Brown Fields Rejuvenation
“Maximizing Production & Recovery”

GPC Workshop

9-11/10/2022

Brown Fields Rejuvenation
"Maximizing Production & Recovery"

Role of Best Practices and Technology in Maximizing Production & Recovery with Emphasis on Formation Damage

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UNIVERSITY IN EGYPT
جامعة المستقبل

Oct. 2022

Brown Fields Rejuvenation
"Maximizing Production & Recovery"

Content:

- **Recognition of Production gap.**
- **Formation Damage.**
- **Best practices in carbonate matrix acidization.**
- **Carbonate Fracture Acidization.**
- **New Technology.**
- **Conclusion.**

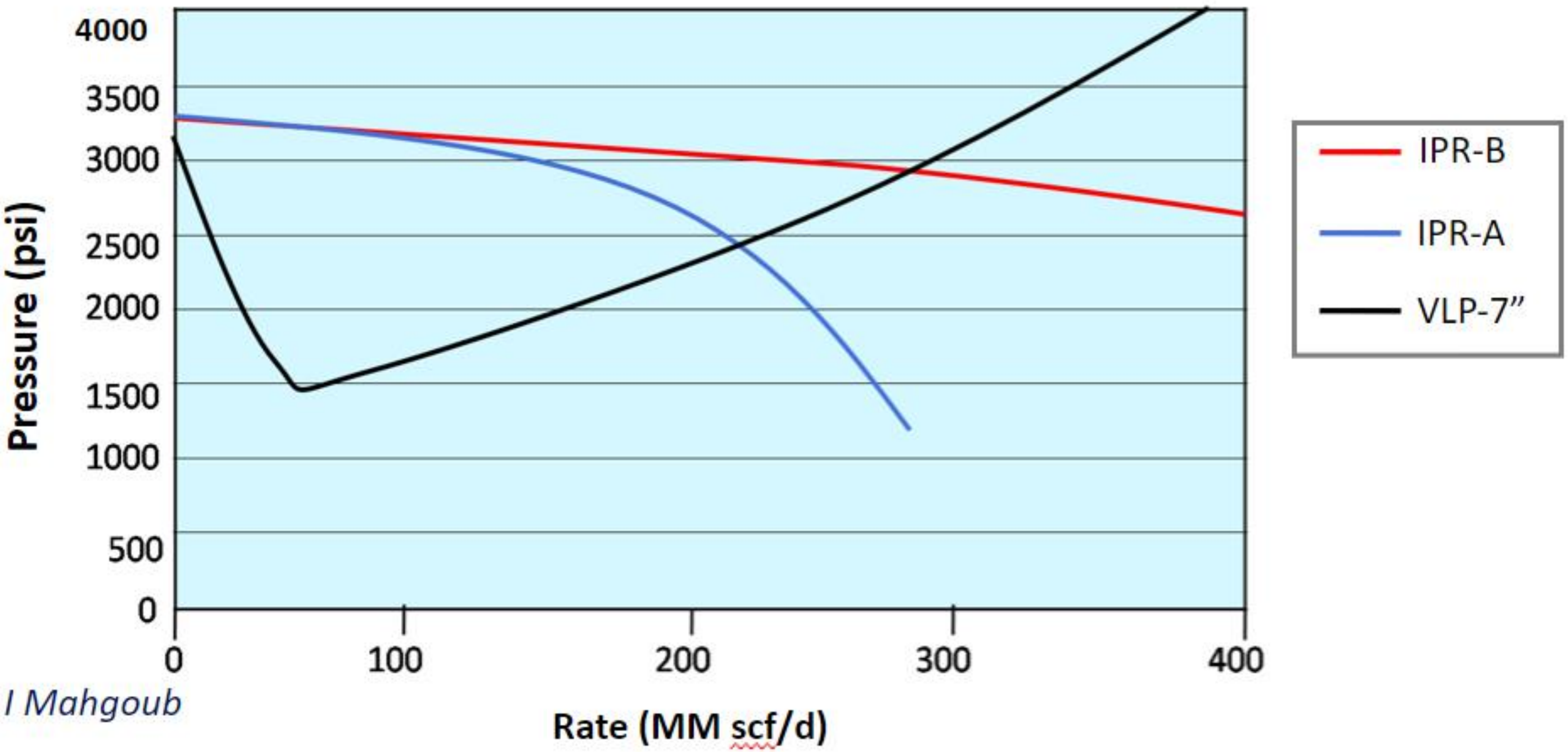
Brown Fields Rejuvenation
"Maximizing Production & Recovery"

Objectives:

- Recognize a production gap on a typical oil well performance.
- Highlight the importance of the near wellbore area in terms of: FD, Low productivity, low RF.
- Provide guidelines to minimize the FD along the well life journey.
- Understand the importance of acidizing in terms of: productivity and RF of carbonate reservoirs.
- Open window to new technology to reduce WC and improve the RF in secondary recovery.

Open hole VS Cased hole Perforation:

- Comparison of performance of actual cased and perforated completion (A) and a replacement well completed open hole 15 meters away in a 2 Darcy dry gas reservoir.



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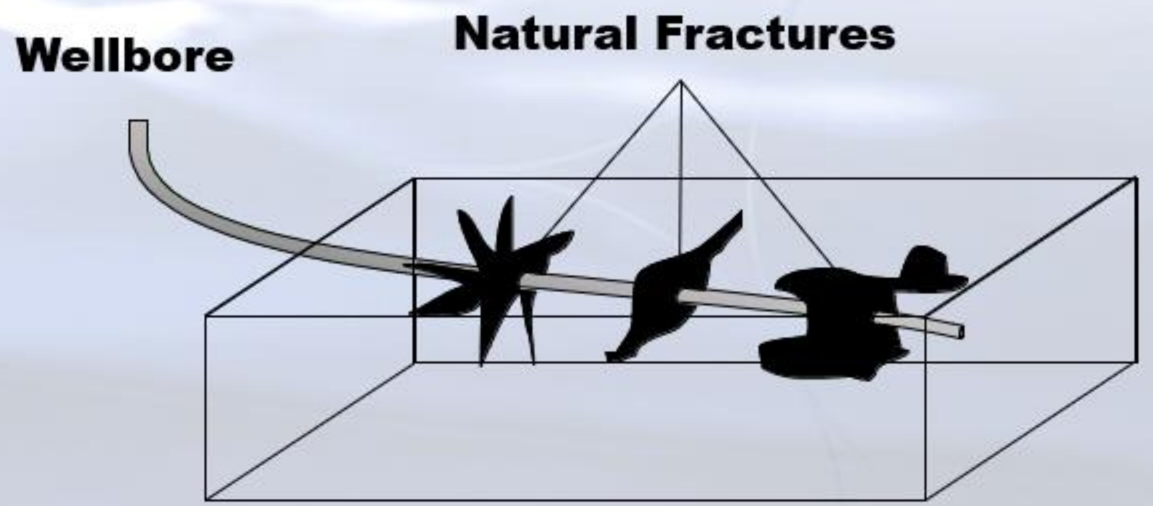
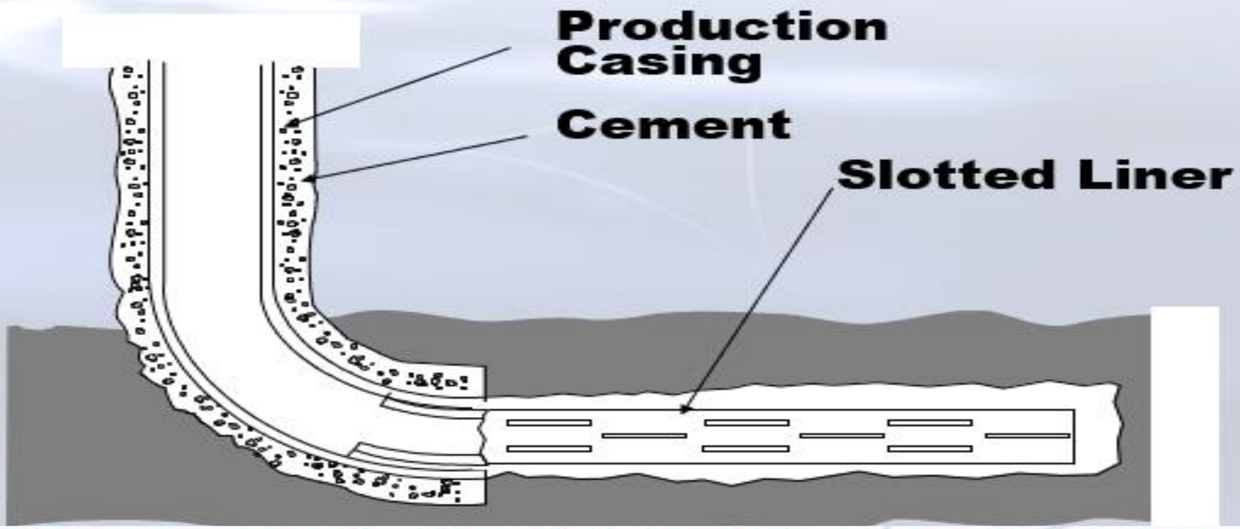
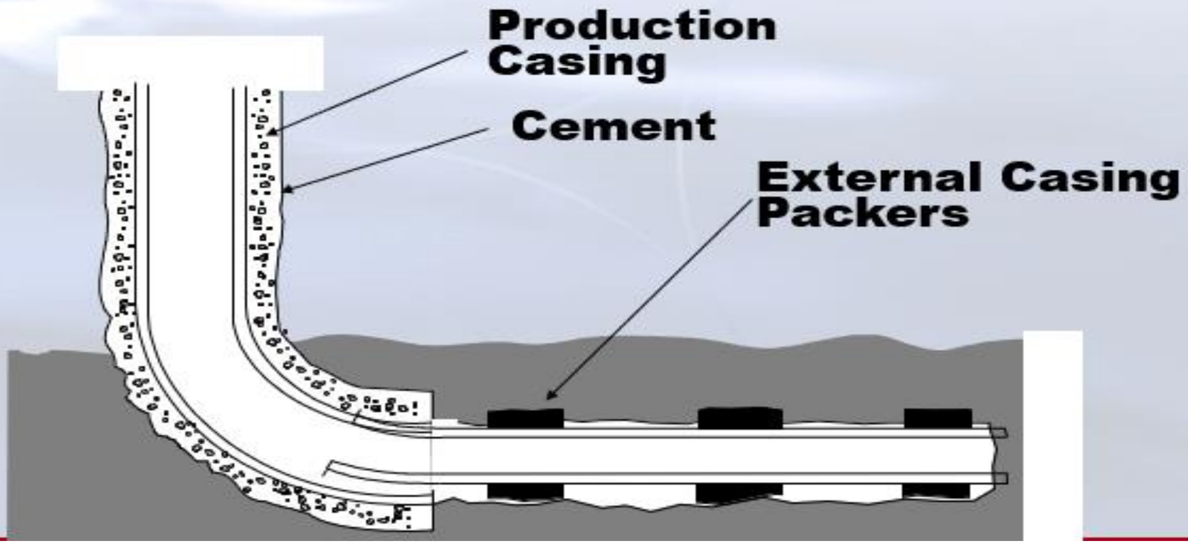
Horizontal Completions



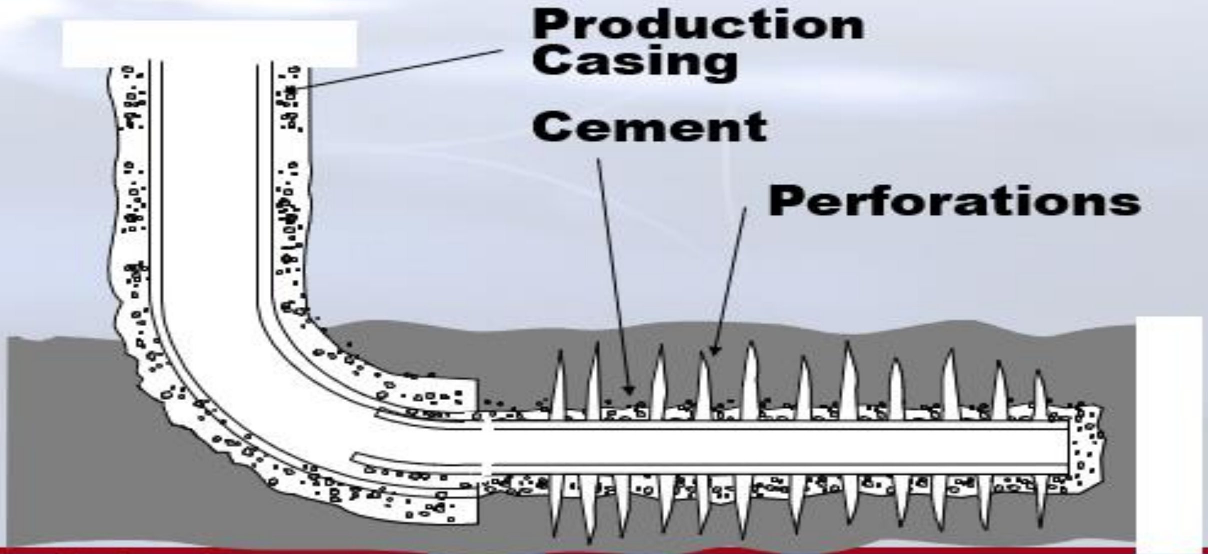
Slotted Liner



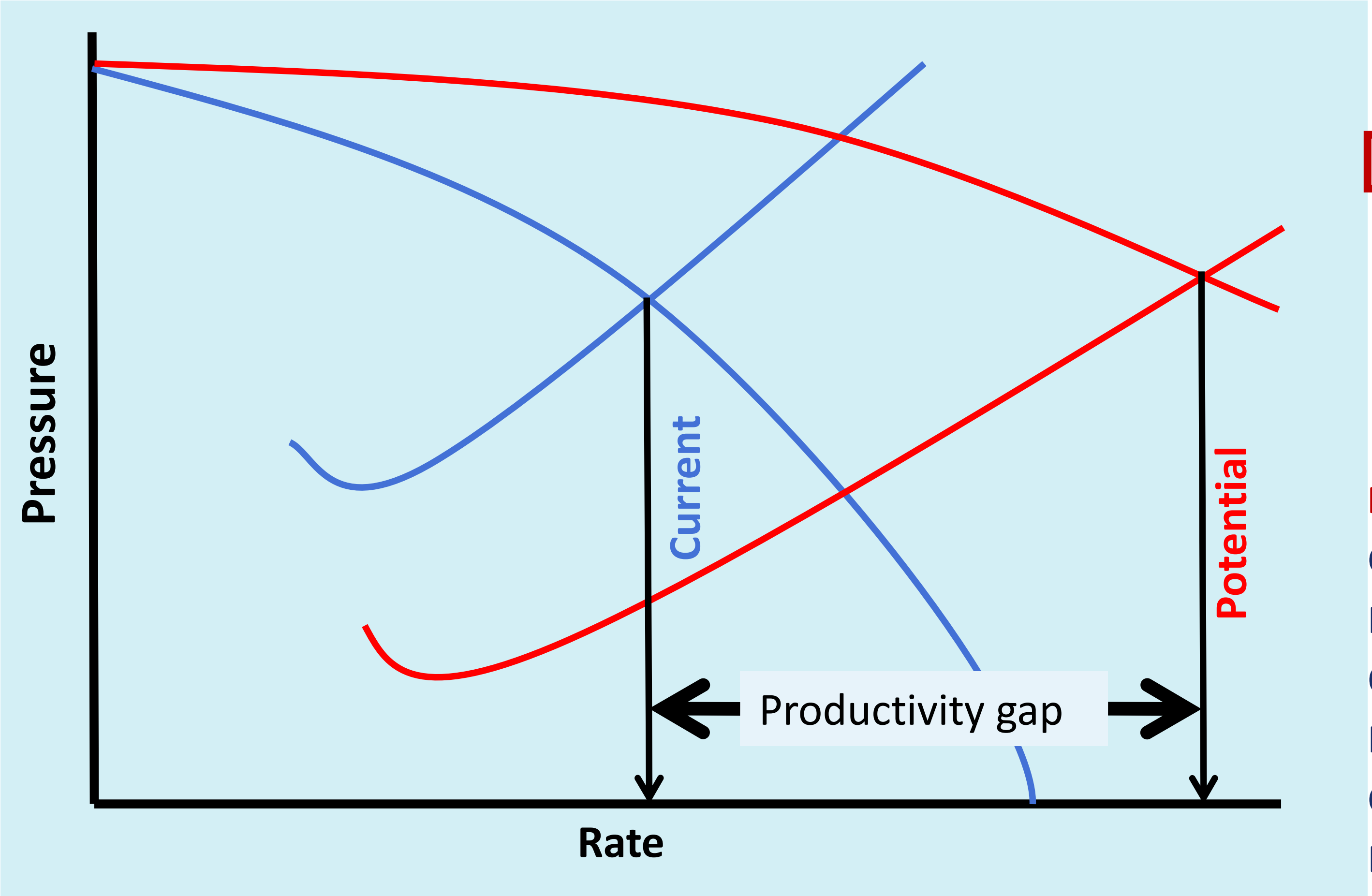
External Casing Packer



Cemented And Perforated Liner



Recognition of Production Gap



Reservoir and Completion

Add pay
Reperforate
$\boxed{\text{Acidize}}$
Fracture
Drill Lateral or horizontal
Control sand
Control water and gas

Flow conduit and facilities

Clean out fill
Remove scale
Optimize tubular designs
Redesign artificial lift
Coiled tubing completions
Early production facilities

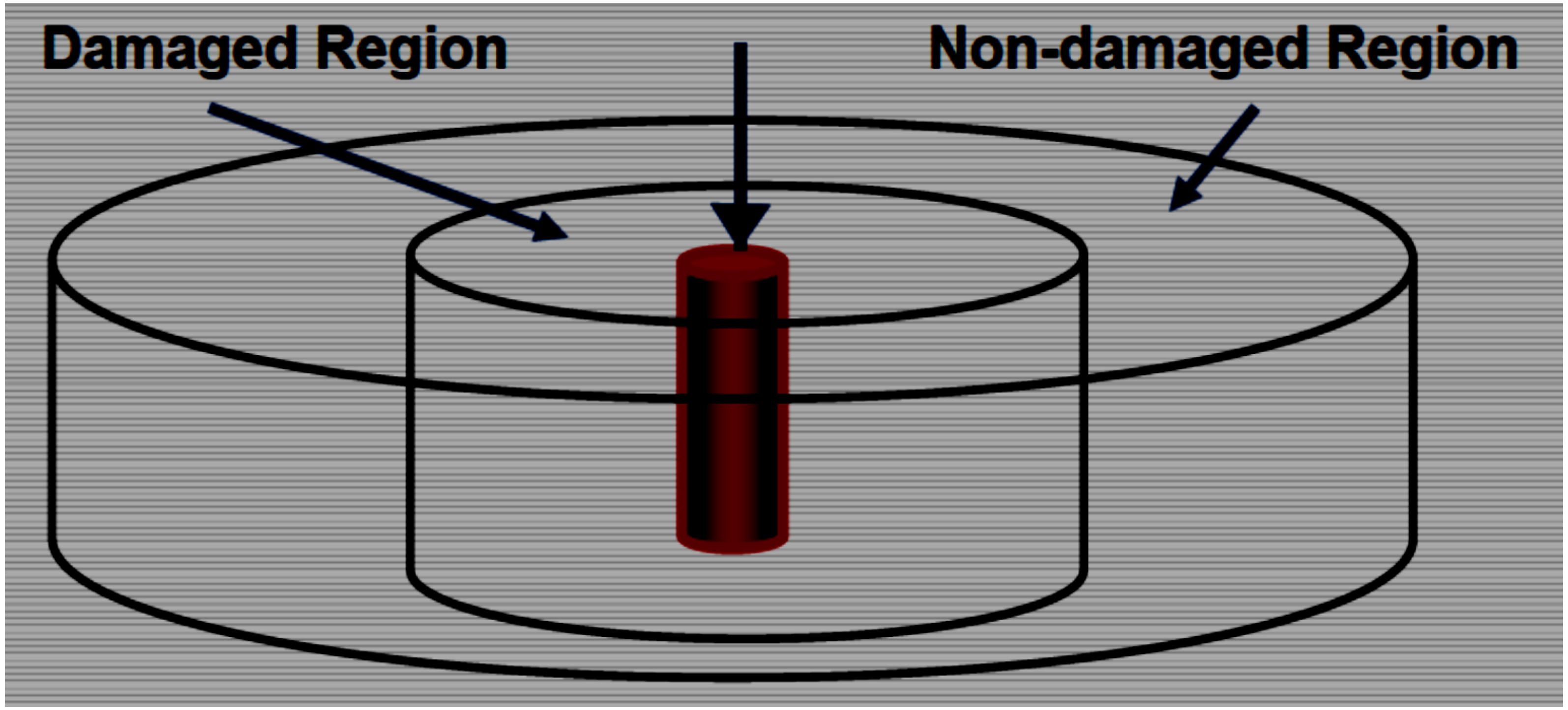
Formation Damage

- It is the process by which the permeability is altered in the vicinity of the wellbore.

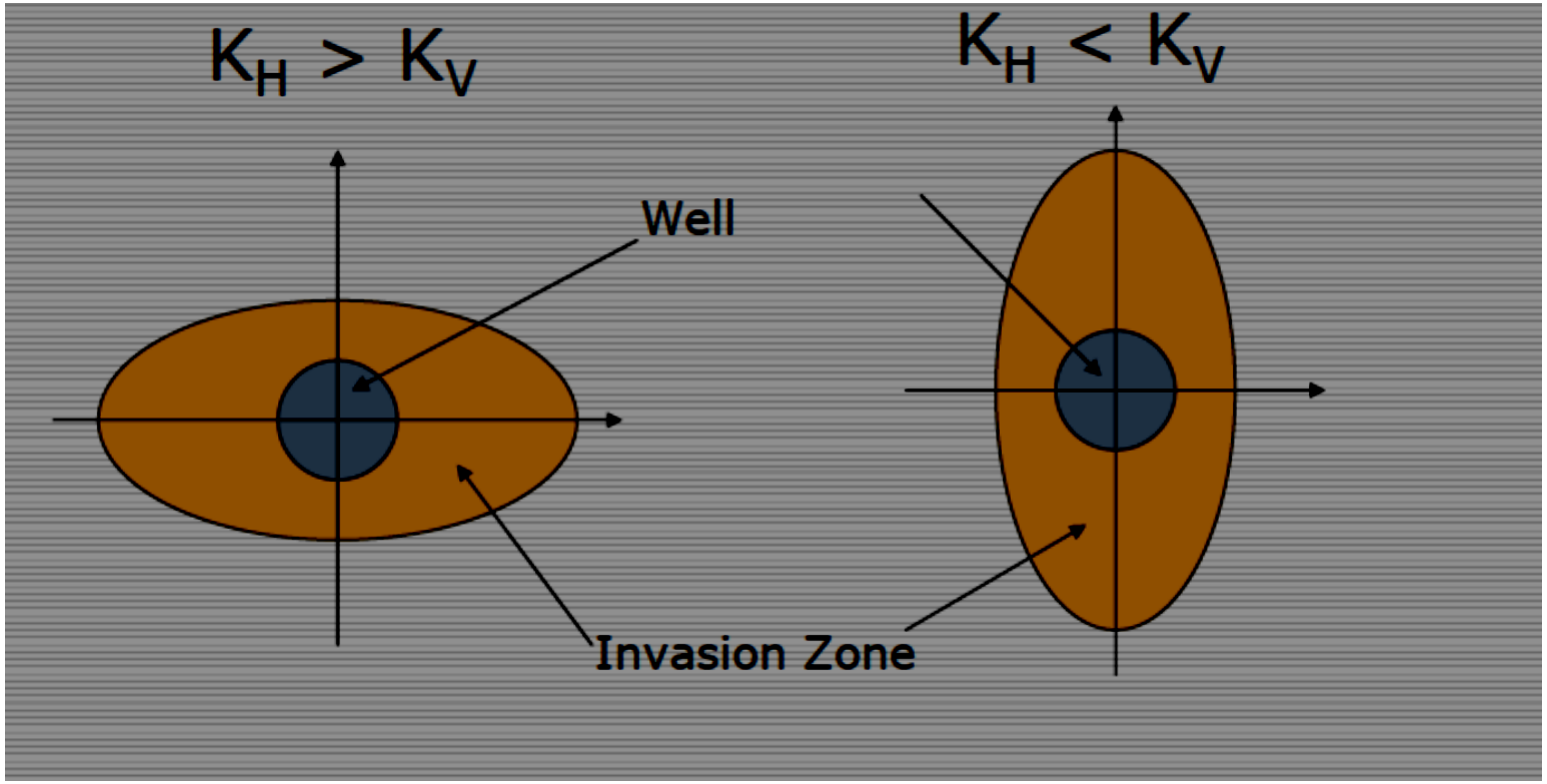
- Almost all operations carried out on a well since the spud date to the abandonment is contributing to formation damage.

- In some case, FD is remediated.
- In some case, FD is irreversible.

Near Wellbore Damage



Effect of Anisotropy and Stress on Damage Zone



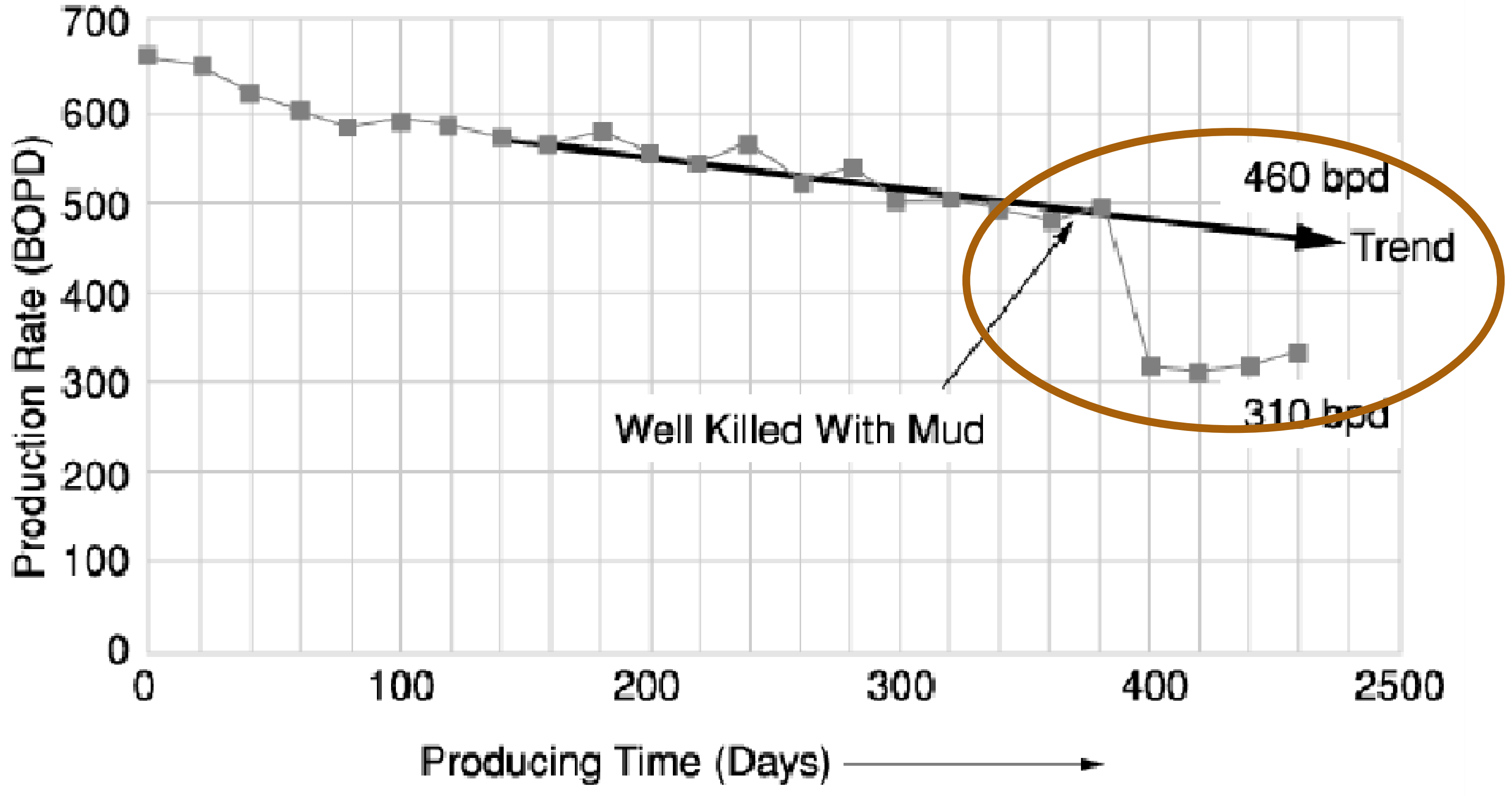
Formation Damage Skin

$$S_{Total} = S_{FD} + S_{Geometry} + S_{Completion} + S_{Production}$$

- **Well geometry**
  - limited entry/partial penetration/off-centre well placement(+)
  - well deviation / slanted well (-)
- **Completion skin**
  - perforations {flow convergence / crushed zone)} (+ or -)
  - gravel packs (+) / natural or hydraulic fractures (-)
- **Production skin**
  - non-Darcy effects / turbulence (+, rate dependent)
  - relative perm. effects (+)
  - pressure dependent phase (gas & condensate) behavior (+)
- **Formation Damage skin**
  - only form of "+ve skin" which can be chemically removed

Formation Damage – Completion & Workover

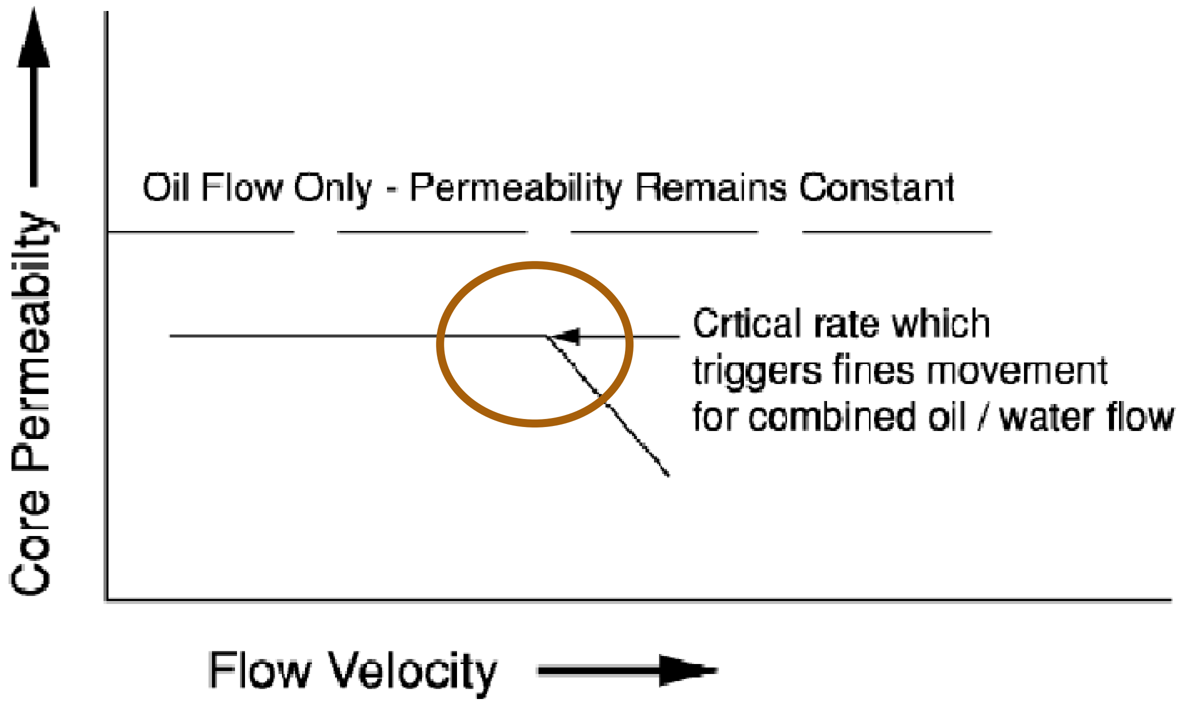
Formation Damage created by killing well



Formation Damage – During Production

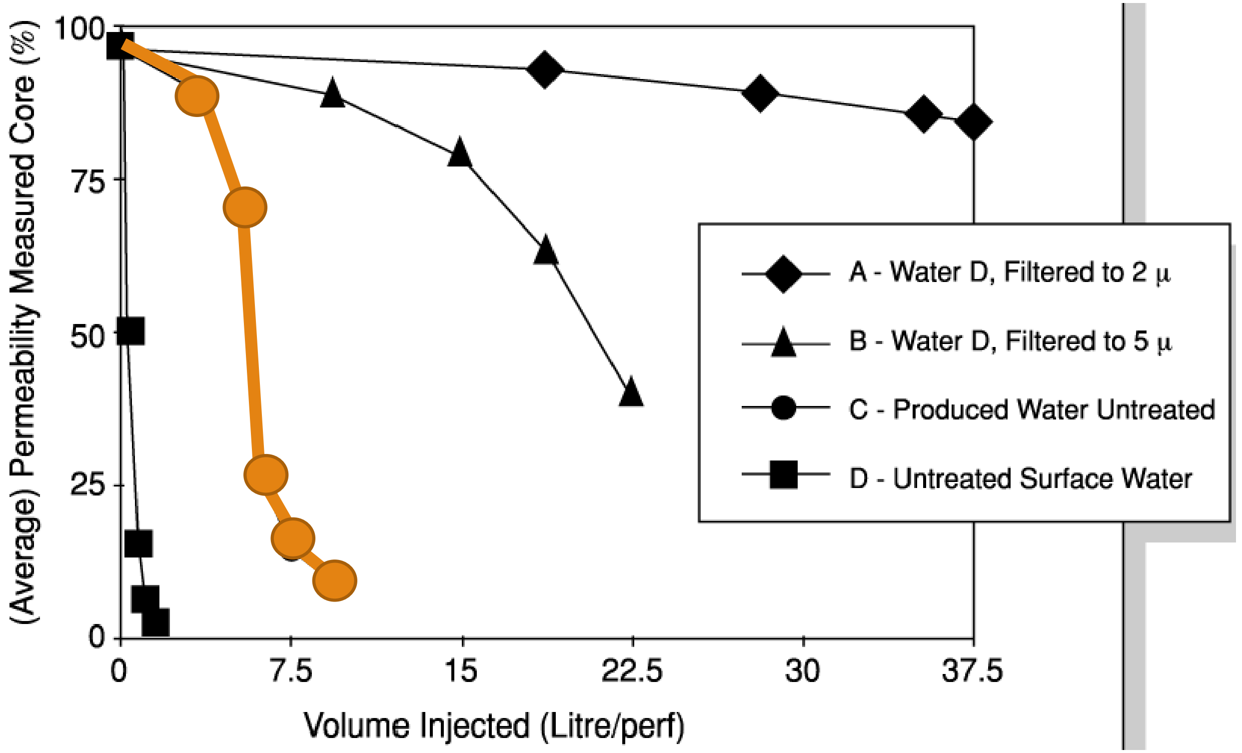
- Fines movement controlled by:
  - Concentration & nature of fines
  - Fluid velocity & Wettability (fluid phase, surfactants)
- Controlled by slow bean up or by chemical treatments

Fines Movement



Formation Damage – During Injection

- Field located within Estuary of major river (silt laden water)
- Fine filtration equipment (mainly) removed from North Sea injection wells due to good water quality

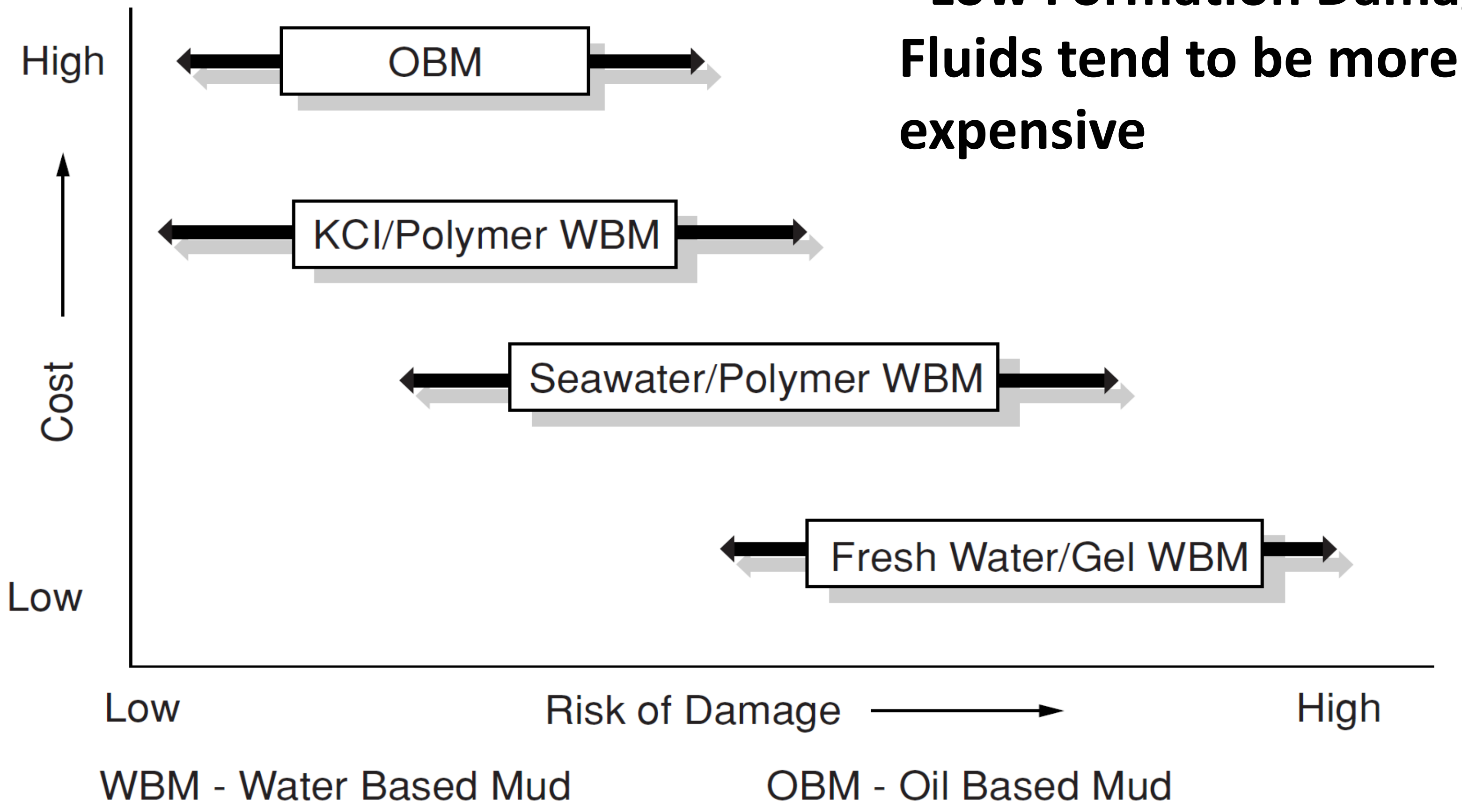


Summary of Formation Damage due to Drilling

- ***Drilling Mud Solids***
  - ➢ particle: pore size ratio determines mud cake efficiency
  - ➢ overbalance
  - ➢ lost circulation - fractures
- ***Drilling Mud Filtrate***
  - ➢ formation sensitivity

    (pH, fluid salinity & other formation-fluid interactions)
  - ➢ capillarity of low permeability rock
  - ➢ fines dispersion / additive residues
  - ➢ depth of fluid invasion obtainable from logs

Formation Damage - Drilling Operations



- **Low Formation Damage Fluids tend to be more expensive**

Formation Damage - Cementing & Perforating

- **Washes & Spacers**
  - destroy mud cake with dispersant additives
  - filtrate invasion - *inches due to limited volume*
- **Cement Slurries Fluid Loss**
  - reactive to clays (high pH)
  - precipitation of $CaCO_3$ / lime /Ca silicates
  - BUT fluid loss control essential for cementing success
- **Perforations bypass damage if *gauge hole drilled***

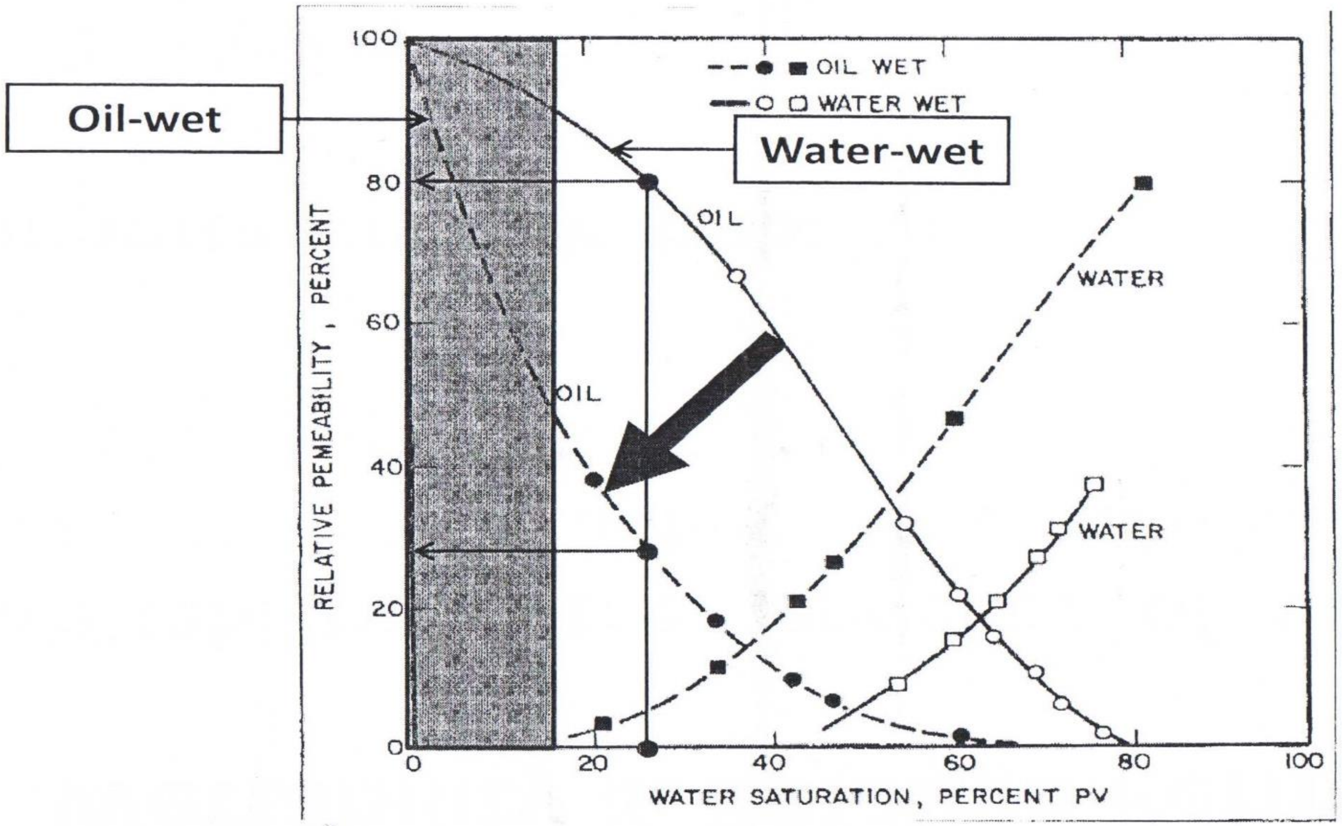
Formation Damage – Stimulation

Reaction of acid with formation rock and fluids can generate formation permeability damage:

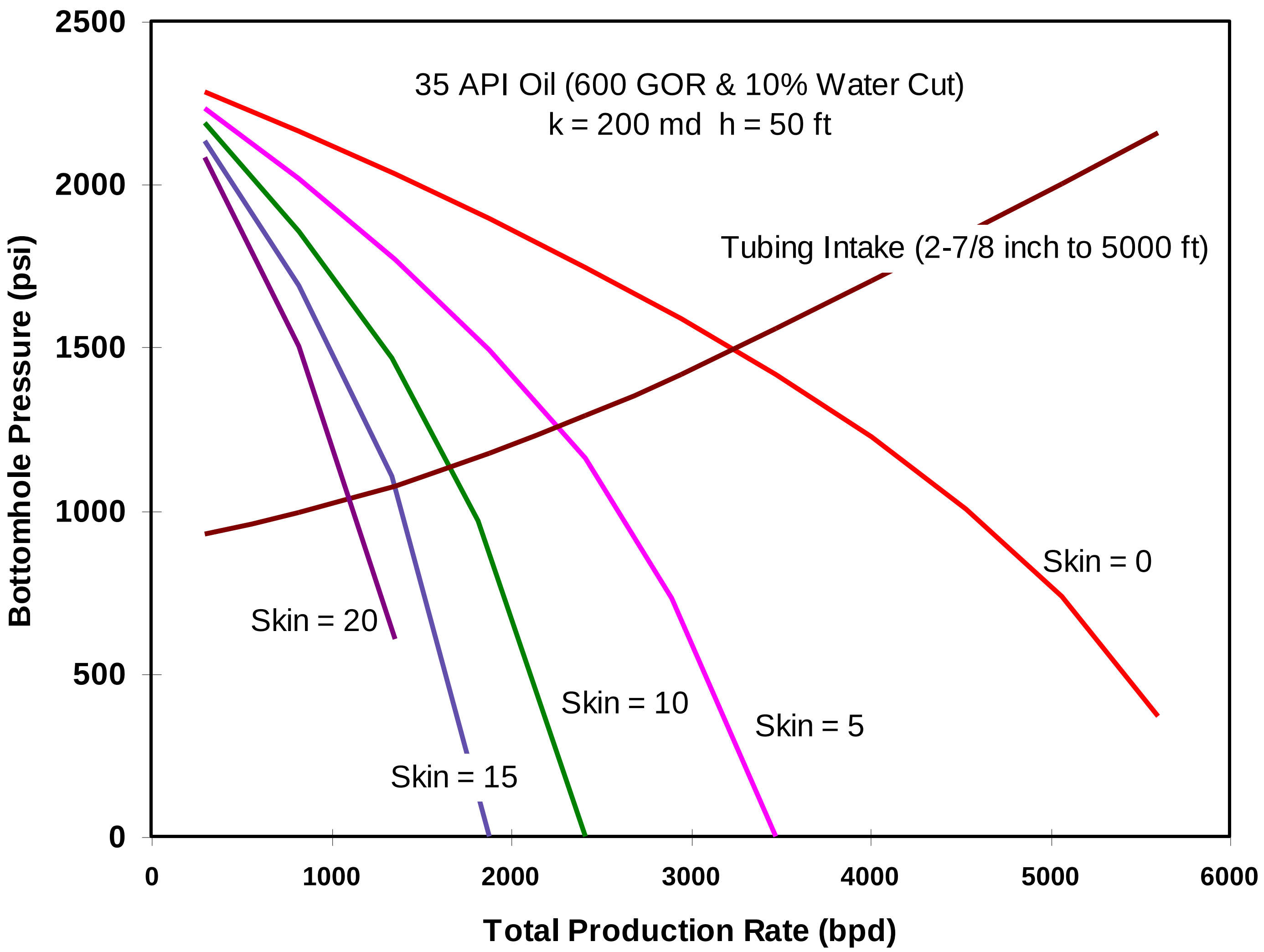
- **Precipitation of acid/rock reaction products**
- **Deconsolidate rock matrix**
- **Generation of migrating fines which block pore**
- **Acid/crude oil sludge formation**
- **Viscous emulsion formation**
- **Wettability changes**
- **Water block**

Acid selection is the key

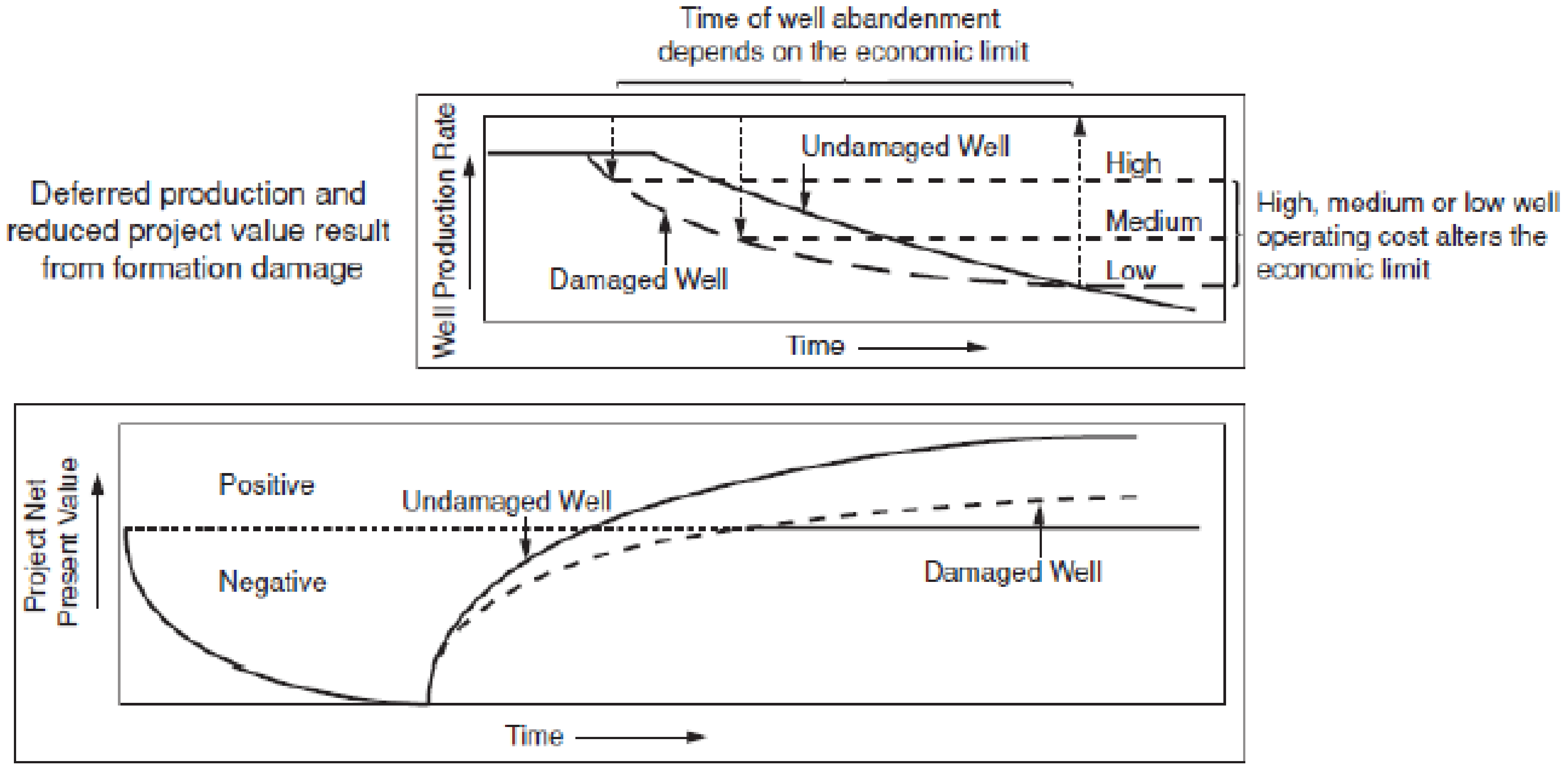
Adsorption and Wettability Alteration



Effect of Skin on Productivity of Oil Well



Formation Damage, Well Production & Profitability



- Formation damage reduces Project Net Present Value

In Brief….

Formation Damage Indicators:

Permeability impairment and reduction

Skin damage

Decrease of well performance.

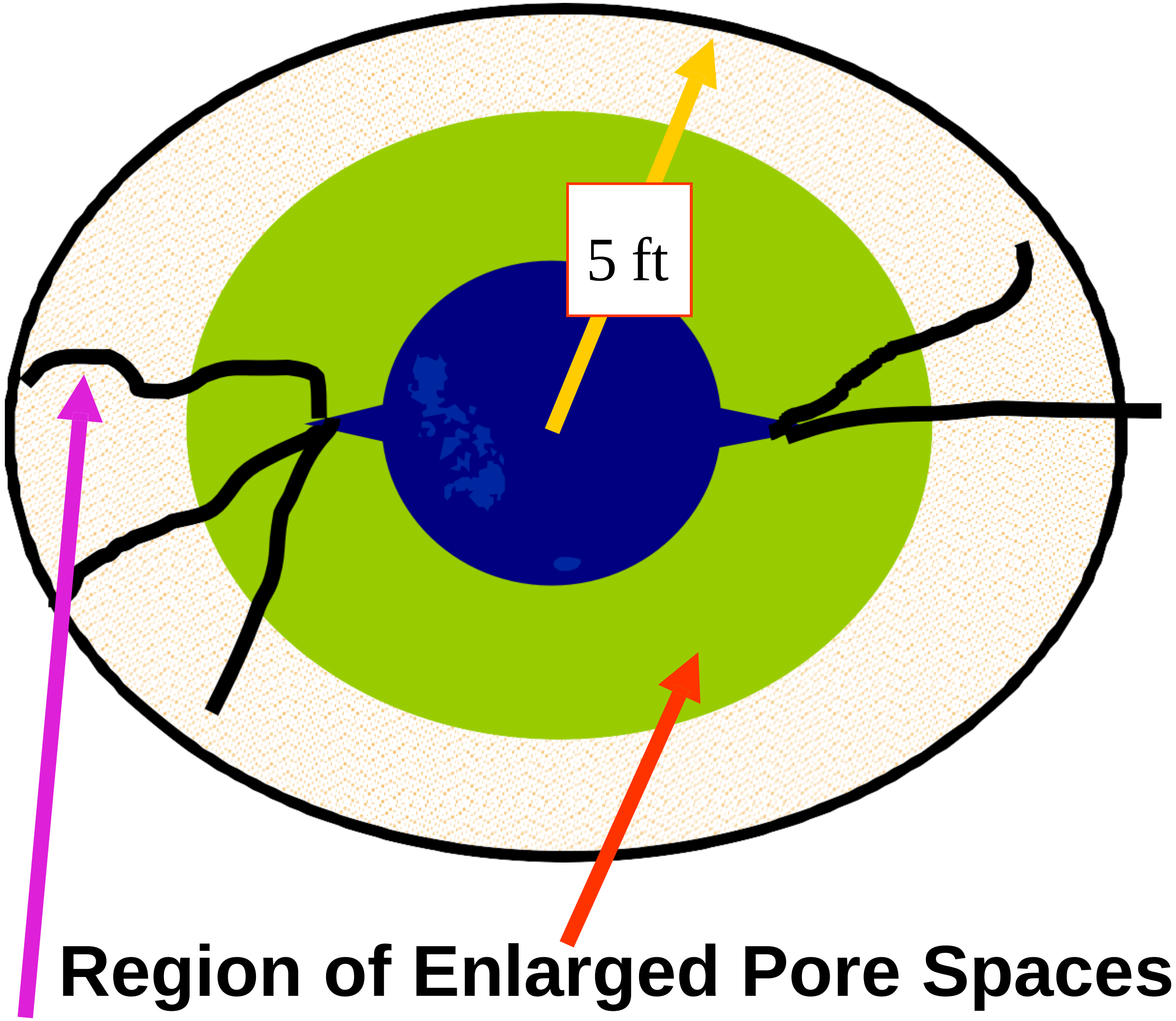
Formation Damage Consequences

Reduction of reservoir productivity

Non-economic operations

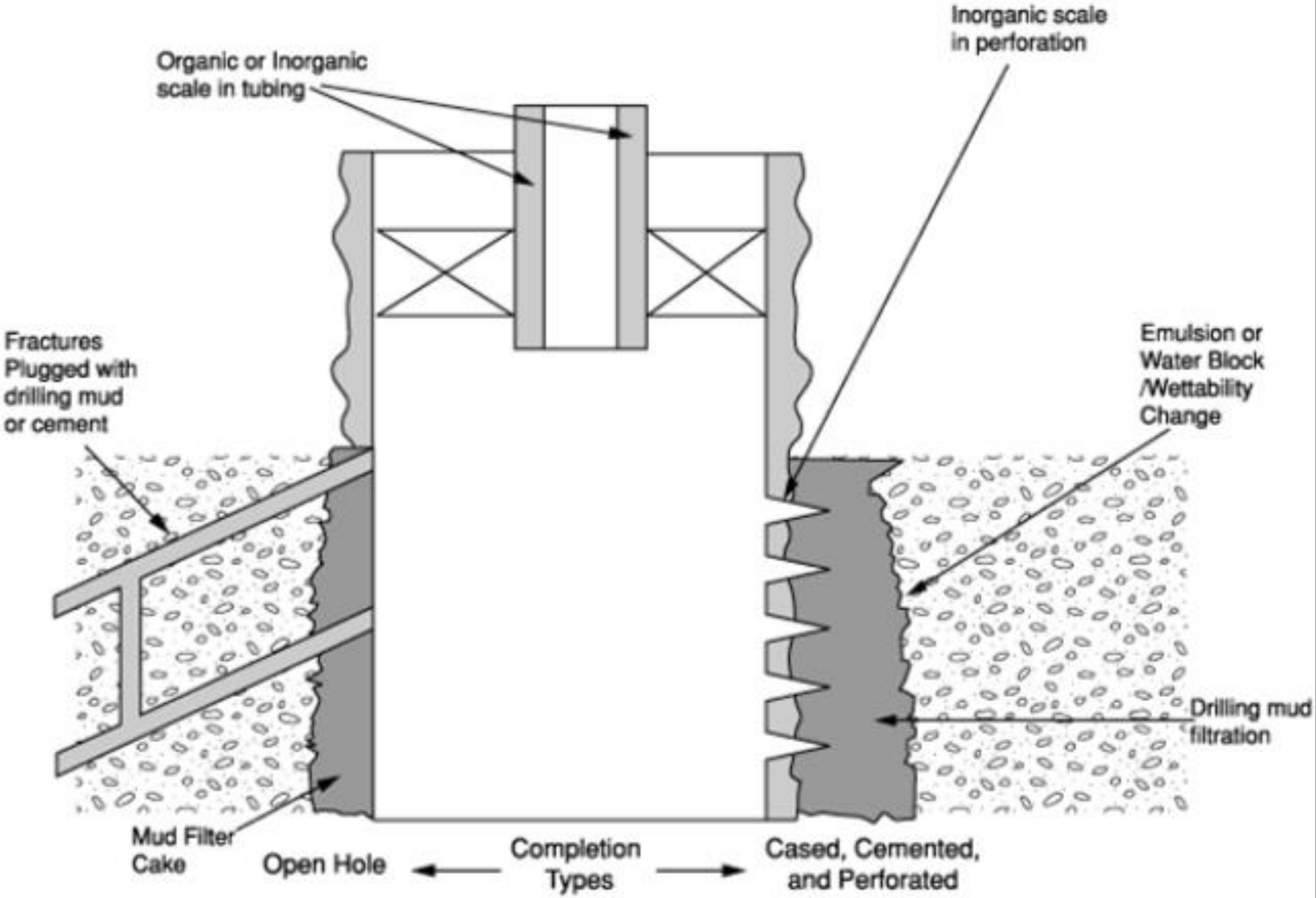
Best Practices
in
Carbonate Matrix Acidization

Matrix Acidizing in Carbonates

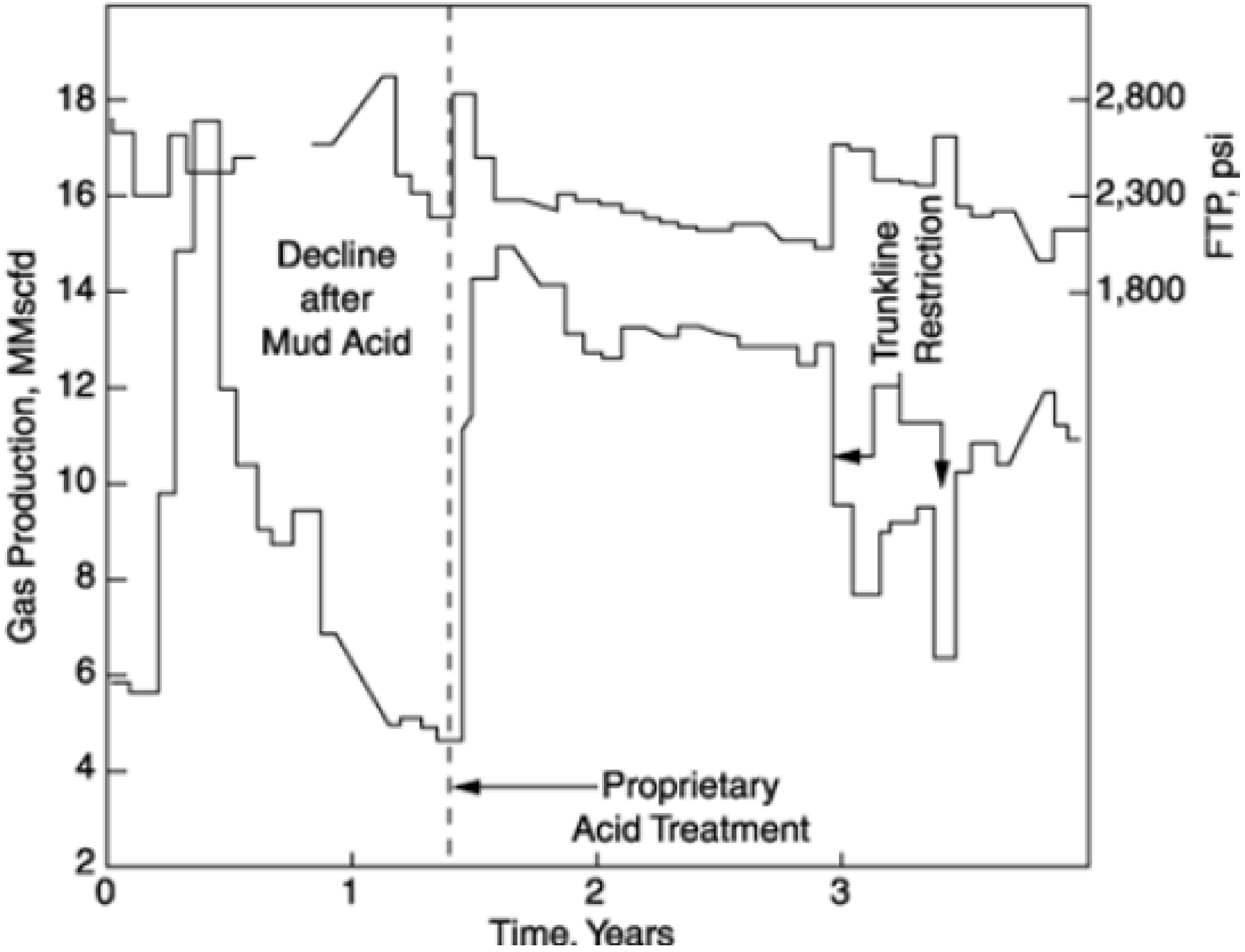


Creates a Region of Enlarged Pore Spaces and/or Wormholes around the Wellbore

Type and Location of Formation Damage



Field Application Proprietary Acid



Laboratory Assisted Acid Selection Criteria:

Acid Selection

- Rock Composition
- Formation Water Composition
- Oil or Gas (PVT)
- Downhole Conditions
- Type of Damage

Now,

What are the Damaging Mechanisms Taken Place During the Carbonate Matrix Acidizing?

Damaging Mechanisms:

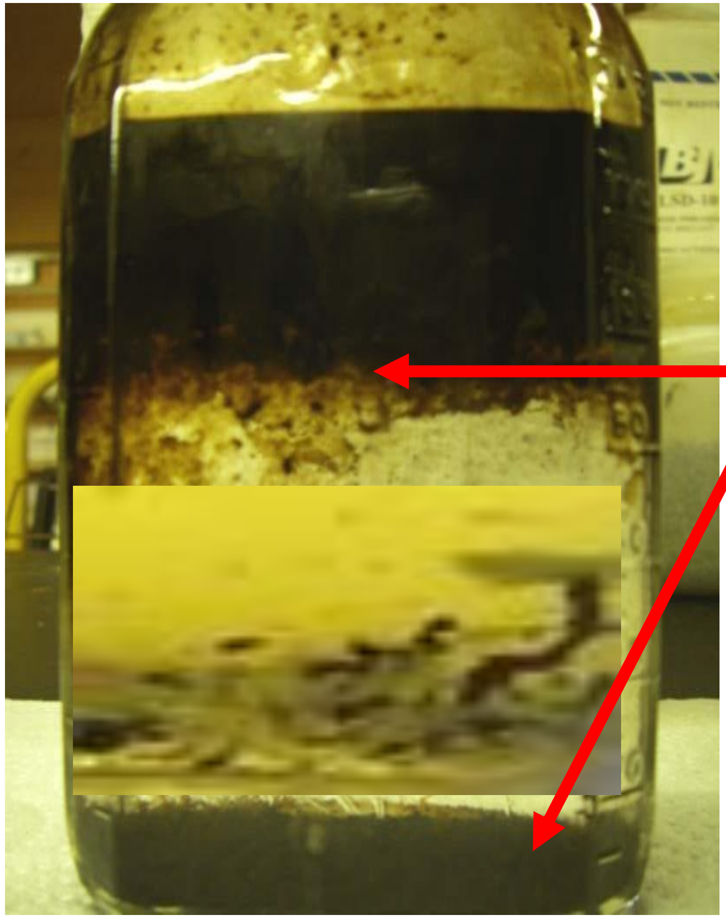
- **Acid- induced and Ferric Iron-induced Asphaltic Sludges.**
- **Stable Emulsions (Live acid, spent acid/crude oil emulsion).**
- **Fine liberation and Precipitates (Rock Composition).**
- **Formation Oil wetting (carbonate positively charged)**
- **Acid Additive Separation.**
-
-

Damaging Mechanism 1.
Acid-induced and Ferric Iron-induced Asphaltic Sludges

- Acid in contact with crude oil can destabilize asphaltenes.
- Exposed reactive sites on asphaltenes cross-link to form acid-induced sludge.
- Relatively small amounts formed.

Acid Induced Asphaltic Sludge

What we saw in acid flow back samples was more sludge than in our acid test bottles.



Spent acid flow back sample - note the amount of asphaltic sludge.

How much sludge is left in the formation?

It will plug the formation

This was evidence that there had to be another mechanism by which the asphaltic sludge was being formed.

- Post-stimulation analysis of sludge revealed one common thread of evidence – the presence of both

Ferric (Fe^{3+}) Ions

and

Ferrous ($Fe2^{+}$) Ions

For 95% of crude oils tested

Acid + Fe^{3+} + Asphaltenes (waxes?)

↓

FERRIC IRON-INDUCED SLUDGE

↓

RISK OF FORMATION DAMAGE

So where does the ferric iron come from to contaminate the acid?

RUST!

Some Sources of Ferric Iron Compound Contamination

- • •Storage tanks
- • •Pumping equipment and lines
- • •Tank trucks
- • •Rusty production and coil tubing
- • •Acid and mix water
- • •Formation minerals

How can we eliminate acid-induced and ferric iron-induced sludges?

Solution – (a) by performing a tubing pickle, and (b) by adding functionally specific chemical additives to the acid blend.

1. Acid antisludge agents and
2. Iron control agents

Tubing Pickling

- **Pickling removes pipe dope, residual mud, corrosion by-products (rust), mill scale, and other debris.**
- **Without pickling, the leading edge of the acid or brine sweeps the junk into the perforations and damages the well.**
- **Failure to effectively pickle or clean the tubing is a leading cause of acid failure**.

Pickling Operations

- **Find the best way to remove the debris:**
  - **Acid sweeps**
  - **Abrasive slurry (sand slurry) sweeps**
  - **Solvent sweeps**

Problems

- **If an acid pickle is left too long in the pipe, the pipe will be attacked by the acid.**
- **Sand slurry cleaning sweeps need to be pumped at turbulence.**
- **Solvent cleaning sweeps must be compatible with other fluids and the seals in the system.**

Pickling Procedure to 8,000 ft (without a Packer)

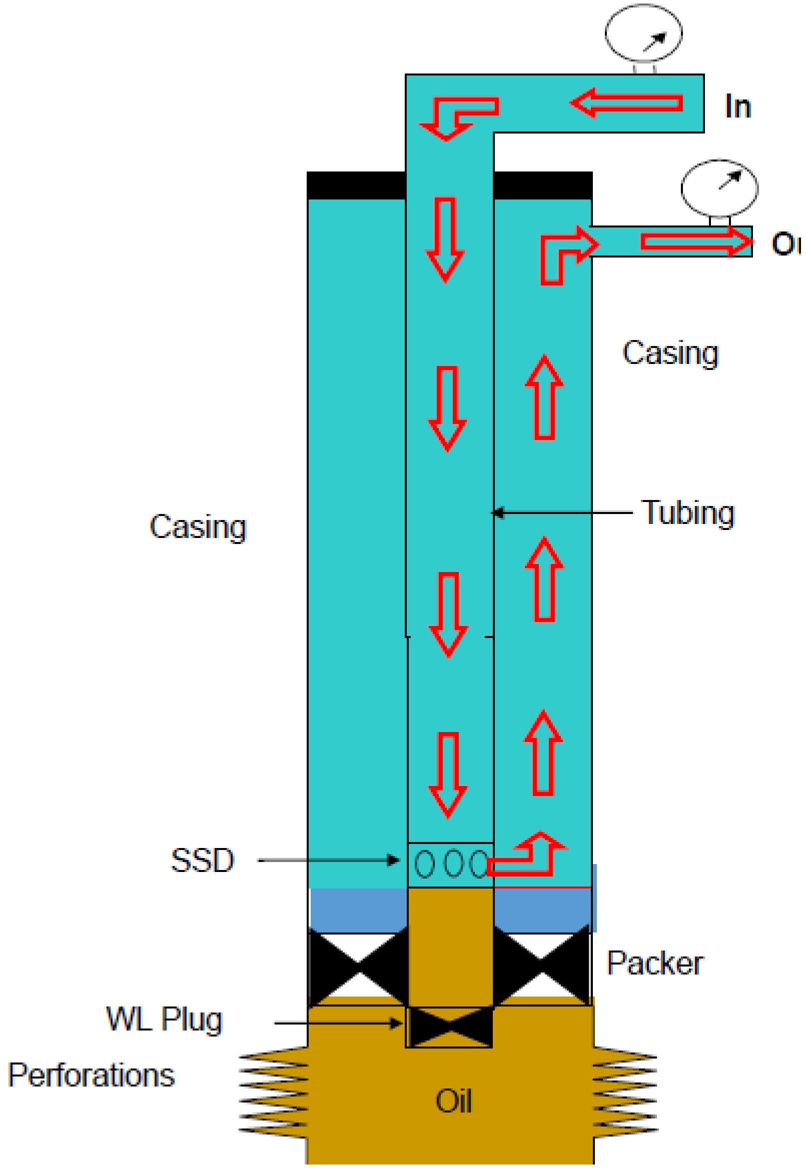
- **Set retrievable bp above perfs**
- **establish circulation w/ water (+ mutual solvent if oily)**
- **pump acid at 0.5 to 1 bpm**
  - **new tubing: 200 to 300 gal**
  - **old tubing: 300 to 500 gal**
  - **heavily scaled: 500 to 700 gal**
- **Displace w/ water until first 10% of acid is out of tubing**
- **Reverse acid out of tubing at 0.5 to 1.0 bpm**

Forward Circulation

Pump fluid through tubing & return through Annulus

<u>Disadvantages</u>

- Large volume pumped (Tubing + Annulus)
- High surface pressure
- Influx will be beneath completion fluid

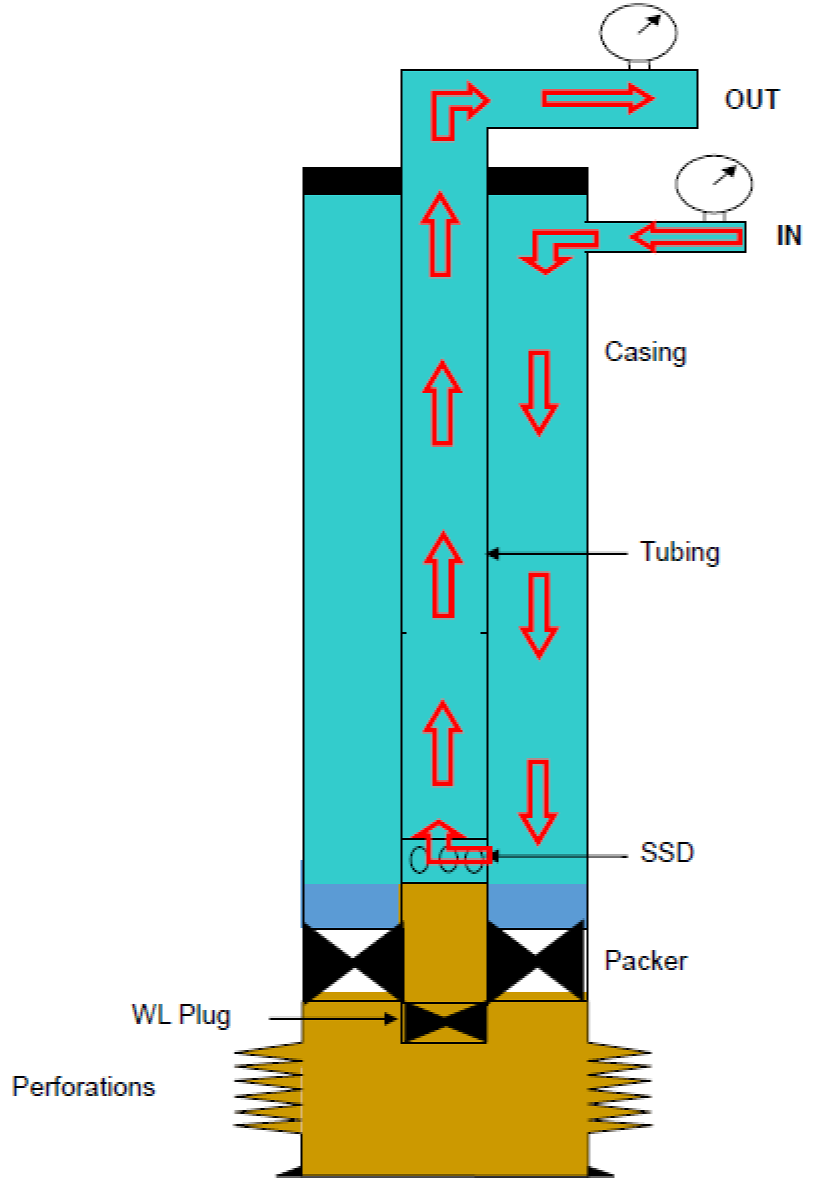


Reverse Circulation

Pump fluid through casing & return through tubing

Advantages

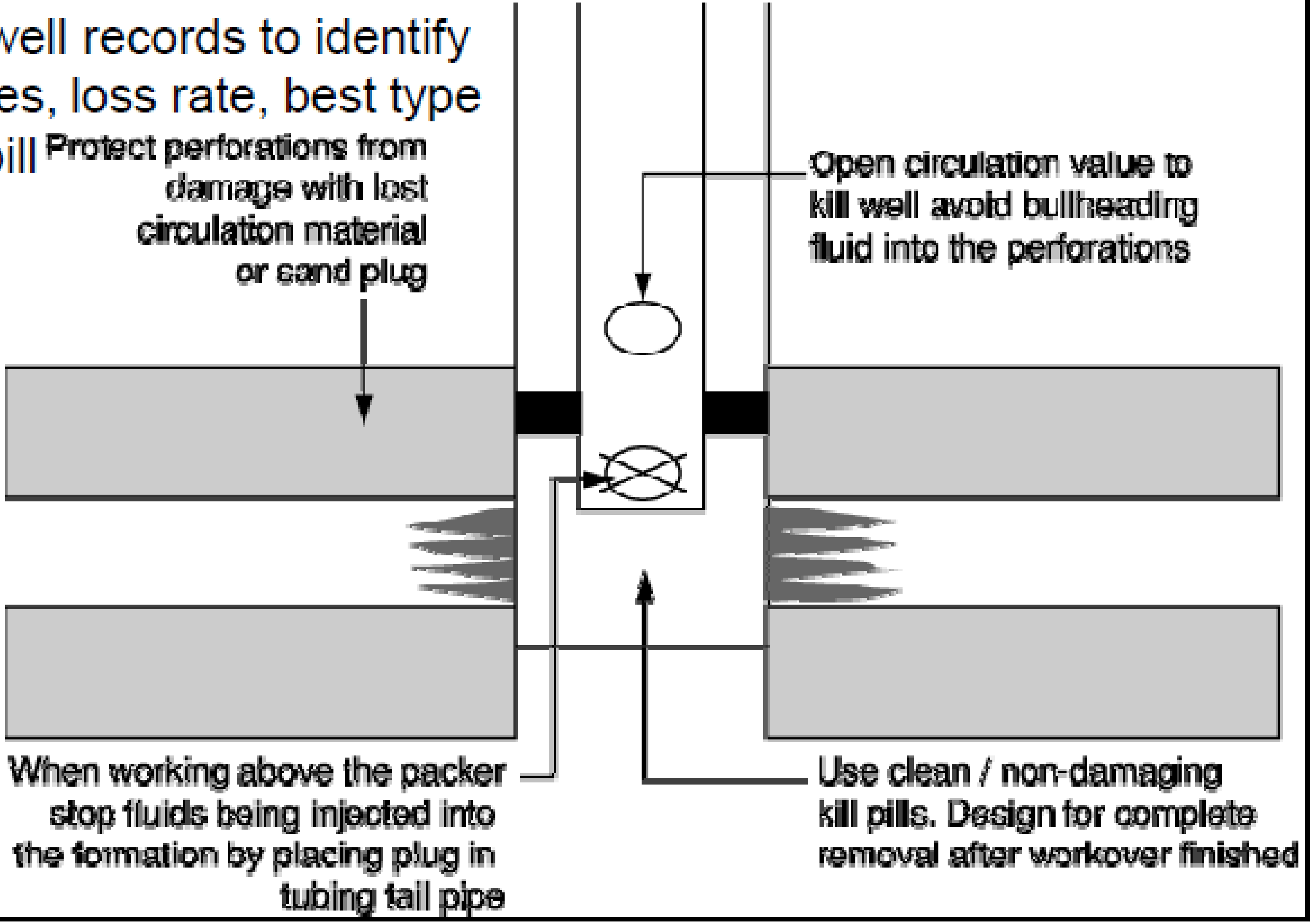
- Small volume pumped (Tubing)
- Low surface pressure
- Influx will not enter Annulus
- Fast and PLANNED

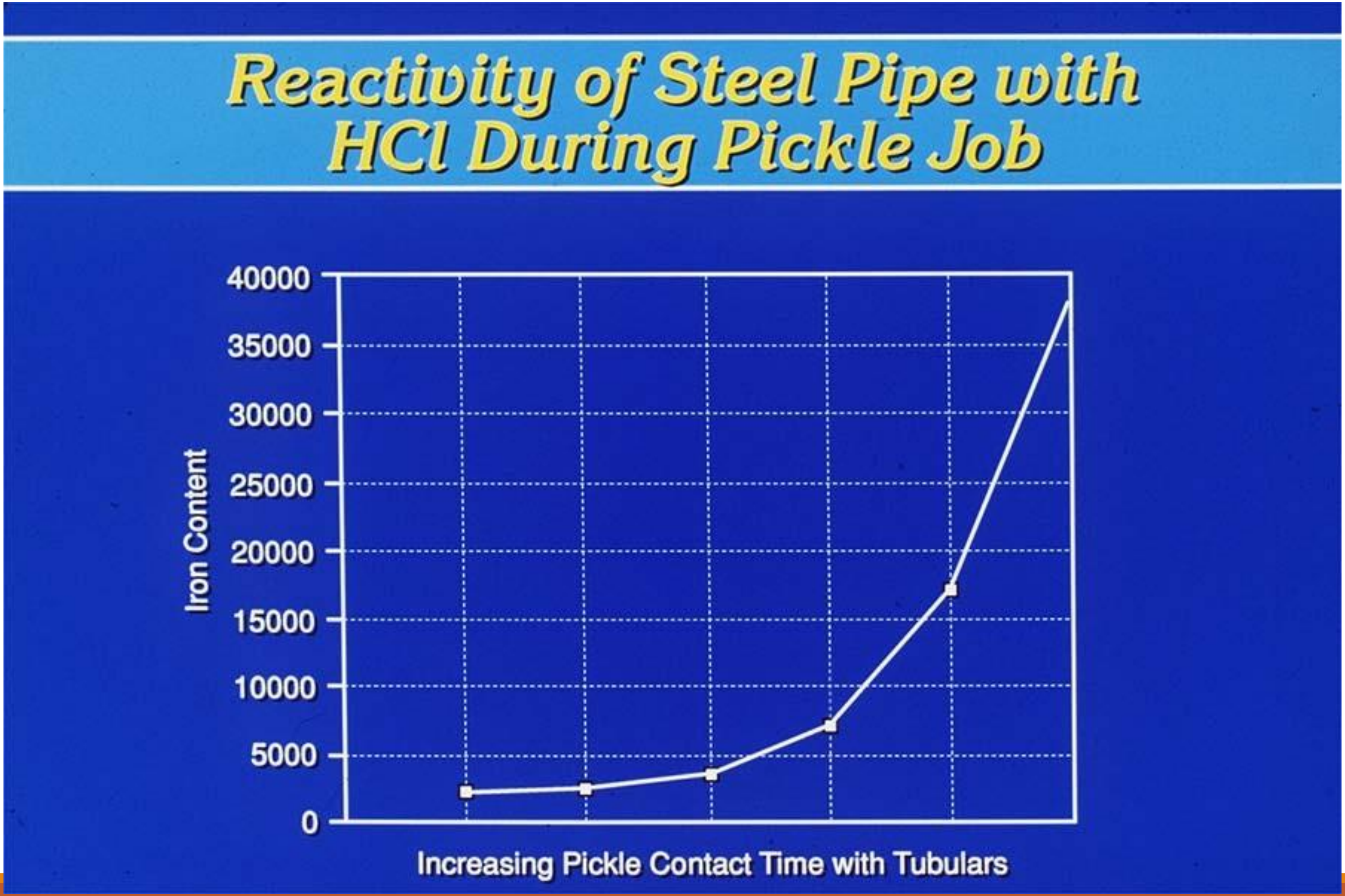


Formation Damage

Workover techniques can avoid Formation Damage

- Use well records to identify fractures, loss rate, best type of kill pill





Reactivity of Steel Pipe with HCl During Pickle Job
40000
35000
30000
25000
20000
15000
10000
5000
0
Iron Content
Increasing Pickle Contact Time with Tubulars

Corrosion Inhibitor Purpose

- **Inhibitors help protect steel pipe and other equipment**
- **However:**
  - **Some inhibitors are much more effective than others**
  - **Chrome tubulars are severely affected by acid and require special inhibitor packages**
  - **Inhibitors are time, temperature and acid strength sensitive**
  - **Inhibitors adsorb in the formation – none on backflow?**
  - **Inhibitors are not Soluble**
    - **separates to top in 30 minutes**
    - **needs vigorous mixing to disperse - gentle circulation will not work.**

Iron Control Agents

- pH control additives.

- Iron sequesterants.

- Reducing agents - converts Fe^{3+} to Fe^{2+}

  Sodium erythorbate

  Stannous chloride

  Organo thio-compounds

Properly Selected Oil Well Acid Receipt:

- 15% hydrochloric acid
- 4 gpt acid corrosion inhibitor
- 12 gpt iron control agent
- 10 % bw calcium chloride
- 1 gpt scale inhibitor
- 22 gpt acid antisludge agent
- 2 gpt non-emulsifier
- 13 gpt coupling agent
- 2 gpt fines suspending agent

  (gpt = gallons per thousand)

Fracture Acidizing

Injection rates above reservoir fracture pressure.

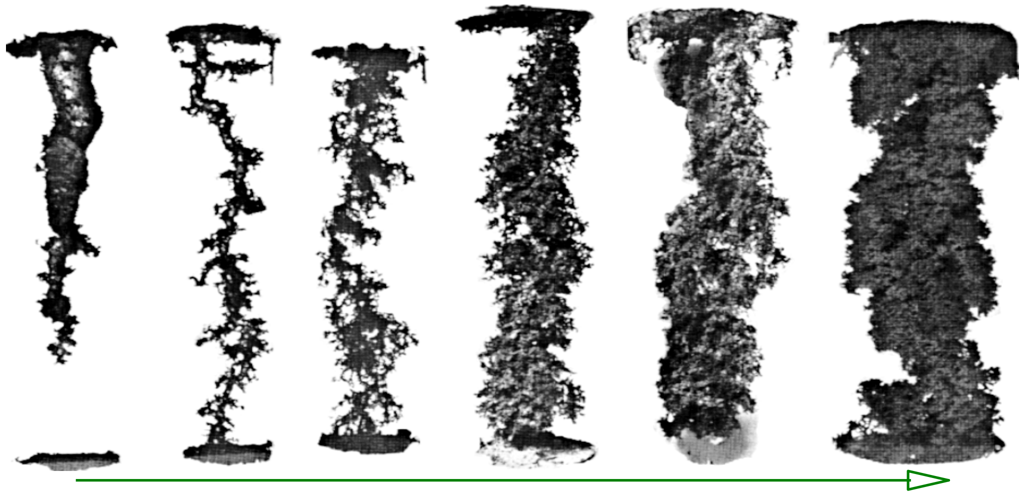
- This is an alternative to hydraulic fracturing and propping. It has no application in sandstone.
- A Pad fluid is injected to initiate fracture and then acid is followed.
- In fracture acidizing, the fracture faces must be etched with acid to provide linear flow channels to the wellbore.
- The *key* to fracture acidizing is to *create* sufficient *flow capacity* (and sufficient channel length) in the etched channels, to significantly increase well productivity.

Injection Rates: dissolution patterns

Patterns change depending on:

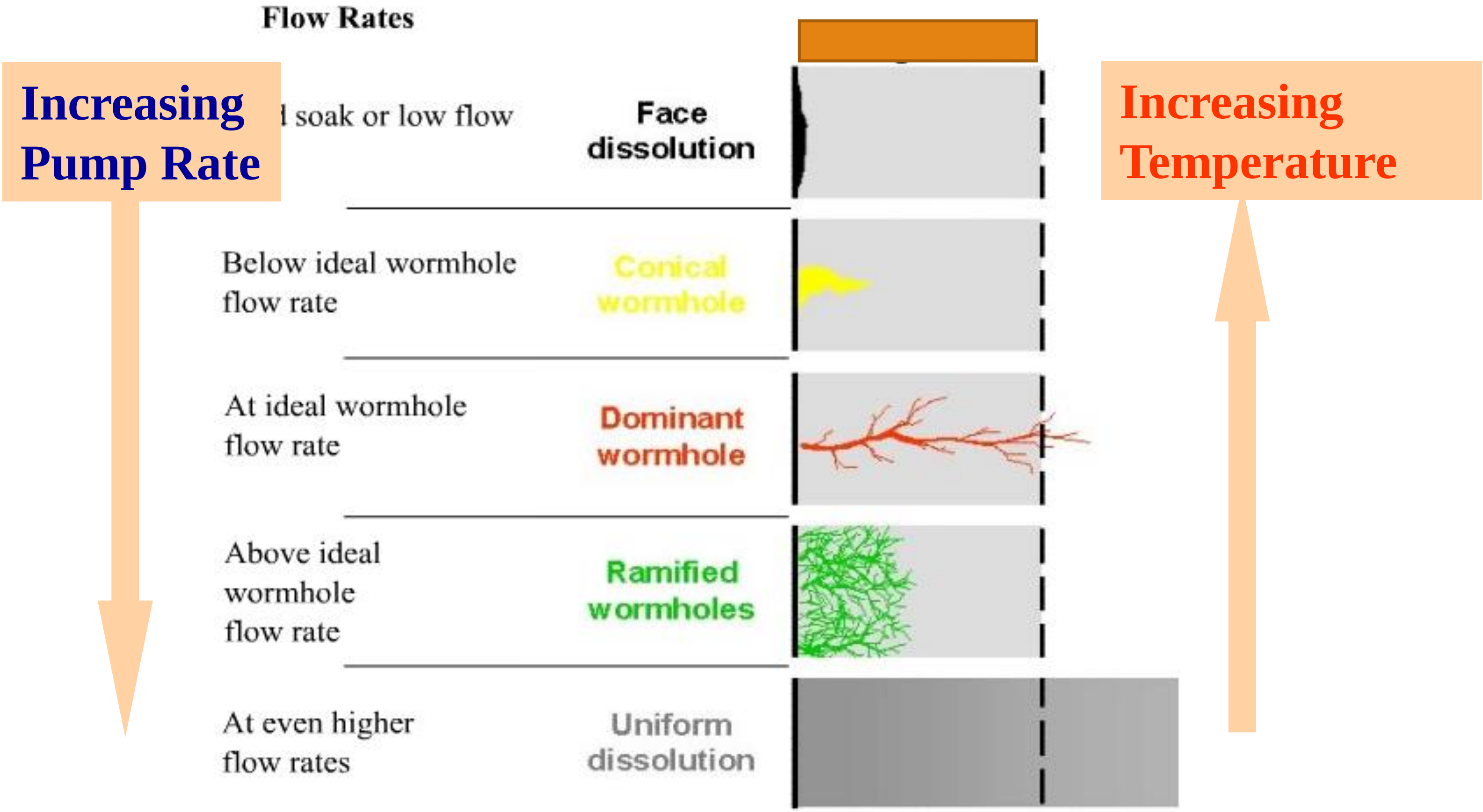
- Temperature
- Injection velocity
- Surface reaction rate

Is there any way to rationalize what is happening?



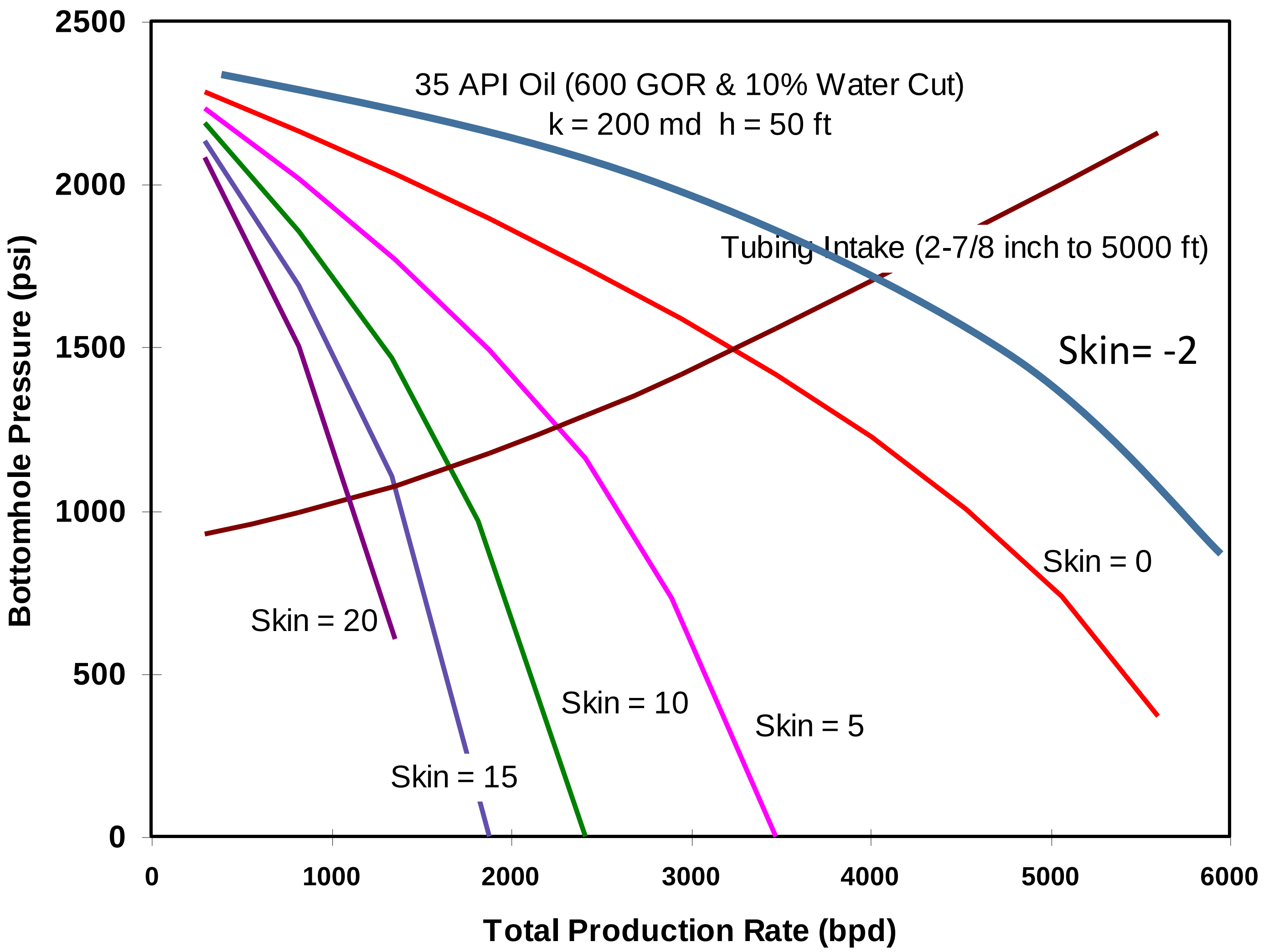
Increasing Injection Rate

Impact of Pump Rate and Temperature

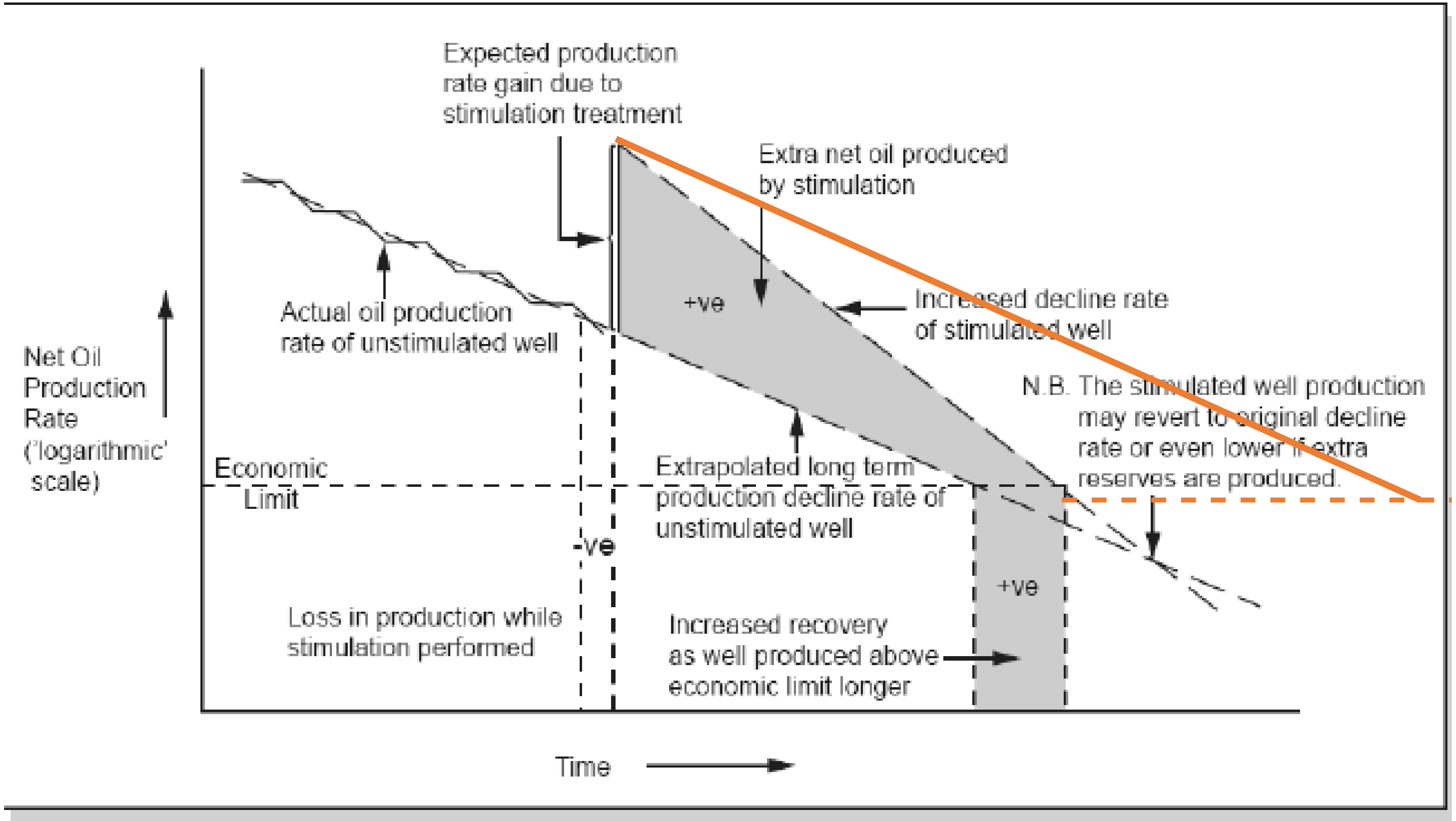


Reaction rate can be too high even with Organic Acids at high temperature.

Effect of Skin on Productivity of Oil Well



Matrix Stimulation - Introductory Well Economics



- Extra oil production has to pay for treatment cost

Additional References:

- Society of Petroleum Engineers (SPE) “Distinguished Lecturer Program”

- SPE one petro website

New Technology to Improve Oil Recovery

http://pubs.acs.org/journal/acsodf

Article

Further Insights into the Performance of Silylated Polyacrylamide-Based Relative Permeability Modifiers in Carbonate Reservoirs and Influencing Factors

Liming Qin, Matthew B. Myers, Claus Otto, Michael Verrall, Zhiqi Zhong, Eghan Arjomand, Ali Saeedi,* and Colin D. Wood*

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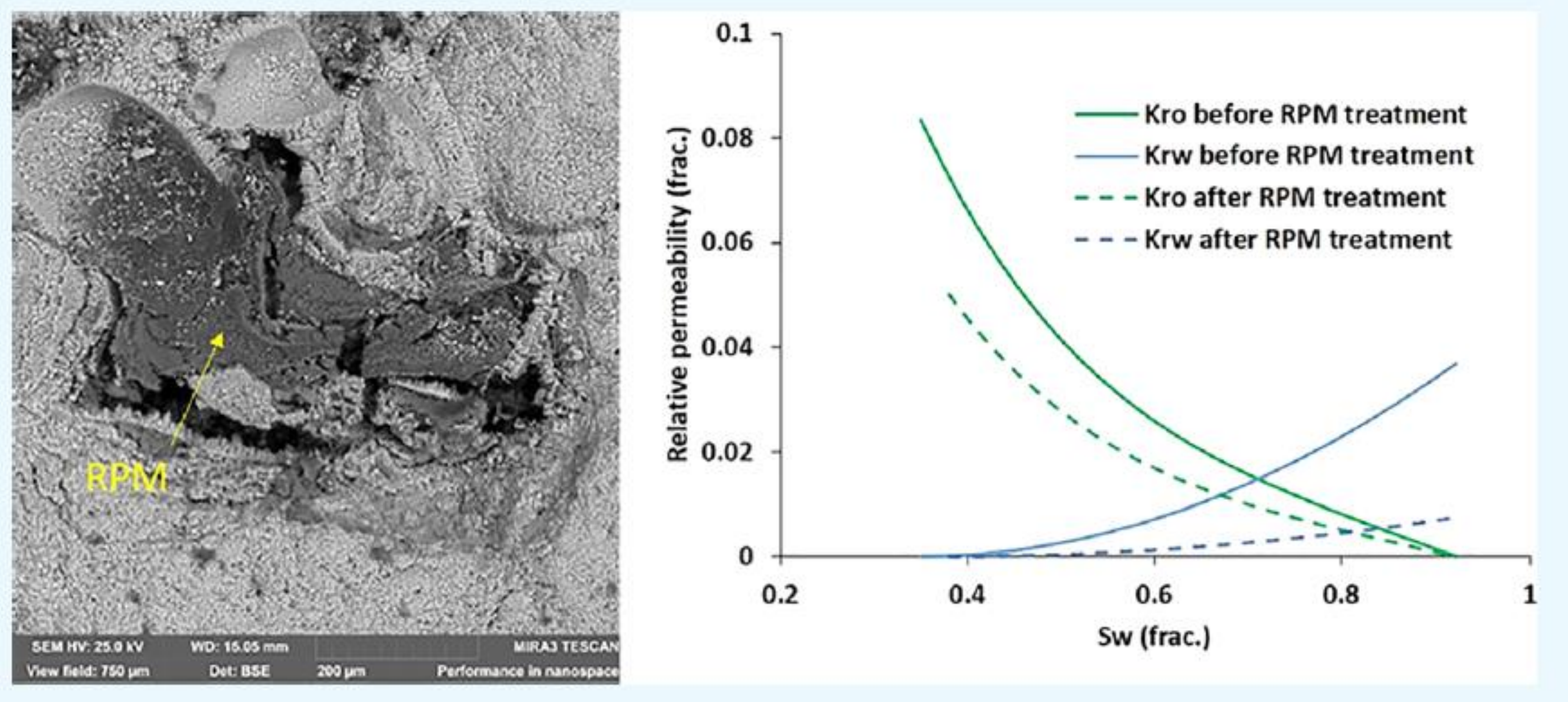
Read Online

ABSTRACT: **We have previously used surface chemistry analysis techniques to optimize the functionalization of carbonate rocks with a silylated polyacrylamide-based relative permeability modifier (RPM). The RPM is expected to selectively reduce the permeability to water in a hydrocarbon reservoir setting, resulting in a reduction in the amount of produced water while maintaining the production of oil/gas.**

This study will focus on using core flooding techniques with brine/crude oil under reservoir conditions (i.e., 1500 psi pore pressure and 60 °C temperature) to understand the impact of a silylated polyacrylamide-based RPM on the fluid transport properties in carbonate rocks.

The effects of RPM concentration, brine salinity, rock permeability, and pore structure on permeability characteristics were studied. Scanning electron microscopy (SEM) combined with energy dispersive spectroscopy (EDX) provided visual images of the polymer adsorbed onto the rock surfaces and

Many RPM strategies use an uncross-linked copolymer containing partially hydrolyzed polyacrylamide (resulting in a combination of acrylate and acrylamide in the polymer backbone), which contains both positive and negative charges. These uncross-linked polymers with their long chains and charged ions can adhere onto a rock surface. When a crosslinking agent is added to the polyacrylamide (called a gelant), the RPM forms a gel in situ that can be used to diminish water permeability substantially.


RPM
SEM HV: 25.0 kV
WD: 15.05 mm
MIRA3 TESCAN
View field: 750 µm
Det: BSE
200 µm
Performance in nanospace
Kro before RPM treatment
Krw before RPM treatment
Kro after RPM treatment
Krw after RPM treatment
Relative permeability (frac.)
Sw (frac.)
0.1
0.08
0.06
0.04
0.02
0
0.2
0.4
0.6
0.8
1

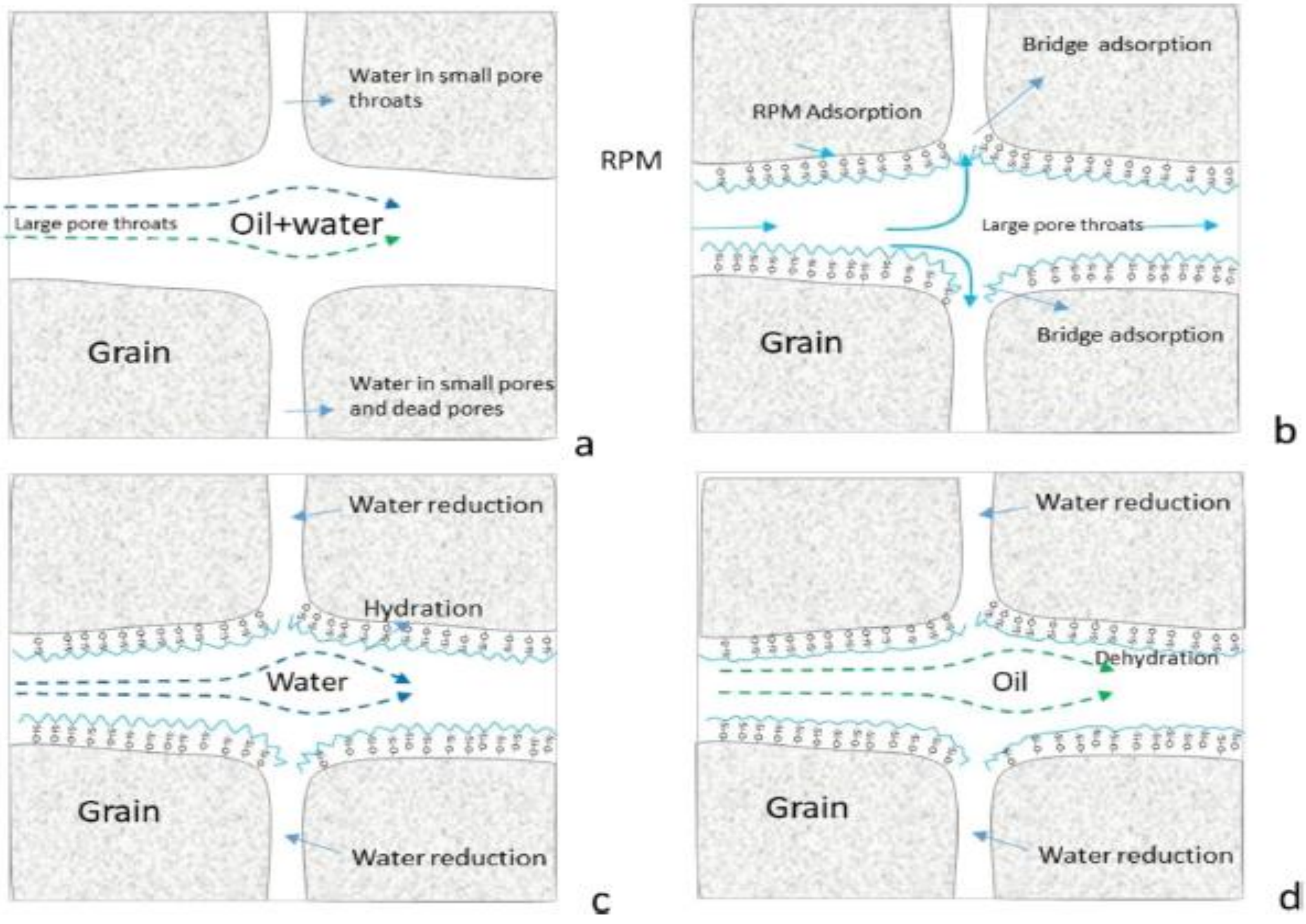


Figure 11. Schematic of RPM flowing through porous carbonate cores: (a) oil and water were injected, and irreducible water existed in smaller and dead pores, (b) RPM transported in larger pores, and bridge adsorption occurred, (c) water permeability decreased because of the hydration of polymer, (d) RPM dehydrated because of oil displacement.

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https://doi.org/10.1007/s13202-020-00912-6

ORIGINAL PAPER--PRODUCTION ENGINEERING

Optimization of engineered water injection performance in heterogeneous carbonates: a numerical study on a sector model

Jamiu Oyekan Adegbite[1] · Emad Walid Al-Shalabi[1]

Received: 9 January 2020 / Accepted: 11 May 2020

One of the emerging technologies for boosting oil recovery in both sandstone and carbonate reservoirs is engineered/lowsalinity water injection (EWI/LSWI).

LSWI

The process of diluting the injected brine while maintaining the same proportions of different ions is termed as low-salinity water injection (LSWI).

EWI

The process of modifying the ionic composition, by either increasing the concentration of the ions (hardening) or decreasing the concentration of the ions (softening), is defined as engineered water injection (EWI).

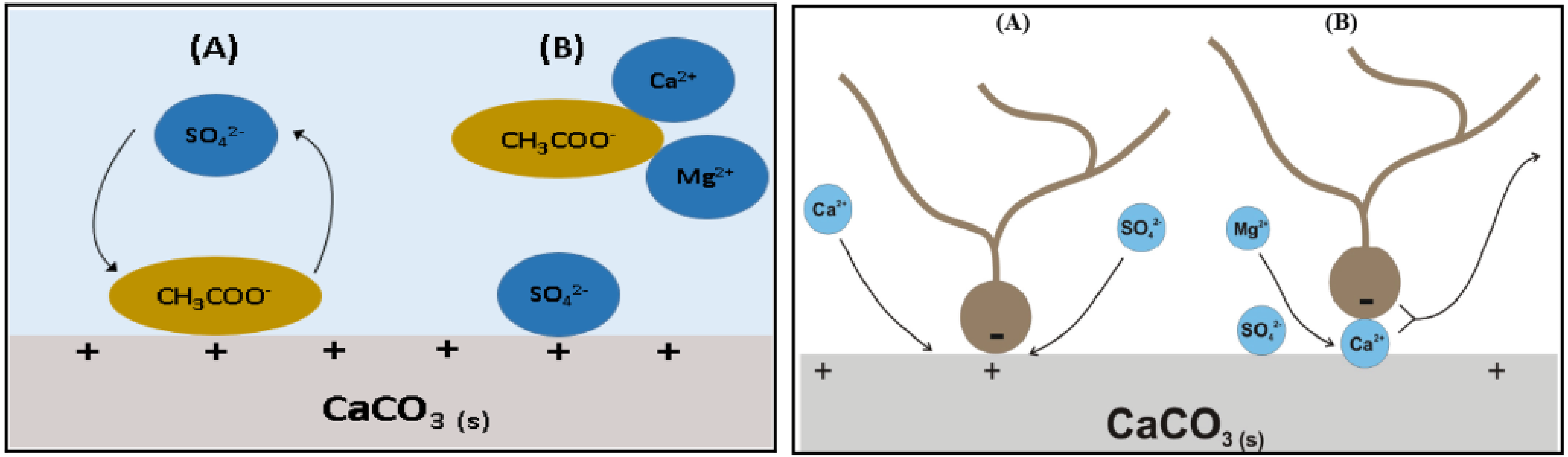
In this paper, optimization of engineered water injection is investigated using three synthetic sector models representing homogeneous, heterogeneous with channeling, and heterogeneous with gravity underride reservoirs. Both oil recovery and net present value were investigated as objective functions for the study.

The optimization study highlighted that secondary EWI is recommended to achieve the best profitability out of the three models.

Engineered water injection model used

Adegbite et al. (2018a) proposed that during EWI, oil carboxylic group undergoes anion exchange reaction with the sulfate-ion present in the EW. This alters the wettability of the carbonate rocks toward a more water-wet condition and hence leads to the release of oil ganglia (Fig. 3a).

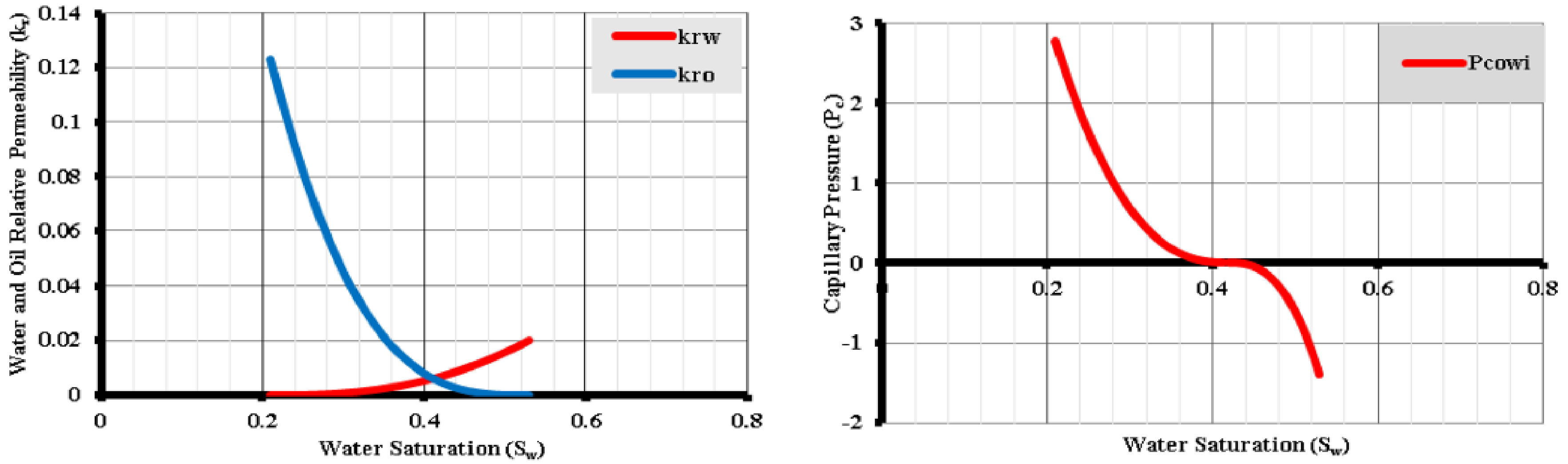
This proposed model differs from Zhang et al. (2007) model (Fig. 3b) where the latter necessitates the presence of other ions, namely calcium ion and/or magnesium ion, along with sulfate to cause wettability alteration.



a EWI mechanism for wettability alteration proposed by Adegbite *et al.* (2018a).

b LSWI mechanism for wettability alteration proposed by Zhang *et al.* (2006).

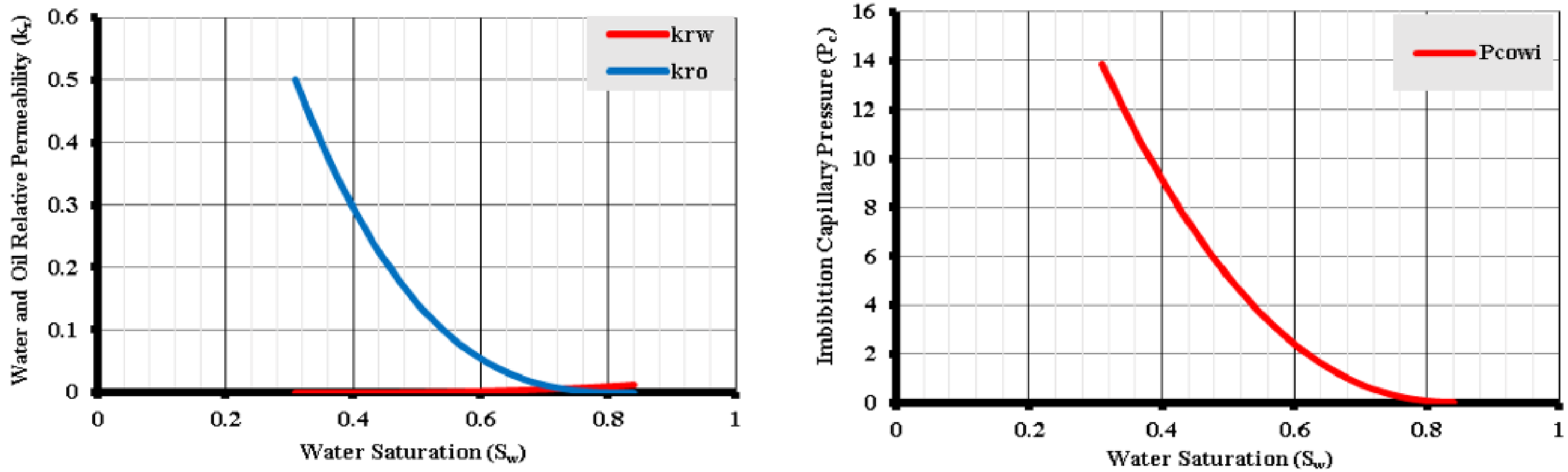
Fig. 3 Wettability alteration in carbonate rocks. **a** EWI mechanism for wettability alteration proposed by Adegbite et al. (2018a). **b** LSWI mechanism for wettability alteration proposed by Zhang et al. (2006)



a FW relative permeability curves (k_r).

b FW imbibition capillary pressure curve (P_c).

Fig. 4 Relative permeability and capillary imbibition curves for FW (Adegbite et al. 2018a). **a** FW relative permeability curves (k_r). **b** FW imbibition capillary pressure curve (P_c)



a EW relative permeability curves (k_r).

b EW imbibition capillary pressure curve (P_c).

Fig. 5 Relative permeability and capillary imbibition curves for EW (Adegbite et al. 2018a). **a** EW relative permeability curves (k_r). **b** EW imbibition capillary pressure curve (P_c)

Conclusion:

- Production gap in a typical oil producer could be bridged by available technology.

- Common Pet. Eng. activities along the life of the well could contribute to FD.
- Best practices while wells intervention could minimize the FD.

However,

Prevention is better than cure

- Comprehensive lab. assisted analysis is needed to achieve the stimulated target.
- Fracture acidizing could add a lot in terms of productivity and reserves.

Thank you