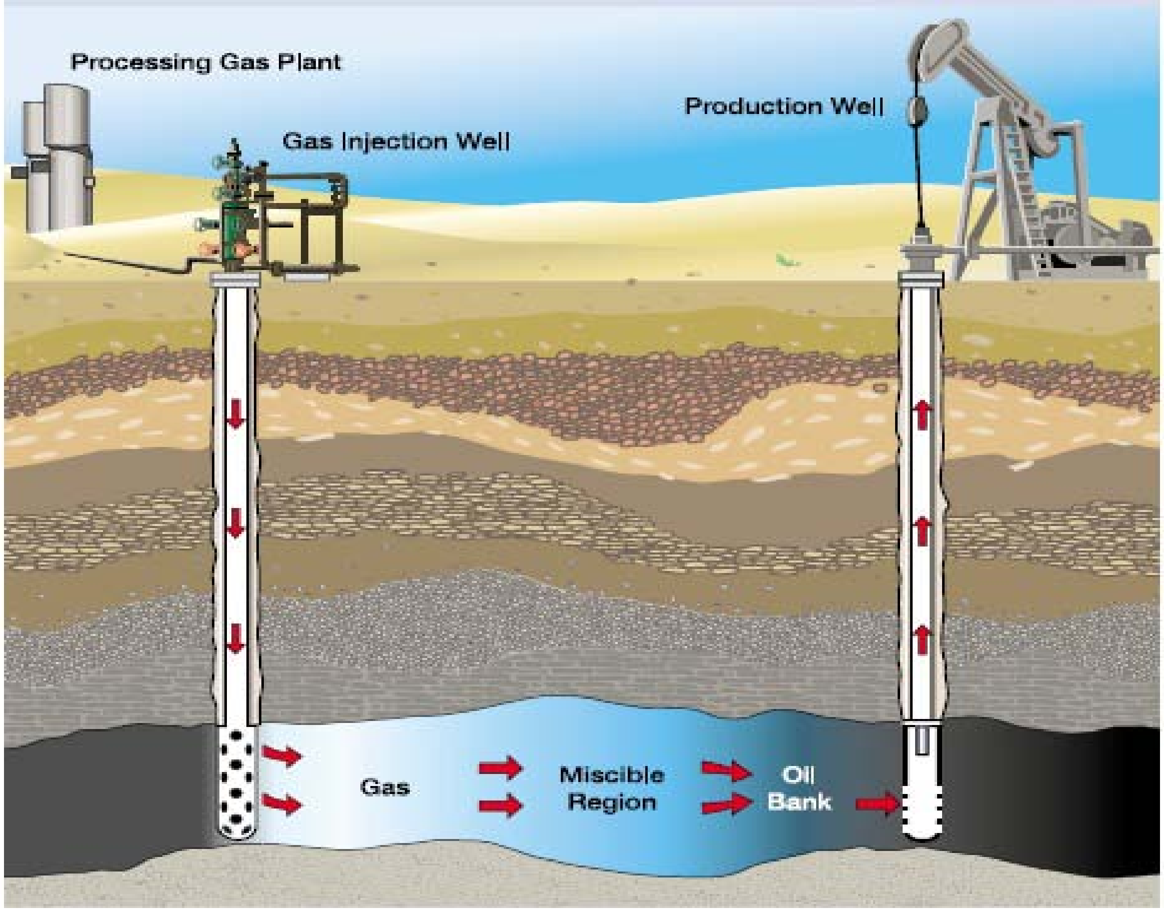
Challenges

- Complex and expensive system.
- High adsorption of surfactant
- Interactions between surfactant and polymer.

Screening Parameters

Gravity	>25 API	**Viscosity**	<20cp
Composition	No critical	**Oil saturation**	>10% pv
Formation type	sandstone	**Net thickness**	>10 ft
Average permeability	>20md	**Transmissibility**	not critical
Depth	<8000ft	**Temperature**	<225 ^{o}F
Salinity of formation brine	<150000 ppm TDS		

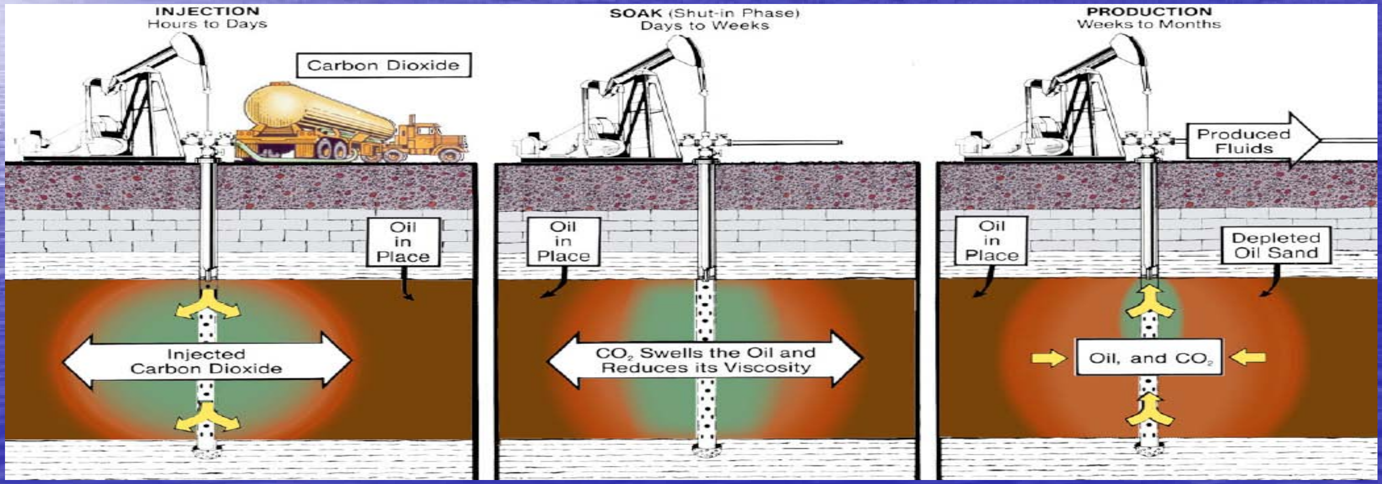
Gas Injection



Gas Injection

Huff-'n'-puff

- Single Well Cyclic CO2-EOR Method
- Utilizes intermittent injections of gas to mobilize the oil.
- When gas is not being injected, the injector wells are used for production of oil.



Description

CO_2 flooding consists of injecting large quantities of CO_2(15% or more hydrocarbon pore volume) in the reservoir to form a miscible flood.

Mechanisms That Improve Recovery

CO_2 extracts the light –to-intermediate components from the oil ,and if the pressure is high enough, develops miscibility to displace oil from the reservoir(vaporizing gas drive)

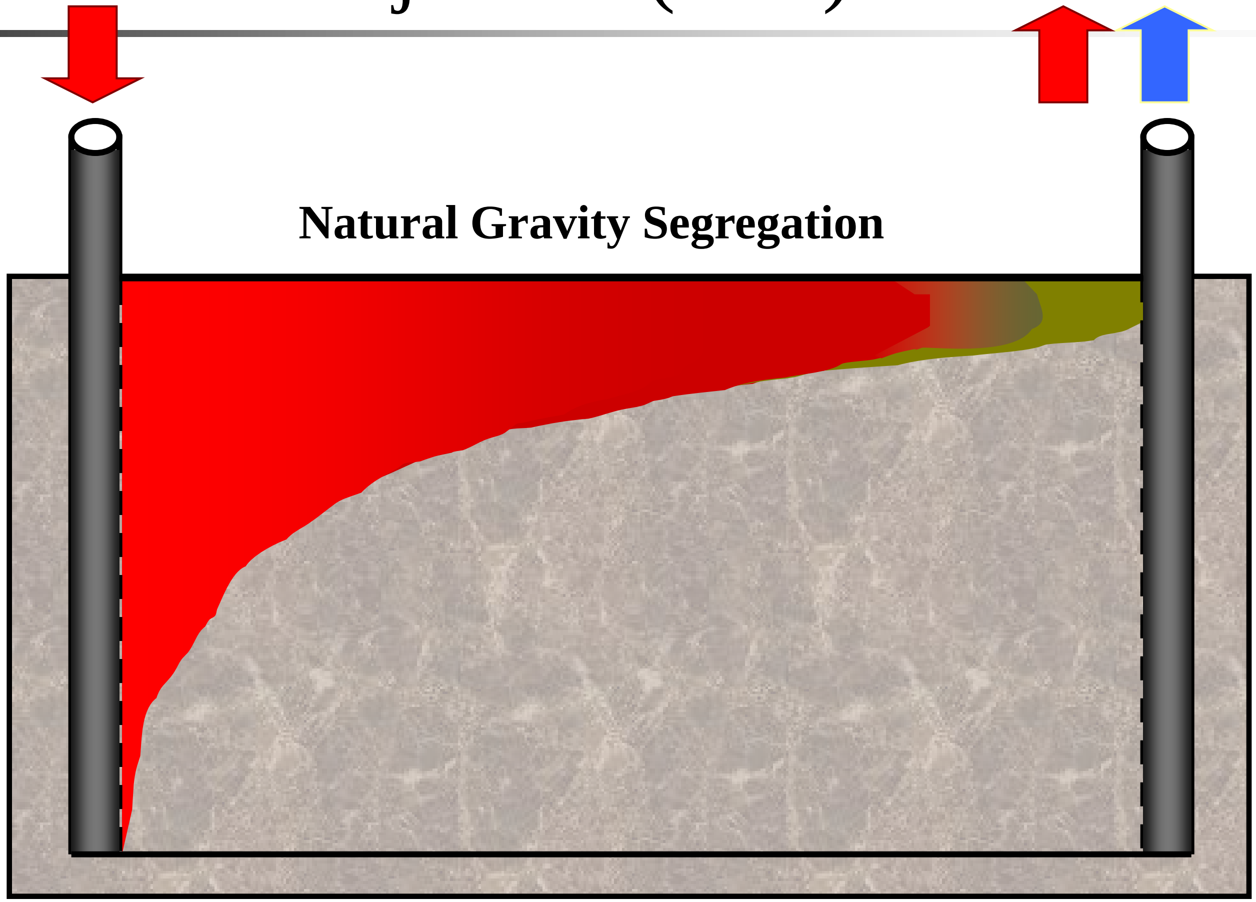
Viscosity reduction/oil swelling.

Limitations

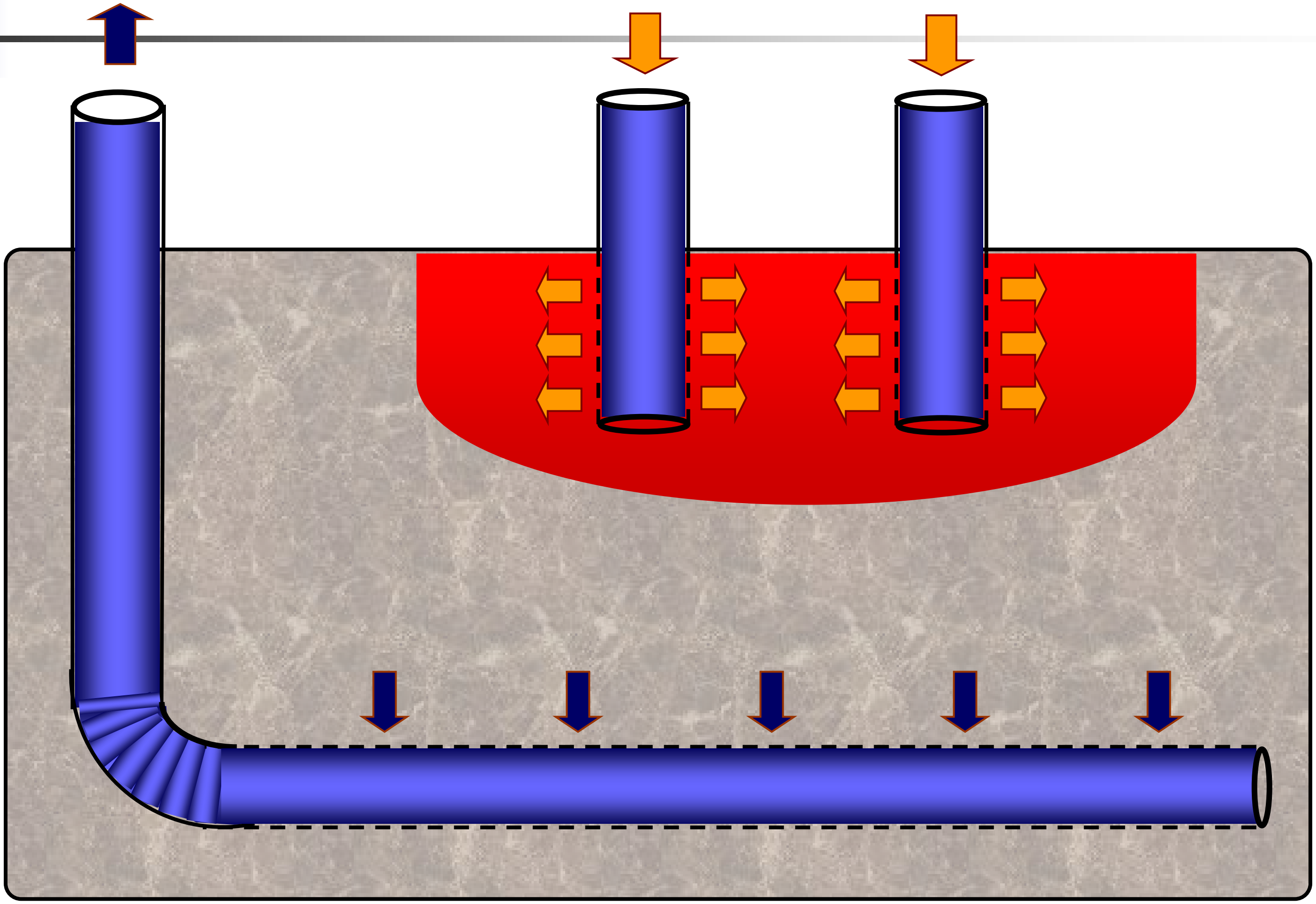
Very low viscosity of CO_2 results in poor mobility control

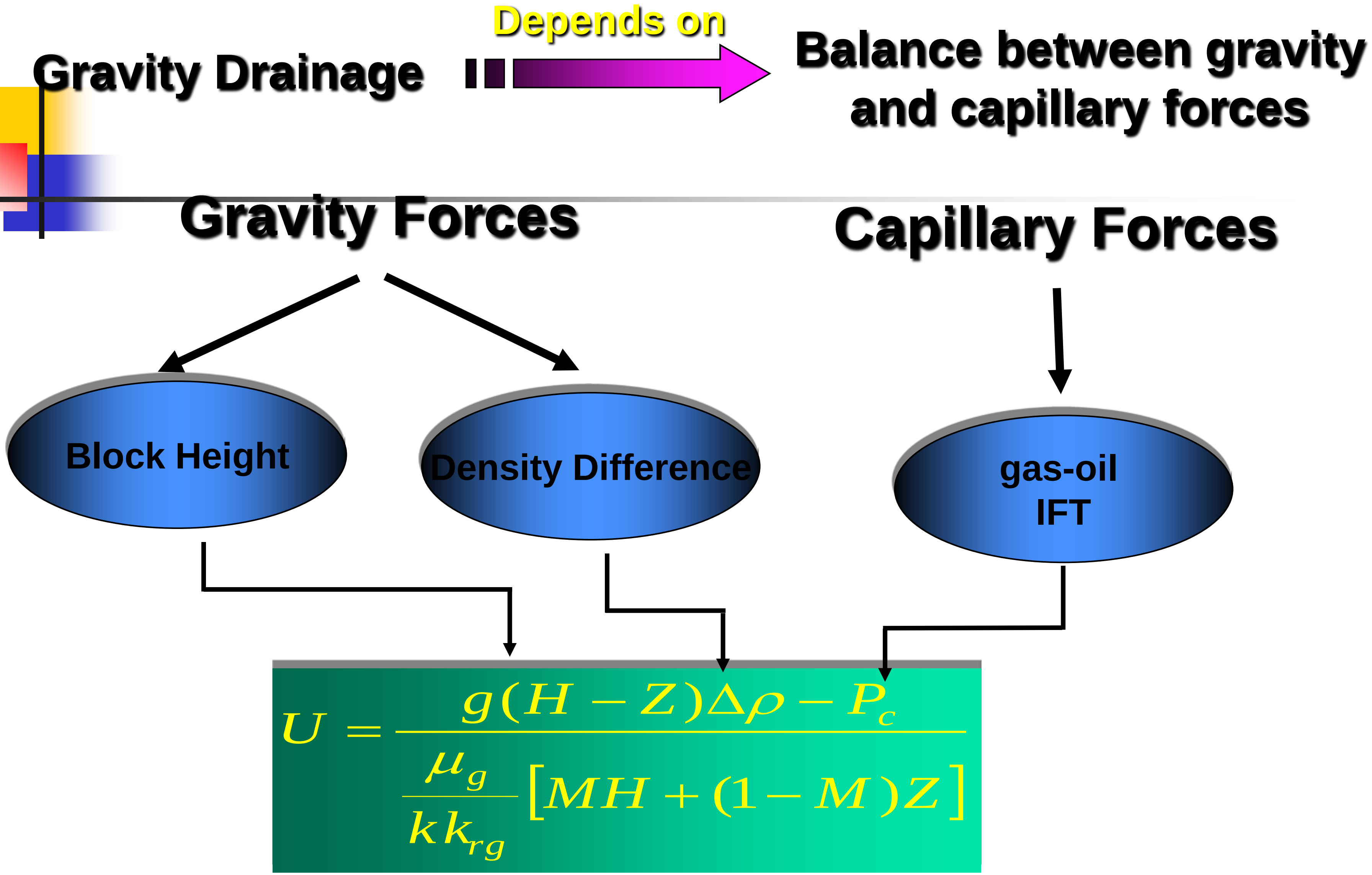
Availability of CO_2

Gas Injection: Continues Gas Injection (CGI)



Gas Assisted Gravity Drainage





Gravity Drainage

Depends on

Balance between gravity and capillary forces

Gravity Forces

Capillary Forces

Block Height

Density Difference

gas-oil IFT

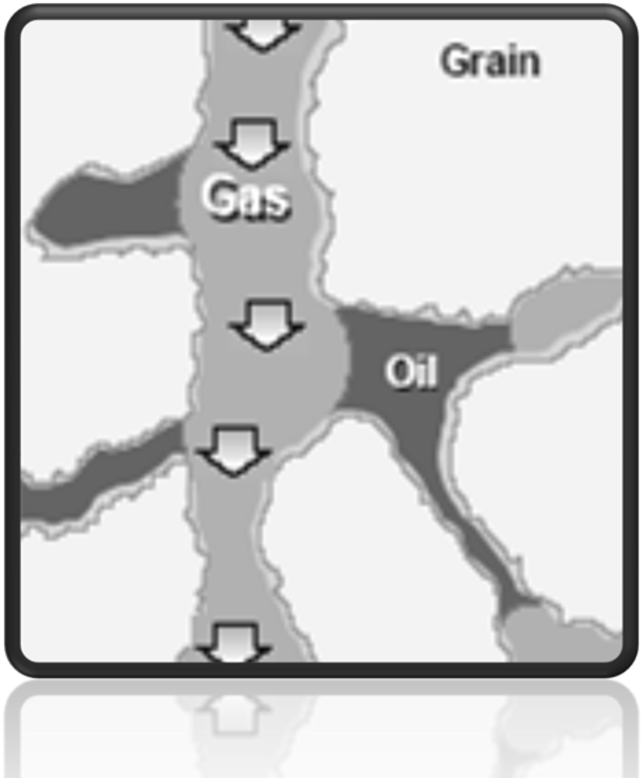
$$U = \frac{g(H-Z)\Delta\rho - P_c}{\dfrac{\mu_g}{k k_{rg}}\left[MH + (1-M)Z\right]}$$

Drainage or Displacement

Gas Injection

High-front velocity displacement

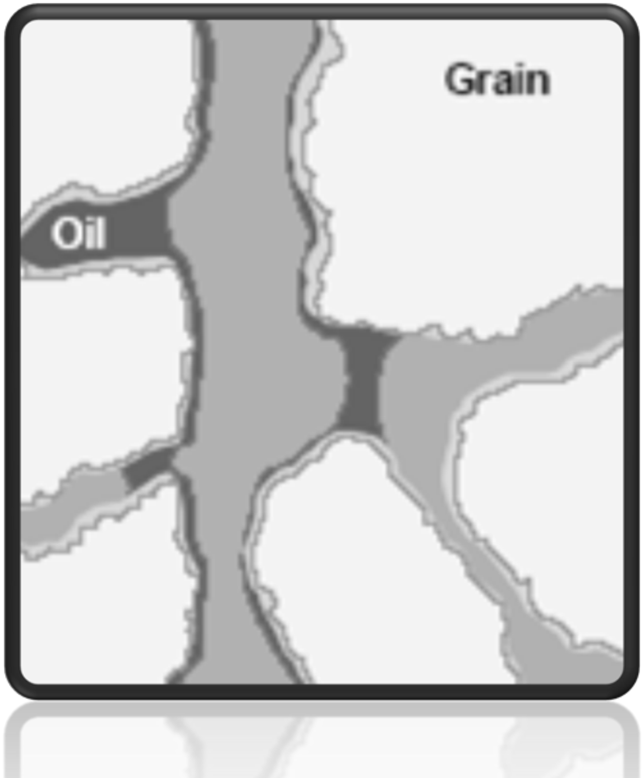
Residual oil disconnected



Gravity drainage

Stabilized gravity drainage

Residual oil connected by thin films



Application of CO_2 for EOR

- Reservoir characteristics determine appropriate stimulation method such as CO_2 flooding
- Residual oil saturation, depth, crude and rock properties, availability of pure CO_2 are some factors affect.

Advantages of CO_2 injection

- Swell Oil
- Reduce oil viscosity
- Extract hydrocarbon from crude oil
- Function as a solution gas drive
- May be available as waste gas
- Non hazardous and Non explosive
- Soluble in water, become acidic and may react with rock to improve permeability

Immiscible Displacement by CO_2

- CO_2 injection affects relative permeabilities by changing the fluid viscosities and interfacial tensions.

- The residual oil saturation obtained by CO_2 injection is lower than that obtained by using natural gas.

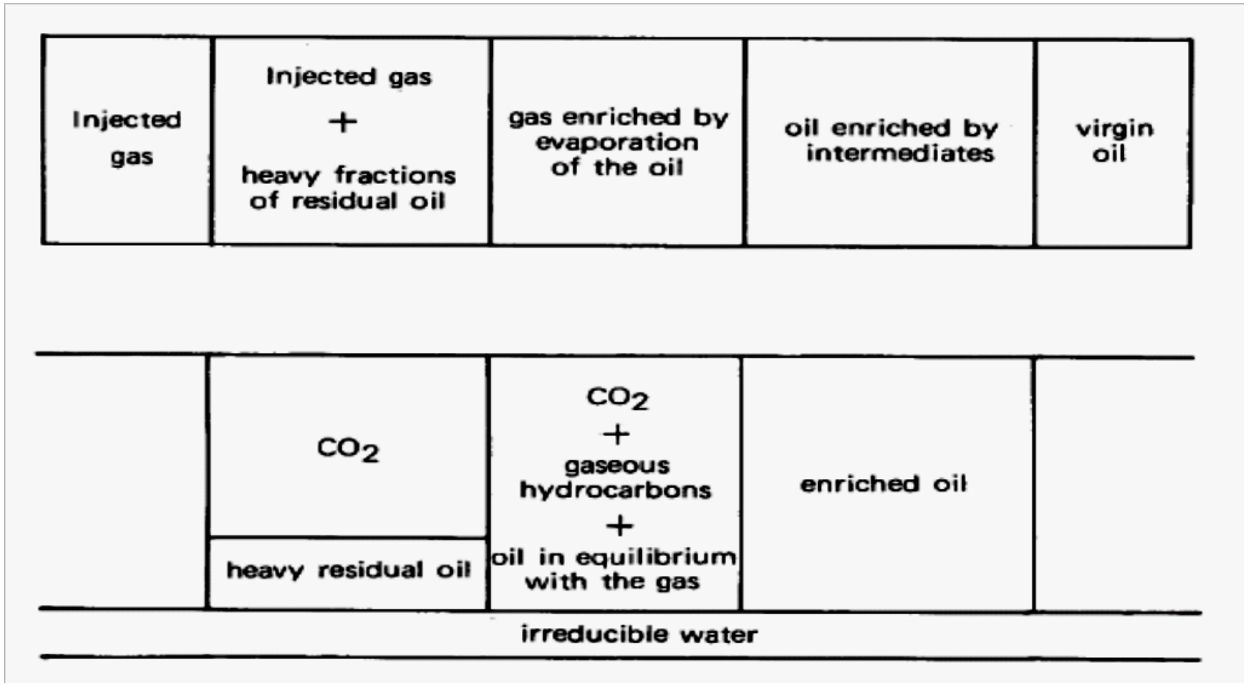
- This is in addition to the already mentioned oil swelling that occurs, and provide an even greater improvement in the recovery factor.

Miscible Displacement by CO_2

- In the case of light oils thermodynamic miscibility may be achieved at pressure of the order of 140 to 210 bar (2000-3000 psi)
- With very viscous oils the miscibility pressure can never be reached.
- However, the CO_2 dissolved in the oil has a direct effect on the properties of the mixture, and the viscosity reduction thus obtained is obviously beneficial.

Formation of the Miscible Bank

- During displacement of the CO2 within the porous medium there is a large contact area between gas and oil.
- A rapid mass transfer between the oil and CO2 takes place by fractionation of the oil.



Sources of CO_2

- The gas must be available up to 20 years
- The gas must be relative pure
- A natural gas source is the best
- Most known CO_2 sources discovered while exploring for oil and gas
- Stack gases from industrial plants must be purified

Cost Feasibility

- Based on 20 $/bbl of oil; CO_2 EOR projects is economical with CO_2 delivered price up to 0.82 $/MCF
- CO_2 Recycling cost is 0.35 $/MCF
- Total Cost for CO_2 injection : 6$/bbl

Challenges

Early breakthrough of CO_2 causes problems.

Corrosion in producing wells

The necessity of separating CO_2 from saleable hydrocarbons. Repressuring of CO_2 for recycling.

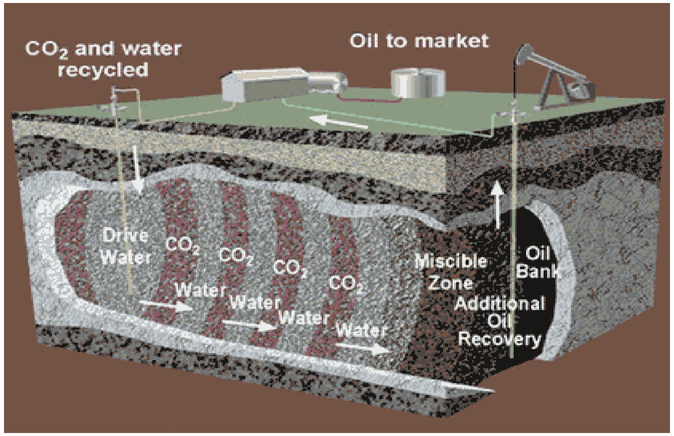
A large requirement of CO_2 per incremental barrel produced.

Screening Parameters

Gravity >27 API	**Viscosity** <10cp
Composition C2-C20(C2-C12)	**Oil saturation** >30% PV
Formation type sandstone/carbonate	**Net thickness** relatively thin
Average permeability not critical	**Transmissibility** not critical
Depth>2300 ft	**Temperature** <250°F

Water-Alternating-Gas Injection (WAG)

- Alternates slugs of miscible gas and water injection to mobilize the target oil.
- Try to: Kr(co2) ↓so that Mco2 ↓
- Gas rises and water falls
- Advantage: less co2 is needed
- Problem: density differences between co2 and water/oil may cause gas to go up in the formation



Thermal Recovery Processes

- Heat generated at the surface.
- Heat generated in-situ.

Group 1:

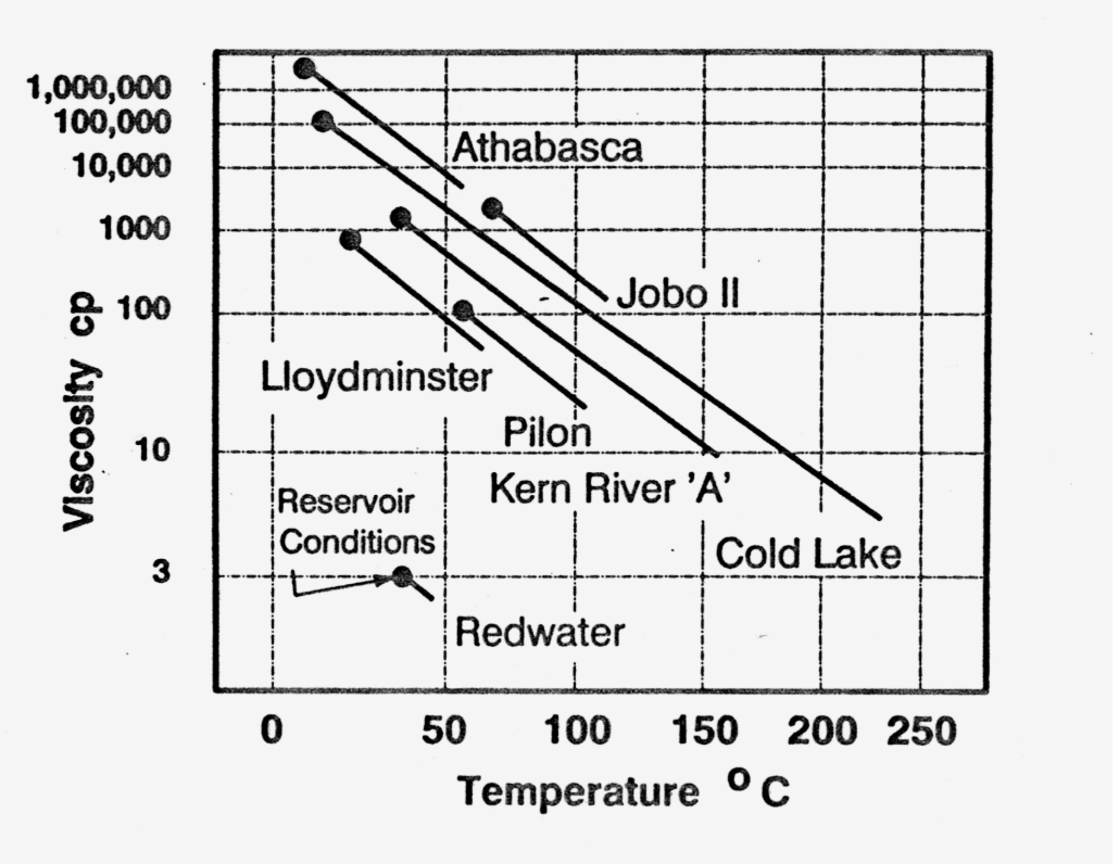
Hot water flood

Steam flood
  - Continuous
  - Huff and Puff
  - Steam/Cold water

Group 2:

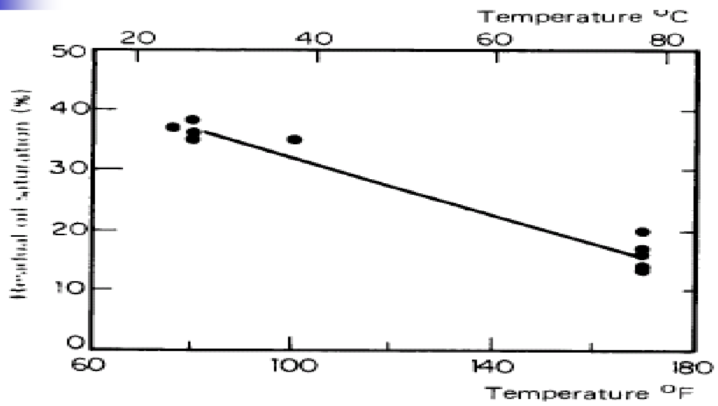
In-situ combustion
  - Forward (Dry or Wet)
  - Reverse
  - Enriched air

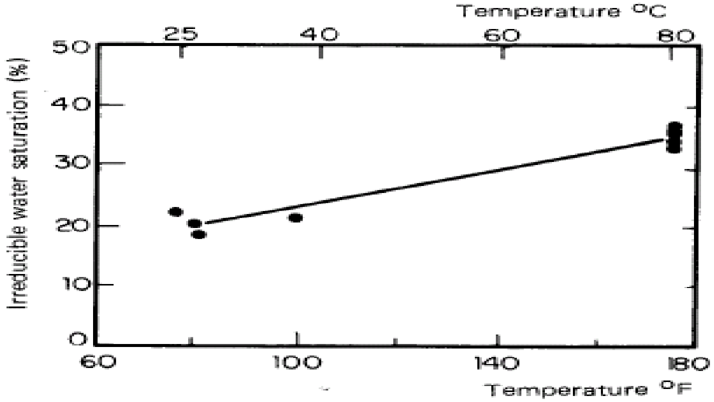
Mechanisms responsible for enhanced recovery Viscosity change Drop in viscosity with T is exponential i.e. $= A \exp(B/T)$

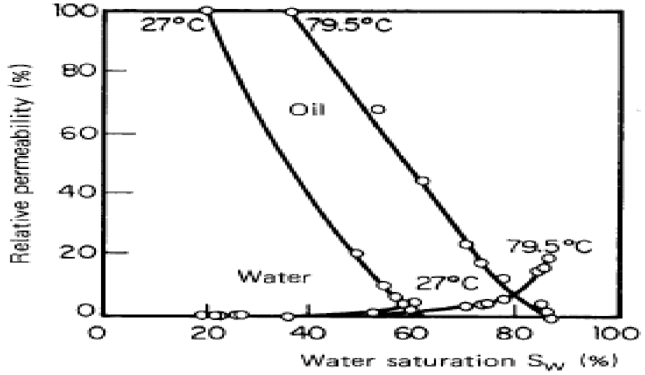


Viscosity Vs. Temperature & API Gravity

Relative permeability change







The effect of T on S_{or} and S_{wr} is the result of both the reduction in the viscosity ratio μ_o/μ_w as T increases

Thermal expansion

Oil: 10^{-3}

Water: 3×10^{-4}

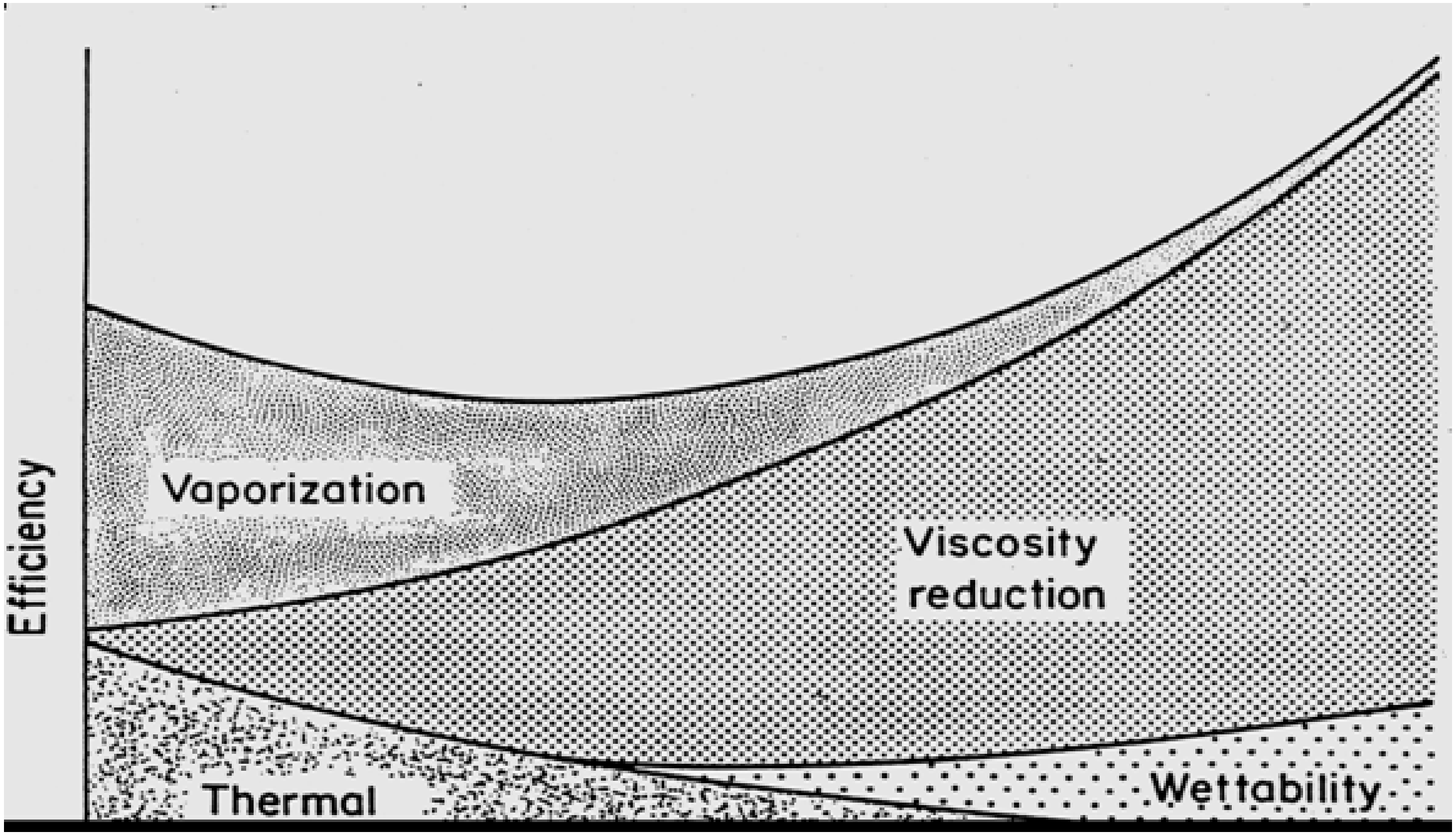
Rock: 10^{-5}

An increase of temperature thus tends to encourage the explosion of oil from the pore space.

Mechanisms responsible for enhanced recovery

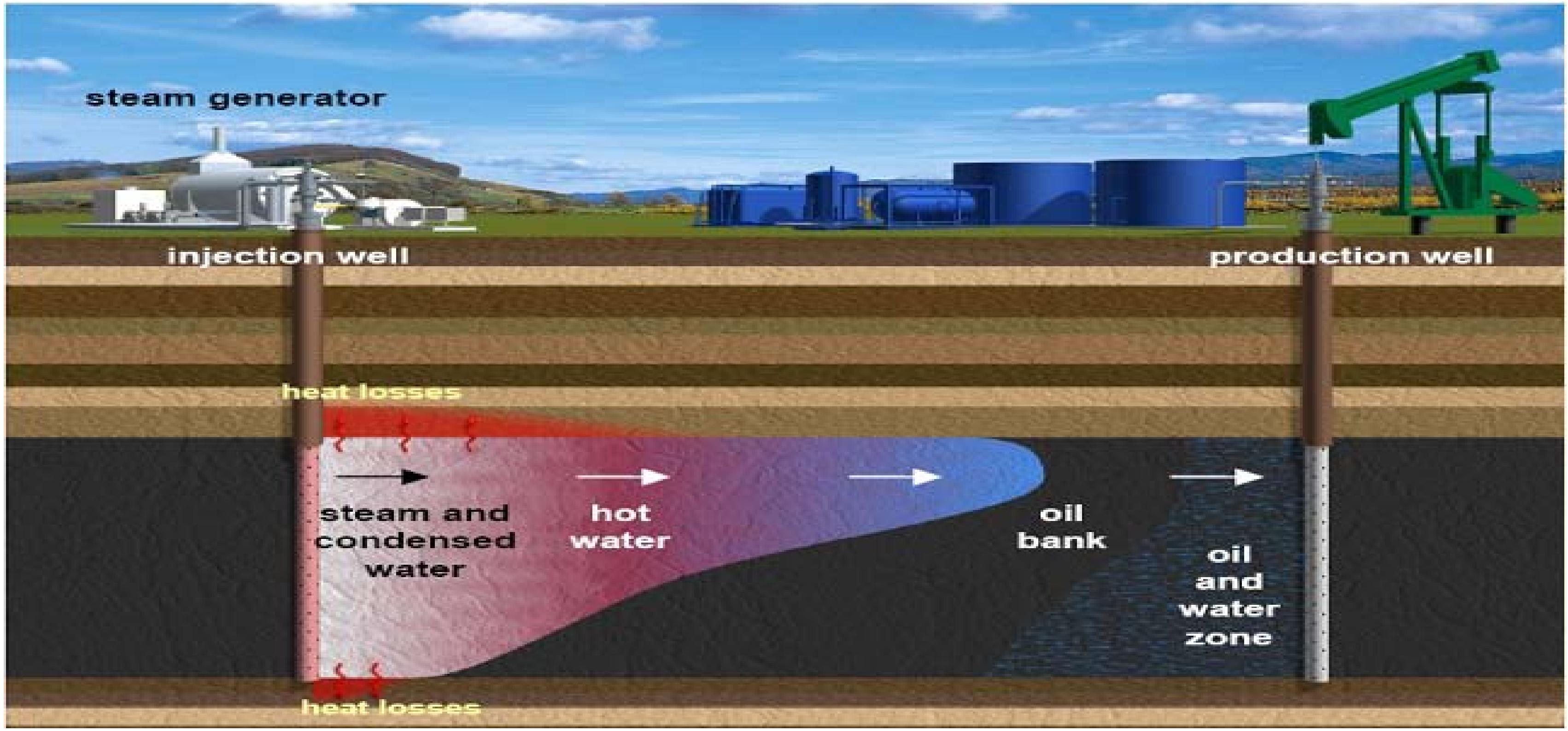
- Vaporization / condensation
- Steam distillation
- Catalytic and thermal cracking
- Light hydrocarbon and / or CO2 dissolution
- Swelling

Contributions of the different mechanisms to the EOR by thermal recovery methods (hot fluid injection)



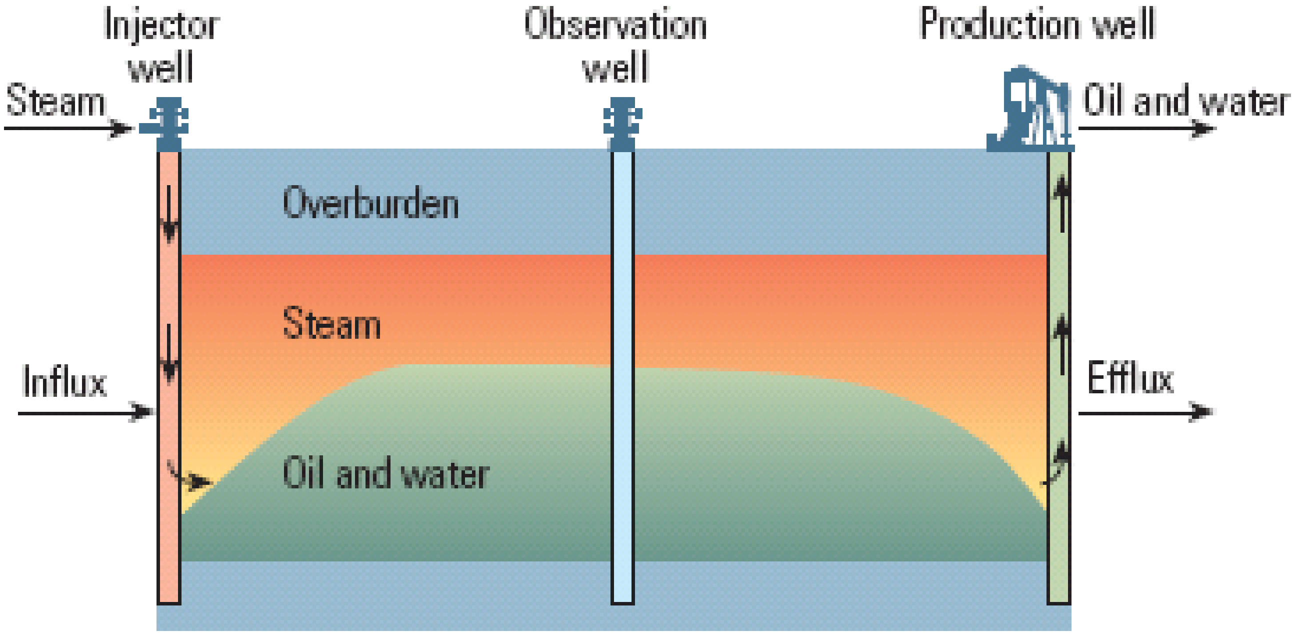
Steam and Hot Water flooding

- Same as water flooding
- Steam is injected continuously into one or more wells and oil is driven to separate production wells.



Steam Injection Process

Steam is injected continuously into one or more wells and oil is driven to separate production wells.



Description

Steamflooding consists of injecting %quality steam to displace oil.
Normal practice is to precede and accompany the steam drive by a cyclic steam stimulation of the producing wells (called huff and puff).

Mechanisms That Improve Recovery Efficiency

Viscosity reduction/steam distillation
Supplies pressure to drive oil to the producing well.

Limitations

Applicable to viscous oils in massive, high permeability sandstones or unconsolidated sands.
Oil saturations must be high, and pay zones should be>20 ft thick to minimize heat losses to adjacent formations.
Less viscous crude oils can be steam flooded if they don’t respond to water.
A low percentage of water –sensitive clays is desired for good injectivity

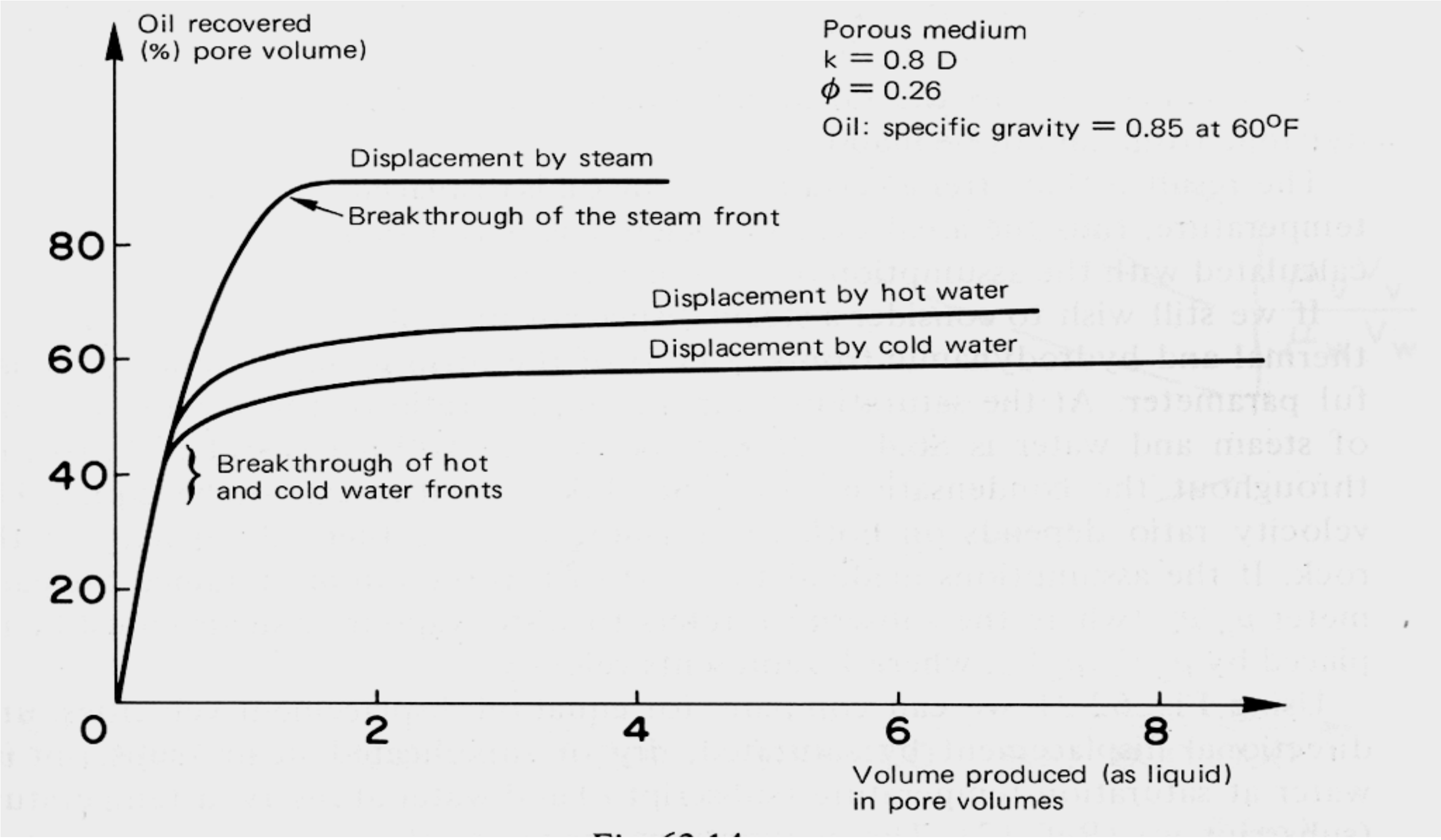
Challenges

Adverse mobility ratio and channeling of steam.

Screening Parameters

Gravity	>35 API(10-35)	**Viscosity**	<20cp(10-5000)
Composition	not critical	**Oil saturation**	>40-50%PV
Formation type	sandstone	**Net thickness**	>20 ft
Average permeability	>200md	**Transmissibility**	>100 md ft/cp
Depth	200-5000 ft	**Temperature**	not critical

A comparison of Displacement by Cold water, Hot water and Steam



Cyclic Steam Stimulation

- This method is sometimes applied to heavy-oil reservoirs to boost recovery during the primary production phase.

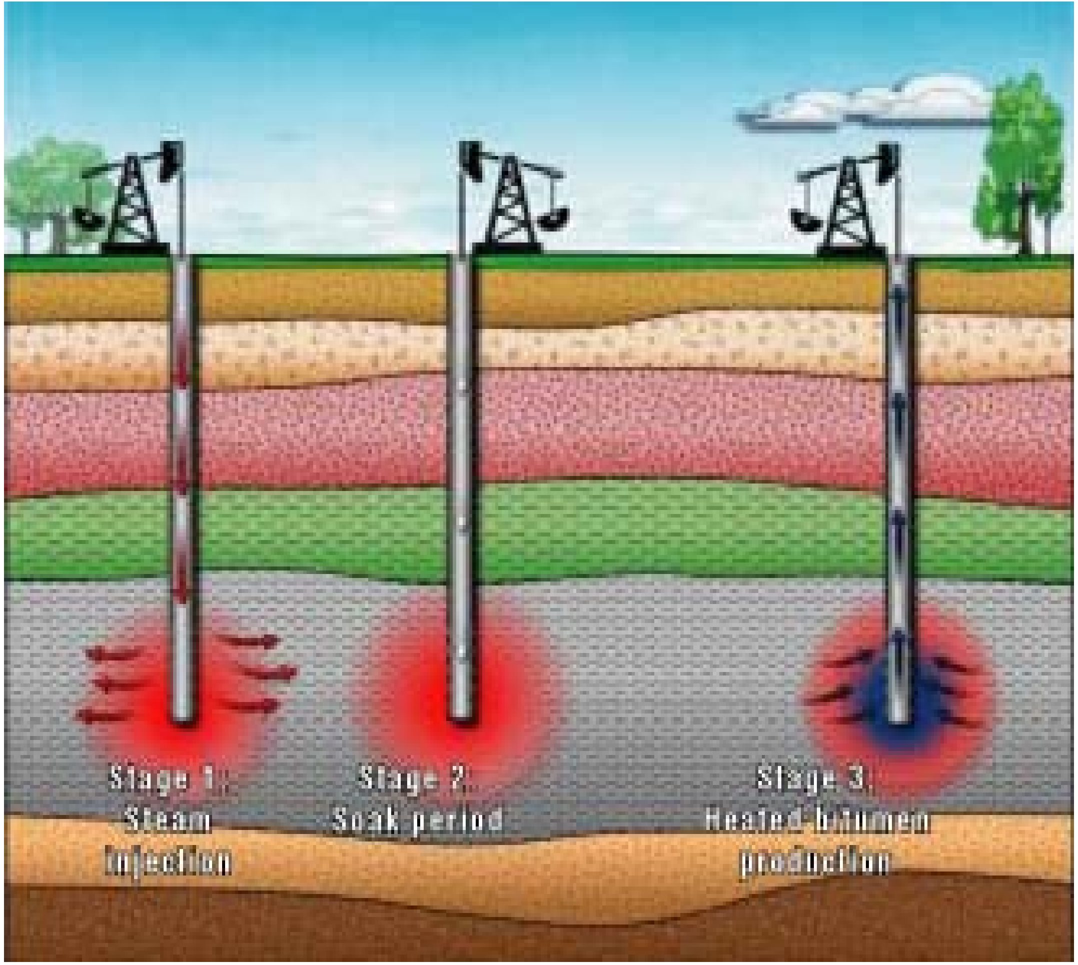
- During this time it assists natural reservoir energy by thinning the oil so it will more easily move through the formation to the injection/production wells.

Cyclic Steam Stimulation(CSS)

CSS or Huff & Puff

Divided into three stages

- Steam injection
- Steam soaking
- Heated oil production



Cyclic Steam Stimulation

- Shell discovered the process of steam stimulation by accident in Venezuela when it was producing heavy crude oil by steam flooding.
- In the steam stimulation process, steam is injected into the reservoir at rates of the order of 1000 B/d for a period of weeks; the well is then allowed to flow back and is later pumped.
- In suitable applications, the production of oil is rapid and the process is efficient, at least in the early cycles.

- Stimulation before flooding is almost essential in order to achieve flow communication between the injection and production wells.
- Communication can be established between pairs of wells by creating a fracture between them. This can be done by injecting steam at a sufficiently high pressure.

Matthews lists the following factors that are unfavorable for steam flooding

- Oil saturation less than 40%
- Porosity less than 20%
- Oil-zone thickness less than 30 ft
- Permeability less than 100 mD
- Ratio of net to gross pay less than 50Vo
- Layers of very low oil saturation and high permeability in the oil zone that act as thief zones

Matthews lists the following factors that are unfavorable for steam flooding

- Extremely high viscosity
- Fractures
- Large permeability variations in the oil zone
- Poor reservoir continuity between injectors and producers
- Deep high-pressure reservoirs and shallow reservoirs with insufficient overburden.

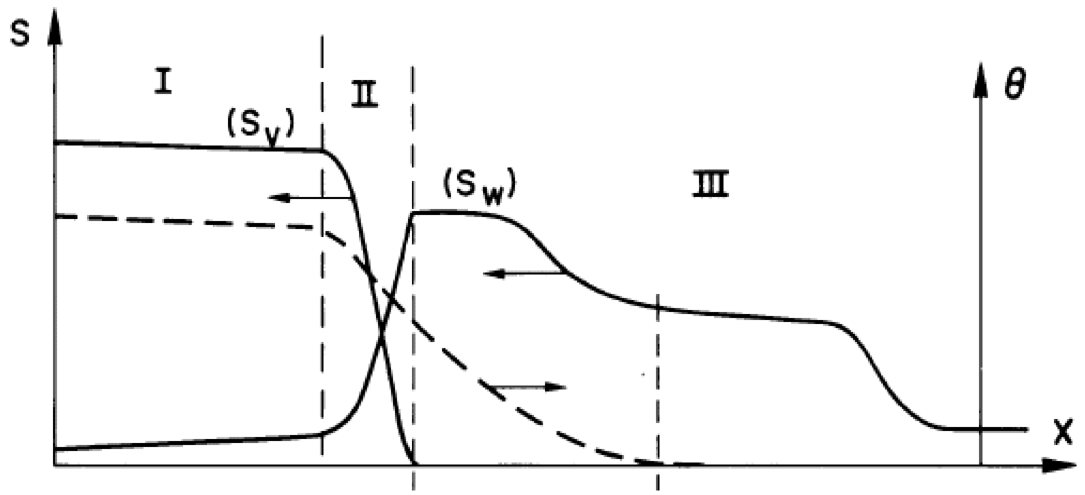
Displacement by Saturated Steam

Three principal zones can be observed:

I. Steam plateau, upstream of the condensation zone

II. Condensation zone, the steam comes into contact with a cooler matrix

III. Hot water bank, displacement is by hot water in this zone

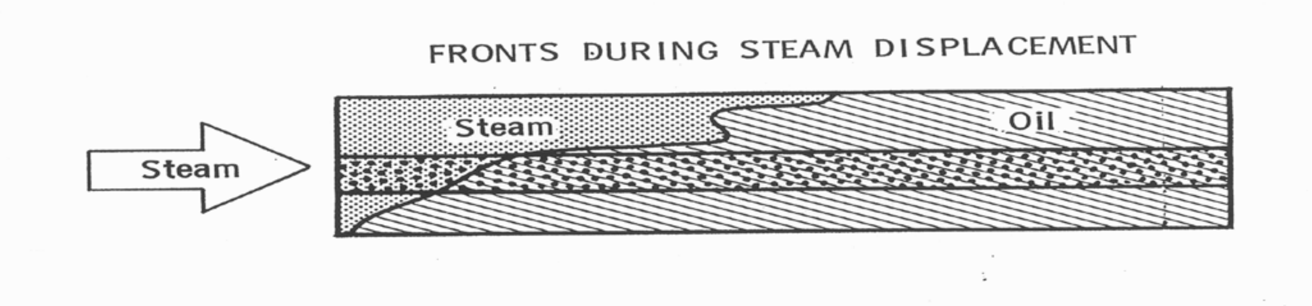


Major Problems

1. **Heat losses**

Heat losses encountered at the surface lines.
Heat losses while in the injection well strings
Heat losses to overburden and under burden layers Heat losses to the swept zone

2. **Steam Override**



Effect of variables

Rock matrix properties

a) ϕ ↑ More oil is produced

b) h ↑ More oil is produced

this effect decreases as reservoir thickness increases

h $\geq$ 180 ft ~ 15% heat loss

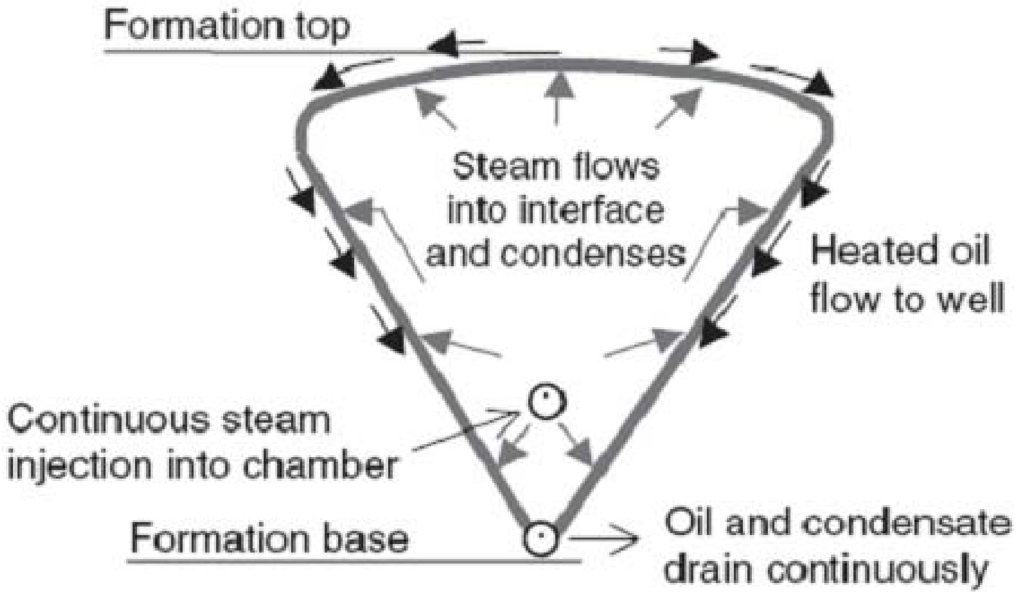
c) Pattern shape of spacing: no effect

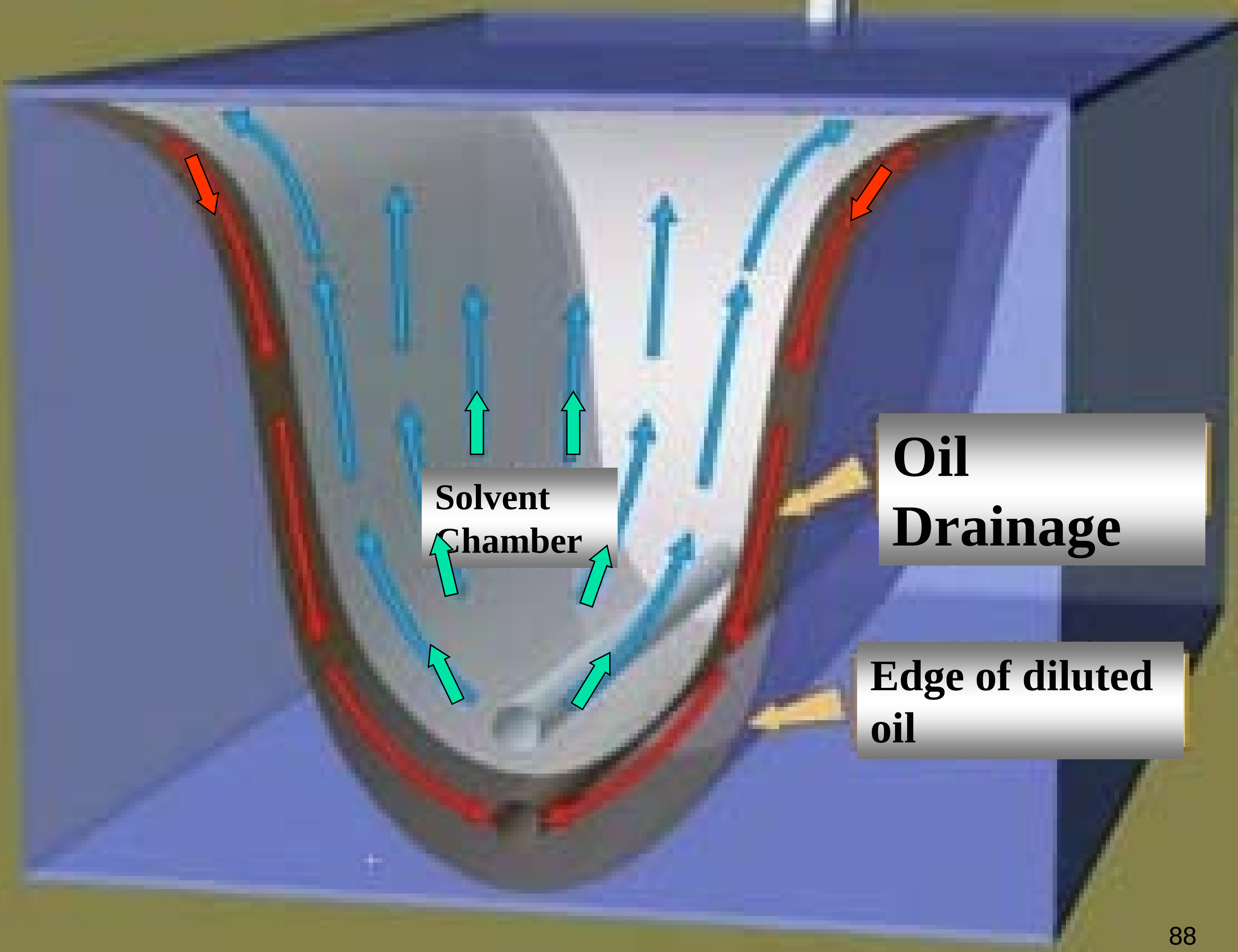
d) K ↑ better performance

e) Depth ↓ better performance

Steam Assisted Gravity Drainage(SAGD)

- Using two parallel horizontal well
- Steam injected into upper and form a steam chamber
- Reduce Oil viscosity
- Steam condenses at interface
- Oil and condensed drain by gravity



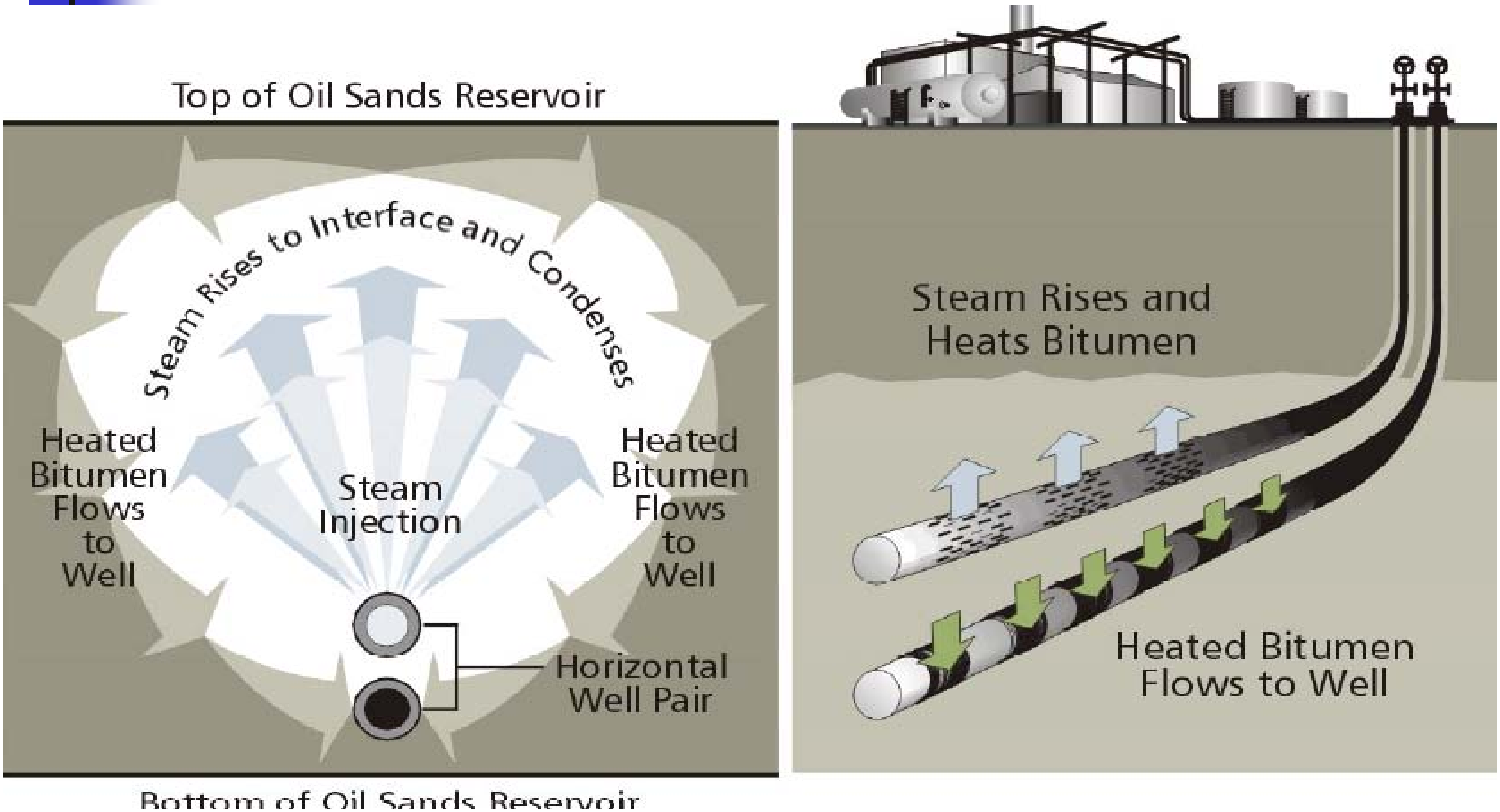


Solvent Chamber

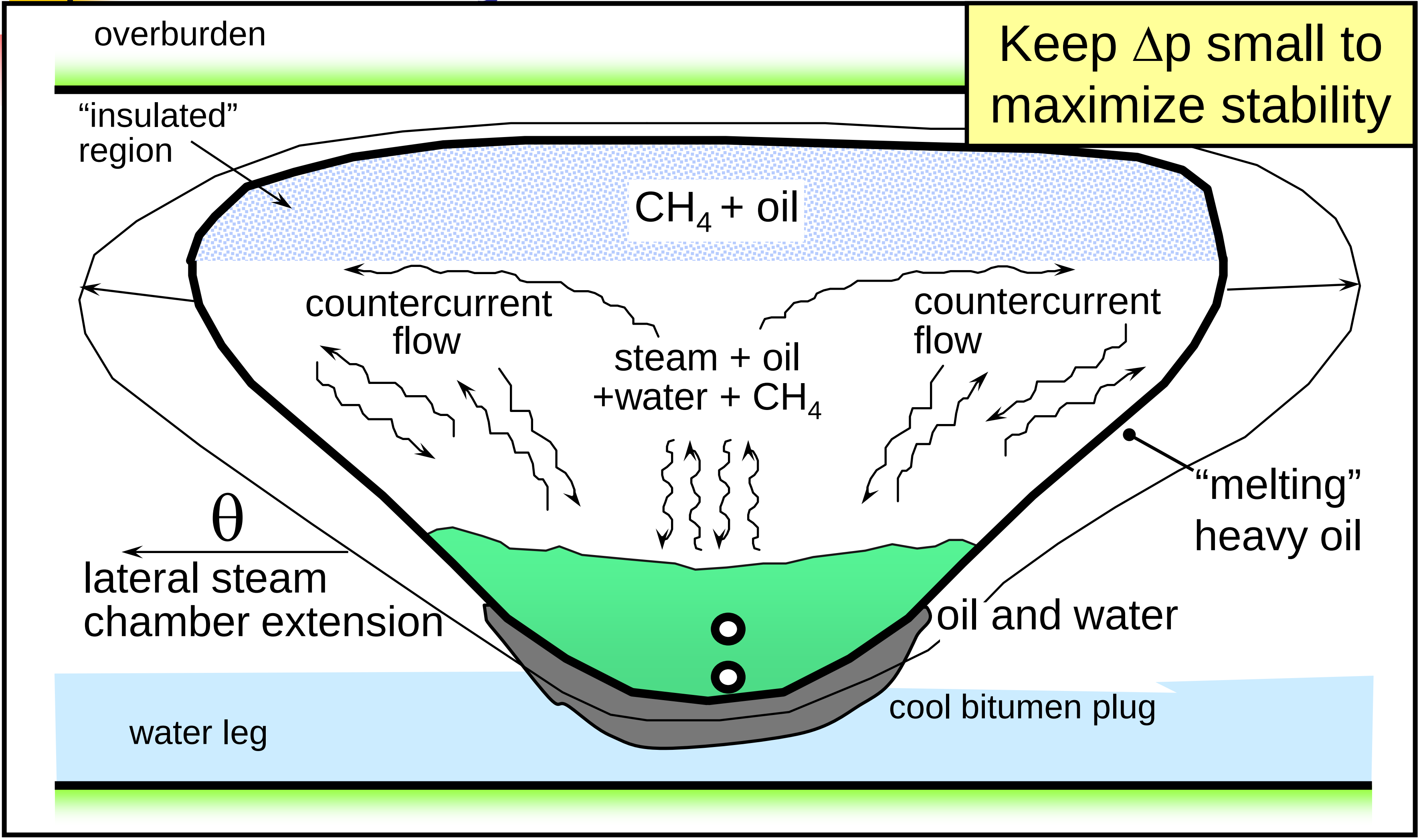
Oil Drainage

Edge of diluted oil

SAGD Process



SAGD Physics



From M. Dusseault, U. of Waterloo, Ontario

SAGD Experience

- The use of the SAGD process can provide an increase in the recovery of about 50% or more which is significantly better than the recovery of 15 % which is achieved using steam stimulation process.

- Successful demonstration of the SAGD process has been carried out by AOSTRA in its Underground Test Facility in Athabasca. This pilot facility employs horizontal steam injectors located parallel to and closely above the horizontal producers.

Series of Adjacent SAGD Pattern

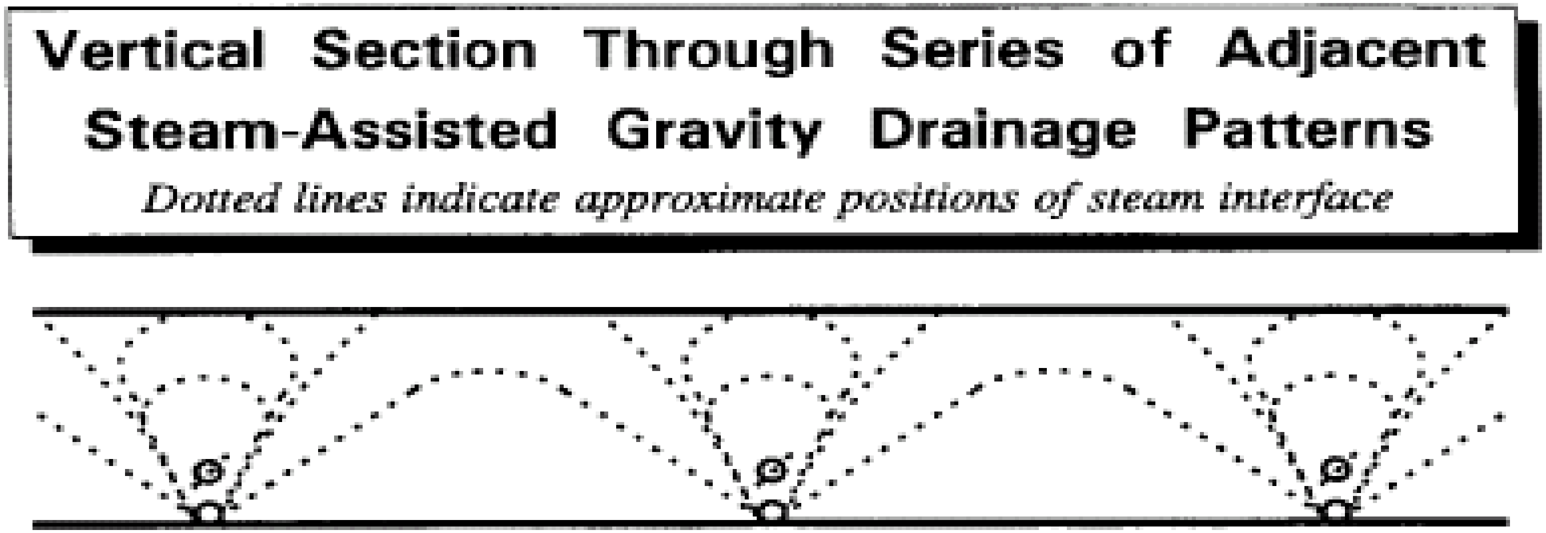
- the use of horizontal wells is required for the economic application of the SAGD principle to the production of heavy oil and bitumen.

- this potential application that encouraged Imperial Oil to build the first Canadian horizontal well in the Cold Lake oil sands in 1978.

- When the process is used to produce conventional heavy oils as distinct from bitumen, there is more flexibility in locating the injector.

Series of Adjacent SAGD Pattern

As the steam chamber grows upwards, it usually encounters the top of the reservoir waiting a year or two and then the chamber spreads sideways.



Vertical Section Through Series of Adjacent Steam-Assisted Gravity Drainage Patterns

Dotted lines indicate approximate positions of steam interface

after Butler and Stephens 1981

Key Design Issues

- Improvising the recovery process to obtain benefits from drive/ geo-mechanics;
- Achieving high rates;
- Ensuring large reserves;
- Increasing success of the project;
- Identifying optimal implementation (well configuration, injection/ production conditions and well completions).

Potential Problems and Limitations

hot effluent/ high water-cut production,

- frequent changes in operating regime
- deterioration of production at late stages, and
- high operating costs as some of the limitations to the current technology.

Non-Thermal Method

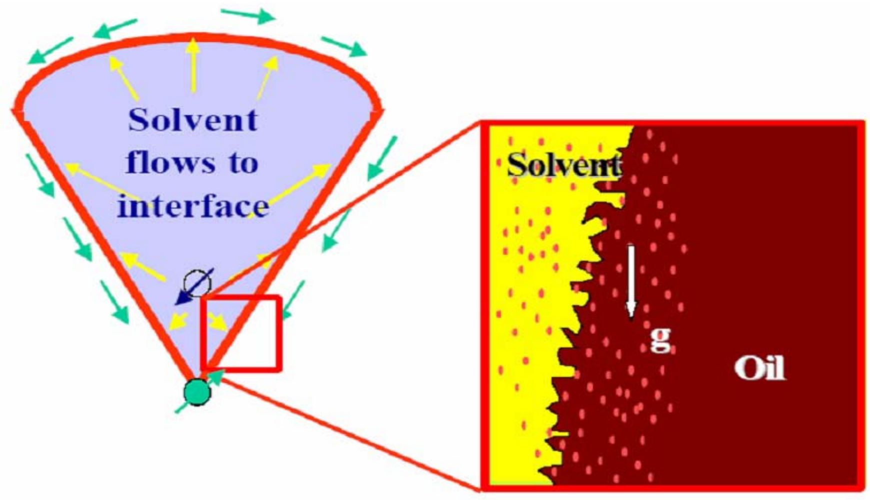
VAPEX Process

VAPEX process

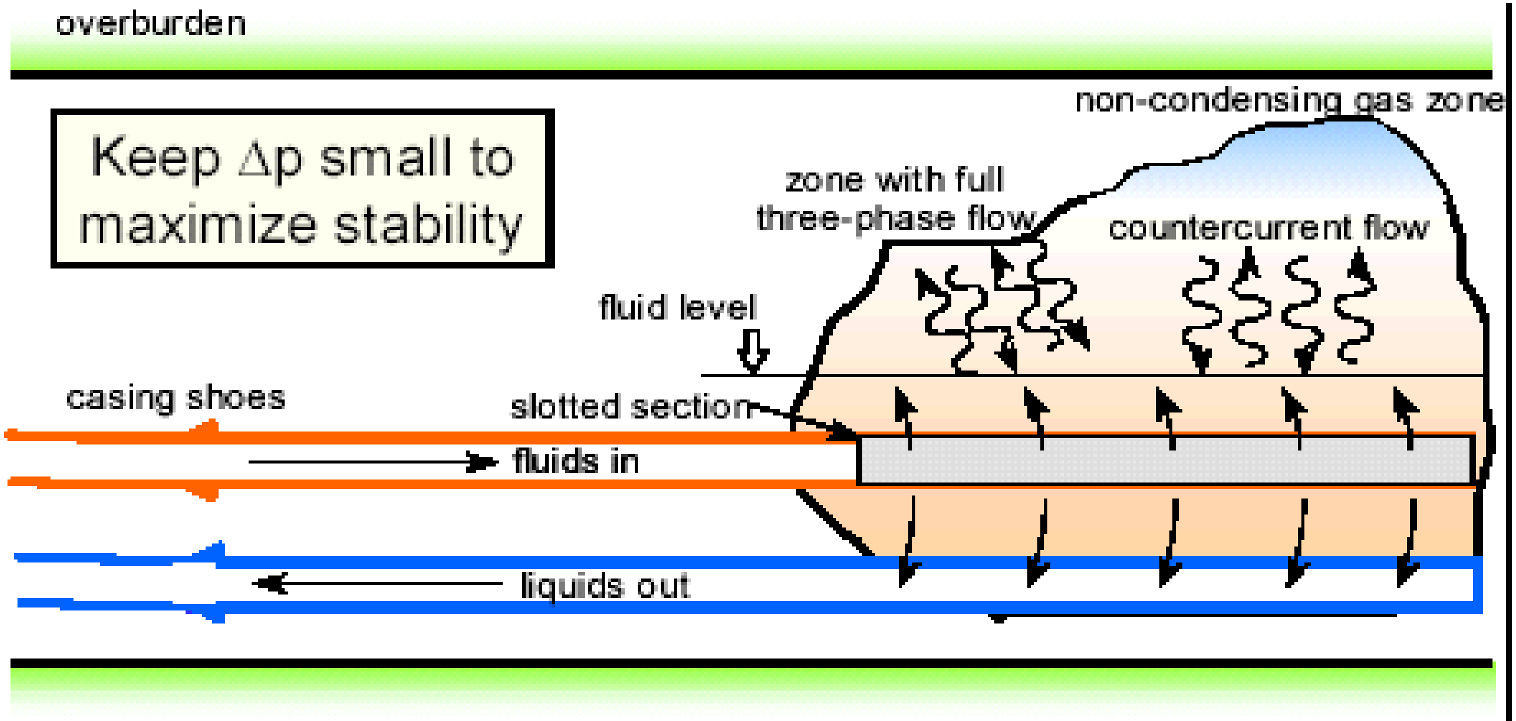
- VAPEX Stands for Vapour Extraction or Vapour Assisted Petroleum Extraction
- A new emerging technology for extraction of heavy oil
- Founded in 1989 by Butler and Mokrys
- Non-Thermal and Immiscible
- Just one field Pilot in Northwest Alberta, DOVAP
- No reports have been officially released

VAPEX Main Mechanisms

- **Molecular Diffusion**
  - De- Asphalting
  - Swelling
  - Dilution
- **Gravity Drainage**



VAPEX Mechanism

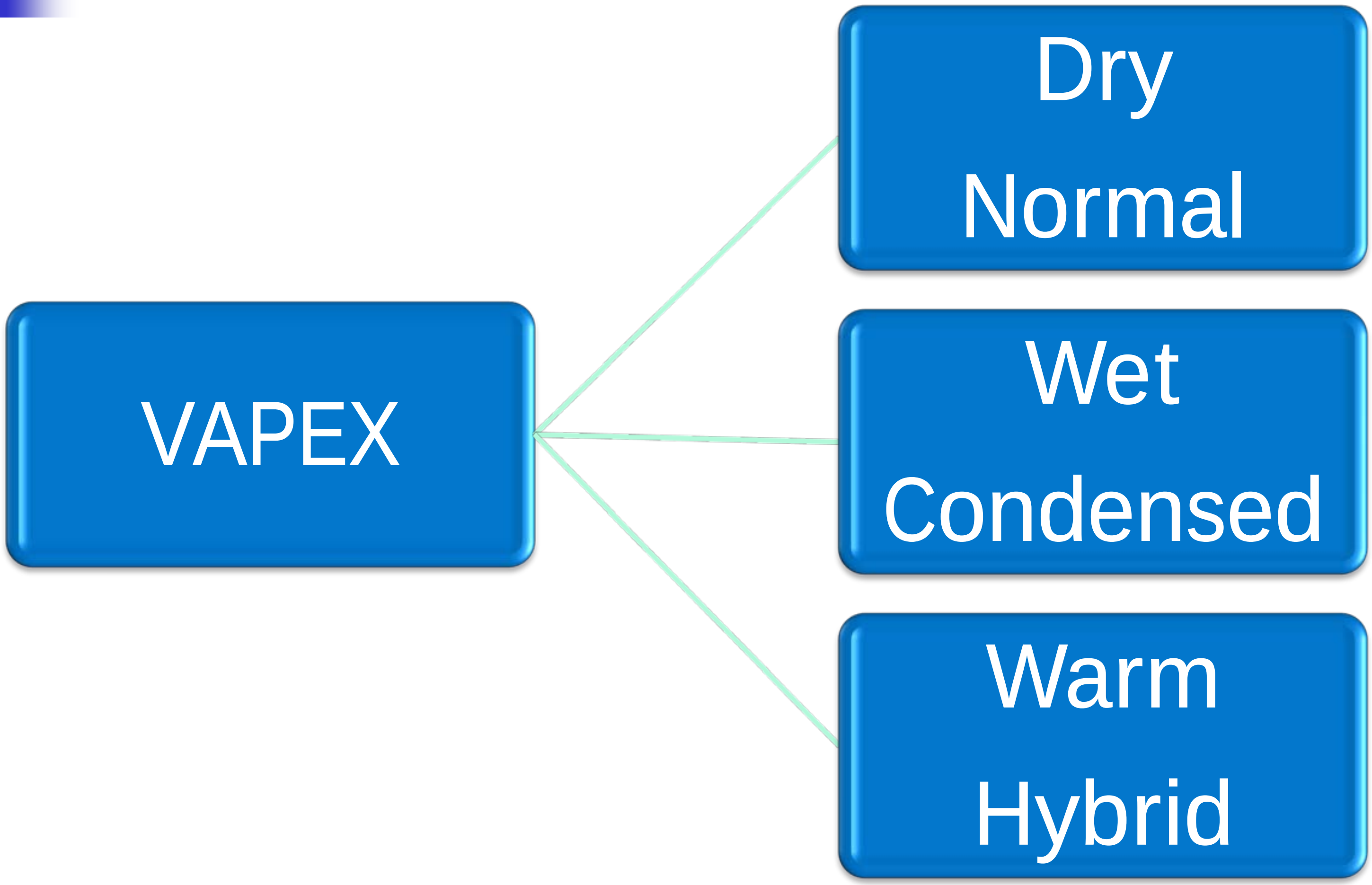

Keep Δp small to maximize stability

CH_4, CO_2, N_2, C_2H_6 etc can be added to maximize spreading and drainage.

VAPEX Process

- In this new concept (Vapex), light hydrocarbon (low molecular weight) vapors at a pressure close to their dew points are injected into the reservoir using a injection well.
- Hydrocarbon vapor diffuses and dissolves in the bitumen or heavy oil and reduces the viscosity.
- The diluted and upgraded oil drains by its gravity to a production well.

Different VAPEX Methods



VAPEX

Dry

Normal

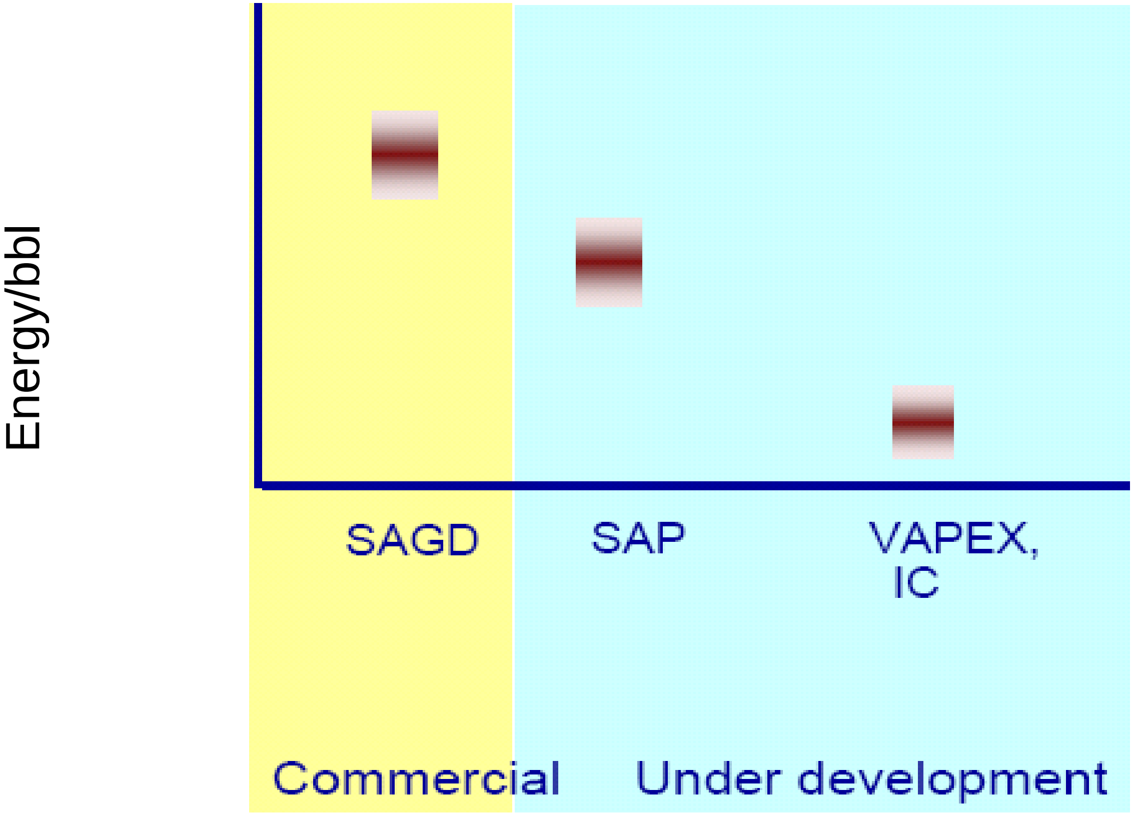
Wet

Condensed

Warm

Hybrid

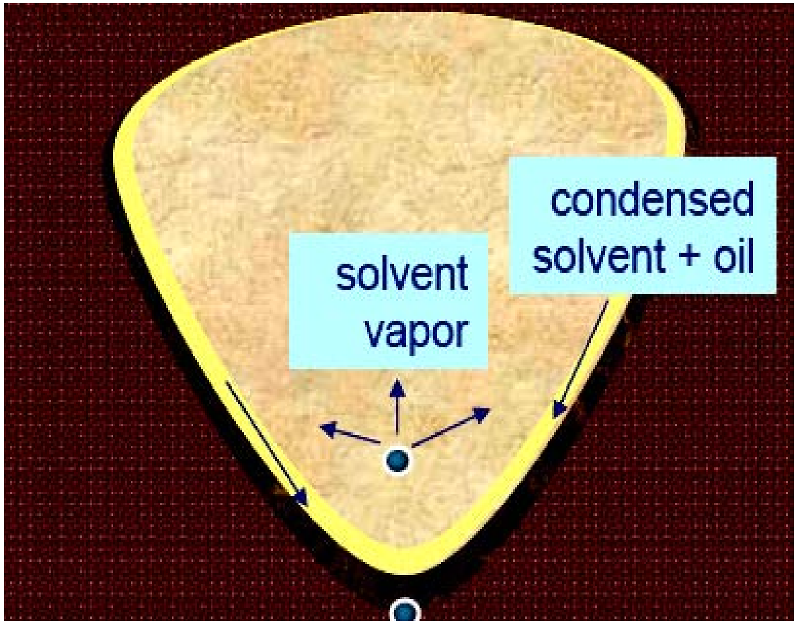
In situ Processes and Energy Efficiency



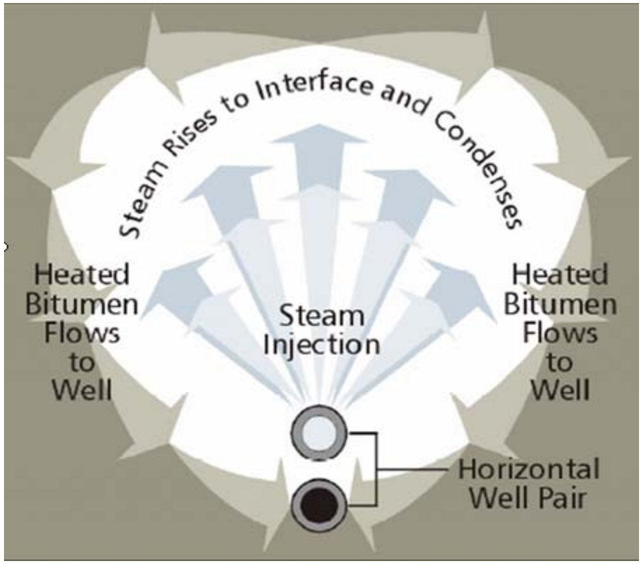
Advantages Of VAPEX

- Low energy requirement
- About 3% of total cost of SAGD
- Solvent occurs in a closed system
- De asphalting causes reduction in sulfur and heavy metal content of oil
- Suitable in thin reservoirs
- Vertical Fractures enhanced recovery
- No water production and disposal treatment
- No CO2 production
- Aquifer enhanced the process

Analogies between SAGD & VAPEX



VAPEX



SAGD

VAPEX vs. SAGD

SAGD

- Not suitable in thin reservoirs
- Severe permeability damage due to clay swelling
- High capital need for steam generation
- Need to water treatment before disposal to environment

VAPEX

- Suitable in thin reservoirs
- No clay swelling
- No water production
- No need to steam generation

VAPEX vs. SAGD

SAGD

- Impractical in offshore fields due to limited area on the platform
- Higher cost of well completion, pump, cement, tubing, and casing at high temperature
- Too much heat loss into reservoirs containing an aquifer

VAPEX

- Low-temperature operation
- Little or no heat loss to the overburden and underburden
- High sweep efficiency
- Simpler recycle compared with SAGD

In-Situ Combustion Process

In Situ Combustion

- In theory this is great!
- minimal fuel requirement
- high recoveries
- no reservoir loss of pricier substance

Why Should In Situ Combustion Be Considered?

- Availability of air.
- Reduced water requirement compared to steam.
- Applicable to a wide range of reservoirs and fluid characteristics.
- No theoretical pressure limitation.
- Can be applied to deep reservoirs where lifting costs make water flood unattractive.
- Can be applied as a follow-up to steam-based processes.
- Lack of obvious alternatives.

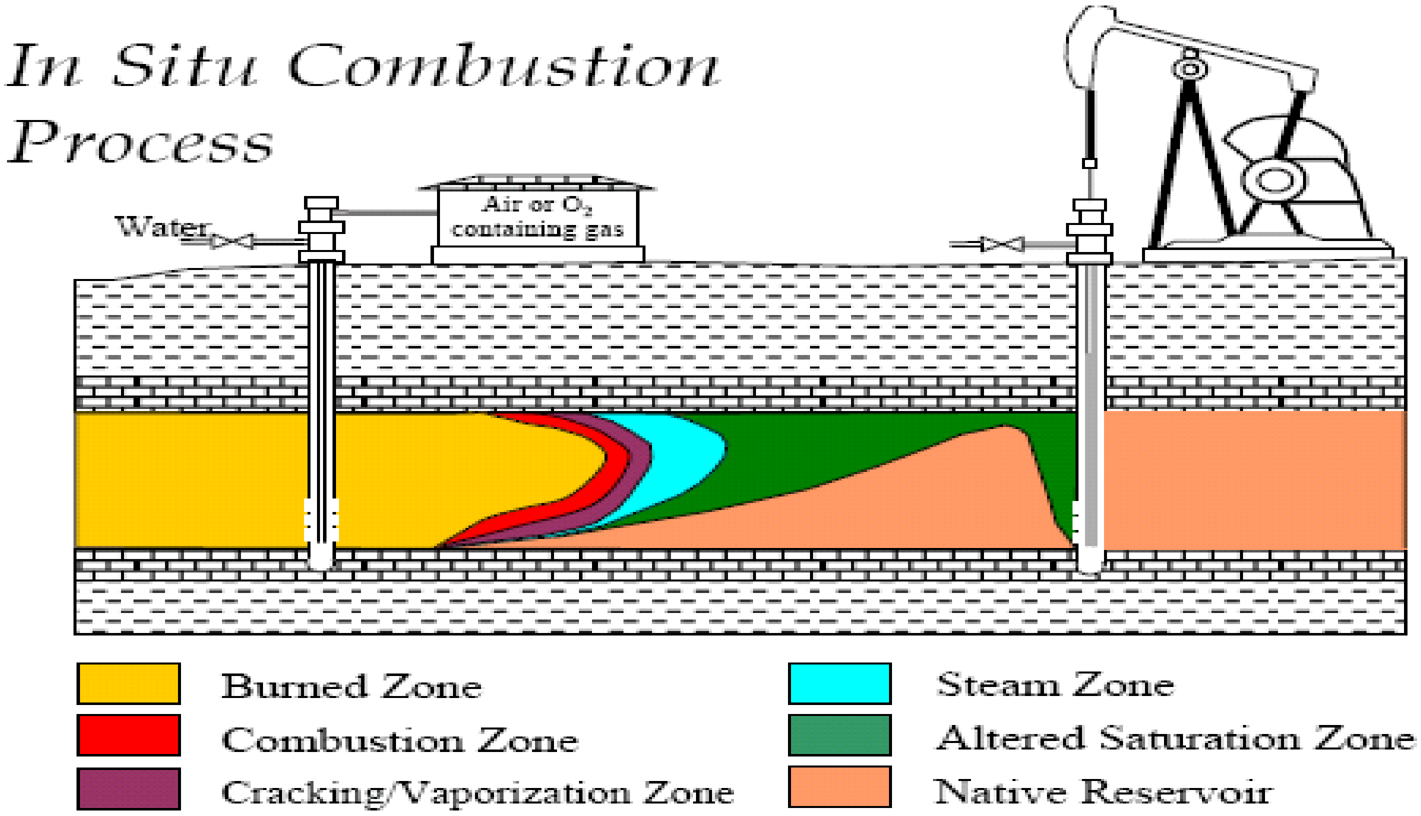
Process Variations

- Dry
- Wet
- Reverse
- Enriched Air

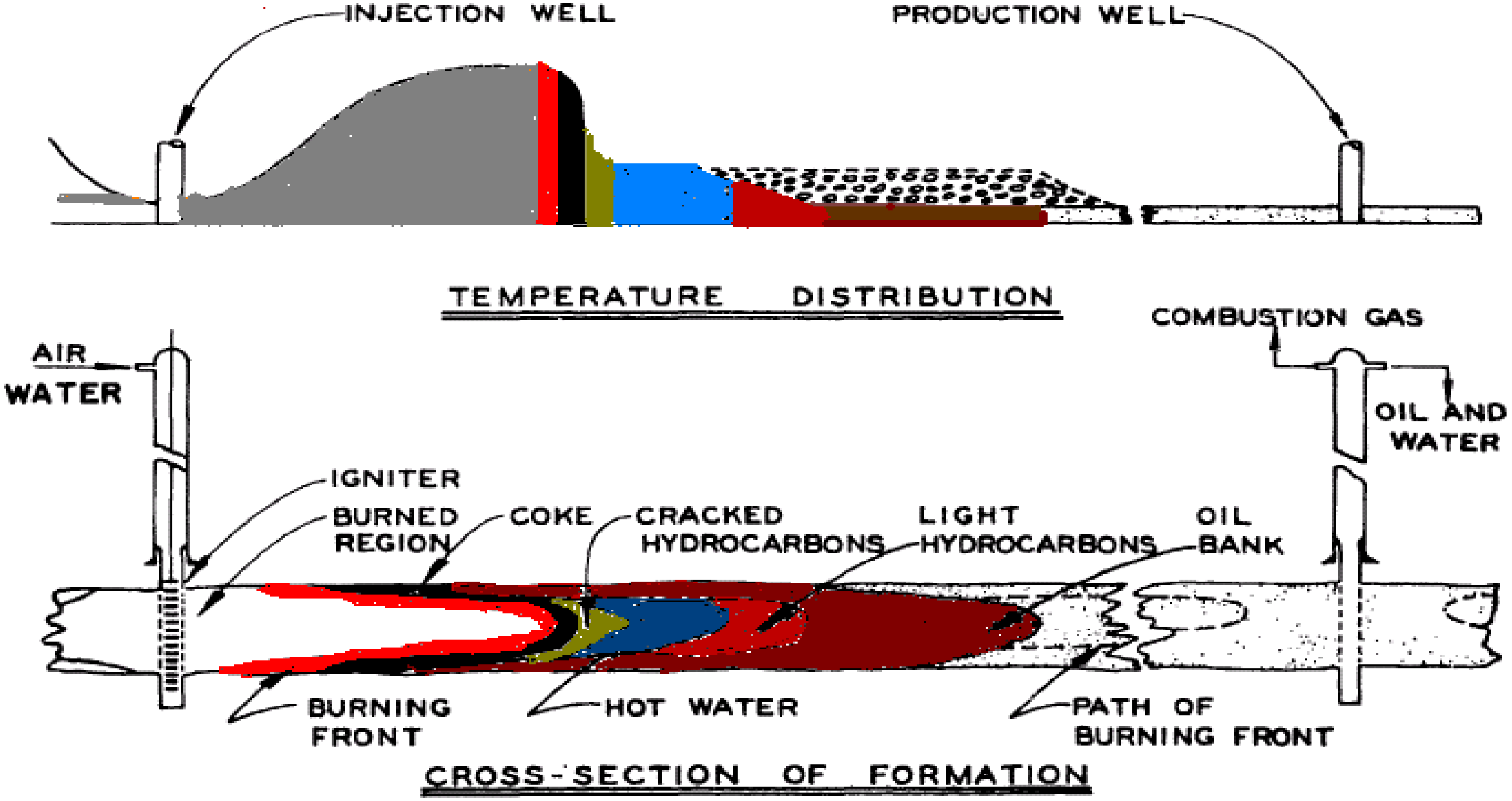
Important Parameters

- Air Requirement
- Air Injection Rate
- Enrichment
- Carbon Dioxide Produced
- Carbon Monoxide Produced
- Mass of Carbon Consumed
- Oil Recovered
- Total fuel Consumed
- Overall H/C Ratio

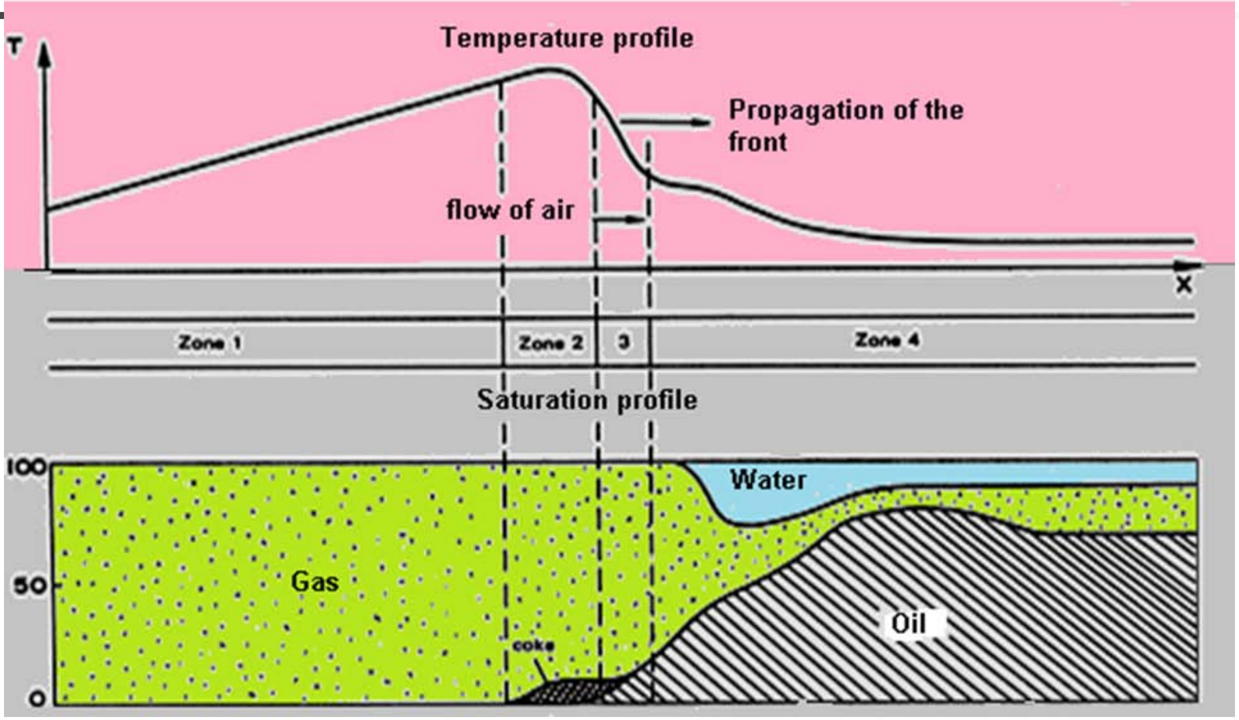
In Situ Combustion Process



In-situ Combustion Process



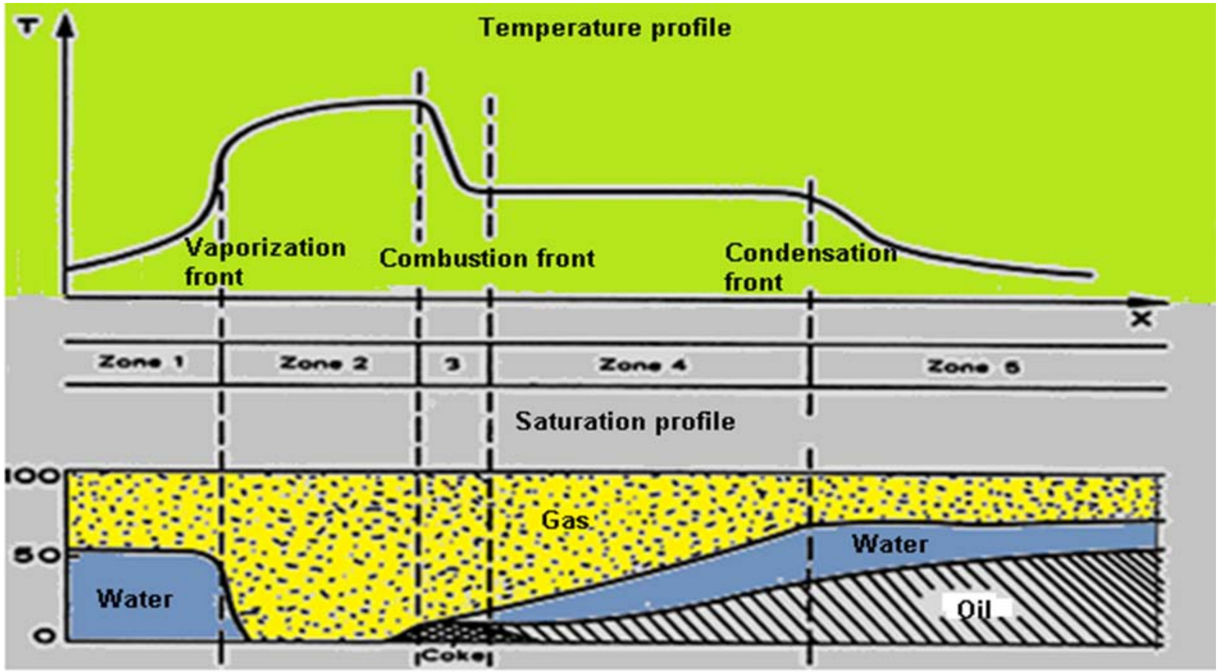
Dry forward combustion



Zone 1: burned zone

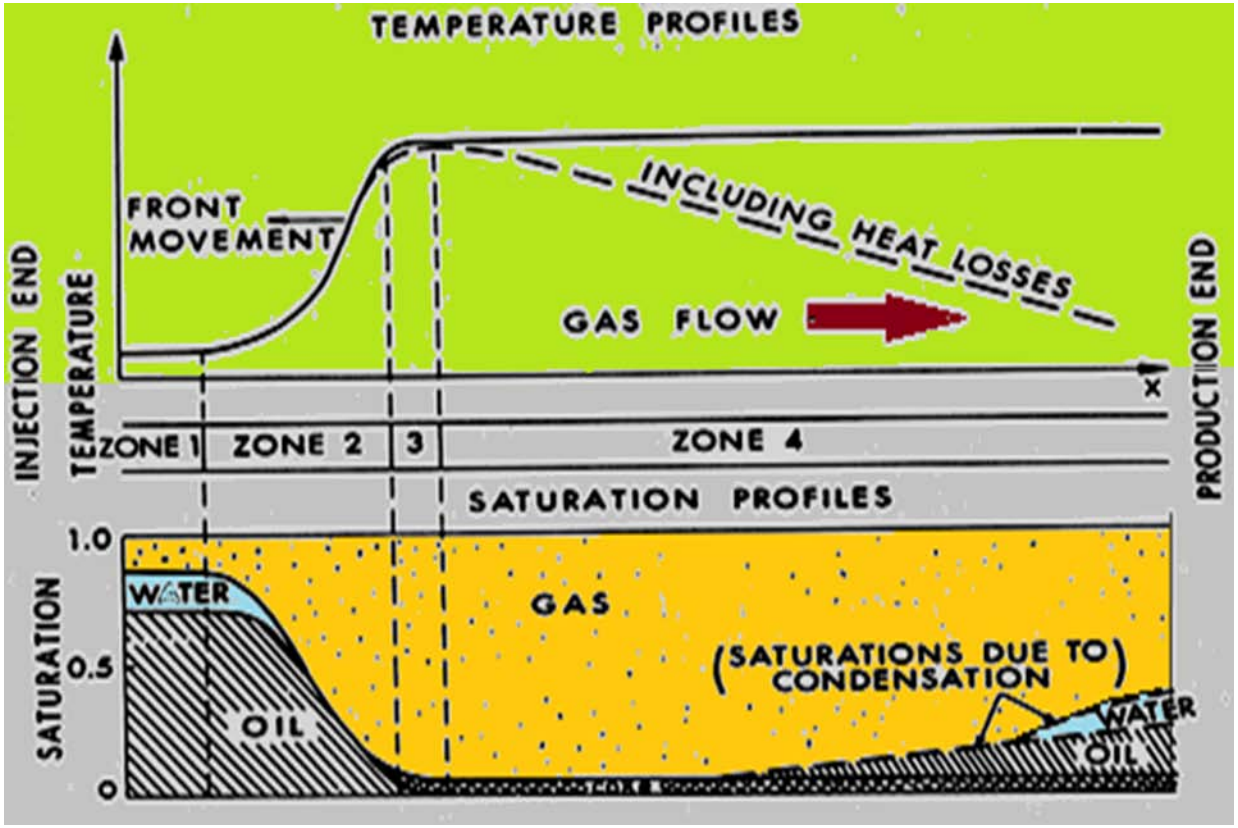
- 2: combustion zone
- 3: coke formation zone
- 4: vaporization/ condensation oil / water bank (high back pressure)

Wet Combustion



Zone 1: swept zone- T below TB of water
- 2: gas / vapor zone
- 3: combustion zone
- 4: vaporization/ condensation
- 5: high back pressure

Reverse Combustion

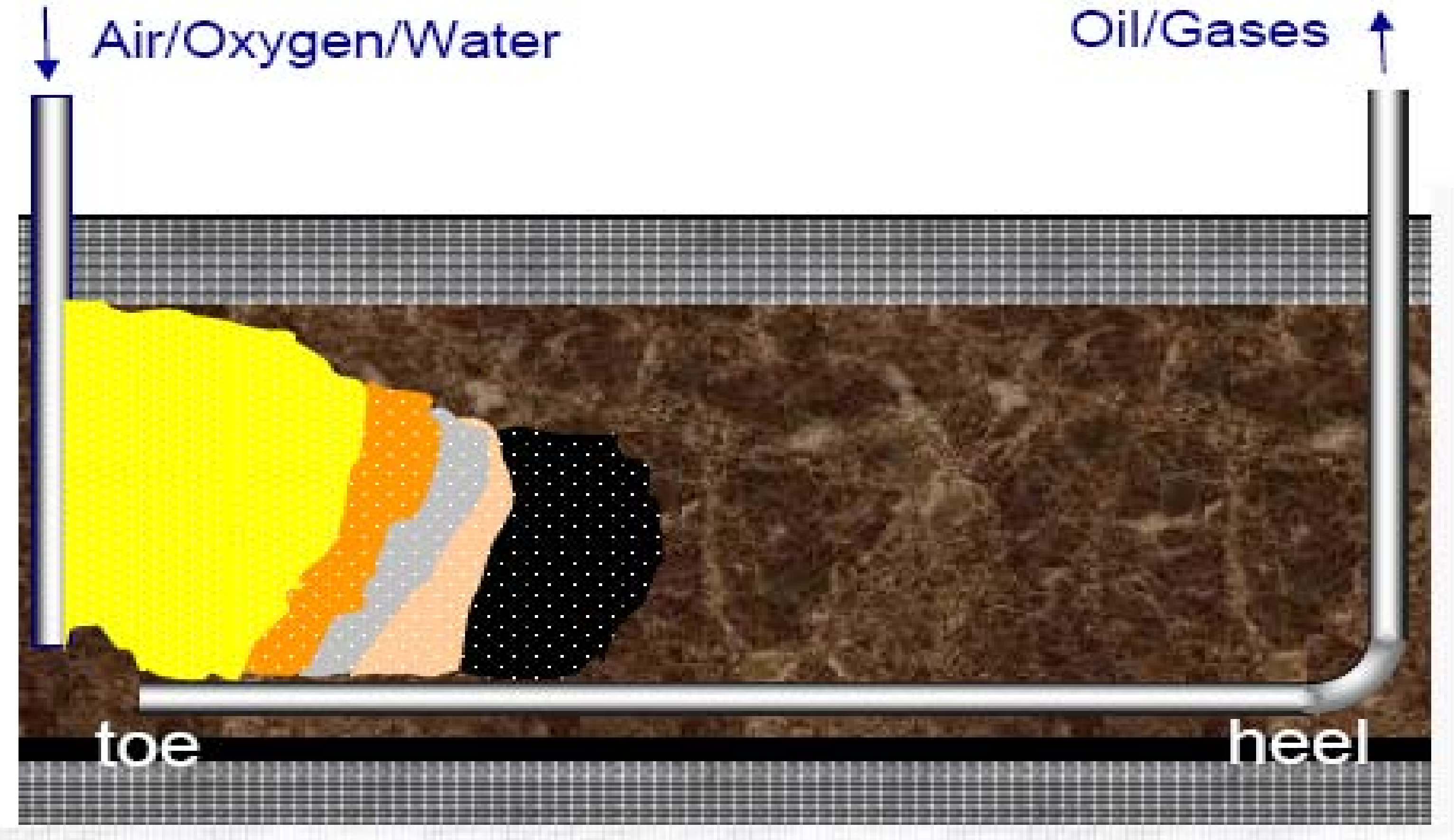


Toe-to Heel Air Injection

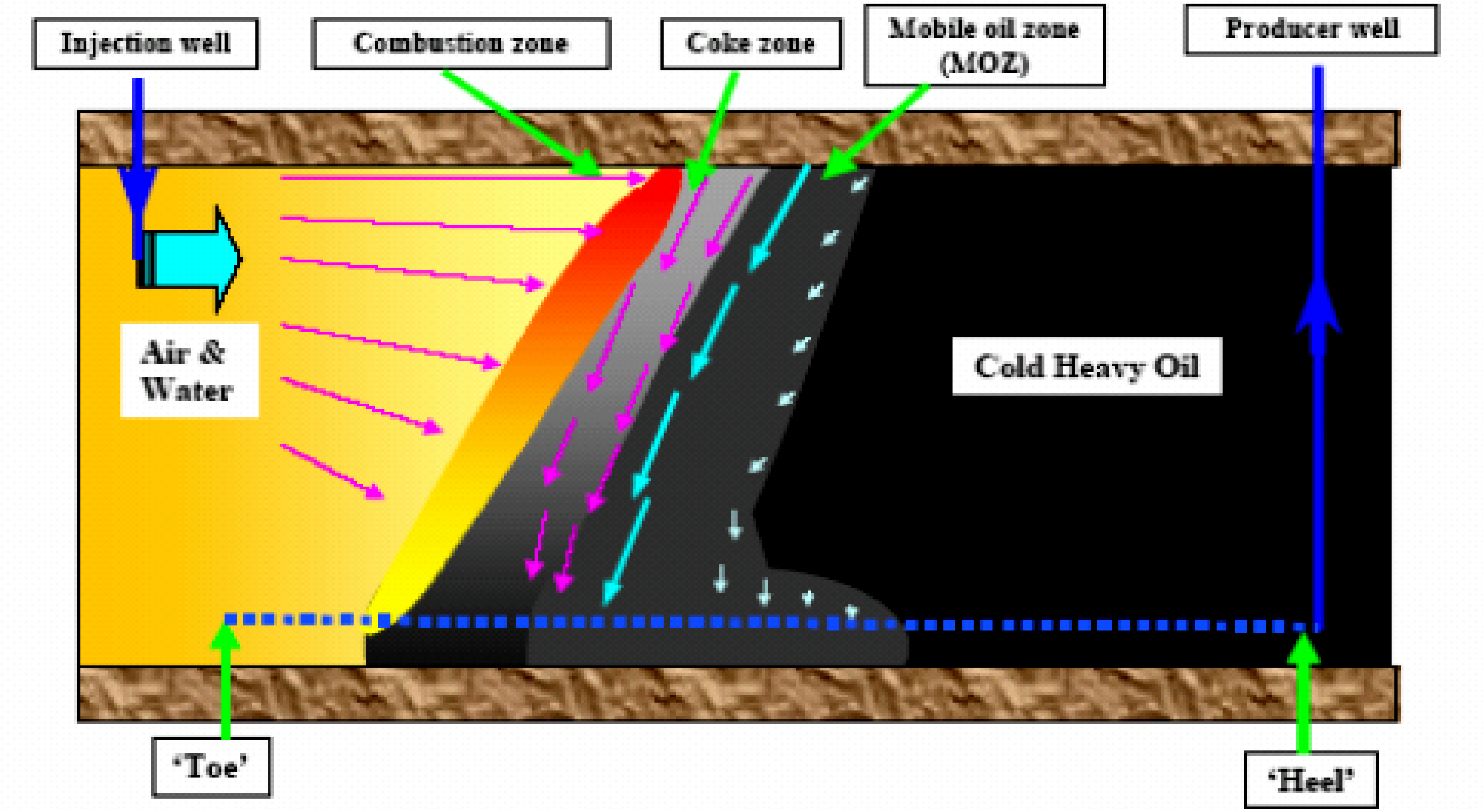
Toe-to Heel Air Injection (THAI)

- Toe-to-Heel Air Injection, or THAI, is a proposed method of recovery that combines a vertical air injection well with a horizontal production well.

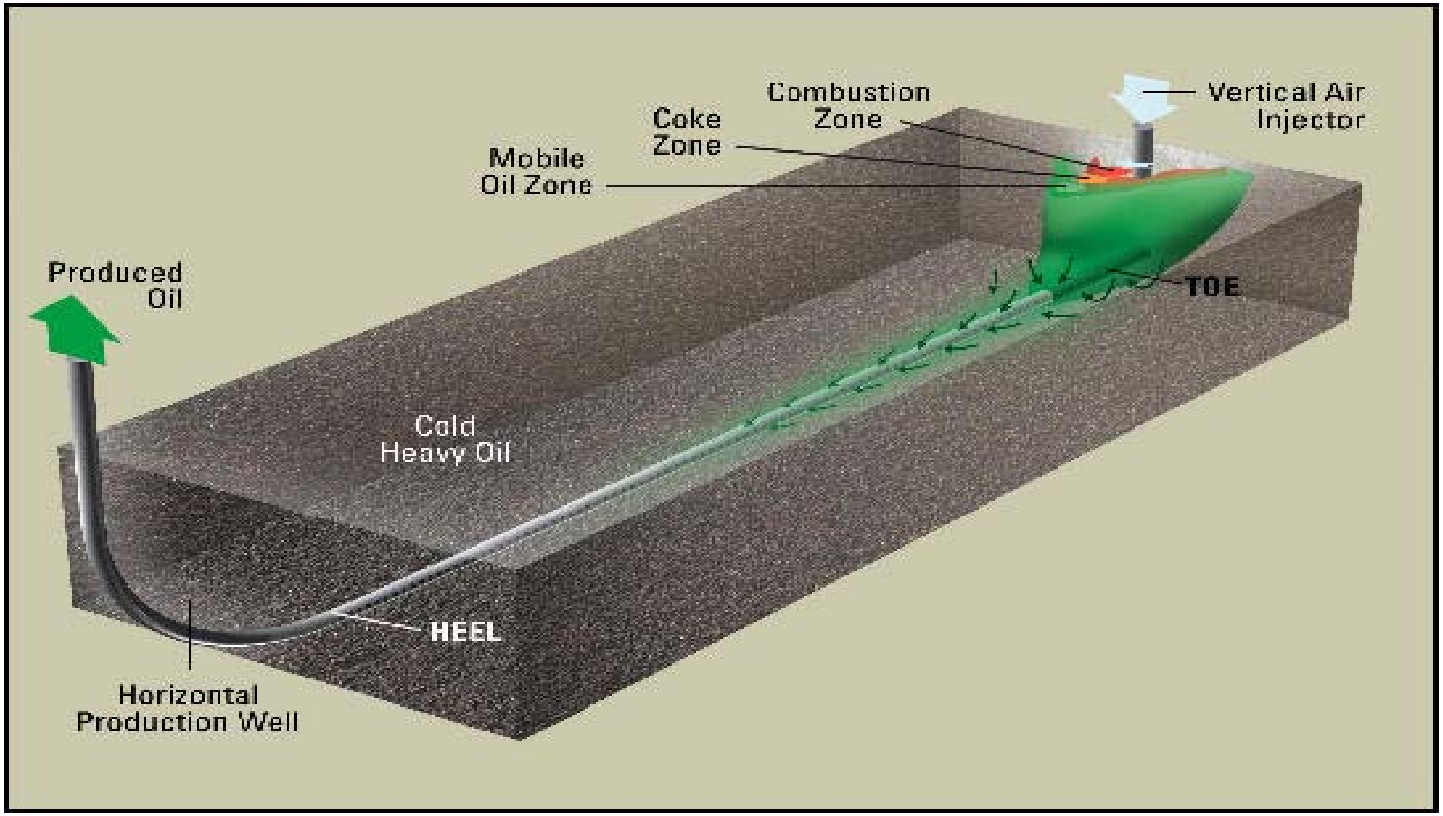
Toe-to Heel Air Injection



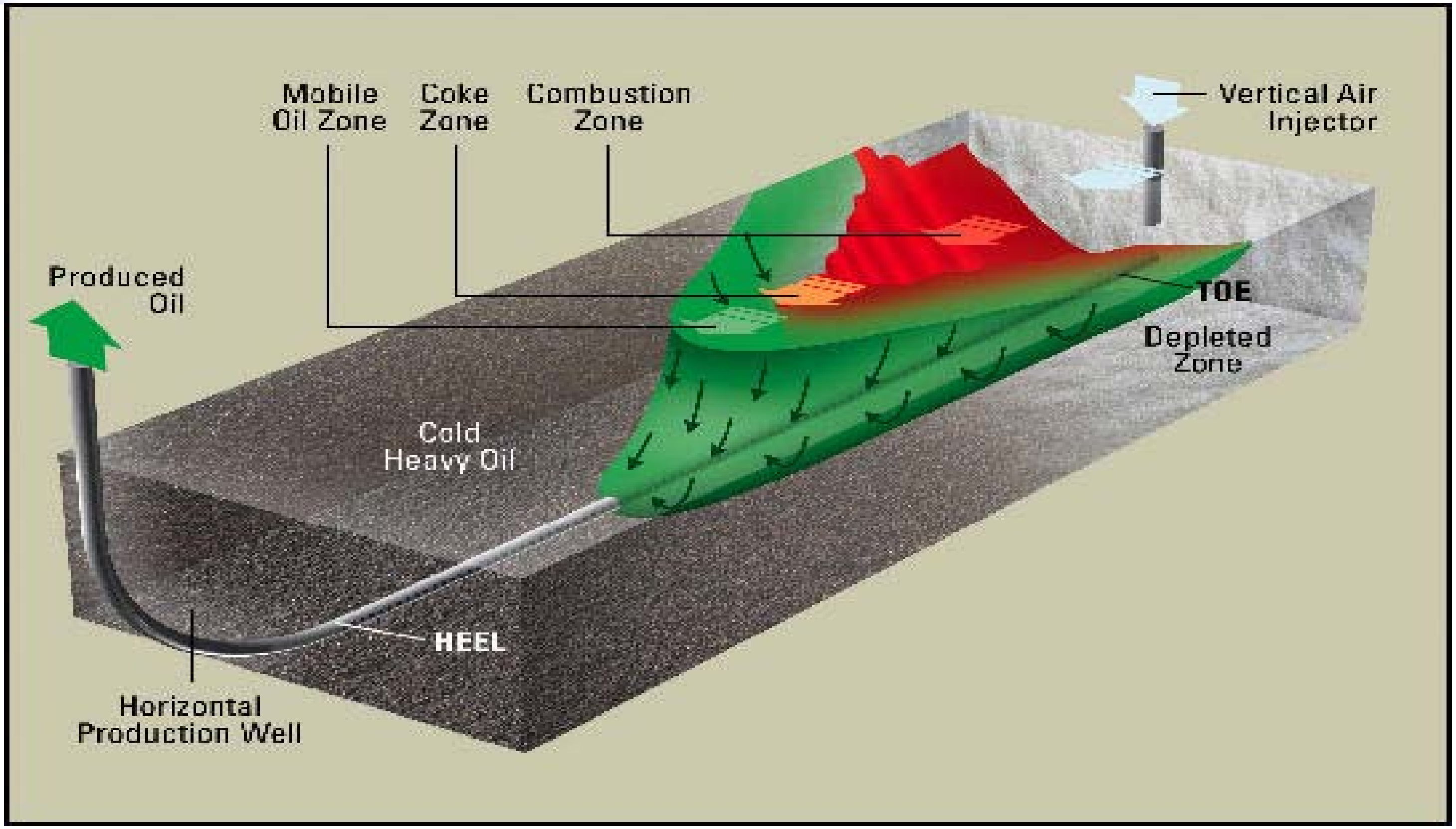
Toe-to Heel Air Injection



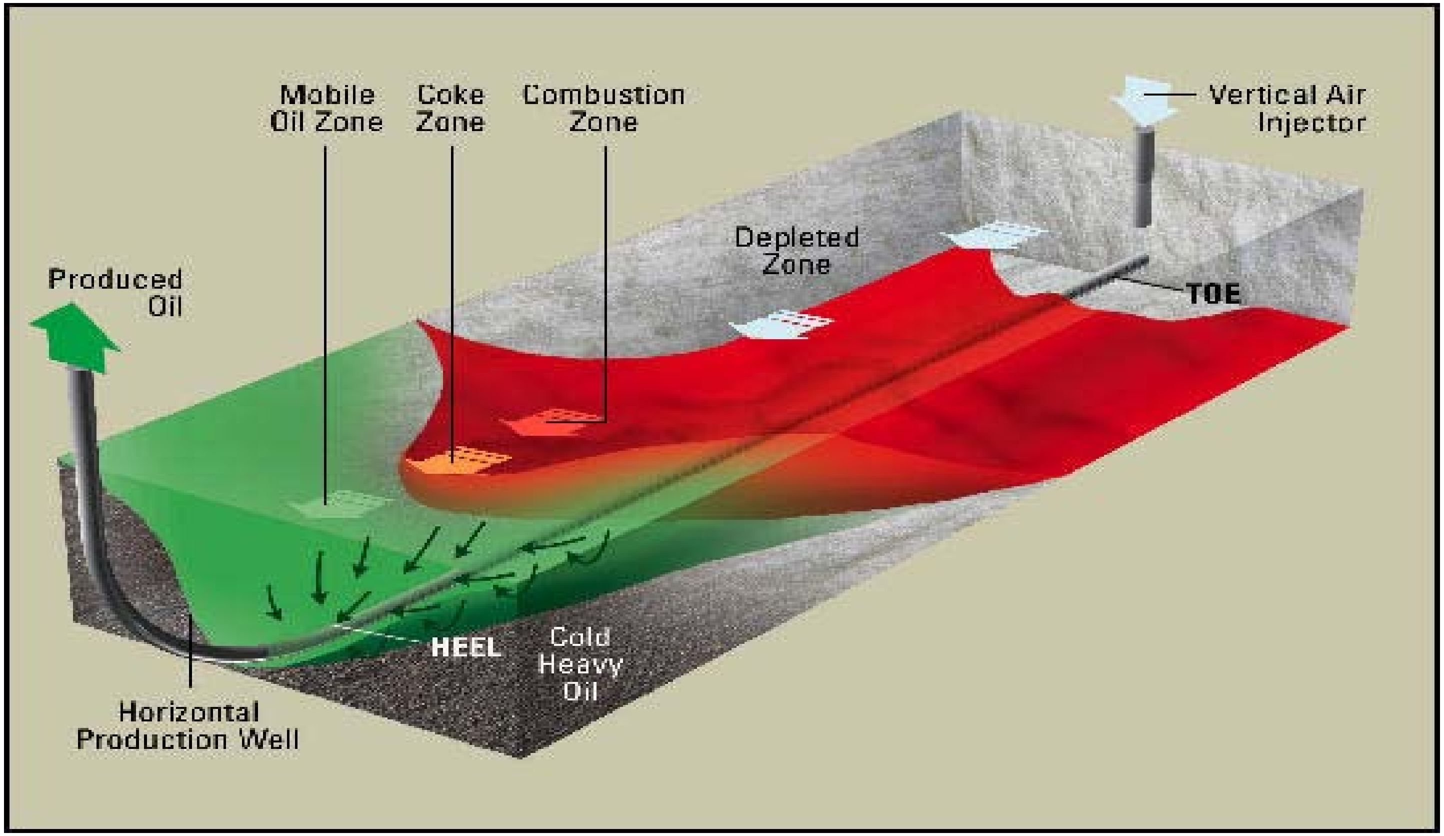
Start up:


Combustion Zone
Coke Zone
Mobile Oil Zone
Vertical Air Injector
Produced Oil
TOE
Cold Heavy Oil
HEEL
Horizontal Production Well

Steady State:



End Phase:


Mobile Oil Zone
Coke Zone
Combustion Zone
Vertical Air Injector
Depleted Zone
Produced Oil
TOE
HEEL
Cold Heavy Oil
Horizontal Production Well

Reaction Mechanisms - Classical

- **Thermal Cracking:**
- Modification of the original crude oil properties by thermal energy in the absence of oxygen. Final products are maltenes, gas, and coke.
- **High Temperature Combustion:**
- Destructive oxidation of either the whole or fractions of the original crude oil by bond scission reactions.
- The reaction products are carbon oxides and water.

$$Hydrocarbon + O2 \longrightarrow CO2 + CO + H2O$$

Chemical Reaction

- Cracking :

$$\underset{\text{(Alkane)}}{C_{n+m}H_{2(n+m)+2}} \longrightarrow \underset{\text{(Alkene)}}{C_2H_{2n}} + \underset{\text{(Alkane)}}{C_mH_{2m+2}}$$

- Dehydrogenation

$$C_nH_{2n+2} \longrightarrow C_2H_{2n} + H_2$$

Chemical Reaction

- Condensation

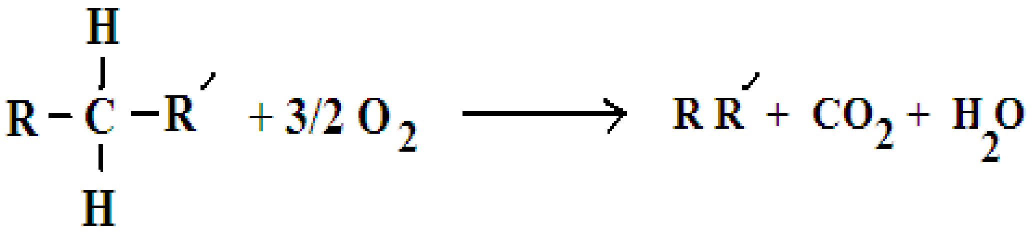
Alkanes + Alkenes $\longrightarrow$ Aromatics

- Oxidation

1. Combustion
2. Low Temperature Oxidation (LTO)

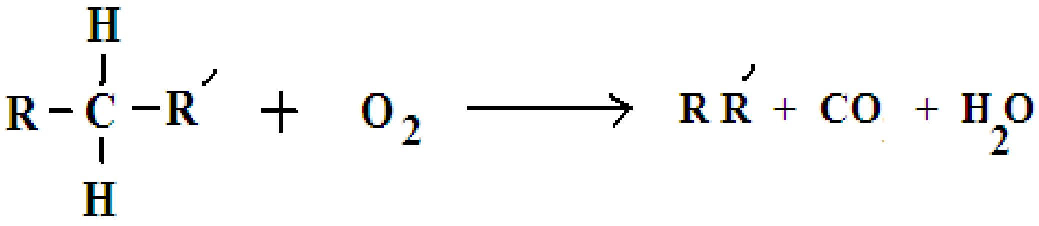
Combustion

- Complete Combustion



$$R-\overset{H}{\underset{H}{C}}-R' + 3/2\,O_2 \longrightarrow RR' + CO_2 + H_2O$$

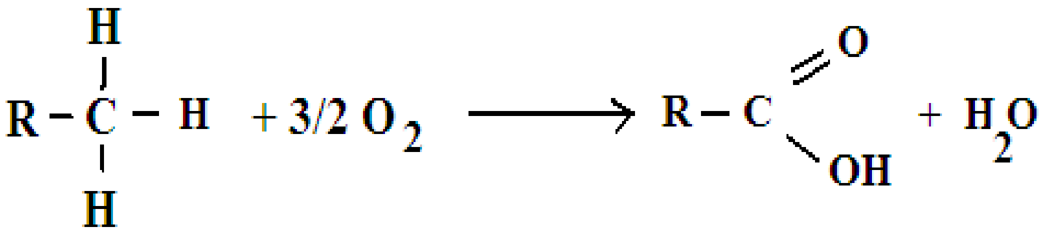
- Incomplete Combustion



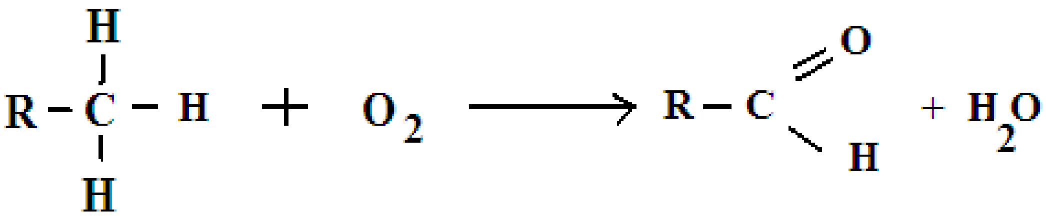
$$R-\overset{H}{\underset{H}{C}}-R' + O_2 \longrightarrow RR' + CO + H_2O$$

Low Temperature Oxidation

- Oxidation to carboxylic acid

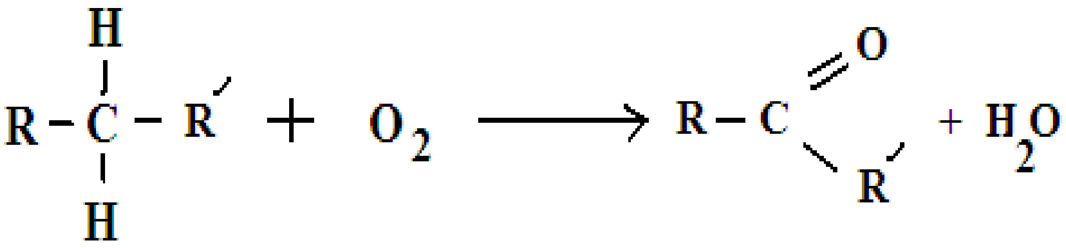


- Oxidation to aldehyde

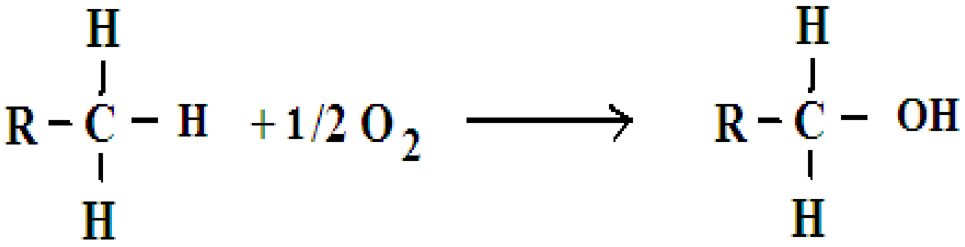


Low Temperature Oxidation

- Oxidation to ketane:



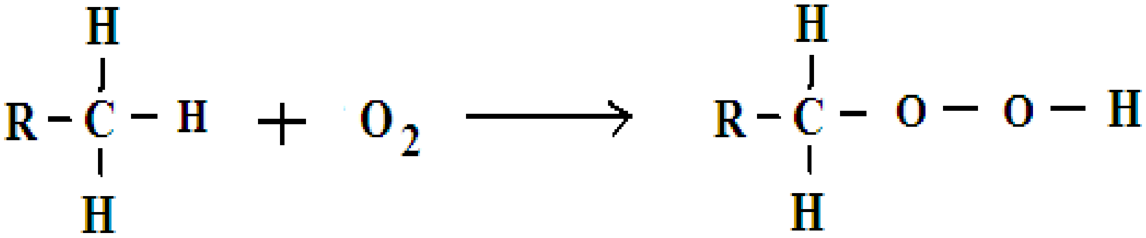
- Oxidation to alcohol:



$$R-\overset{\displaystyle H}{\underset{\displaystyle H}{C}}-H + 1/2\,O_2 \longrightarrow R-\overset{\displaystyle H}{\underset{\displaystyle H}{C}}-OH$$

Low Temperature Oxidation

- Oxidation to hydroproxide



$$\mathrm{R-\overset{H}{\underset{H}{C}}-H} + \mathrm{O_2} \longrightarrow \mathrm{R-\overset{H}{\underset{H}{C}}-O-O-H}$$

Study of In Situ Combustion Processes by Physical Simulation

- Combustion Tube Experiments
- Thermal Analysis
- Different Types of Physical Simulators (Models)

Prediction of process variables

1. Minimum front temperature
2. Minimum crude oil saturation
3. Average H / C atomic ratio
4. Minimum amount of fuel lay-down
5. Minimum heat requirement
6. Estimation of combustion zone thickness
7. Average carbon combustion rate
8. Combustion front velocity
9. Average fuel heat value
10. Heat available to sand
11. Average combustion peak temperature

Information From In Situ Combustion Tube Tests

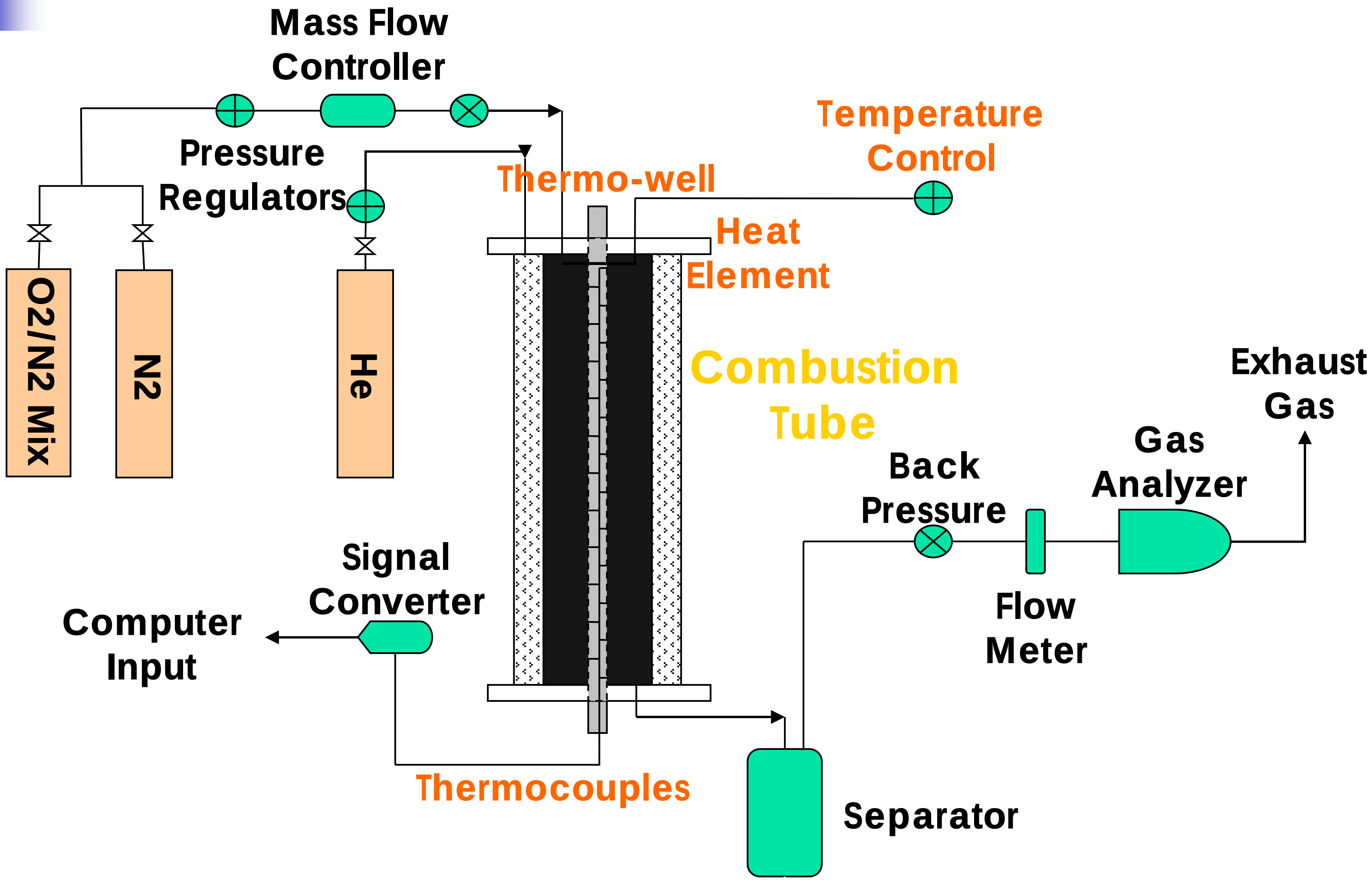
- Economic
- Air and Fuel Requirements
- Operating Parameters
- CO_2 fraction, H/C ratio, H_2S Production, Oil Upgrading, Acidic Water, Emulsions, etc.
- Correlate well with field
- Operating Strategies
- Dry, Wet, Superwet, O_2
- How Well It Burns
- Laboratory is best-case scenario

Key Concepts

- Laboratory data often correlates well with field observations, particularly produced gas compositions, H2S and aqueous sulfates, and oil recovery vs. volume burned.

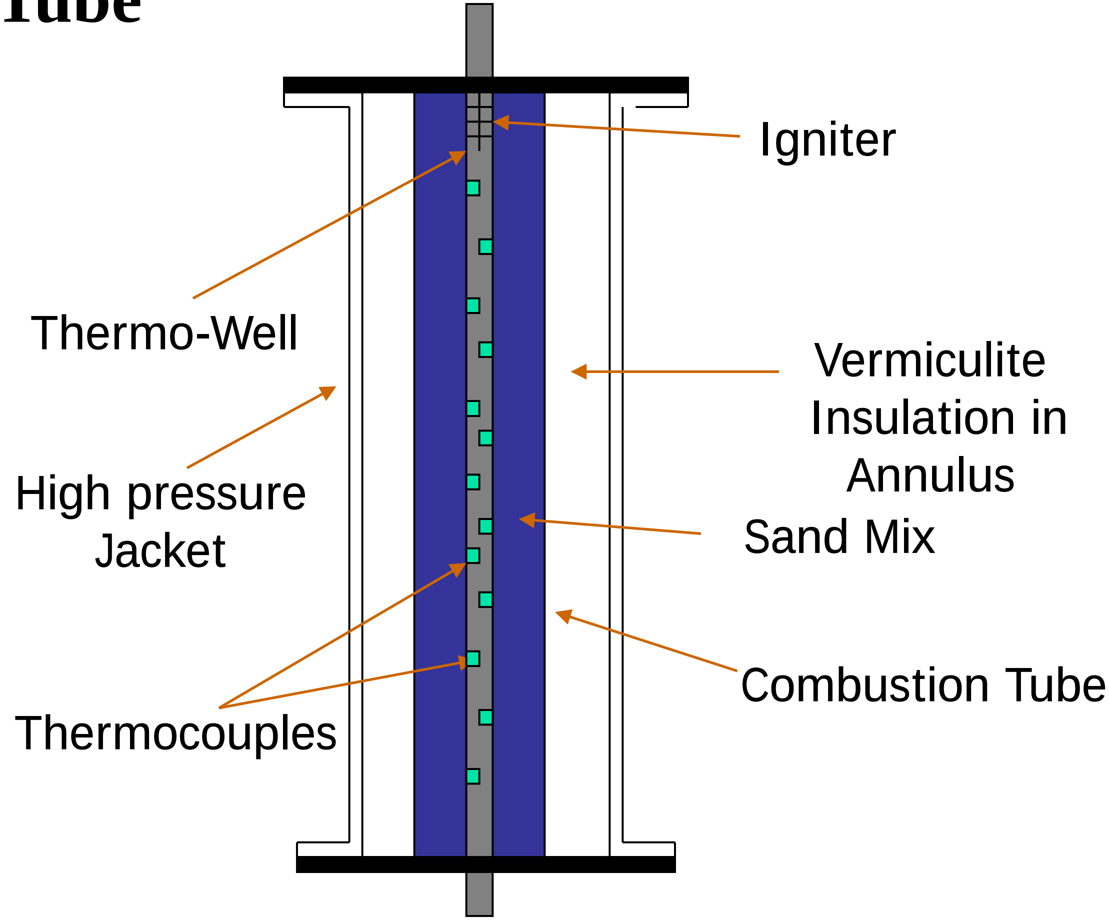
- Laboratory is the best-case scenario. “If we can’t burn it in the lab, it probably won’t work in the field!”

Experimental Setup



Experimental Setup

Combustion Tube



Microbial Enhanced Oil Recovery

1) Nutrients for field application

2) Lack of well documented field tests

3) Limited to reservoir temperature < 170

4) Limited to reservoir salinity < 10% NaCl

5) Insufficient basic understanding of the mechanisms of microbial technologies.

In-Situ Permeability Modification

In-Situ Permeability Modification

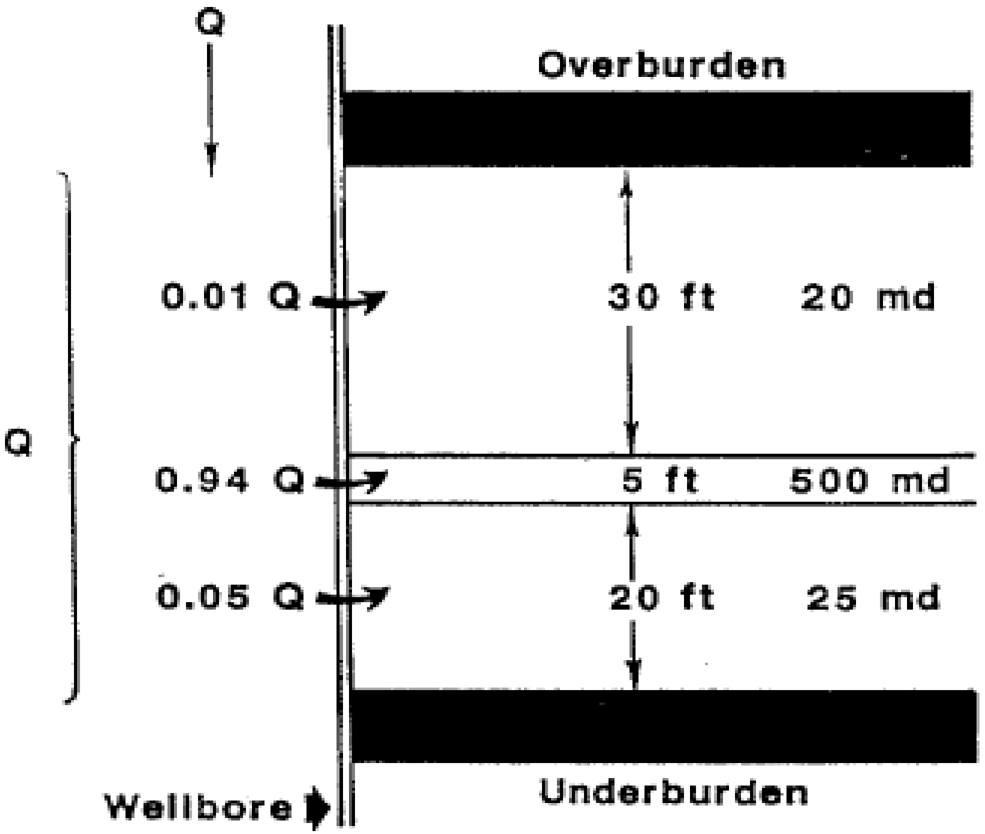
Areally

Permeability variation occurs

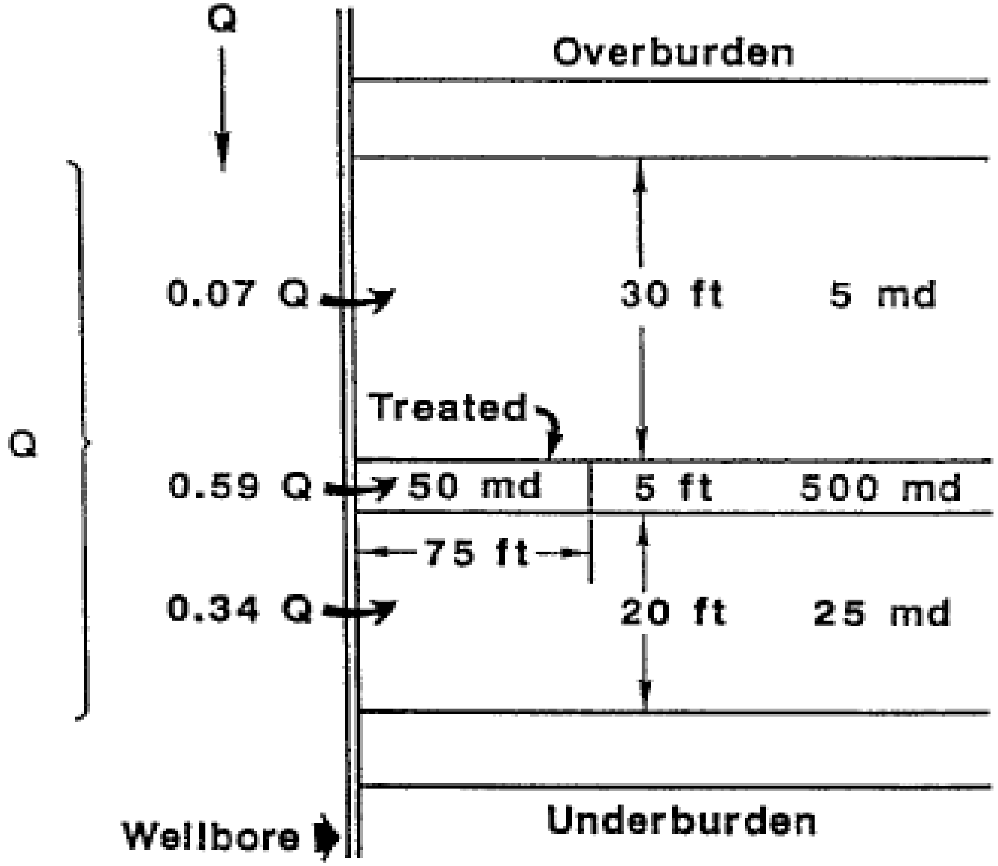
Vertically

Different zones of different permeability in vertical direction is very common

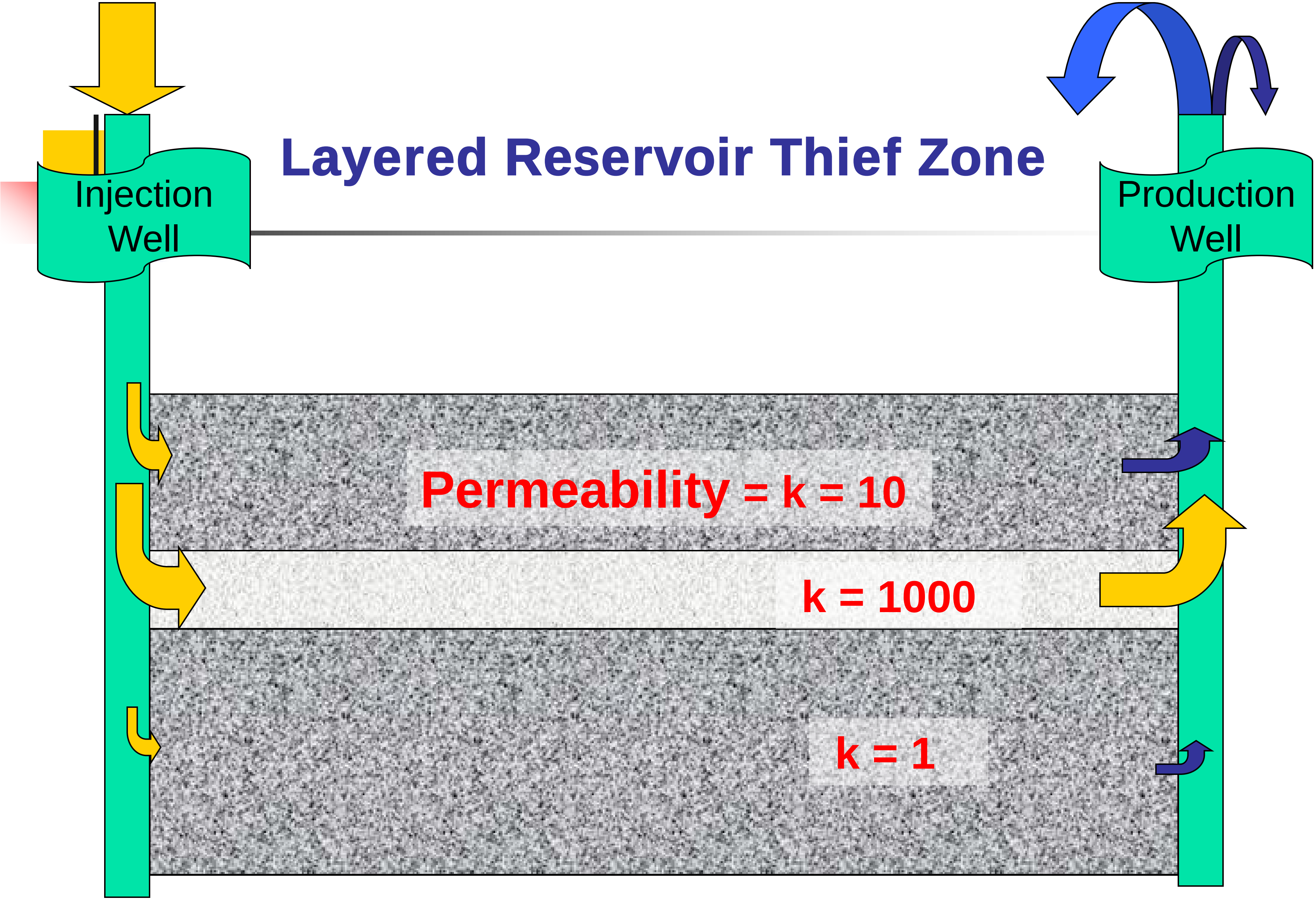
Vertical Variation in Permeability



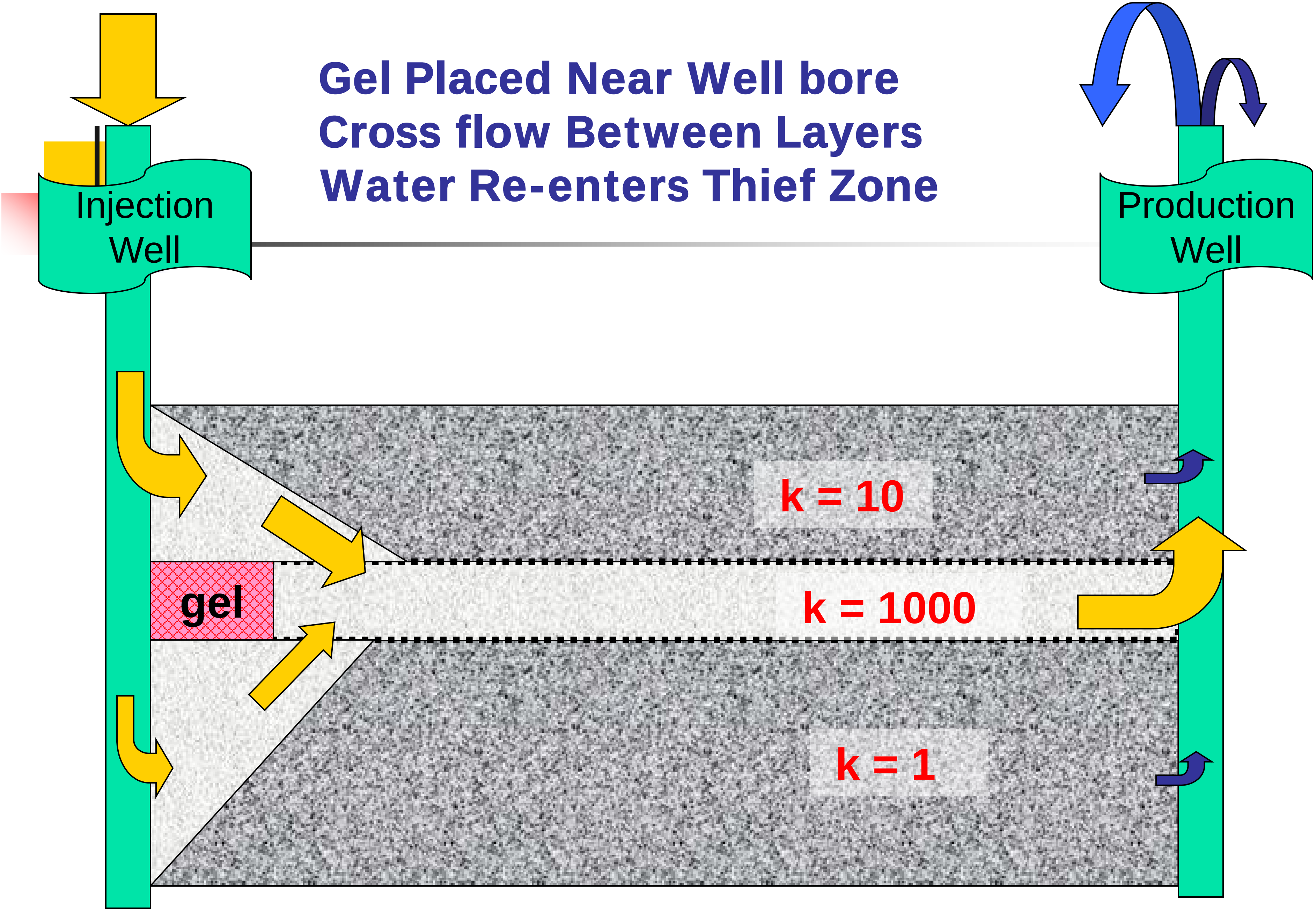
Vertical Variation in Permeability



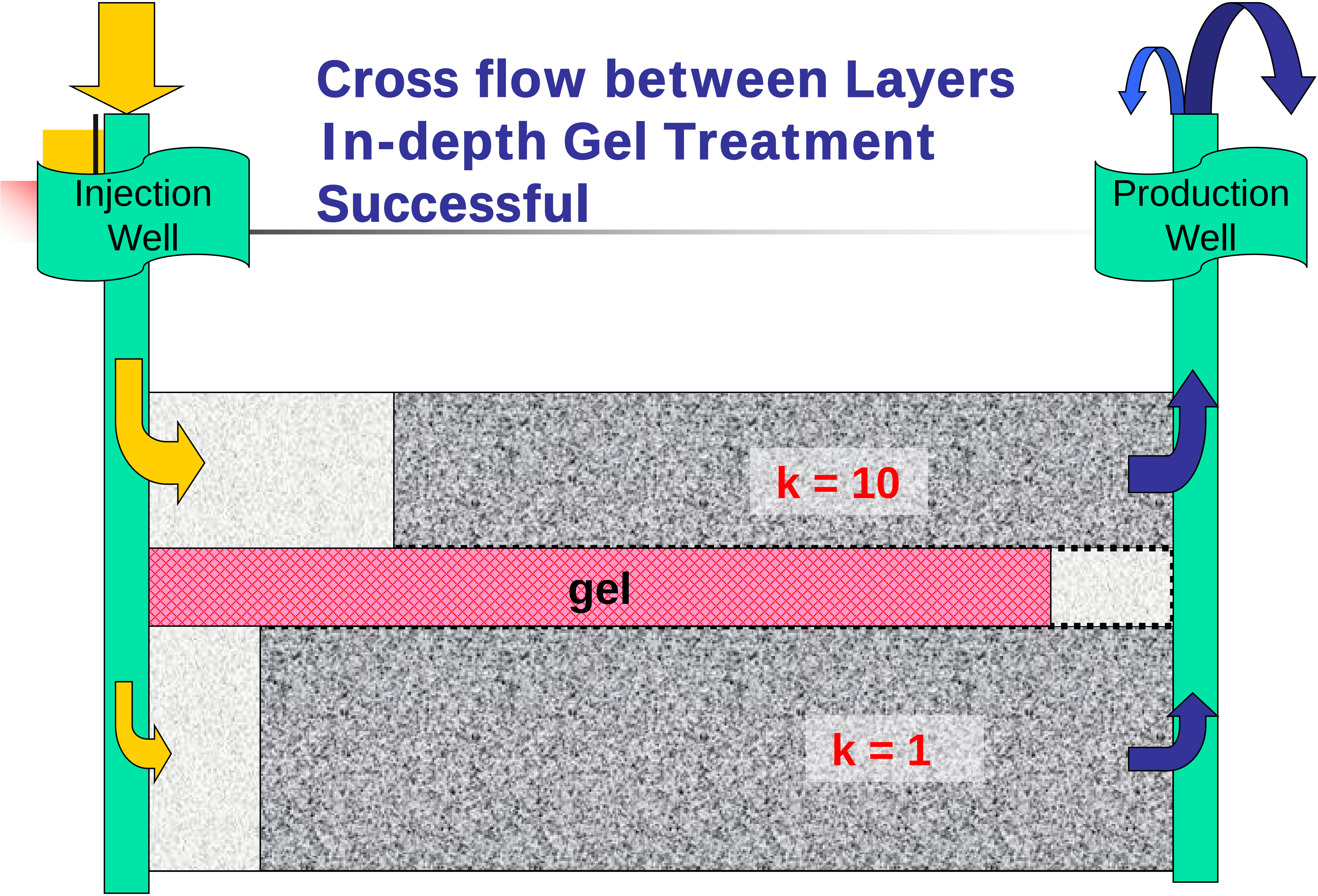
Layered Reservoir Thief Zone



Gel Placed Near Well bore
Cross flow Between Layers
Water Re-enters Thief Zone



Cross flow between Layers
In-depth Gel Treatment Successful



Gelation Process

- Mostly cross linked polymer
- Cross linker: Heavy Metal Ions

$$\mathrm{Re}\,ducing\ \ Agent\ \ +\ \ M^{+6} \rightarrow\ \ M^{+3}$$

$$Polymer + M^{+3} \rightarrow\ \ M^{+3} - Polymer$$

$$Polymer\ \ +\ \ Polymer - M^{+3} \rightarrow\ \ Polymer - M^{+3} - Polymer$$

Important Characteristics

- Gelation time
- Stability
- Non-toxic
- Salt tolerant

Constraints for EOR technologies

The following list summarizes the constrains to some of the advanced recovery technologies identified in this study.

Gas EOR

1)Reservoir heterogeneity

2) Mobility control

3) Incomplete mixing

4) Lack of predictive capability

5) Poor injectivity

6) Corrosion problems with C02

Surfactant/Polymer Flooding

1- Reservoir heterogeneity
2- Excessive chemical loss
3- Coherence, stability and cost-effectiveness of
4- Surfactant slugs
5- Limited to reservoir salinity <20% NaCI
6- Limited to reservoir temperature <200
7- Limited to permeability> 100 md
8- Polymer propagation

Alkaline Flooding

(1) Limited range of applicable salinity

(2) High chemical consumption

(3) Brine incompatibility - precipitation

Thermal EOR

1) Lower crude oil prices due to gravity, sulfur and heavy metal content

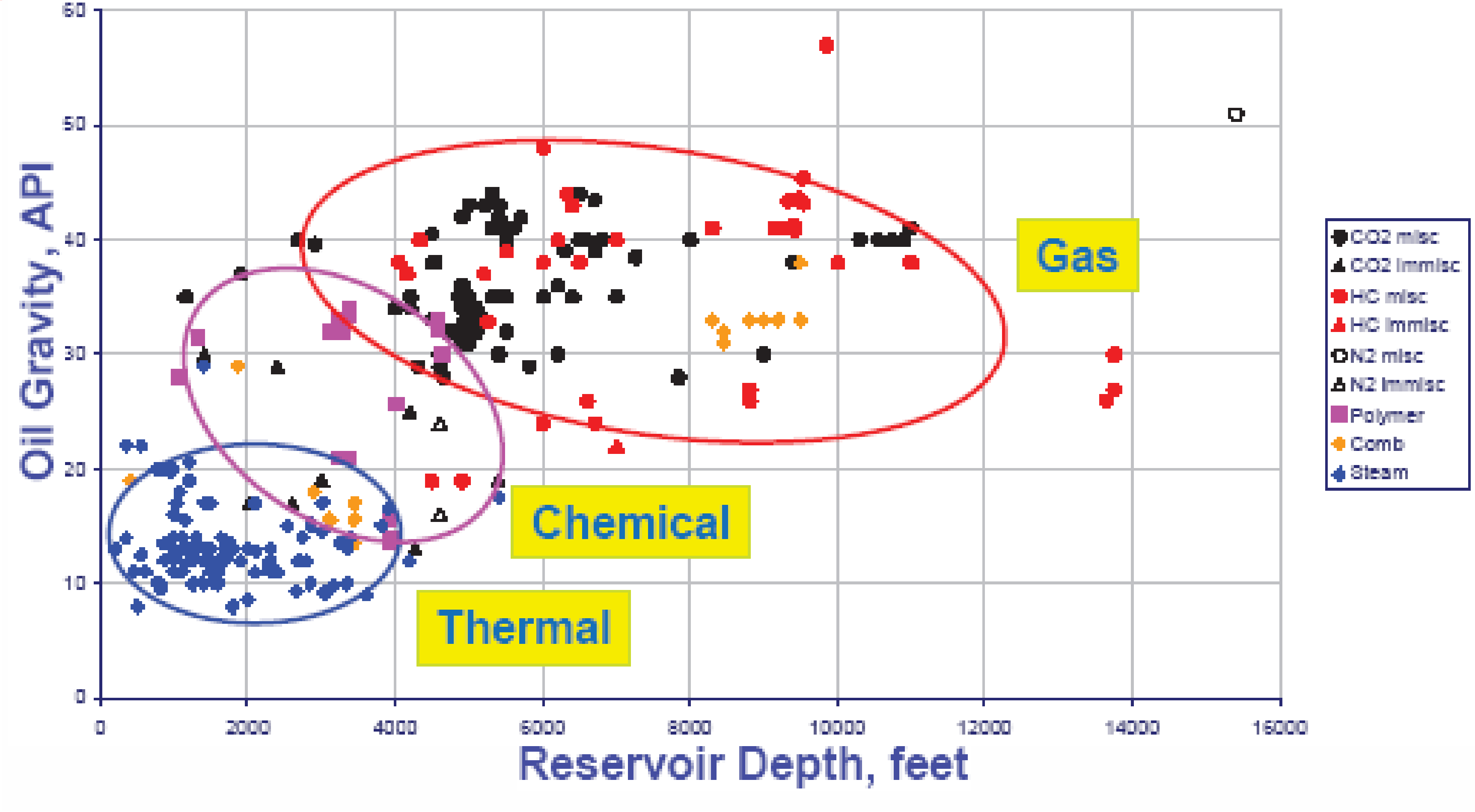
2) Large front end investments and delayed responses

3) Absence of cost-effective technology to upgrade low-quality, low-gravity crude into salable products

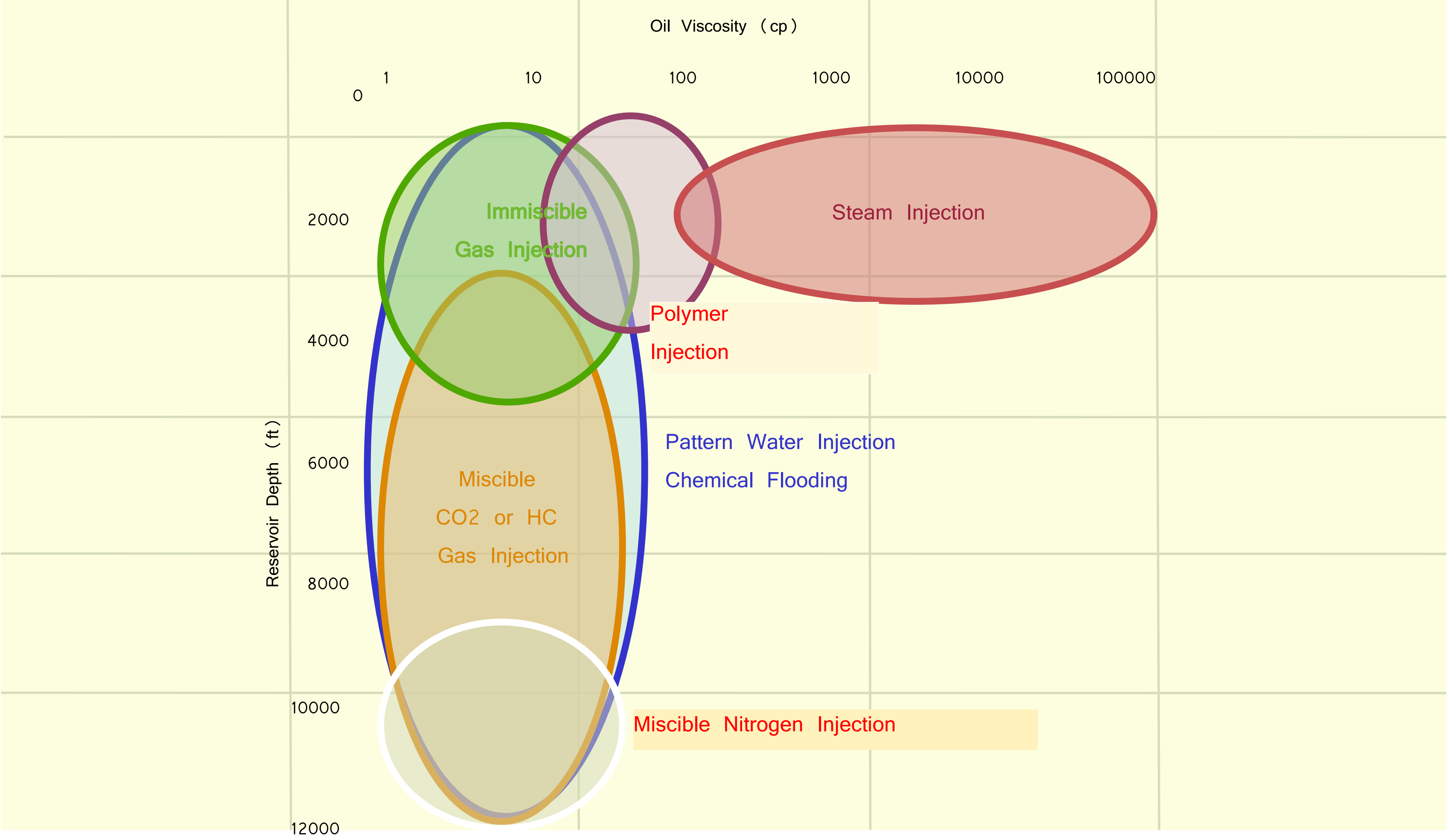
4) Absence of cost effective technology that permits the use of low-grade fuel such as coal, petroleum coke, high sulfur crude oil and brackish water to generate steam without violating the environmental regulations.

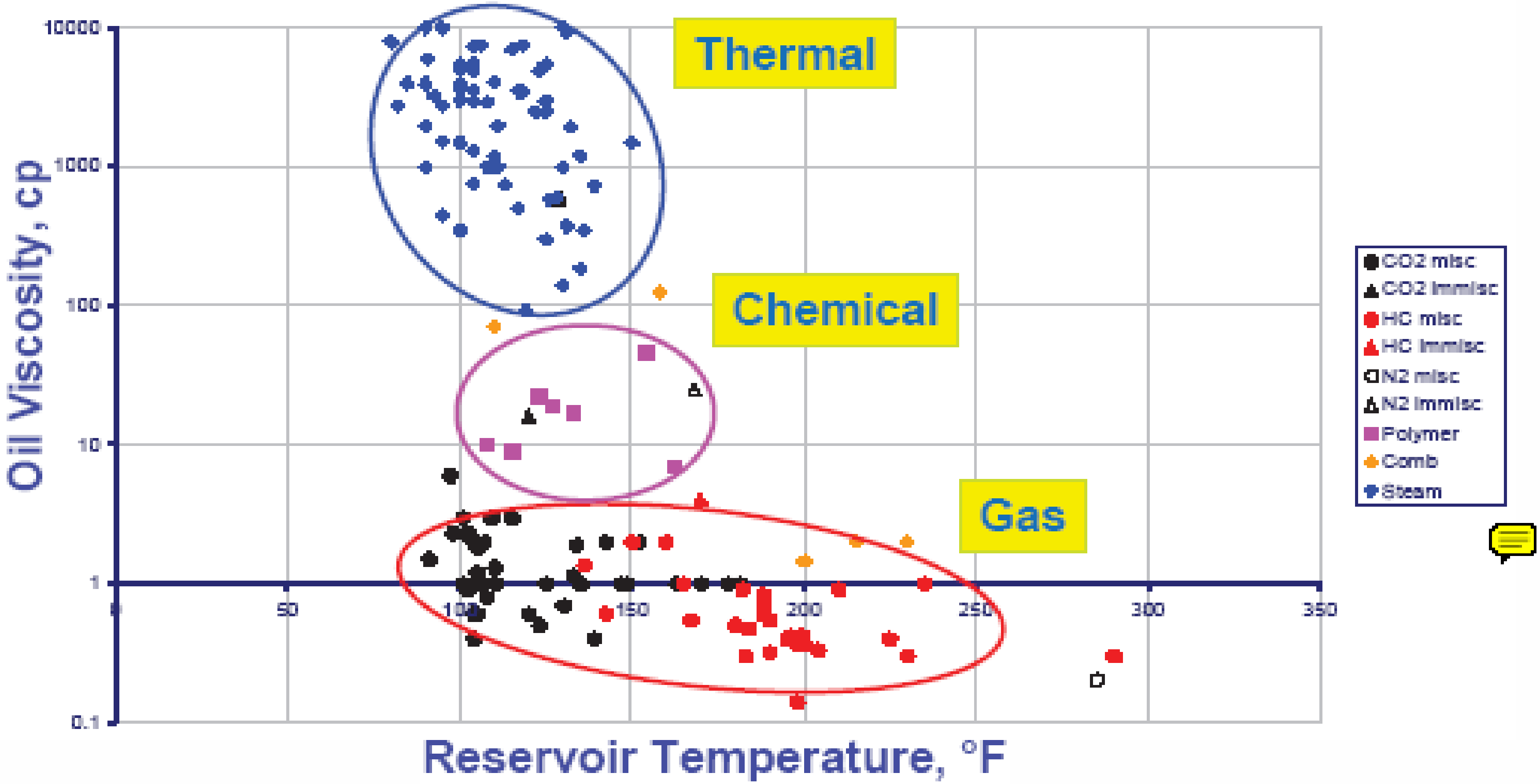
Summery of Screening for Enhanced Oil Recover Methods

Preferred Oil Gravity Ranges for Enhanced Oil Recovery Methods



Kind of processes to be applied




Thermal
Chemical
Gas
Oil Viscosity, cp
10000
1000
100
10
1
0.1
0
50
100
150
200
250
300
350
Reservoir Temperature, °F
● CO2 misc
▲ CO2 immisc
● HC misc
▲ HC immisc
□ N2 misc
△ N2 immisc
■ Polymer
◆ Comb
◆ Steam

		Oil Properties				Reservoir Characteristics				
		Gravity °API	Viscosity (cp)	Composition	Oil Saturation	Formation Type	Net Thickness (ft)	Average Permeability (md)	Depth (ft)	Temp (°F)
	Waterflood	>25	<30	N.C.	>10% mobile oil	Sandstone or carbonate	N.C.	N.C.	N.C.	N.C.
Gas Injection Methods	Hydrocarbon	>35	<10	High % of C_2-C_7	>30% PV	Sandstone or carbonate	Thin unless dipping	N.C.	>2000 (LPG) >5000 (H.P. gas)	N.C.
	Nitrogen & Flue Gas	>24 >35 for N_2	<10	High % of C_1-C_7	>30% PV	Sandstone or carbonate	Thin unless dipping	N.C.	>4500	N.C.
	Carbon Dioxide	>26	<15	High % of C_5-C_{12}	>30% PV	Sandstone or carbonate	Thin unless dipping	N.C.	>2000	N.C.
	Surfactant / Polymer	>25	<30	Light intermediate desired	>30% PV	Sandstone preferred	>10	>20	<8000	<175
Chemical Flooding	Polymer	>25	<150	N.C.	>10% PV	Sandstone preferred; carbonate possible	N.C.	>10 (normally)	<9000	<200
	Alkaline	13-35	<200	Some organic acids	Above waterflood residual	Sandstone preferred	N.C.	>20	<9000	<200
Thermal	Combustion	<40 (10-25 normally)	<1000	Some asphaltic components	>40-50% PV	Sand or sandstone with high porosity	>10	>10*	>500	>150 preferred
	Steamflooding	<25	>20	N.C.	>40-50% PV	Sand or sandstone with high porosity	>20	>200**	300-5000	N.C.

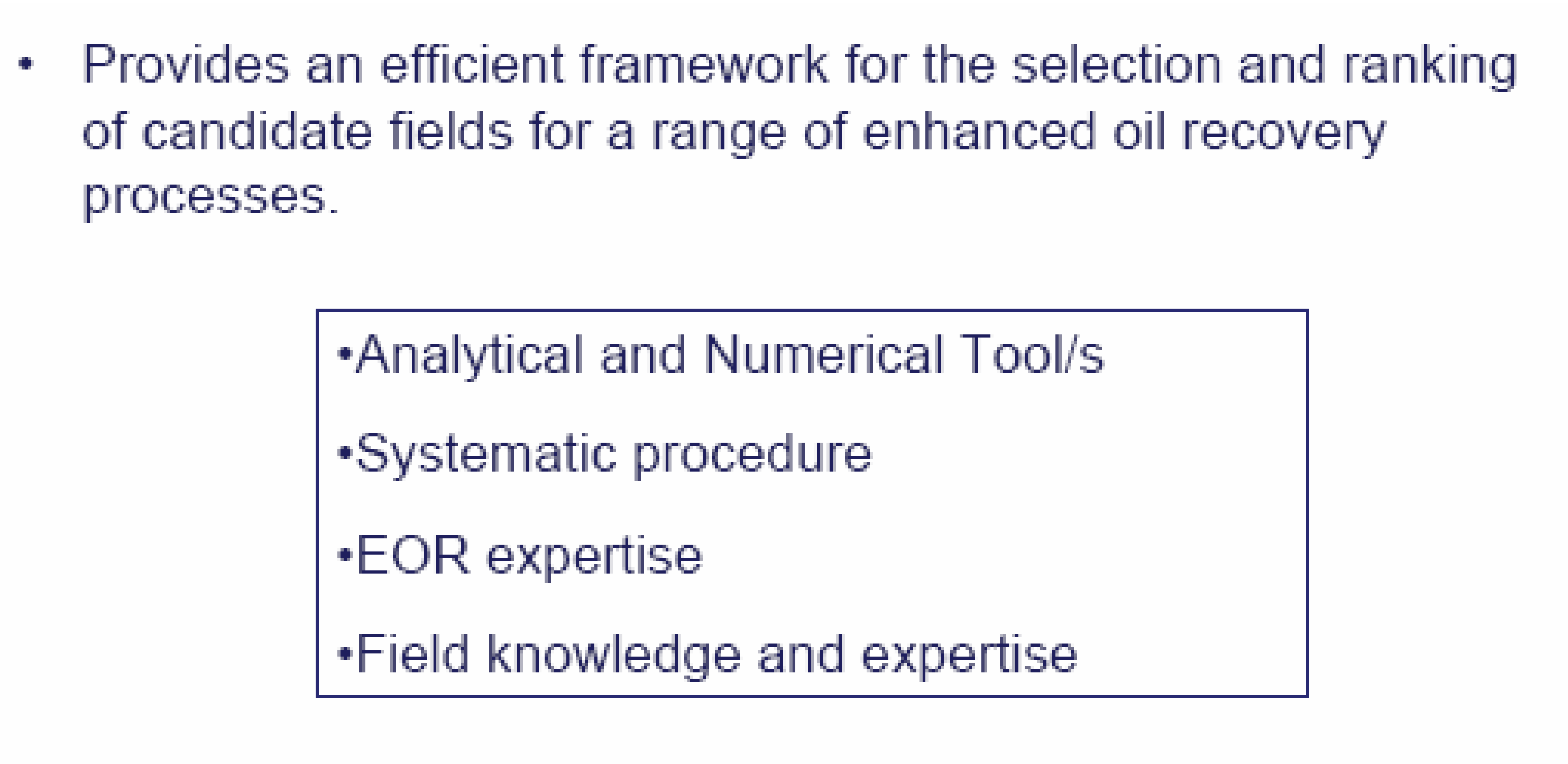
N.C. – Not Critical

Major production methods in Pilot phase possibly ready for commercial use after

Method	Description	Comment
VAPEX	Use solvent rather than steam in SAGD-type wells	Lower energy consumption, low production rates. In situ upgrading
Hybrid	Solvent plus steam in SAGD, CSS and steamflood wells	Lower energy consumption, increased production, in situ upgrading
In situ combustion with vertical and horizontal wells	Uses heavy oil in reservoir and injected air	Eliminate need for natural gas for steam generation, in situ upgrading
TAGD	Uses elemental heating	Environmentally friendly, in situ upgrading
Downhole heating with electricity	Resistance, induction, radio-frequency (RF)	Offshore, deep and arctic regions, in situ upgrading

EOR Methods Screening for Oil & Gas fields

Developing Screening Methodology



- Provides an efficient framework for the selection and ranking of candidate fields for a range of enhanced oil recovery processes.

- Analytical and Numerical Tool/s
- Systematic procedure
- EOR expertise
- Field knowledge and expertise

EOR Reservoir Database

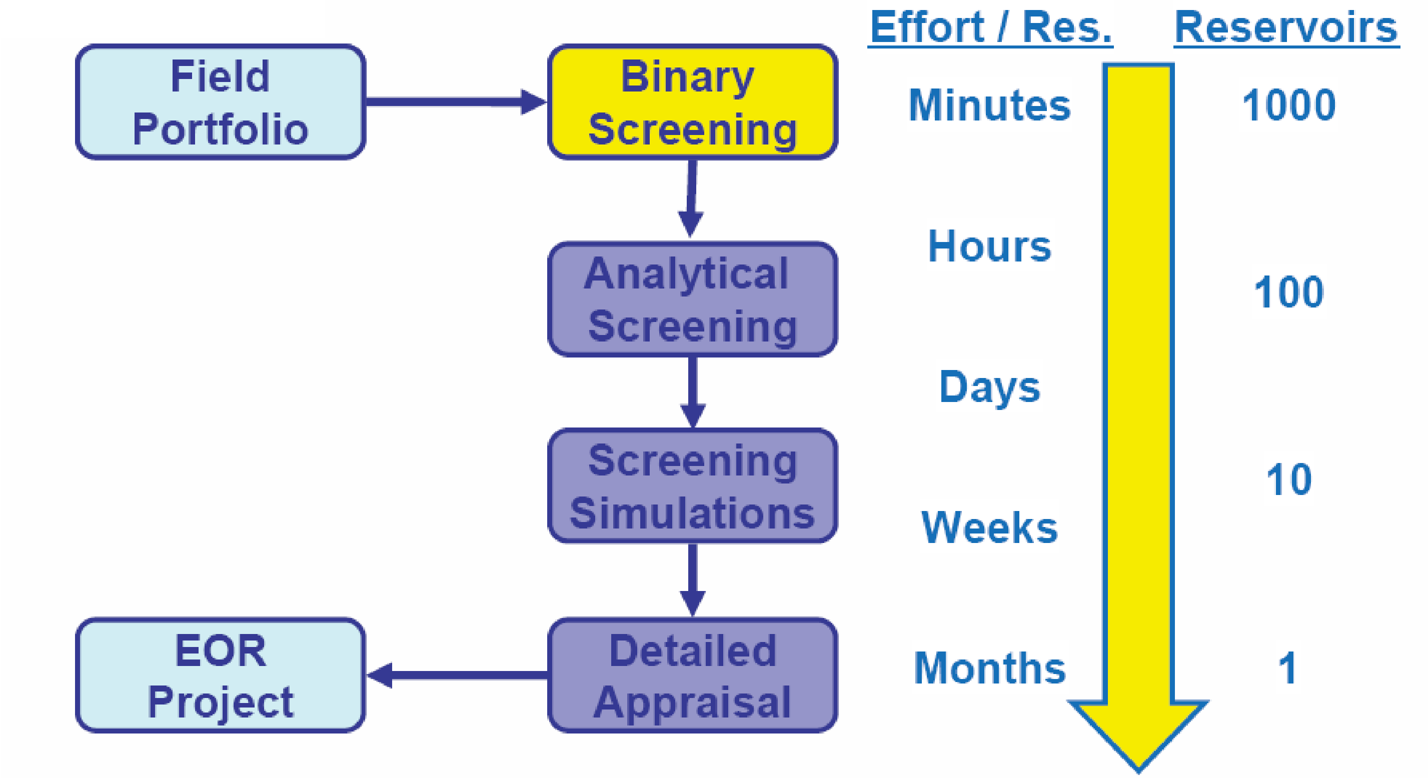
A data base of EOR pertinent parameters include:

- ✓ Production related: Cumulative Prod., OOIP, decline rates, water cut
- ✓ Petrophysical: Poro-perm, Field size, Net pay, Lithology, Depth, Temp., Fracture Pressure.
- ✓ Crude Chemistry: API, Viscosity, mwC5+, MMP, Sulfur content.
- ✓ Produced Water Chemistry: TDS, pH, Calcium, Chloride, Magnesium.
- ✓ Field information: locations, shape files, well counts.

- ➢ **Data sources**
- ✓ External datasets – Various Associations & Organization through the world are providing in-house or international data base of EOR projects, such as USA Department of Energy/National Energy Technology Laboratory (DOE/NETL), Wyoming Geological Association (WGA), Wyoming Oil & Gas Conservation Commission (WOGCC),...
- ✓ Internal data acquisition – decline curve analysis, lab studies.

Methodology

- Many tools and methodologies have been developed that provide a systematic approach for evaluating technical and economic EOR potential within a risk management framework.



Field Portfolio

Binary Screening

Analytical Screening

Screening Simulations

Detailed Appraisal

EOR Project

Effort / Res.

Minutes

Hours

Days

Weeks

Months

Reservoirs

1000

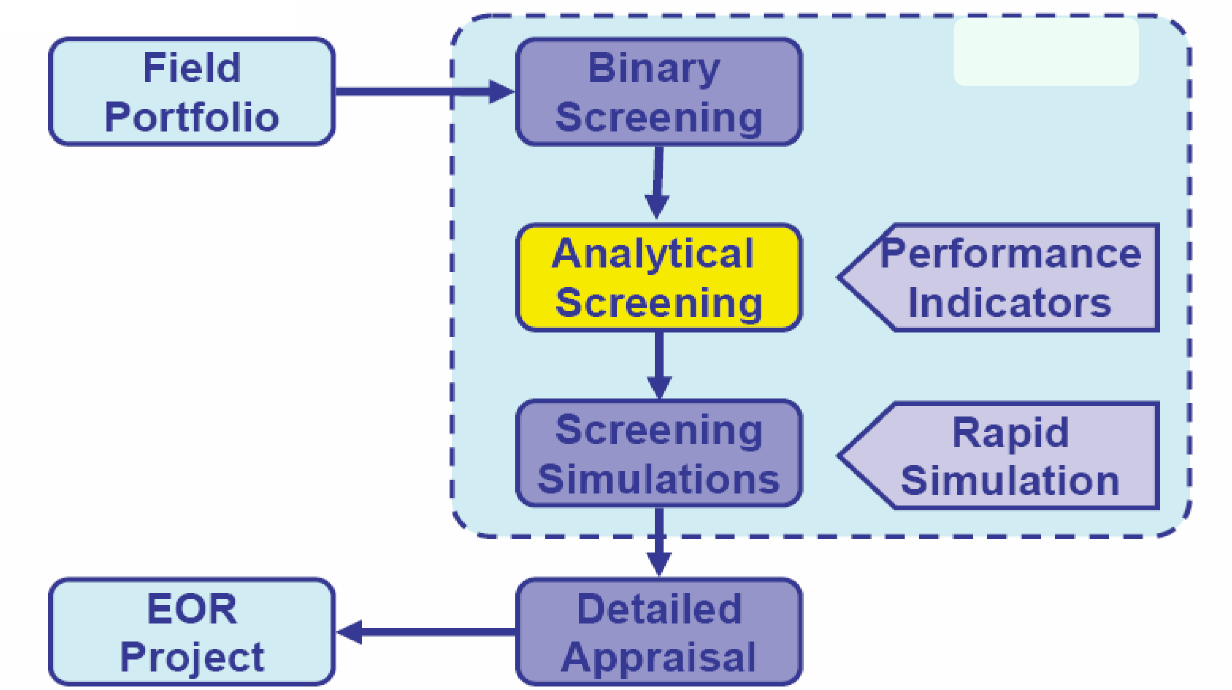
100

10

1

Methodology

- One of these methodologies is to use a **three stage approach** enables EOR projects to be compared directly with conventional exploration and development projects such as such as further development drilling or exploration and the subsequent appraisal and development of new fields.



Field Portfolio

Binary Screening

Analytical Screening

Performance Indicators

Screening Simulations

Rapid Simulation

Detailed Appraisal

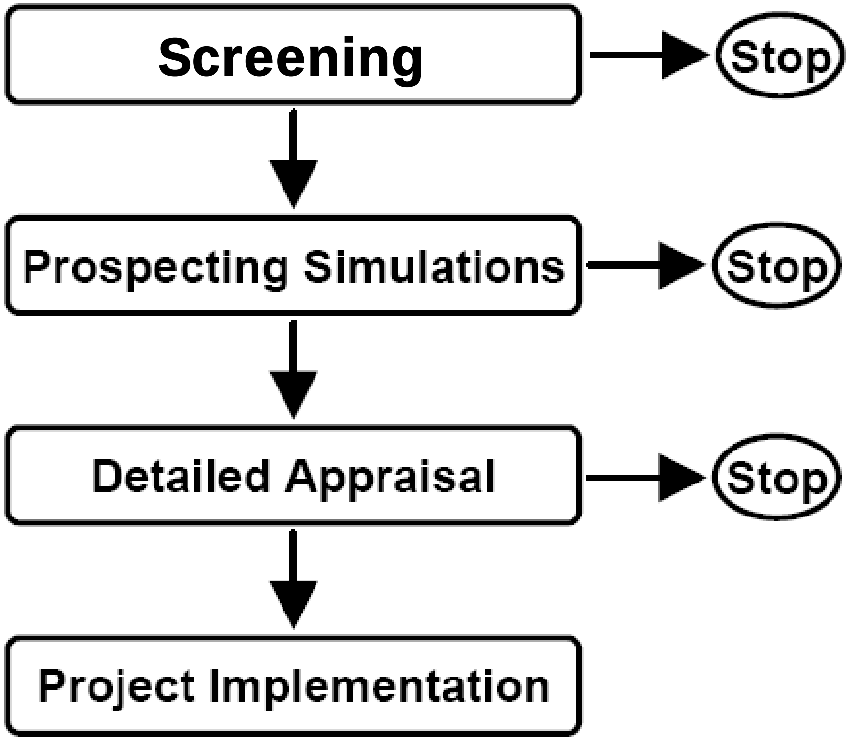
EOR Project

Three Stage Approach for EOR Screening

1th : **Rapid initial assessment (screening) of EOR methods** within a field portfolio.

2nd : Assessing using **“prospecting” simulations (sector modeling).**

3rd : **Detailed appraisal and project design**, which may include the **acquisition of additional field or laboratory data**.



First Stage; Rapid (initial) Screening Methods

- This ensures that more detailed studies are focused on those methods with the best prospect of a successful outcome.

- During the first stage, an industrial software (such as the MAESTRO tool, SWORD, or SelEOR) is used to provide a rapid initial screening of IOR potential within a field portfolio to estimate:

1. The technical viability
2. The incremental recovery
3. The economics of each combination of reservoir and IOR technique

- ***As result*** **: Possible EOR projects to be ranked so that clearly unviable processes can be eliminated and priorities will be set for the subsequent stages of evaluation.**

Rapid (initial) Screening Methods

Five major types:

1. **Database screening** - filtering database using certain criteria, e.g. Reservoir crudes with API > 22^{o}
2. **Process Screening** - screen database for all reservoirs amenable to certain EOR method, e.g. Reservoirs amenable to CO2 miscible flooding
3. **Project Screening** - Assess amenability of various EOR methods in a single reservoir based on criteria, e.g-1 What is the most appropriate EOR method for reservoir ‘A’, or e.g-2 Will CO2 flooding be technically (or economically) feasible in reservoir ‘A’.
4. **Geospatial screening** - screening on proximity to other resources. e.g. Reservoirs within ‘x’ miles of CO2 pipeline.
5. **Economic Screening (Scoping)** - using some economic function determine economic viability of CO2 flood. e.g. Reservoirs profitable with 20% ROR.

Rapid (initial) Screening Methods

Systematic screening has two requirements:

- A **set of criteria** built **on empirical evidence** or **experience**.
- A framework within which to compare parameters to the criteria set.

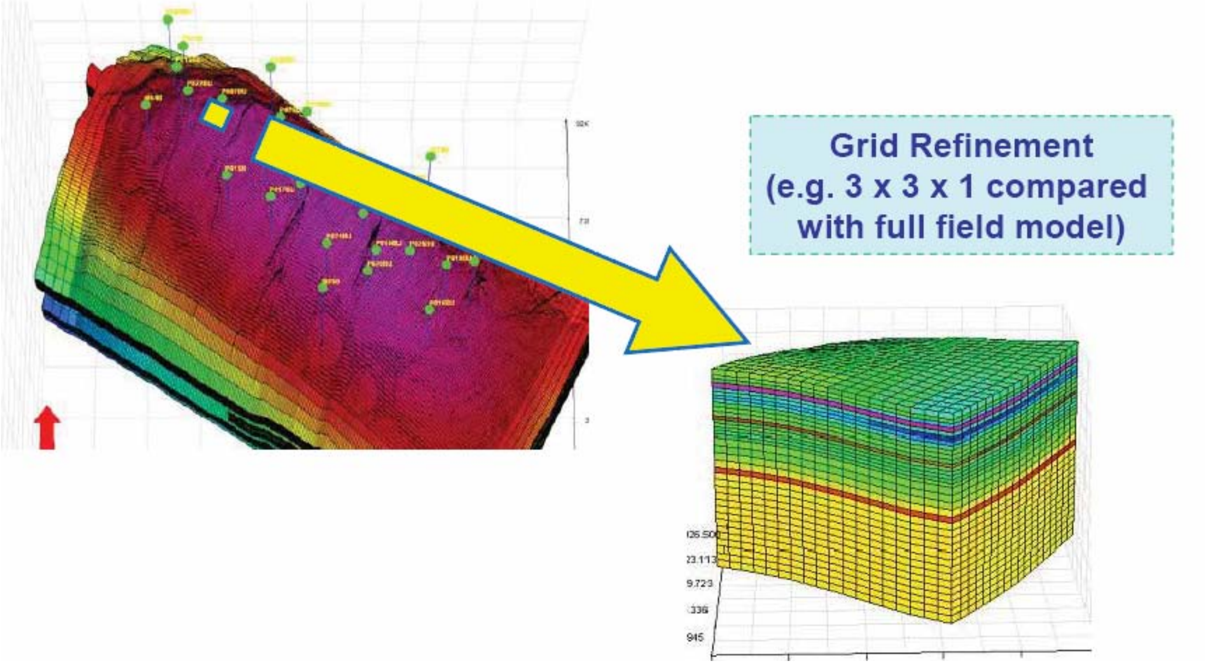
1. "Go/no-go" criteria
2. "Fuzzy" criteria (**as Commercial Example SWORD)**
3. Neural networks, machine learning, artificial intelligence

- Benchmark example: Taber et. al. 1997 Parts I & II. SPE 35385 & 39234

Second Stage; Simulation Sector Models

- The remaining projects are assessed using “prospecting” simulations (or sector modeling):

1. to examine the recovery mechanisms in more detail,
2. to establish base case economics.


Grid Refinement
(e.g. 3 x 3 x 1 compared with full field model)

Second Stage's Notices

- Some of the important reservoir specific parameters that control the EOR processes will not be known at this time.
- Experience is used to define credible sets of process parameters, taking into account typical distributions of values, the cost of subsequently determining them and the potential project rewards.
- At this level, good reservoir engineering is needed to ensure that EOR projects are not prematurely eliminated.
- ***As result :*** **Only projects with economic base cases proceed to the final stage of evaluation.**

Second Stage “Economic” Screening

Requirements

- ✓ New cost and revenue based parameters
- ✓ Single criteria (ROR)
- ✓ Some method of estimating production
- ✓ Production analogues, Compositional model

Outputs

- ✓ Incremental Oil
- ✓ PV of Profits
- ✓ Cumulative CO2 use
- ✓ Average CO2 demand
- ✓ Operating Period

Economic Screening Scoping

Requirements for example for a CO_2 project.

- ✓ P = Price of Oil
- ✓ Q_t = the projected incremental amount of oil recovered in period t
- ✓ x^R = Royalties
- ✓ x^{SP} = severance and property taxes
- ✓ pq^p_t = cost of purchasing CO2
- ✓ $c^r_t\, q^r_t$ = cost of recycling and re-injecting CO2
- ✓ c^o_t = other incremental operating costs
- ✓ K = upfront investment costs

$$NPV = \sum_{t=1}^{T} \frac{PQ_t(1-x^R)(1-x^{SP}) - pq_t^p - c_t^r q_t^r - c_t^o}{(1+r)^t} - K$$

Third Stage

- During this stage, the prospecting simulations and detailed appraisal studies are conducted in a risk management framework to :

1. quantify project risk,
2. identify the Critical Project Parameters (CPPs)

- Proactive risk management techniques, including improved project design, key data acquisition and contingency planning must be used to improve the balance between project return and exposure.

Third Stage ; Project Results

1. Ranking of possible EOR projects for a specific field.
2. The incremental recovery of each EOR method.
3. The economics of each combination of reservoir and EOR method.
4. Detailed plan for acquisition of additional field or experimental data.

Software for EOR methods screening

Worldwide Petroleum Industry's Experience on EOR Methods Screening

1. SelectEOR
2. EORgui
3. SWORD
4. MAESTRO

EOR SCREENING SOFTWARE

EORgui

PetroleumSolutions.co.uk

Graphical User Interface for the USA DOE

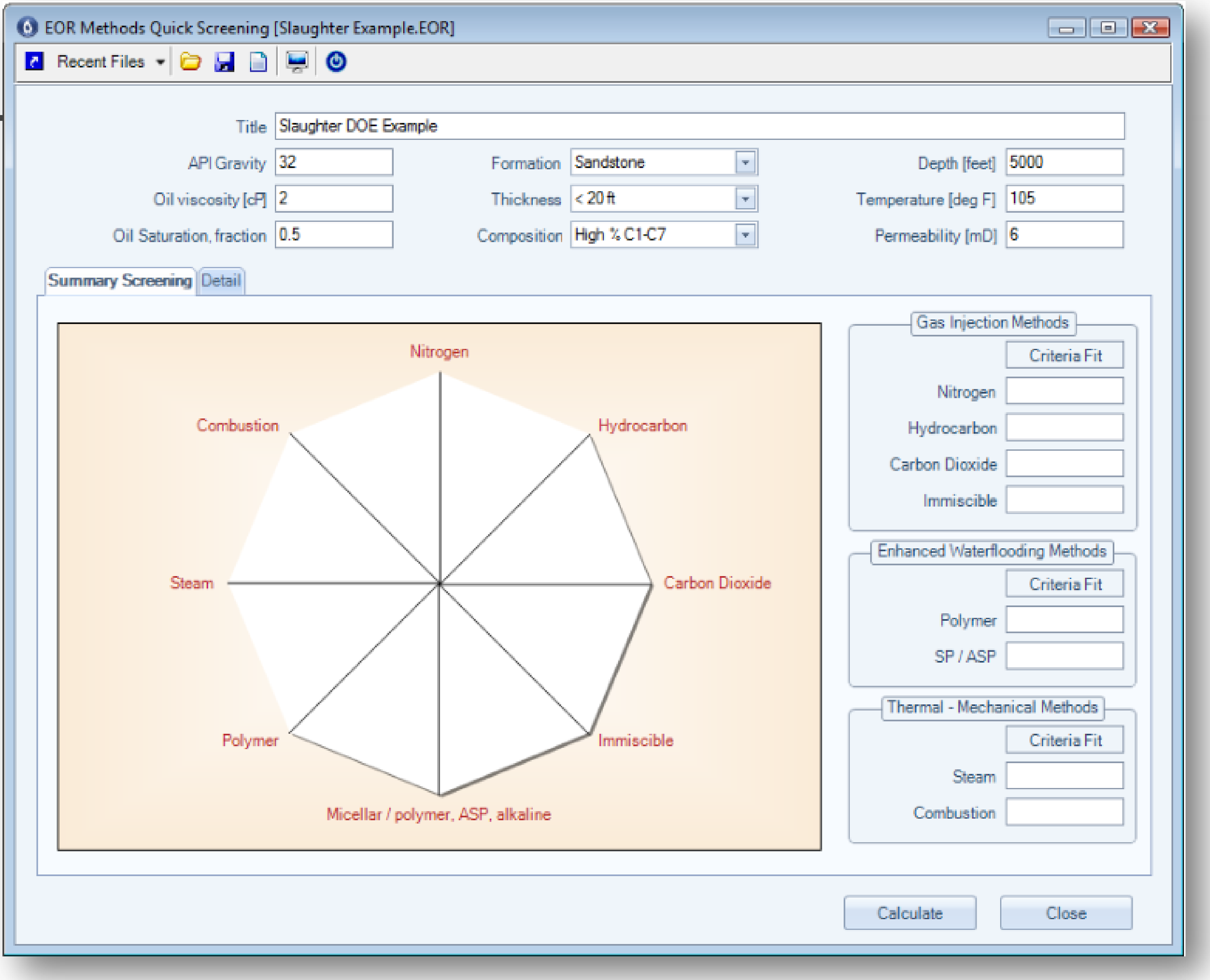
Introduction

- Quickly screen and rank appropriate EOR methods for a given set of summary reservoir and fluid properties.
- Prepares the input files required for the technical analysis portions of the publicly available fortran applications. Namely, the GUI does not prepare the input required to calculate the economic analysis that is also available within these publicly available software.
- The GUI runs the fortran applications and imports the results back into the application.
- The results are input into convenient data tables for export into other applications (eg. Microsoft Excel), and also plotted in high output quality charts for use with other applications (eg. Microsoft Powerpoint).

Quick Screening

- This routine is based on the 1996 Society of Petroleum Engineers Paper entitled "EOR Screening Criteria Revisited" by Taber, Martin, and Seright. Contained within this paper are concise screening guidelines for various EOR techniques, all of which are listed in the table provided in the Detail tab, as shown in the third figure on the next slide.

Quick Screening



EOR Methods Quick Screening [Slaughter Example.EOR]

Title: Slaughter DOE Example

API Gravity: 32

Oil viscosity [cP]: 2

Oil Saturation, fraction: 0.5

Formation: Sandstone

Thickness: < 20 ft

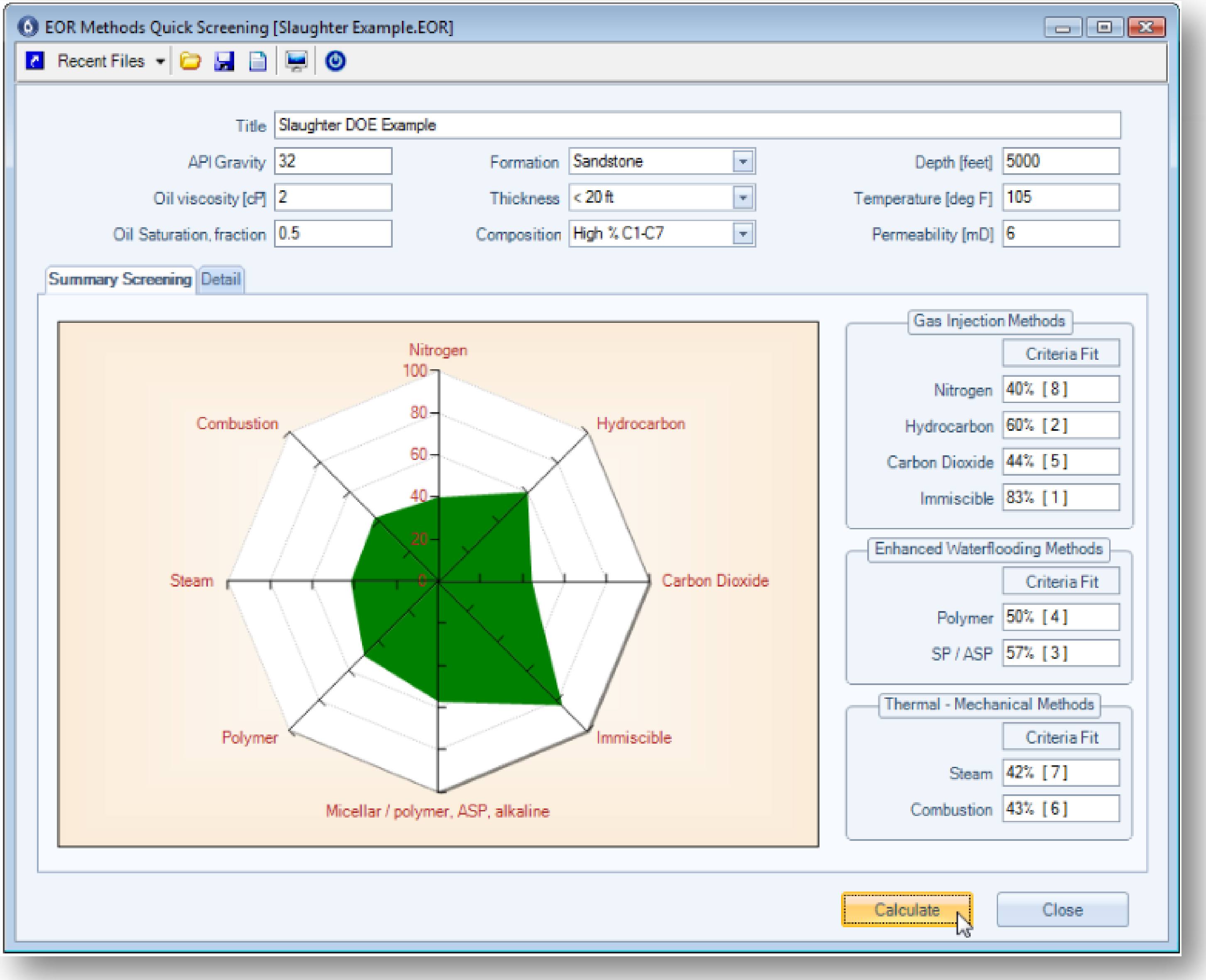
Composition: High % C1-C7

Depth [feet]: 5000

Temperature [deg F]: 105

Permeability [mD]: 6

Quick Screening



EOR Methods Quick Screening [Slaughter Example.EOR]

Title	Slaughter DOE Example				
API Gravity	32	Formation	Sandstone	Depth [feet]	5000
Oil viscosity [cP]	2	Thickness	< 20 ft	Temperature [deg F]	105
Oil Saturation, fraction	0.5	Composition	High % C1-C7	Permeability [mD]	6

Gas Injection Methods

	Criteria Fit
Nitrogen	40% [8]
Hydrocarbon	60% [2]
Carbon Dioxide	44% [5]
Immiscible	83% [1]

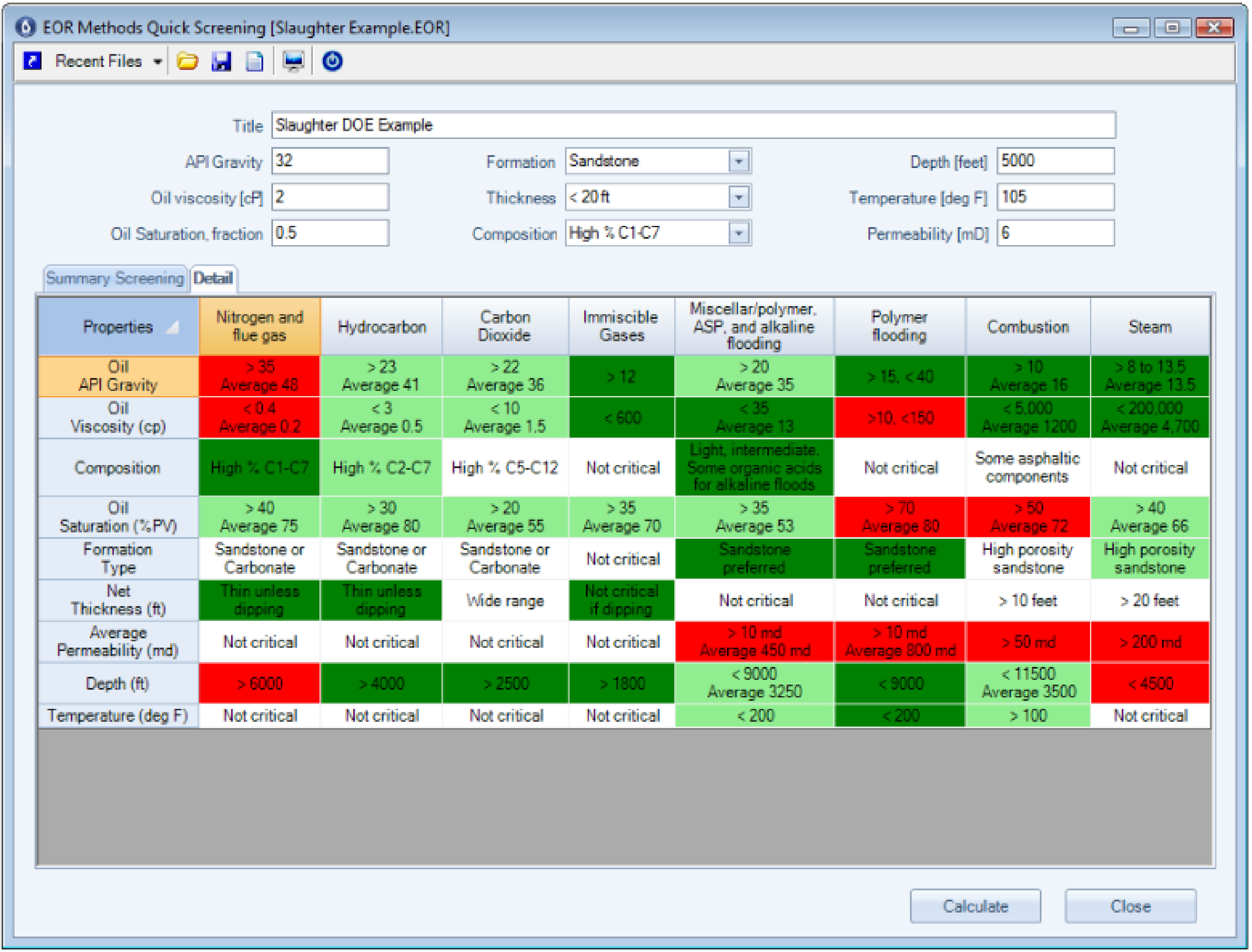
Enhanced Waterflooding Methods

	Criteria Fit
Polymer	50% [4]
SP / ASP	57% [3]

Thermal - Mechanical Methods

	Criteria Fit
Steam	42% [7]
Combustion	43% [6]

Quick Screening



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Formation: Sandstone

Thickness: < 20 ft

Composition: High % C1-C7

Depth [feet]: 5000

Temperature [deg F]: 105

Permeability [mD]: 6

Properties	Nitrogen and flue gas	Hydrocarbon	Carbon Dioxide	Immiscible Gases	Miscellar/polymer, ASP, and alkaline flooding	Polymer flooding	Combustion	Steam
Oil API Gravity	> 35 Average 48	> 23 Average 41	> 22 Average 36	> 12	> 20 Average 35	> 15, < 40	> 10 Average 16	> 8 to 13.5 Average 13.5
Oil Viscosity (cp)	< 0.4 Average 0.2	< 3 Average 0.5	< 10 Average 1.5	< 600	< 35 Average 13	>10, <150	< 5,000 Average 1200	< 200,000 Average 4,700
Composition	High % C1-C7	High % C2-C7	High % C5-C12	Not critical	Light, intermediate. Some organic acids for alkaline floods	Not critical	Some asphaltic components	Not critical
Oil Saturation (%PV)	> 40 Average 75	> 30 Average 80	> 20 Average 55	> 35 Average 70	> 35 Average 53	> 70 Average 80	> 50 Average 72	> 40 Average 66
Formation Type	Sandstone or Carbonate	Sandstone or Carbonate	Sandstone or Carbonate	Not critical	Sandstone preferred	Sandstone preferred	High porosity sandstone	High porosity sandstone
Net Thickness (ft)	Thin unless dipping	Thin unless dipping	Wide range	Not critical if dipping	Not critical	Not critical	> 10 feet	> 20 feet
Average Permeability (md)	Not critical	Not critical	Not critical	Not critical	> 10 md Average 450 md	> 10 md Average 800 md	> 50 md	> 200 md
Depth (ft)	> 6000	> 4000	> 2500	> 1800	< 9000 Average 3250	< 9000	< 11500 Average 3500	< 4500
Temperature (deg F)	Not critical	Not critical	Not critical	Not critical	< 200	< 200	> 100	Not critical

CO2 Miscible Flooding Predictive Model

- - The CO2 flooding process consists of injecting large quantities of CO2 into the reservoir.
- - Although CO2, is not first-contact miscible with the crude oil, the CO2 extracts the light-to-intermediate components from the oil, and, if the pressure is high enough, develops miscibility to displace the crude oil from the reservoir.
- - Immiscible displacements are less effective, but they recover oil better than waterflooding.
- - CO2 recovers oil by swelling the crude oil, lowering the viscosity of the oil and lowering the interfacial tension between the oil and the CO2 phase in the near miscible region.

CO2 Miscible Flooding Predictive Model

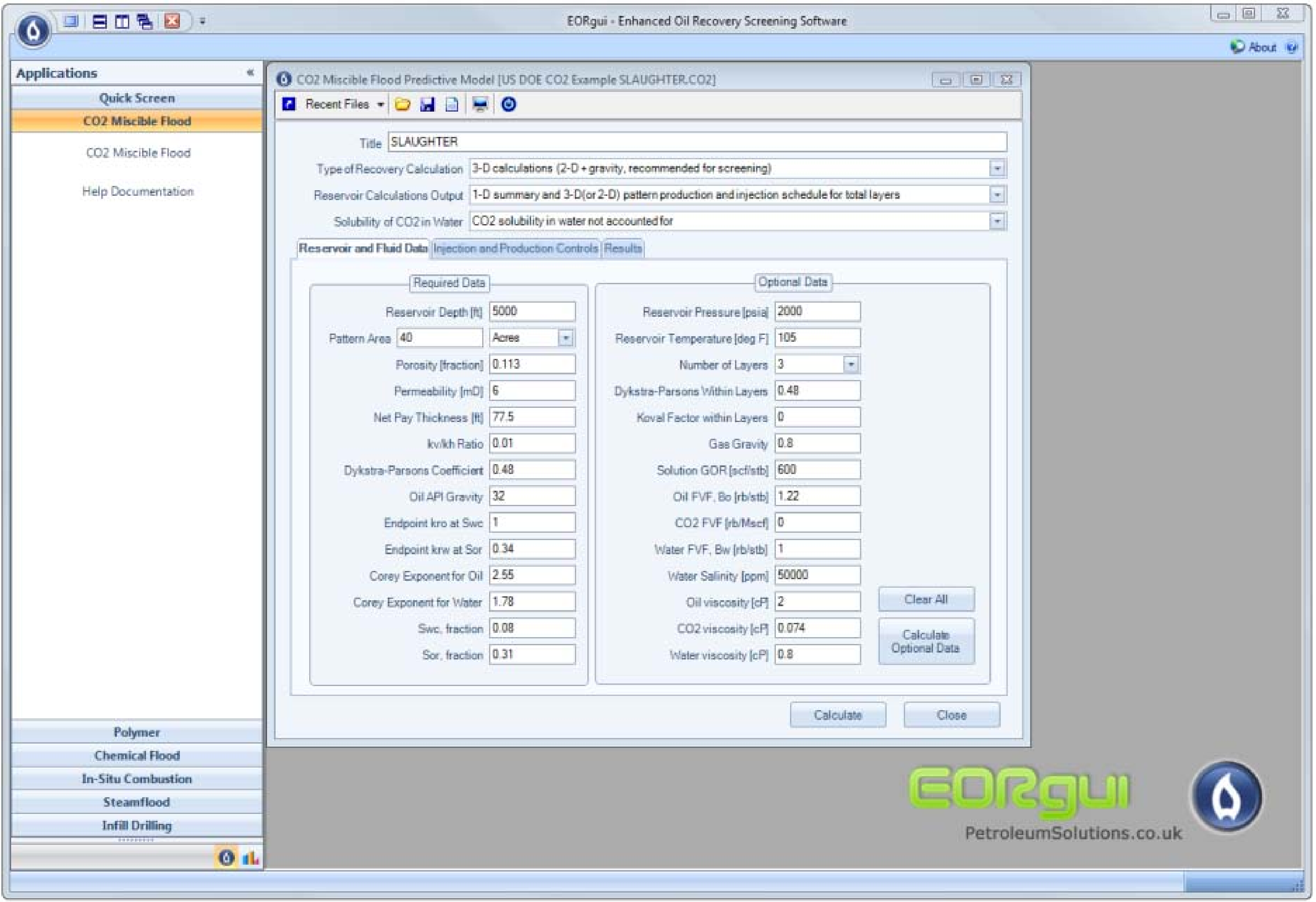
➢- Used model is three-dimensional (layered, five-spot), two-phase (aqueous and oleic), three component (oil, water, and C02) model.

➢- It computes oil and C02 breakthrough and recovery from fractional theory modified for the effects of viscous fingering, areal sweep, vertical heterogeneity and gravity segregation.

➢One-dimensional fractional flow theory is applied to first-contact miscible displacements in the presence of a second immiscible phase.

➢- The theory is based on a specialized version of the method of characteristics known as coherence or simple wave theory. The theory incorporates the Koval (1963) factor method to account for unstable miscible displacements (fingering).

CO2 Miscible Flooding Predictive Model



CO2 Miscible Flood Predictive Model [US DOE CO2 Example SLAUGHTER.CO2]

Title: SLAUGHTER

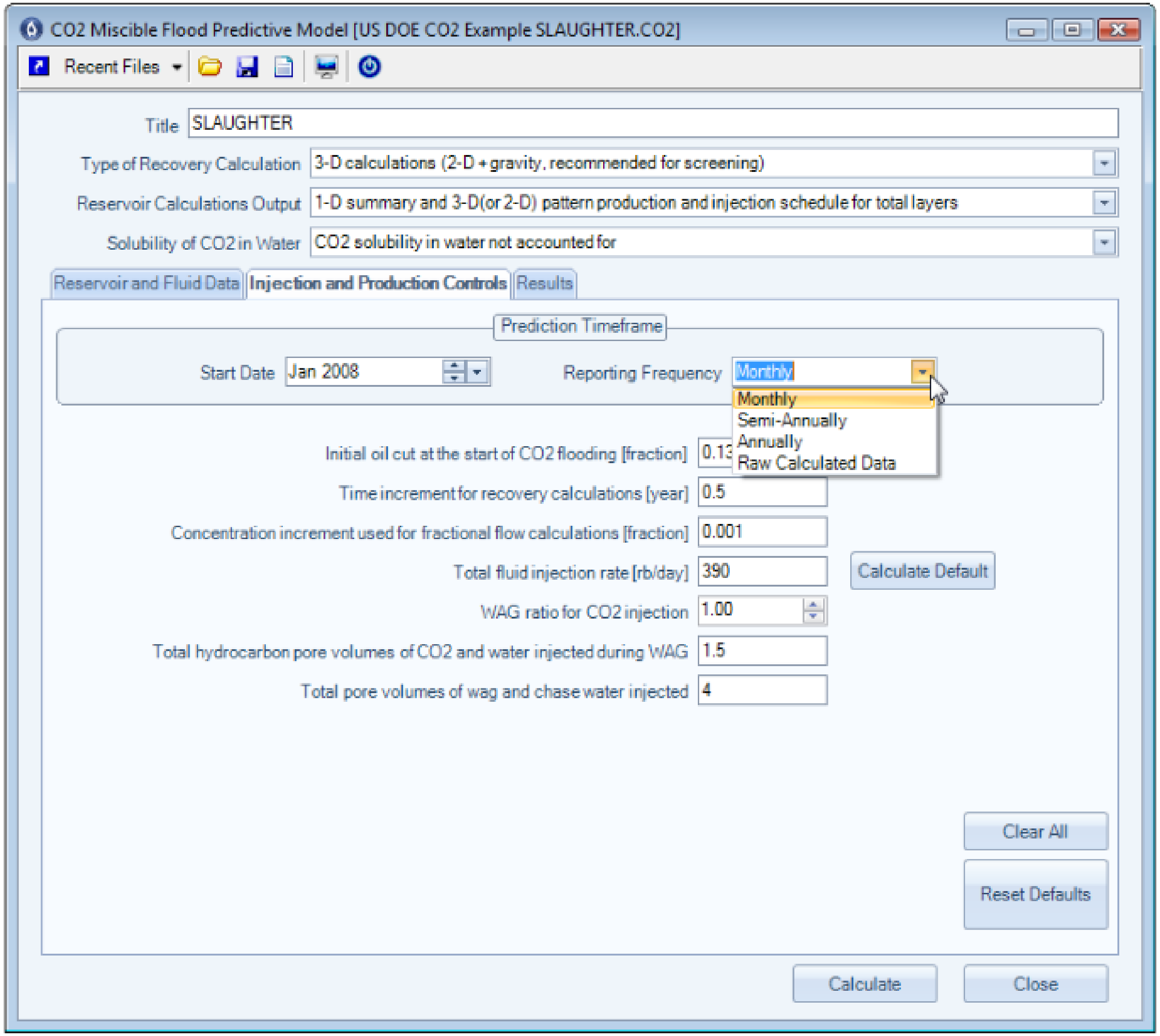
Type of Recovery Calculation: 3-D calculations (2-D + gravity, recommended for screening)

Reservoir Calculations Output: 1-D summary and 3-D(or 2-D) pattern production and injection schedule for total layers

Solubility of CO2 in Water: CO2 solubility in water not accounted for

Required Data		Optional Data	
Reservoir Depth [ft]	5000	Reservoir Pressure [psia]	2000
Pattern Area	40 Acres	Reservoir Temperature [deg F]	105
Porosity [fraction]	0.113	Number of Layers	3
Permeability [mD]	6	Dykstra-Parsons Within Layers	0.48
Net Pay Thickness [ft]	77.5	Koval Factor within Layers	0
kv/kh Ratio	0.01	Gas Gravity	0.8
Dykstra-Parsons Coefficient	0.48	Solution GOR [scf/stb]	600
Oil API Gravity	32	Oil FVF, Bo [rb/stb]	1.22
Endpoint kro at Swc	1	CO2 FVF [rb/Mscf]	0
Endpoint krw at Sor	0.34	Water FVF, Bw [rb/stb]	1
Corey Exponent for Oil	2.55	Water Salinity [ppm]	50000
Corey Exponent for Water	1.78	Oil viscosity [cP]	2
Swc, fraction	0.08	CO2 viscosity [cP]	0.074
Sor, fraction	0.31	Water viscosity [cP]	0.8

CO2 Miscible Flooding Predictive Model



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Prediction Timeframe

Start Date: Jan 2008

Reporting Frequency: Monthly

Initial oil cut at the start of CO2 flooding [fraction]: 0.13

Time increment for recovery calculations [year]: 0.5

Concentration increment used for fractional flow calculations [fraction]: 0.001

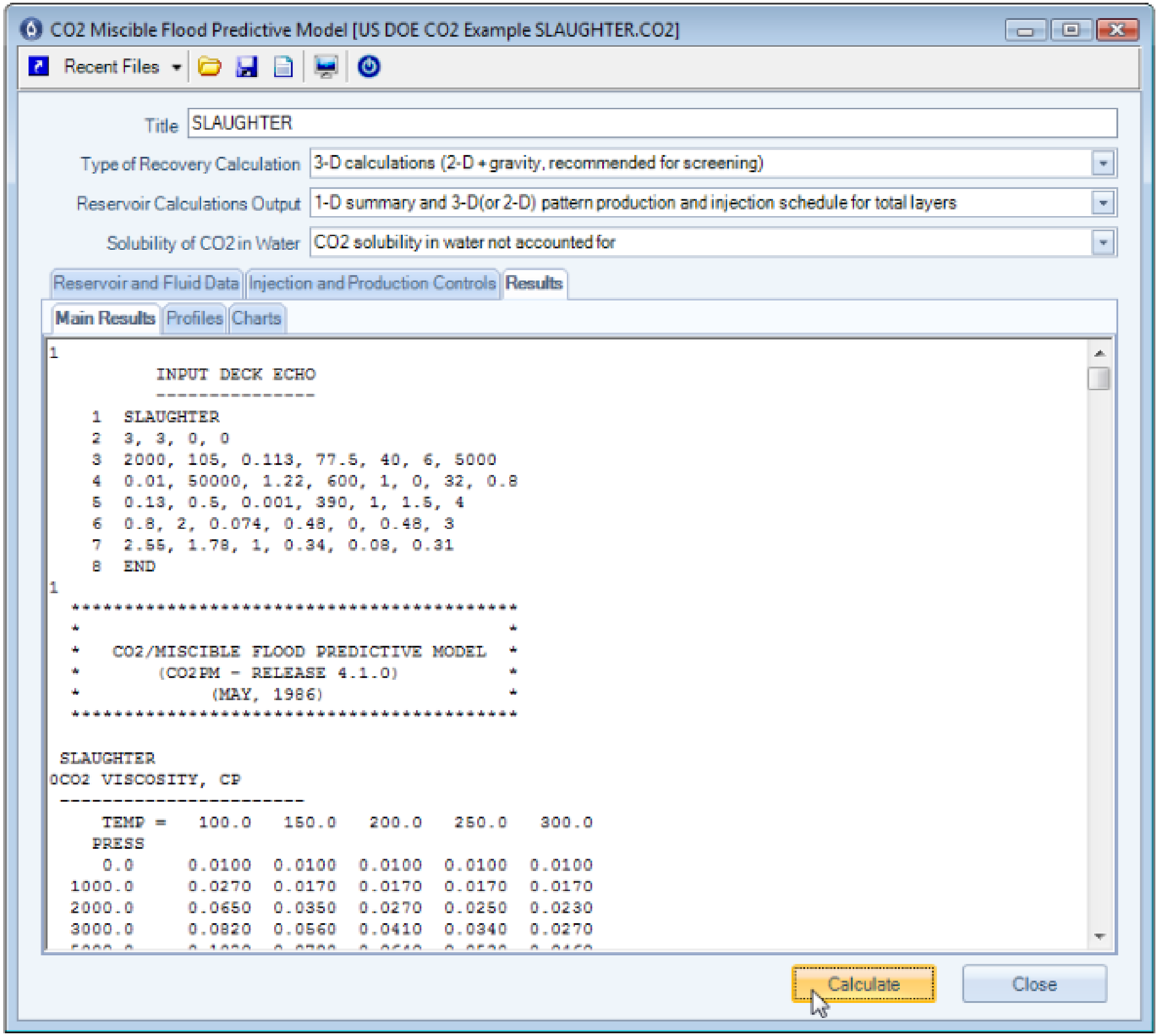
Total fluid injection rate [rb/day]: 390

WAG ratio for CO2 injection: 1.00

Total hydrocarbon pore volumes of CO2 and water injected during WAG: 1.5

Total pore volumes of wag and chase water injected: 4

CO2 Miscible Flooding Predictive Model



CO2 Miscible Flood Predictive Model [US DOE CO2 Example SLAUGHTER.CO2]

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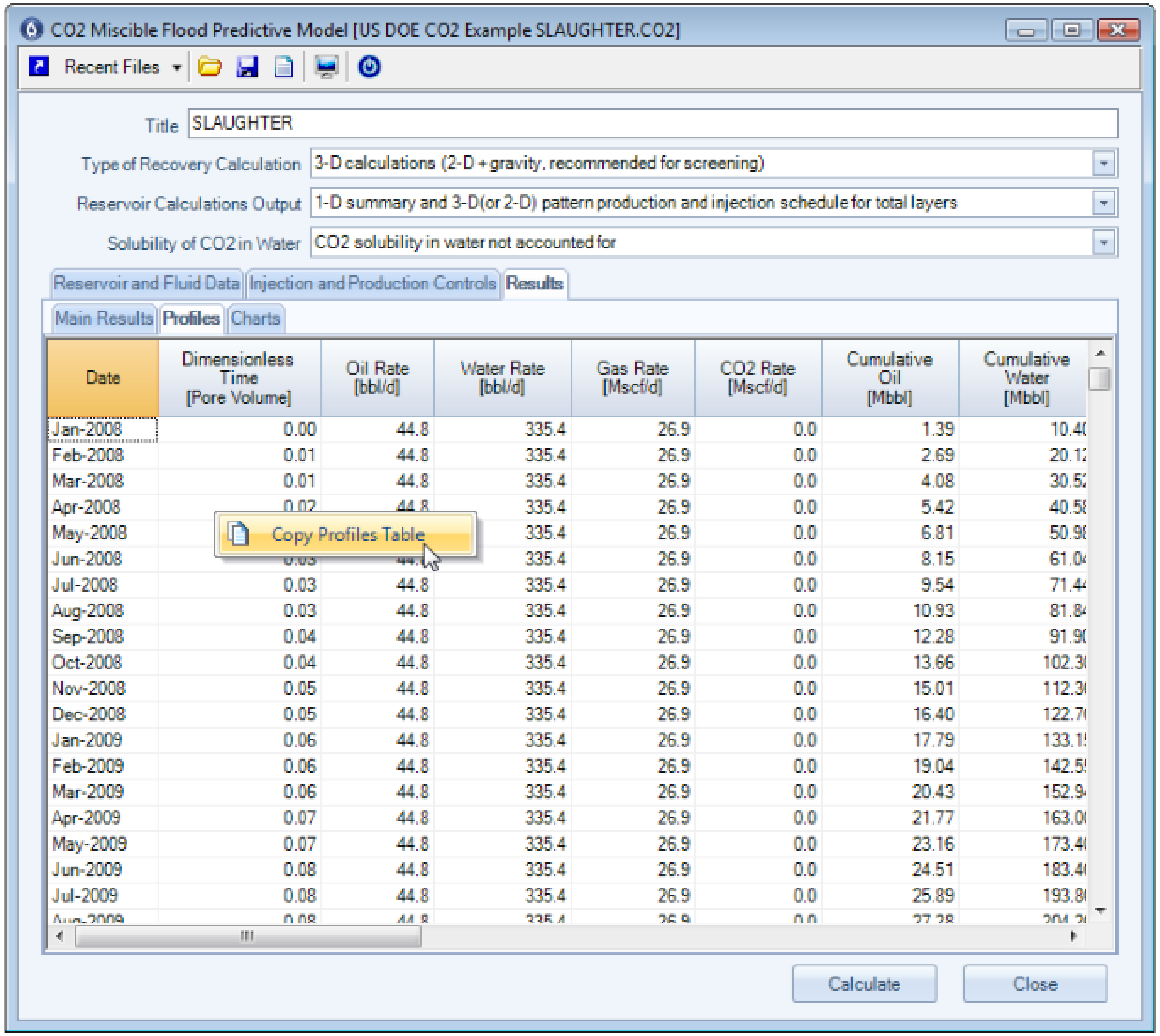
Solubility of CO2 in Water: CO2 solubility in water not accounted for

```
1
          INPUT DECK ECHO
          ---------------
    1  SLAUGHTER
    2  3, 3, 0, 0
    3  2000, 105, 0.113, 77.5, 40, 6, 5000
    4  0.01, 50000, 1.22, 600, 1, 0, 32, 0.8
    5  0.13, 0.5, 0.001, 390, 1, 1.5, 4
    6  0.8, 2, 0.074, 0.48, 0, 0.48, 3
    7  2.55, 1.78, 1, 0.34, 0.08, 0.31
    8  END
1
  ******************************************
  *                                        *
  *   CO2/MISCIBLE FLOOD PREDICTIVE MODEL  *
  *       (CO2PM - RELEASE 4.1.0)          *
  *            (MAY, 1986)                 *
  ******************************************


 SLAUGHTER
0CO2 VISCOSITY, CP
 -----------------------
    TEMP =   100.0   150.0   200.0   250.0   300.0
   PRESS
    0.0     0.0100  0.0100  0.0100  0.0100  0.0100
  1000.0    0.0270  0.0170  0.0170  0.0170  0.0170
  2000.0    0.0650  0.0350  0.0270  0.0250  0.0230
  3000.0    0.0820  0.0560  0.0410  0.0340  0.0270
```

CO2 Miscible Flooding Predictive Model



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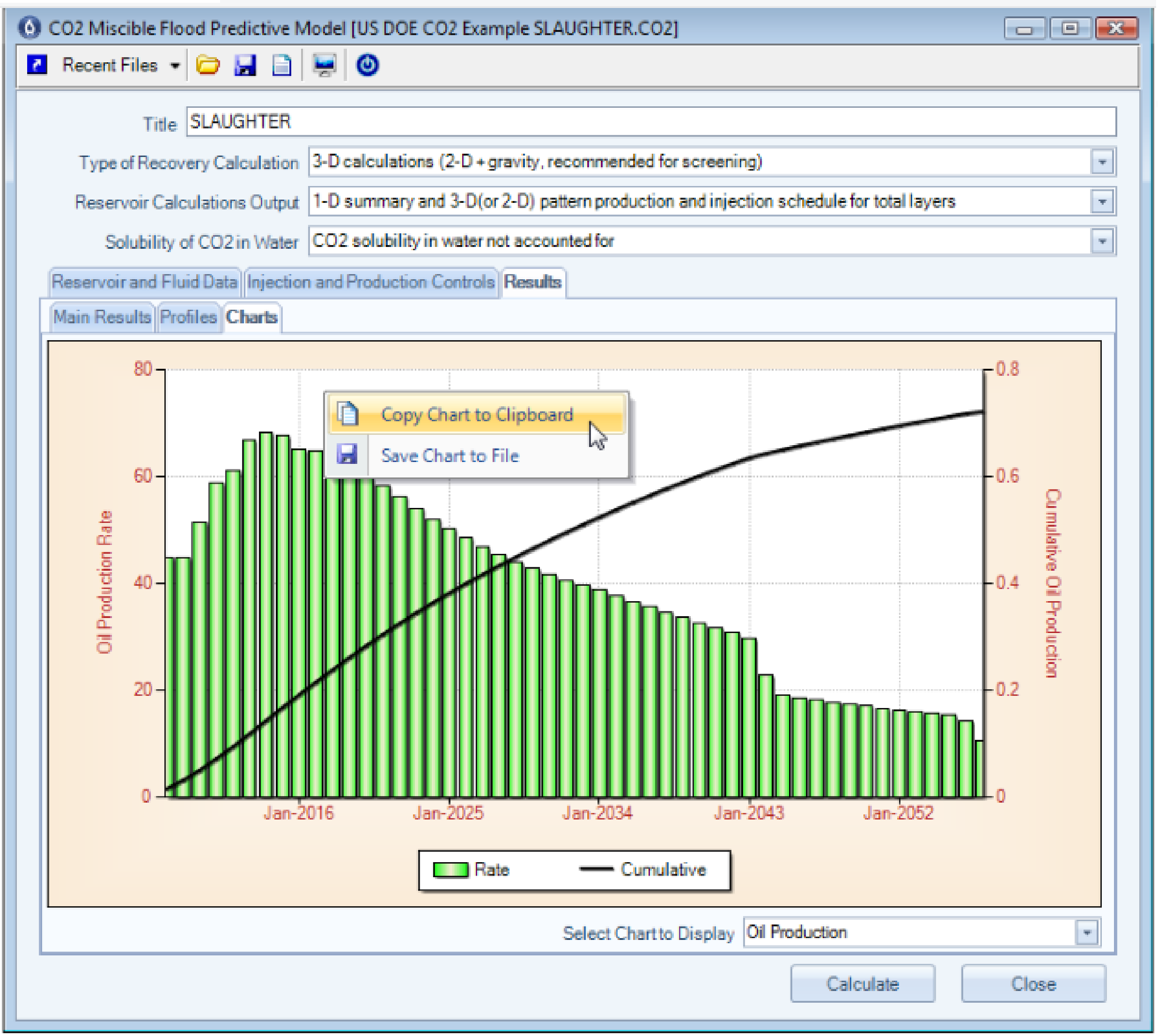
Solubility of CO2 in Water: CO2 solubility in water not accounted for

Date	Dimensionless Time [Pore Volume]	Oil Rate [bbl/d]	Water Rate [bbl/d]	Gas Rate [Mscf/d]	CO2 Rate [Mscf/d]	Cumulative Oil [Mbbl]	Cumulative Water [Mbbl]
Jan-2008	0.00	44.8	335.4	26.9	0.0	1.39	10.4
Feb-2008	0.01	44.8	335.4	26.9	0.0	2.69	20.1
Mar-2008	0.01	44.8	335.4	26.9	0.0	4.08	30.5
Apr-2008	0.02	44.8	335.4	26.9	0.0	5.42	40.5
May-2008	[illegible]	[illegible]	335.4	26.9	0.0	6.81	50.9
Jun-2008	[illegible]	[illegible]	335.4	26.9	0.0	8.15	61.0
Jul-2008	0.03	44.8	335.4	26.9	0.0	9.54	71.4
Aug-2008	0.03	44.8	335.4	26.9	0.0	10.93	81.8
Sep-2008	0.04	44.8	335.4	26.9	0.0	12.28	91.9
Oct-2008	0.04	44.8	335.4	26.9	0.0	13.66	102.3
Nov-2008	0.05	44.8	335.4	26.9	0.0	15.01	112.3
Dec-2008	0.05	44.8	335.4	26.9	0.0	16.40	122.7
Jan-2009	0.06	44.8	335.4	26.9	0.0	17.79	133.1
Feb-2009	0.06	44.8	335.4	26.9	0.0	19.04	142.5
Mar-2009	0.06	44.8	335.4	26.9	0.0	20.43	152.9
Apr-2009	0.07	44.8	335.4	26.9	0.0	21.77	163.0
May-2009	0.07	44.8	335.4	26.9	0.0	23.16	173.4
Jun-2009	0.08	44.8	335.4	26.9	0.0	24.51	183.4
Jul-2009	0.08	44.8	335.4	26.9	0.0	25.89	193.8
Aug-2009	0.08	44.8	335.4	26.9	0.0	27.28	204.2

CO2 Miscible Flooding Predictive Model



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Select Chart to Display: Oil Production

Chemical Flood Predictive Model

Polymer Predictive Model

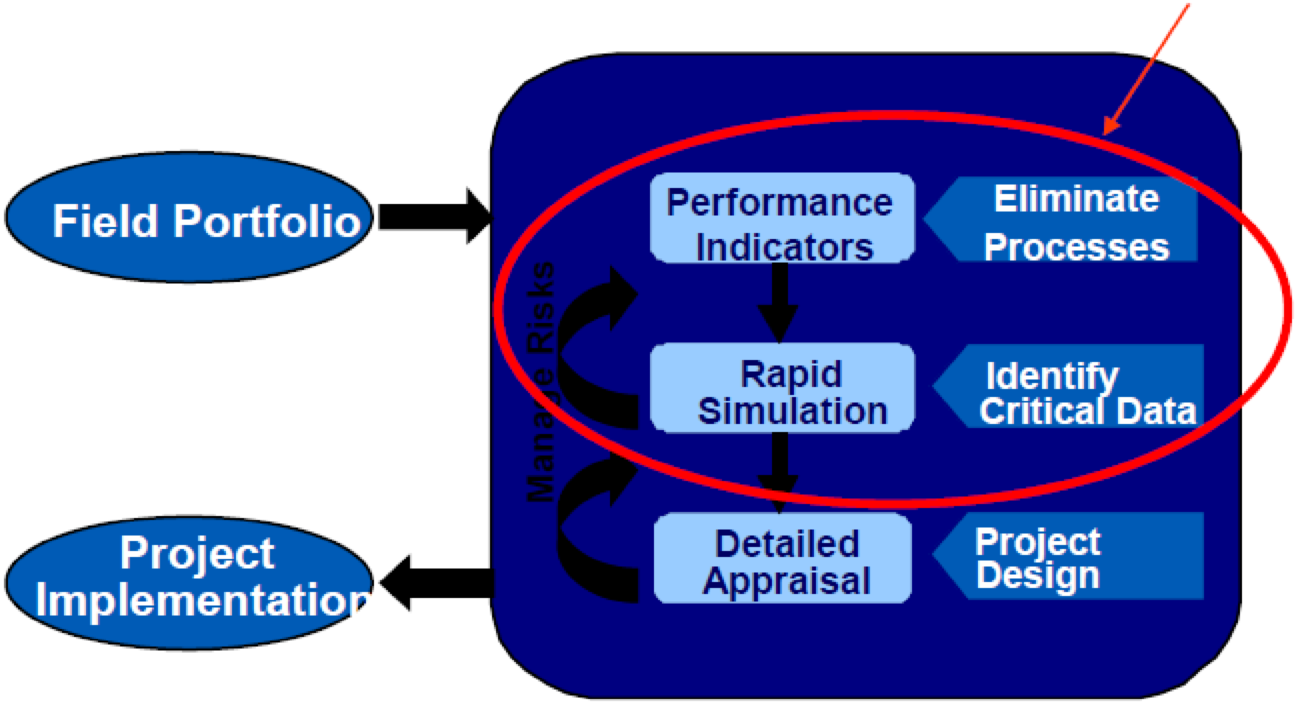
In-situ Combustion Predictive Model

Steamflood Predictive Model

Infill Drilling Predictive Model

MAESTRO

- Developer Company : **ECL Technology (Subsurface group at Winfrith Dorset).**
- Supporter : **Collaboration with BP Institute, Cambridge .**



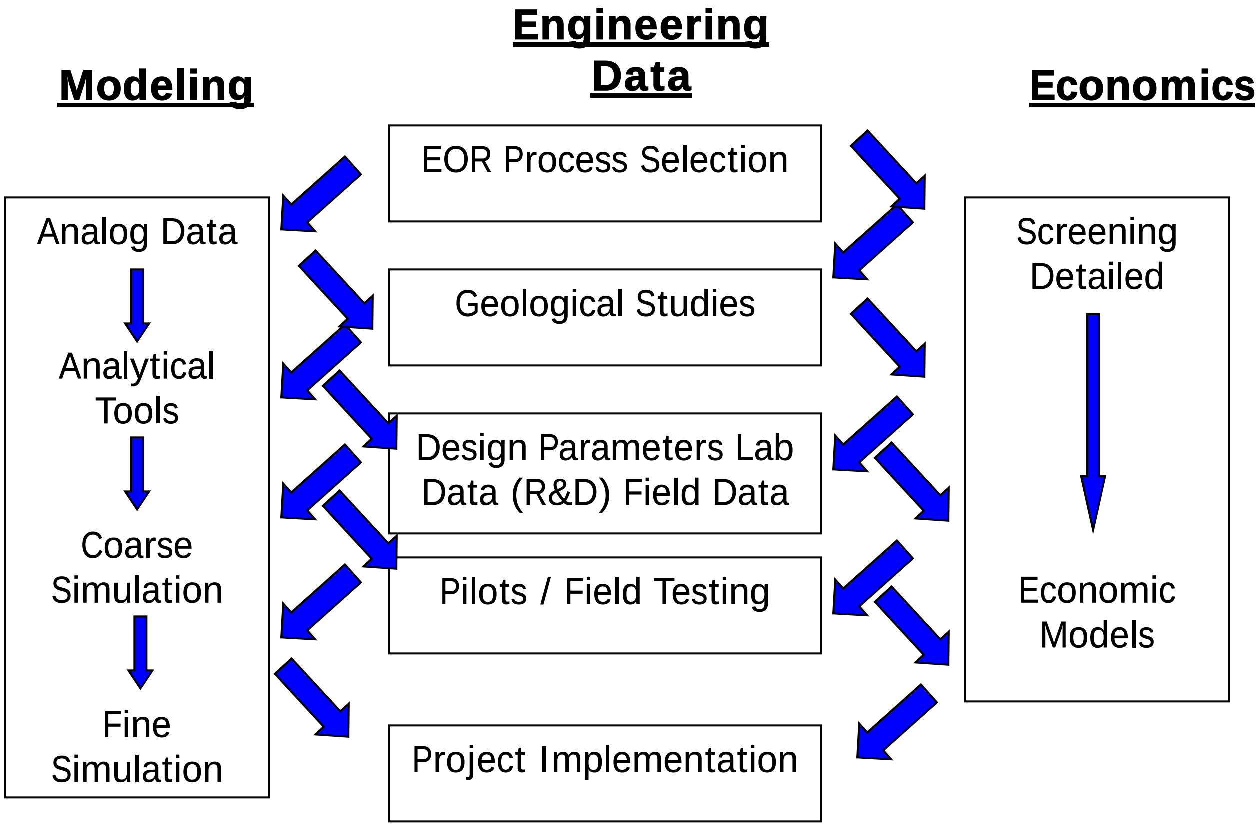
MAESTRO

- is the first of three stages of IOR screening system
- It quickly identifies potentially viable IOR processes and eliminates unviable processes for each asset in a Field Portfolio
- Maestro Rapid Simulation can then be focused on the detailed modeling of the most potentially viable processes

MAESTRO processes are currently considered

- Waterflooding
- WAG (Lean hydrocarbon gas (LHG), CO2, nitrogen, enriched hydrocarbon gas (EHG))
- SWAG (LHG, CO2, nitrogen, EHG)
- GSGI (LHG, CO2, nitrogen, EHG)
- Polymer for mobility control
- Polymer/gels for vertical conformance
- Surfactants

Planning Successful EOR Projects



Modeling

Analog Data

Analytical Tools

Coarse Simulation

Fine Simulation

Engineering Data

EOR Process Selection

Geological Studies

Design Parameters Lab Data (R&D) Field Data

Pilots / Field Testing

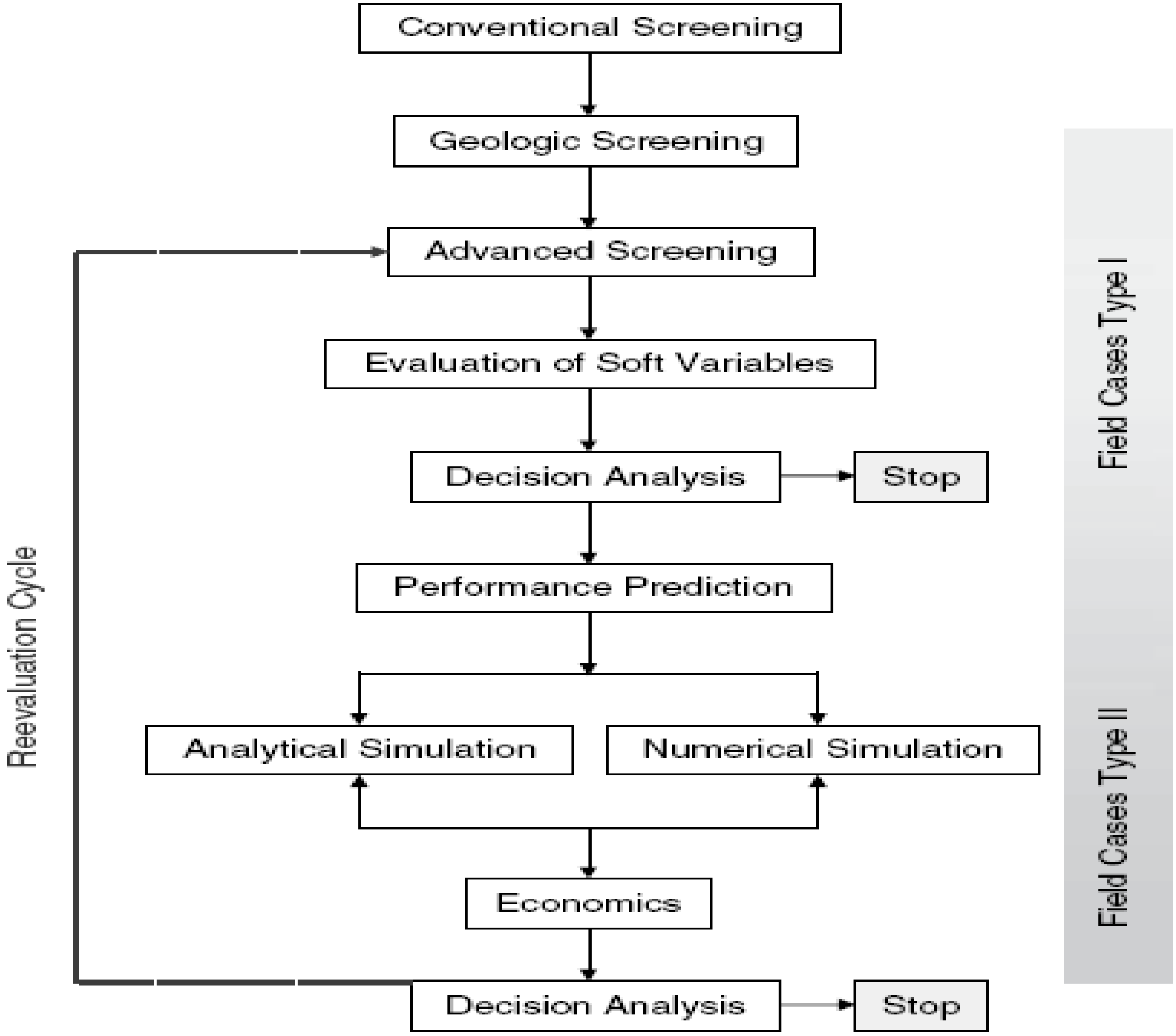
Project Implementation

Economics

Screening Detailed

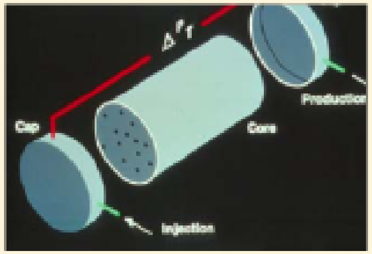
Economic Models

EOR Decision making work flow



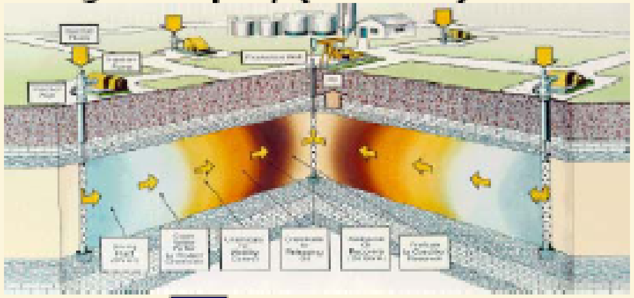
Typical EOR Implementation Approach

Lab Core Flood Evaluation



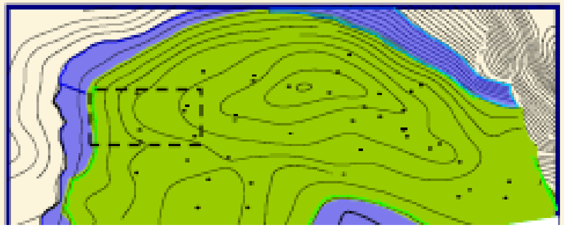
- 3-6 Months Work
- Scale; PV < 250 milliliters (0.001 bbls)
- Cost ~ $200K
- Justification: Essential Screening Step

Single 5-Spot, (or More) Pattern



- 3-5 Years Work
- Scale; PV ~ **500,000 bbls**
- Cost ~ $10MM-$20MM
- Justification: Oil in Tank
  In-Situ Test
  Reduce Further Risk

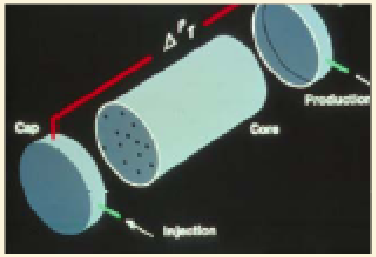
Field Wide or Expanded Flood Pattern



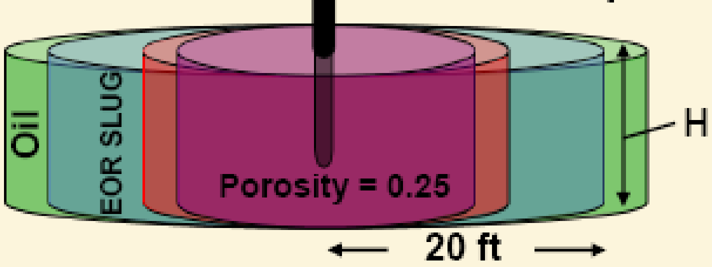
- 5-15 Years Work
- Scale; PV ~ **10MM to >100MM bbls**
- Risk ~ $100MM-$400MM
- Justification: Additional OOIP Recovery

Better EOR Implementation Approach

Lab Core Flood Evaluation

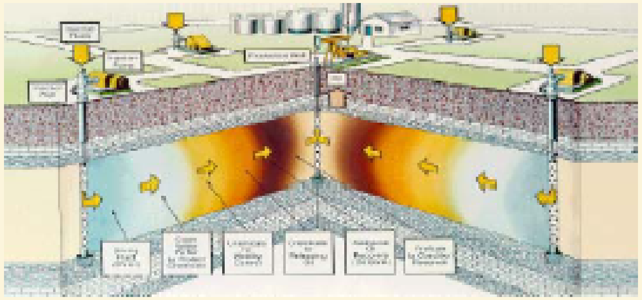


SWCT One-Spot-Pilot

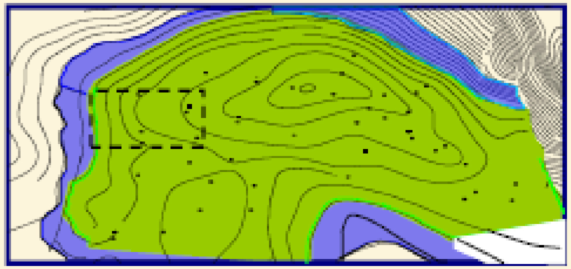


- One Month of Work
- Scale; PV ~ 1,000 bbls
- Cost ~ $150-200K
- Justification: Establish EOR Target Oil
  EOR Injectivity Test
  In-Situ Demonstration
  Reduce Further Risk

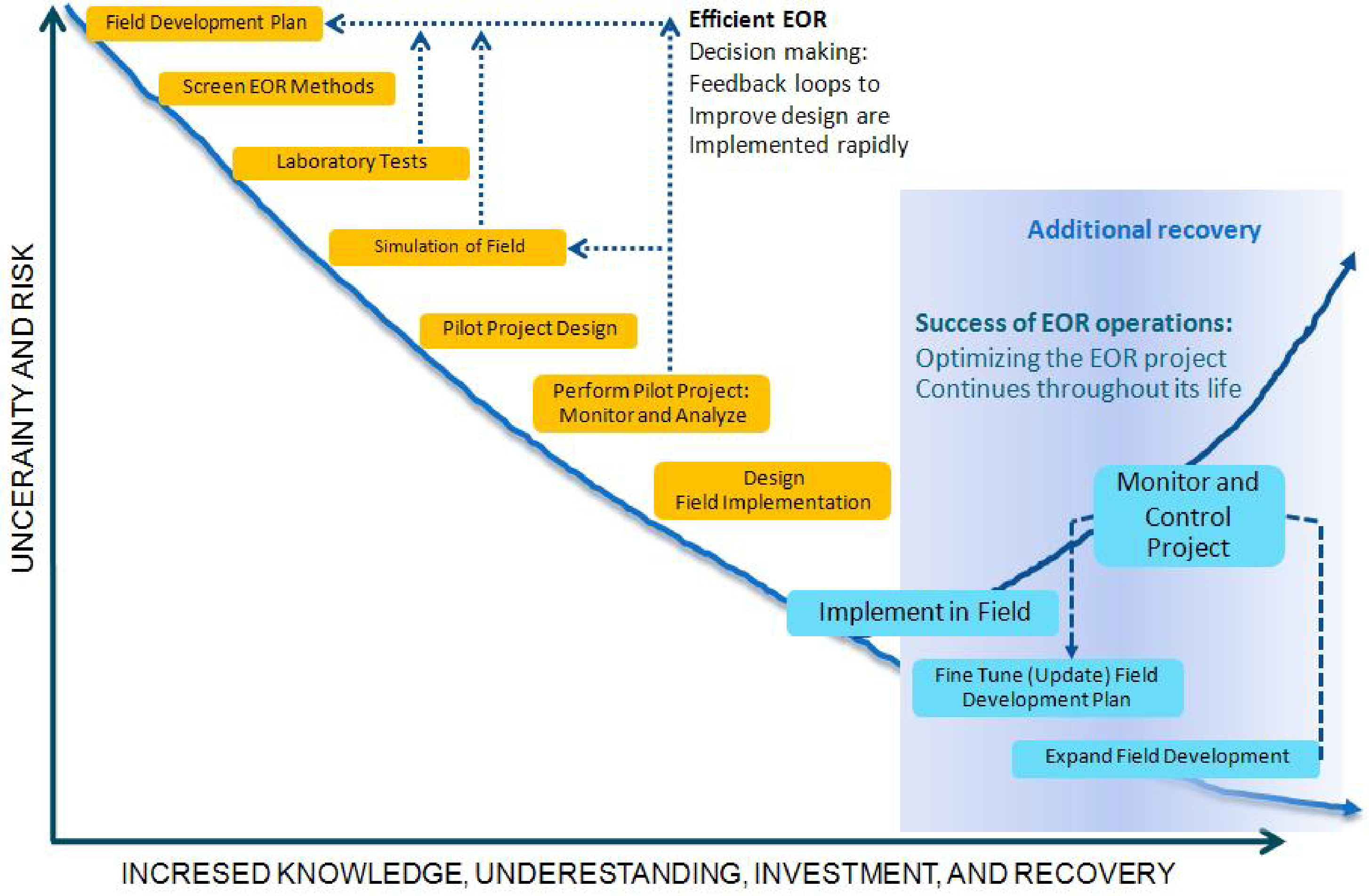
Single 5-Spot, (or More) Pattern



Field Wide or Expanded Flood Pattern



EOR Planning



Efficient EOR
Decision making:
Feedback loops to
Improve design are
Implemented rapidly

Additional recovery

Success of EOR operations:
Optimizing the EOR project
Continues throughout its life

IOR / EOR developments
Ultra mature carbonate environment
Abu Al Bukhoosh Field

- Review of IOR / EOR development on ABK field
  - Tertiary gas injection
- Lessons to be learned

Screening study – Phased approach

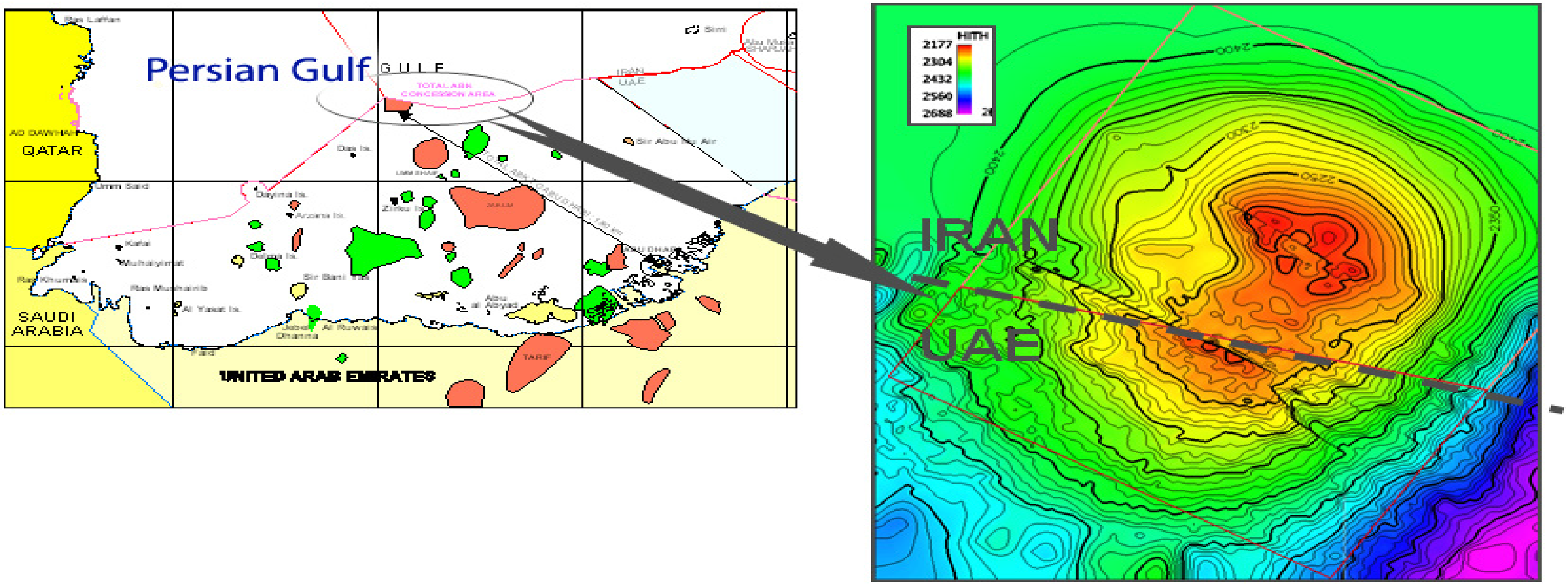
1. Evaluate potential for Enhanced Oil Recovery based on optimized field management
2. Screening of alternative production mechanisms
    - injection of various gas
    - WAG
    - steam injection
    - chemical treatments
    - microbial EOR
3. Numerical modeling on selected fields for selected techniques

Tertiary Process Selection Criteria

- Reservoir characteristics and status
- Microscopic / Macroscopic efficiencies
- Maturity level of the technique
- Injected fluids:
  - Availability / Cost / Suitability *(environment, safety)*
- Process efficiency:
  - Additional reserves
- Economics:
  - Capex, Opex, Barrel price

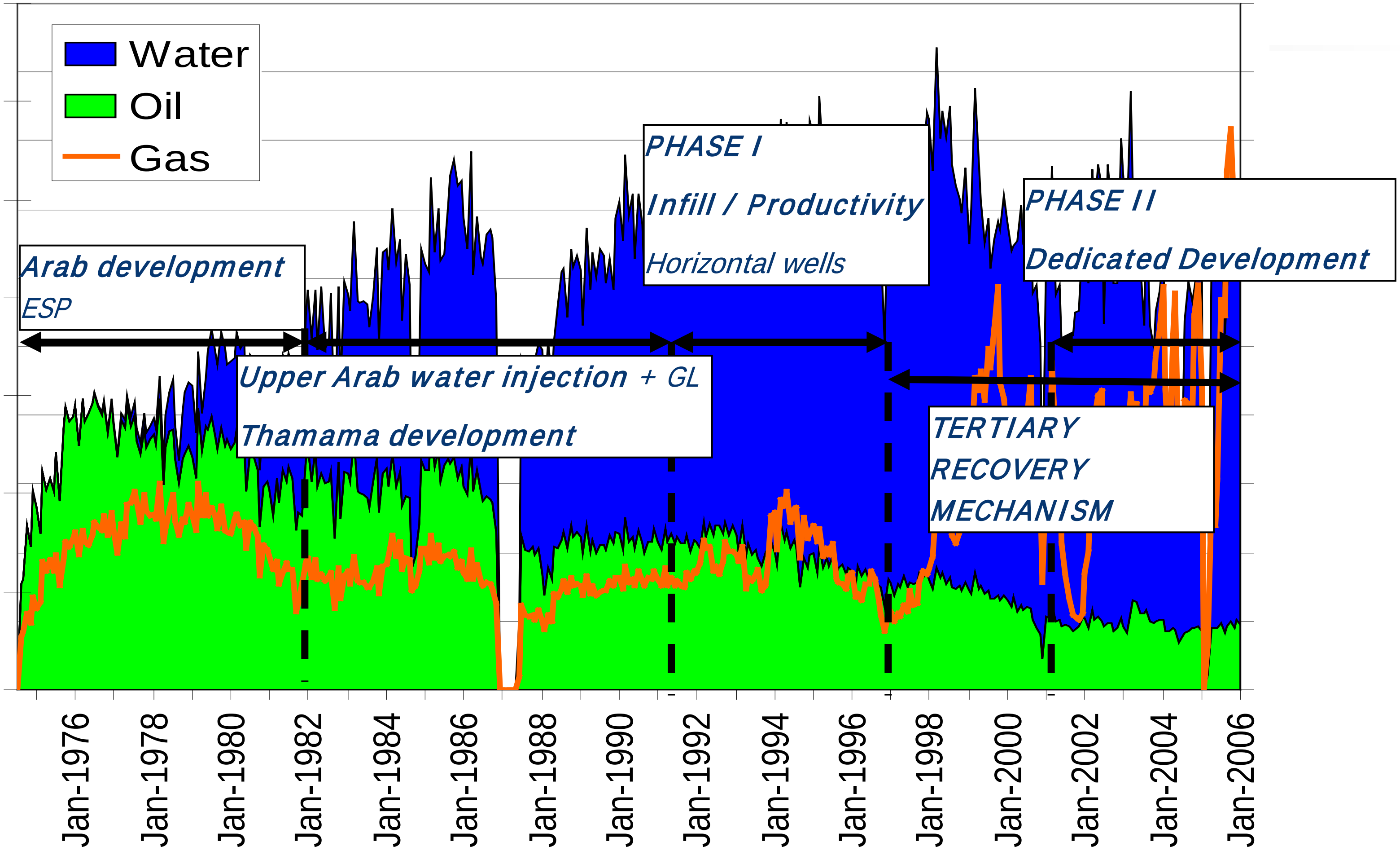
Geological heterogeneities is most of the time a killing factor

ABK field overview



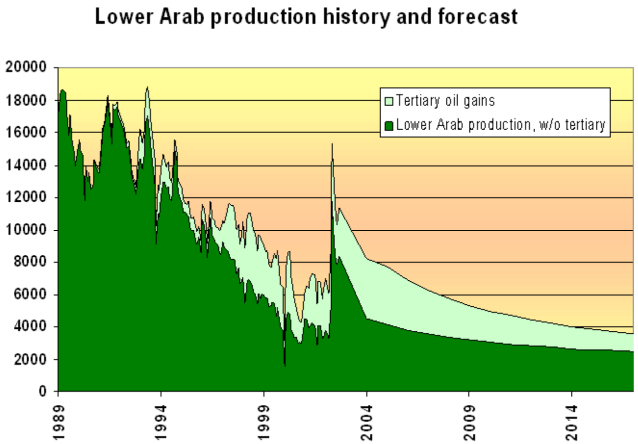
- **2/3 of the structure is located in Iran**
- **Produced since:**
  - 1968 in Iran
  - 1974 in the UAE
- **Production history on the Iranian side is known up to mid-2001**

ABK production history

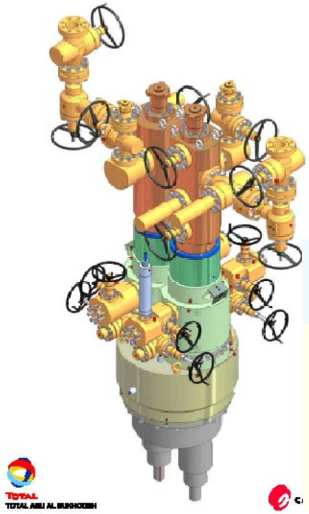


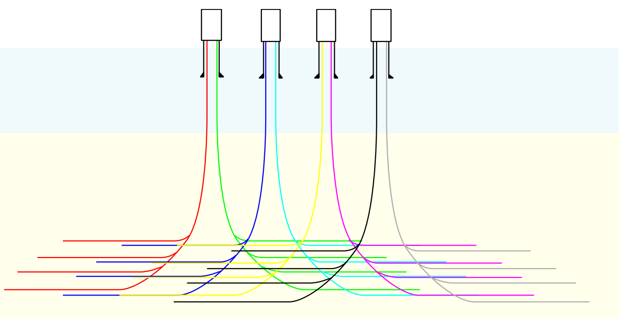
Developed IOR concepts

Tertiary gas injection (swelling)

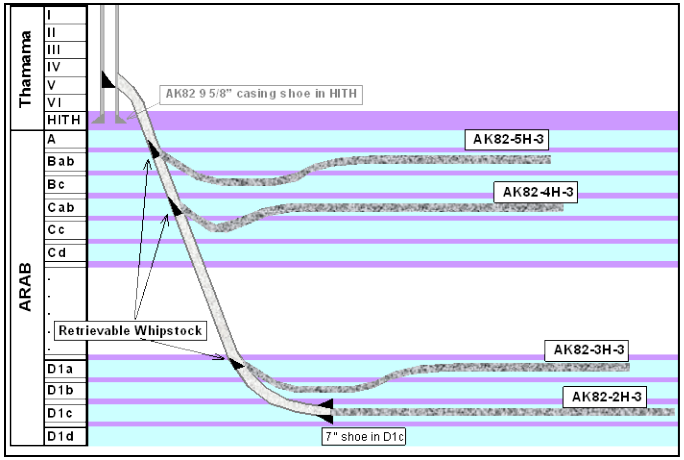


Slots optimization

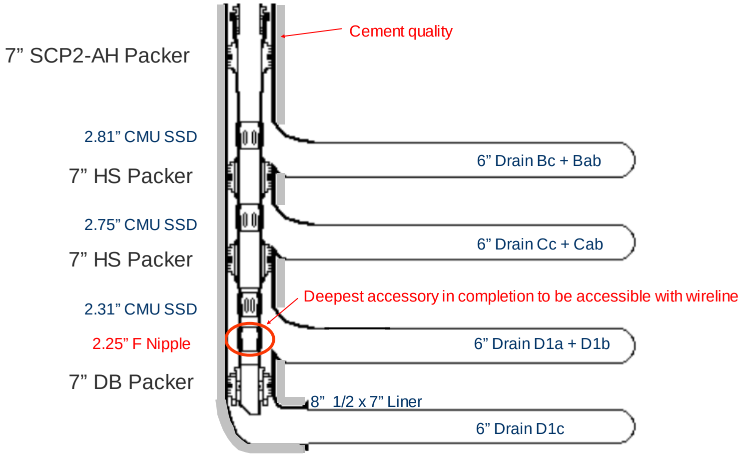




Dedicated production



Selective completion



Cement quality

7” SCP2-AH Packer

2.81” CMU SSD

6” Drain Bc + Bab

7” HS Packer

2.75” CMU SSD

6” Drain Cc + Cab

7” HS Packer

Deepest accessory in completion to be accessible with wireline

2.31” CMU SSD

2.25” F Nipple

6” Drain D1a + D1b

7” DB Packer

8” 1/2 x 7” Liner

6” Drain D1c

Tertiary non miscible gas Injection

- Lab experiments
  - Centrifuge experiments: no reduction of residual oil saturation
  - Swelling tests: 16% volume increase
  - Recovery efficiency: 200stb/MMScf gas injected)
    - High variation depending upon permeability
    - High sensitivity to rock wettability
- Sweep efficiency
  - Gravity: gas breakthrough in updip producers
  - Impact of the open fractures
  - Efficiency impaired by permeability reduction and low Kv/Kh
- Objectives
  - 10 MMSbbls in 10 years incremental recovery
- Results
  - Excellent response to gas injection
  - Recovery in line with objectives

Key elements

- EOR is complex technically and not totally risk free
  - Ability to master a gas injection project
  - Need for accurate reservoir characterization, extensive reservoir studies and sophisticated lab experiments
  - Validation by pilots before implementation at field scale
  - Careful monitoring mandatory for continuous project optimization
  - Synergy between geoscientists and engineers
- EOR is more expensive than primary/secondary recovery techniques
  - Tax incentives may play a role
- EOR successful implementation has three main issues
  - Time / Economy / Technique
  - Any of these may be a killing factor
  - Need for anticipation and technical/economical integrated studies

Lessons to be learned

The reservoir is best known when it is abandoned

- Due to lack of information, initial development are never optimized
  - What are the fundamental heterogeneities
- Tertiary recovery should be always initiated at the earliest stage of field development
  - What are the most important secondary heterogeneities
- ABK field is a precursor in terms of maturity for carbonate fields in the Middle East
- Total ABK will study all adapted EOR techniques
  - Surfactant / Polymer injection
  - Water Alternate Gas