Produced Water Re-injection:
Opportunities and Challenges

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Oilfield Water Handling and Re-injection
The University of Texas at Austin

Single Well Models For Injectors

Mobility control with pH sensitive polymers

Combining single well models with reservoir simulators

Desalination Membranes

Distributed Models

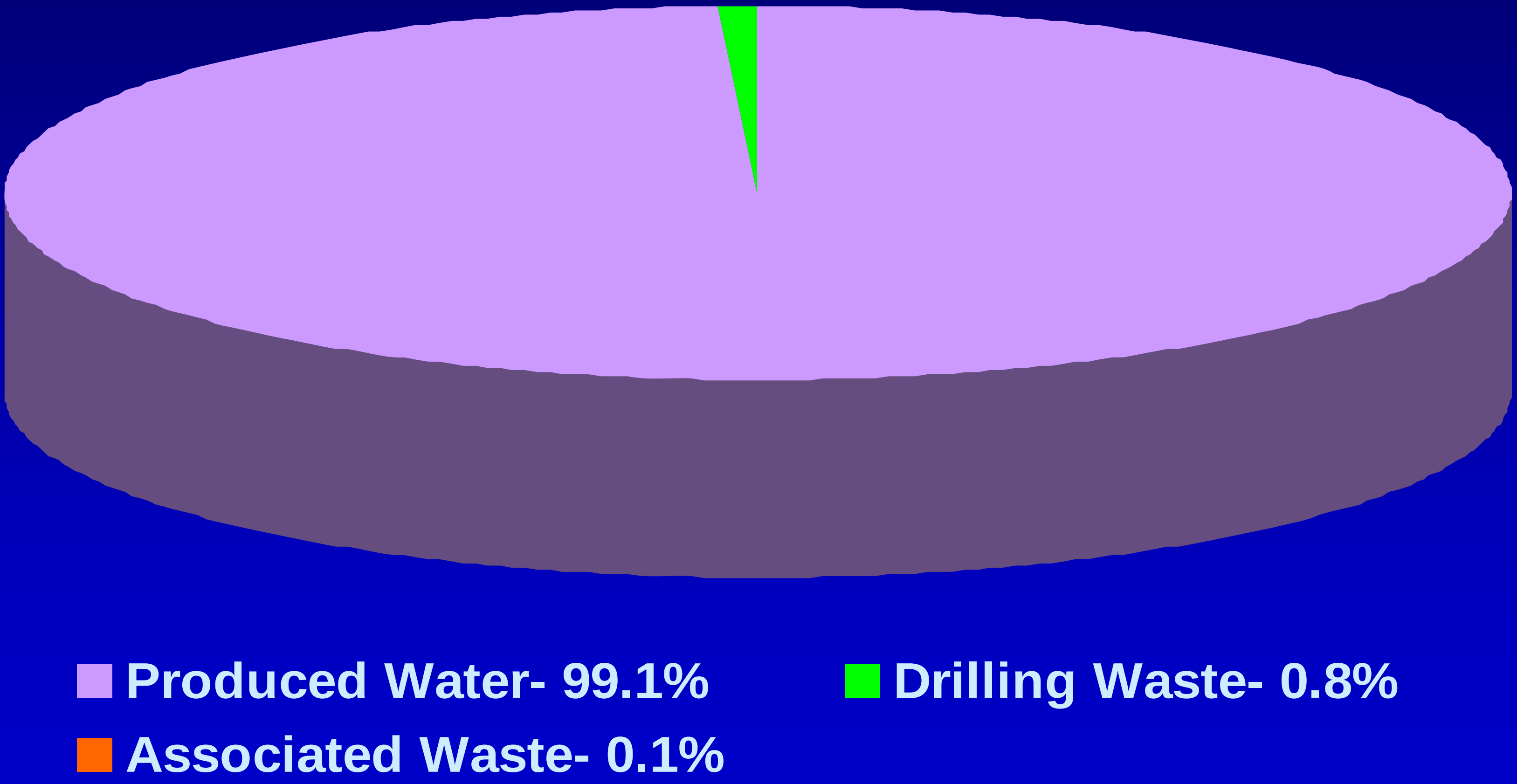
Oily Water Injection

Fractured Injectors

Injection Into Soft Sands

Case Studies

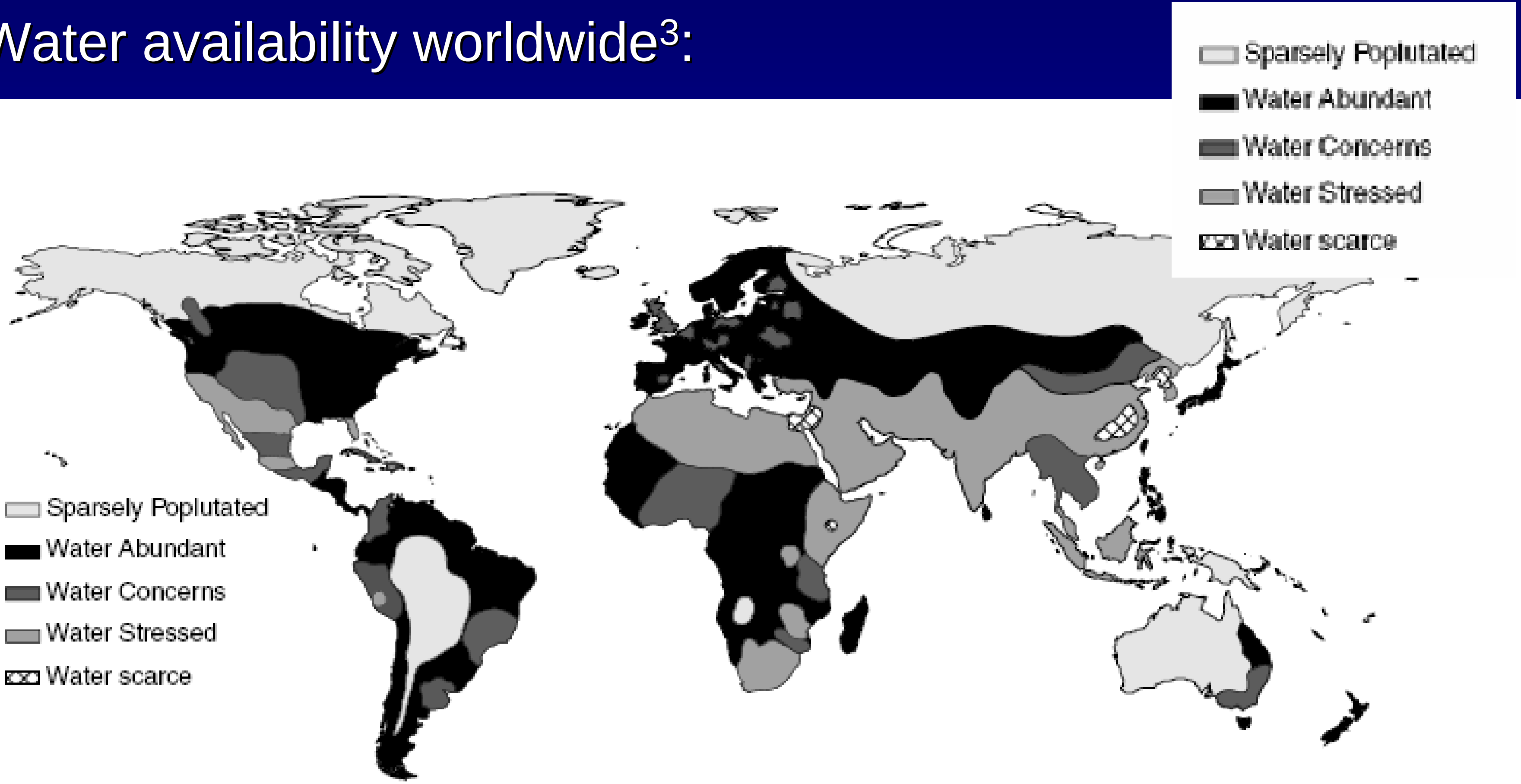
99% Of U.S. E&P Waste Volume is Produced Water



Source: API "Overview of Exploration and Production Waste Volumes and Waste Management Practice in the U.S." 2000

Produced Water: Worldwide Generation

- Estimated 77 billion bbl/year generated worldwide[1]
- Water availability worldwide[3]:



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1. Veil, J. A.; Puder, M. G.; Elcock, D.; Redweik, R. J.; U.S. DOE, 2004.
2. http://www.eia.doe.gov/emeu/cabs/nonopec.html
3. Marks, D.H. et al., Review of the Desalination and Water Purification Technology Roadmap, National Academy of Sciences, 2005.

Produced Water: A New Resource?

- Currently, 91% of produced water is reinjected[1]
  - 70% injected for oil recovery
  - 21% injected for disposal
- Other treatment options:
  - Discharge
  - Evaporation
  - Membrane separations
- Effective purification of produced water could provide water for:
  - Agricultural irrigation
  - Power generation
  - Livestock watering
  - Human consumption

1. Veil, J. A.; Puder, M. G.; Elcock, D.; Redweik, R. J.; U.S. DOE, 2004.

Why is Produced Water not Currently Used as a Resource?

- Cost of desalination
- Liability issues
- The primary technological barrier is the fouling of desalination membranes by,
  - Dissolved organics
  - Suspended oil droplets
  - Bacteria

Desalination membranes work well for sea-water but not for produced-water

Synthesis and Characterization of Fouling-Resistant Coatings for Reverse Osmosis Membranes

Grad students: Alyson Sagle, Liz van Wagner
Faculty: Benny Freeman, and Mukul M. Sharma
The University of Texas at Austin
2006

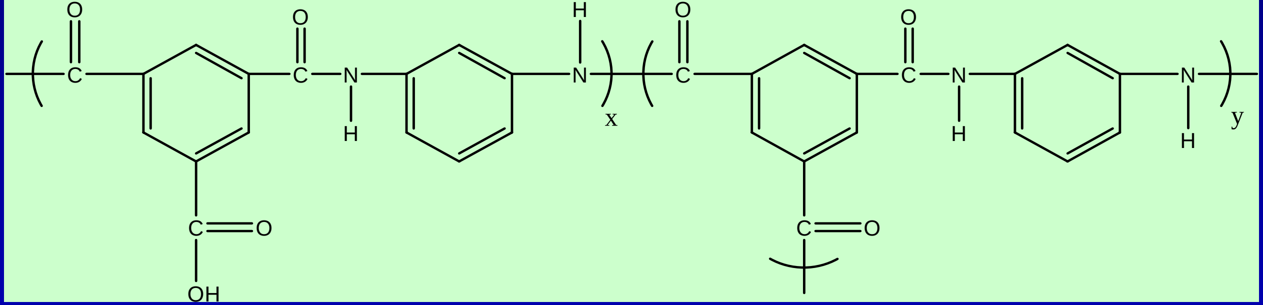
Reverse Osmosis: The Primary Method for Produced Water Treatment

- Commercial RO membranes can reject up to 99.9% NaCl ions
- Currently 43.5% of desalination capacity worldwide uses RO
- RO uses 1/10th power of evaporation-based desalination technologies
- Smaller footprint than conventional technologies

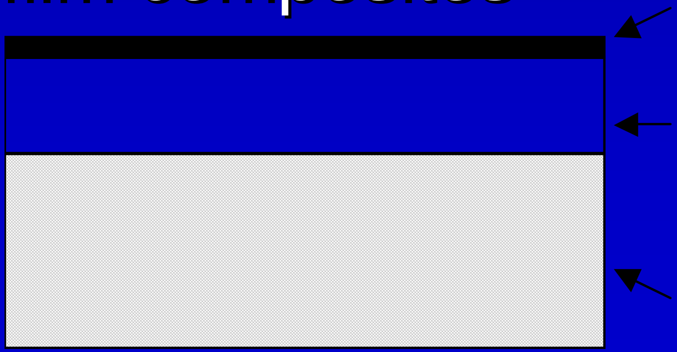
R. F. Service, Desalination Freshens Up, Science, 313 (2006) 1088-1090.
D. H. Marks et al., Review of the Desalination and Water Purification Technology Roadmap (2005) National Academy of Sciences.

Composition and Structure of Reverse Osmosis Membranes

- Effectively non-porous
- High flux and high salt rejection provided by crosslinked polyamide:



- Most RO membranes on the market are polyamide thin film composites

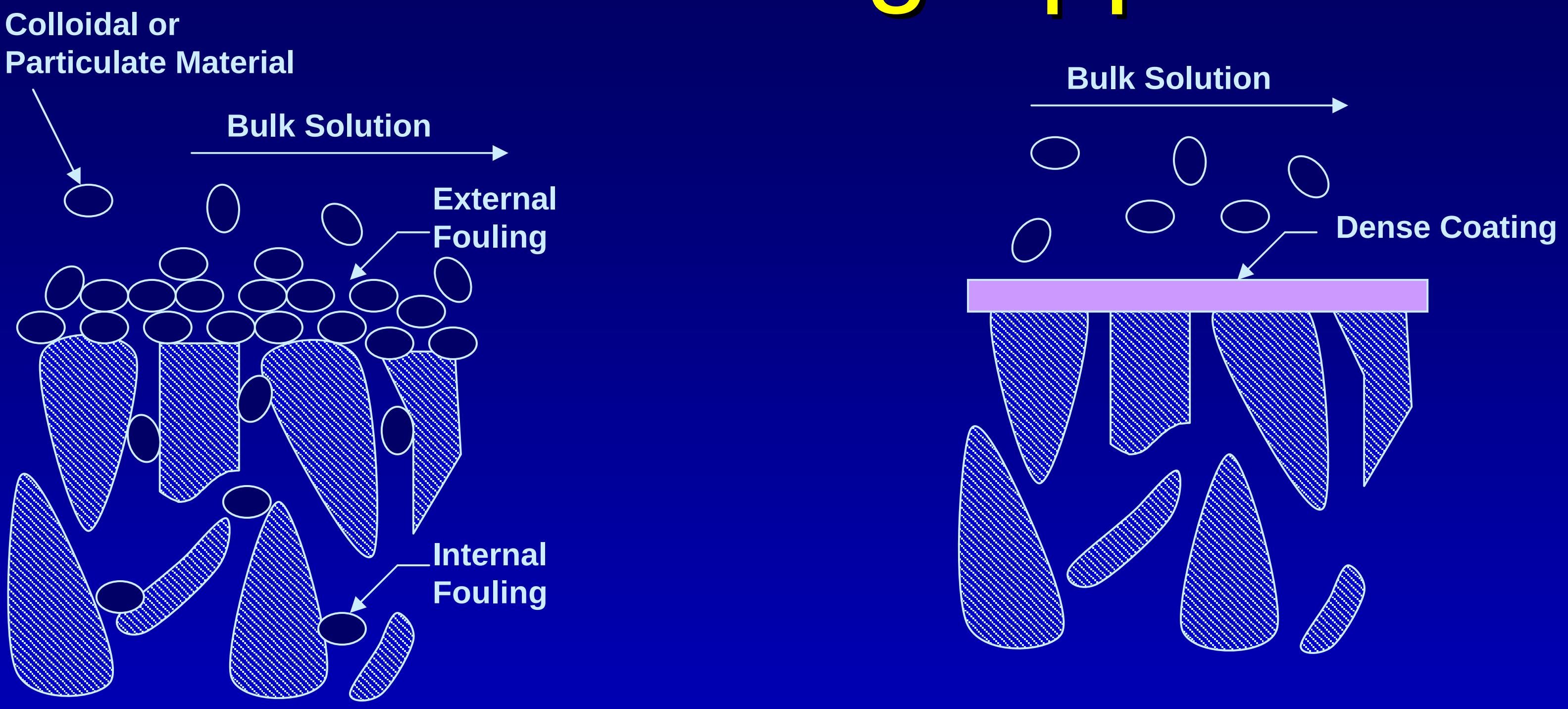


Ultrathin crosslinked polyamide
0.05 -1 μm

Microporous polysulfone
~50 μm

Non-woven backing
~100 μm

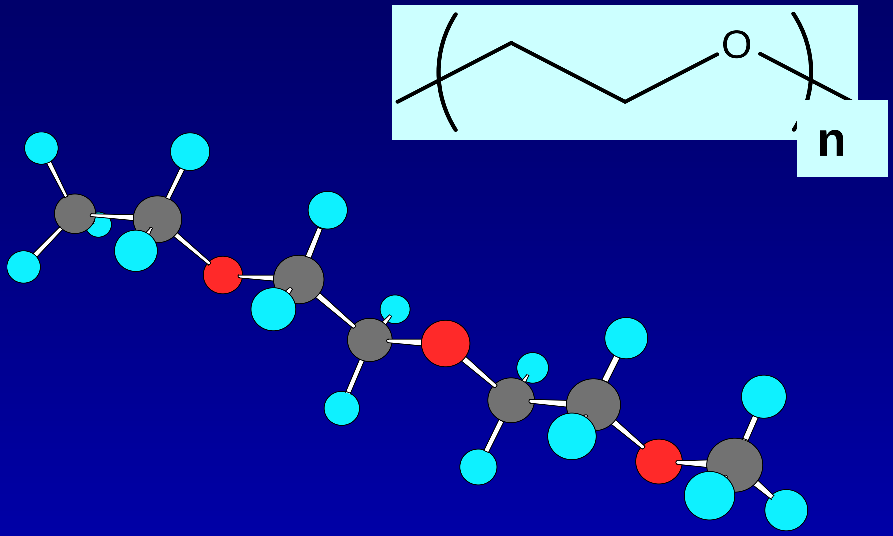
Surface Coating Approach



- A water-permeable, thin coating on a conventional RO membrane can:
  - Reduce external fouling due to its hydrophilic nature
  - Reduce surface roughness
  - Change the surface charge
- Disadvantages include:
  - An increased resistance to water and salt permeation

S.P. Nunes, M.L. Sforca, K.V. Peinemann, “Dense hydrophilic composite membranes for ultrafiltration,” J. Membrane Sci. **106**, 49-56 (1995).

Poly(ethylene glycol) (PEG) Derivatives



- **PEG is:**
  - water soluble
  - easy to chemically modify
  - relatively nontoxic
- **PEG-based hydrogels:**
  - resist protein adhesion
  - are extremely hydrophilic
  - are biocompatible
- **PEG-based materials are used in applications such as:**
  - drug delivery
  - contact lenses
  - wound dressings

1. N. A. Peppas, Z. H. Hilt, A. Khademhosseini and R. Langer, Hydrogels in biology and medicine: from molecular principles to bionantechnology, Advanced Materials, 18 (2006) 1345-1360.

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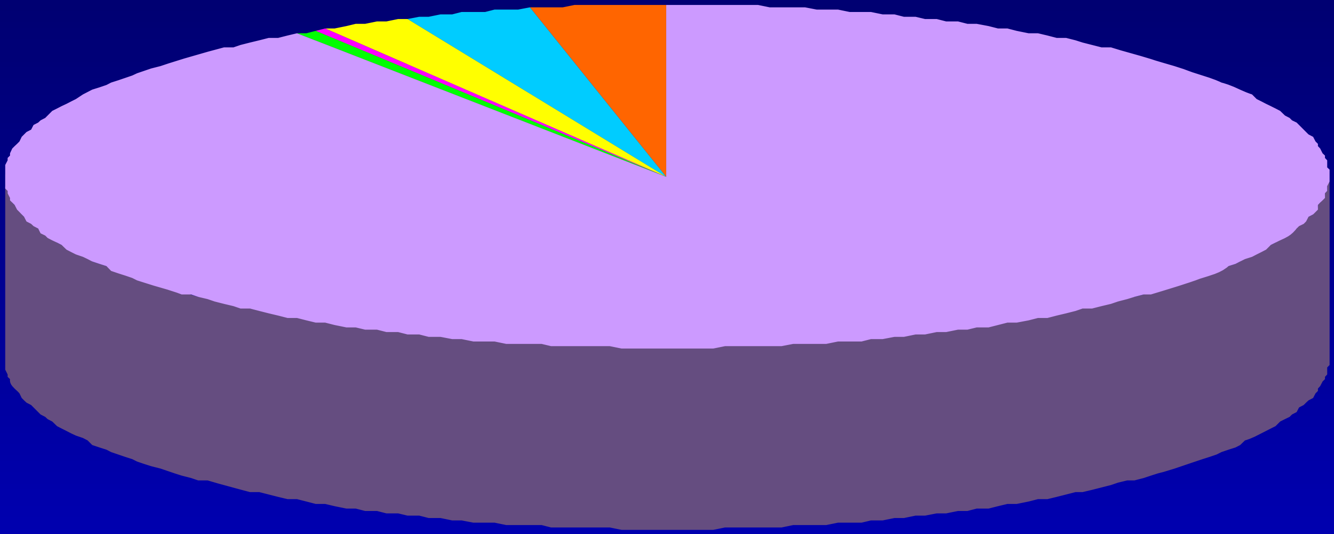
Mobility Control with pH Sensitive Polymers

- Viscosity increases sharply at a critical, controllable pH (about 3 to 4)
- This strategy allows low viscosity polymer to be injected in low pH buffer (improved injection rates)
- The reservoir then restores the pH and viscosifies the polymer for mobility / profile control
- Reservoir models and experiments show that the pH sensitivity of the polymer improves the sweep efficiency dramatically compared to currently used polymers.

91% of U.S. E&P Waste Volumes Are Returned to the Subsurface



- 🟪 **Injection- 90.8%**
- 🟪 **Commercial Facility- 0.5%**
- 🟦 **Discharge*- 3.0%**
- 🟩 **Evaporation- 0.4%**
- 🟨 **Reuse, Recycle, Reclaim- 2.1%**
- 🟧 **All Other- 3.4%**

*Discharges are primarily for agricultural and livestock use of produced water in the Western U.S.

Source: API "Overview of Exploration and Production Waste Volumes and Waste Management Practice in the U.S." 2000

Many Reasons to Inject Water

- Waterflooding (recover oil)
  - Produced water
  - Sea water
  - Fresh water source
- Pressure maintenance
- Water disposal
  - Produced water

Regardless of the source, water handling and injection is the single biggest operating cost for producers in mature fields.

Subsurface Water Injection

- We estimate ~ 500 million bbl of water/day is injected into the subsurface.
- We estimate that over $100 billion is spent annually on water injection.
- Stricter offshore water quality requirements favor water reinjection for disposal.
- Produced water/oil ratio increasing in mature fields.

Opportunities and Challenges

Challenges

- Design water handling and injection systems to reduce the cost of water injection.
  - Specify injection water quality, rates & pressures
  - Subsurface separation?
  - Subsea vs topsides
- Reduce water cut (the holy grail).

Opportunities

- Major cost reductions to improve production economics.
- Significant improvements in oil recovery.

Decisions, Decisions!!!

Water management decisions have a very significant impact on project economics.

- How clean should the water be?
  - Controls design of the treatment facility.
- Injection rates and pressure?
  - Injector performance ?
  - Impact on oil recovery?
- Well completion design for injectors
- Topsides vs sub-sea separation.
- Downhole vs surface separation.

Gulf of Mexico Case Study Water Injection Project History

- Expected injection rates: 10,000 bbl/day/well
- Avoidance of fracturing was essential to:

  (a) avoid early water breakthrough, and

  (b) maintain water injection in the target sand
- 1 Darcy sand, gravel pack completions.
- Low initial injectivity, high skins.

Waterflood Facilities (GOM)

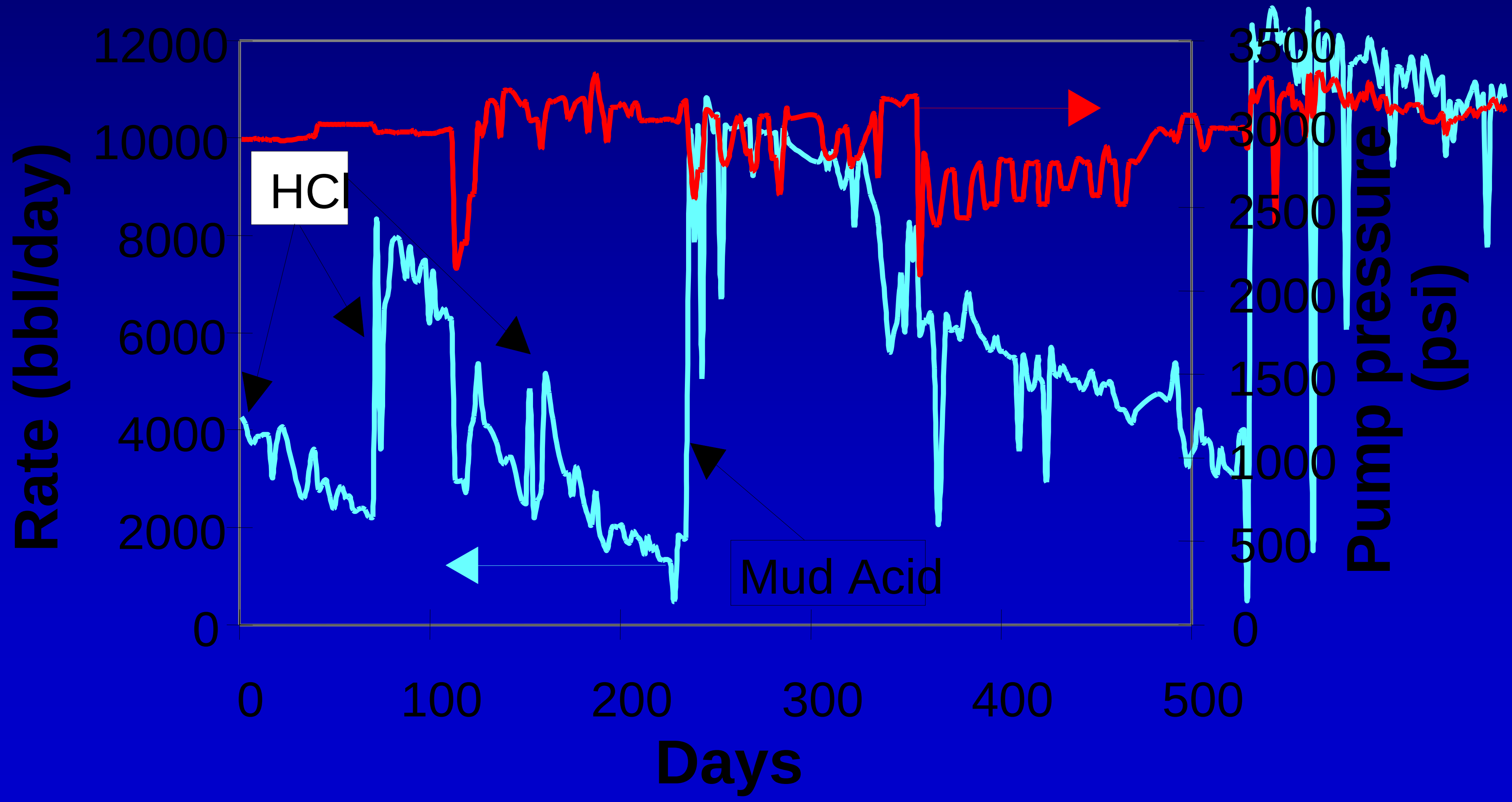
- Seawater taken from 150’ subsea
- Deoxygenation to 200 ppb by countercurrent gas stripping
- Deoxygenated to <10 ppb by chemical scavengers
- Sodium hypochlorite used for bacteria control
- Calcium carbonate scale inhibitor used
- Primary multimedia filters used
- Secondary cartridge filters (5 to 10 μm)

Water Quality (GOM)

- Solids content in injection waters, 1 to 7 ppm
- Average particle size 2 to 3 µm
- Elemental analysis performed on digested solids
- Excellent water quality
- Simple rules of thumb predict long half life
- Rather rapid decline in injectivity actually observed

Injection Rate and Pump Pressure Well A10

(From Sharma et. al. 1996)

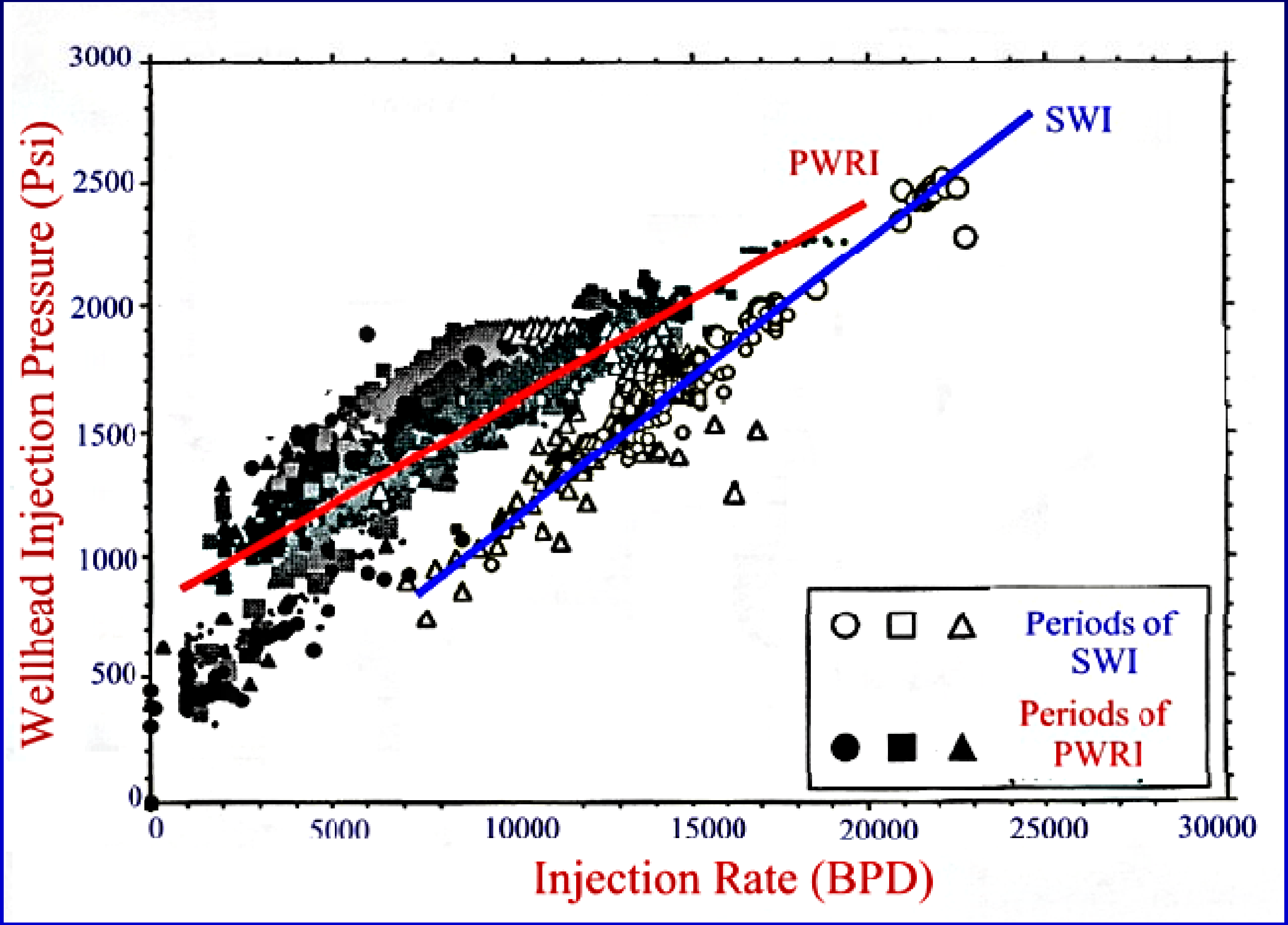


Prudhoe Bay
Water Injection Experience

- 1.2 MMbbl/day produced water and 0.85 MMbbl/day of seawater injected via 159 injectors.
- No decline in injectivity when injecting up to 2000 ppm solids and oil.
- All injectors are fractured.
- PW (150 ^{0}F) frac gradient = 0.57- 0.6
- SW (80 ^{0}F) frac gradient = 0.53 - 0.54
- Well orientation affects injectivity.

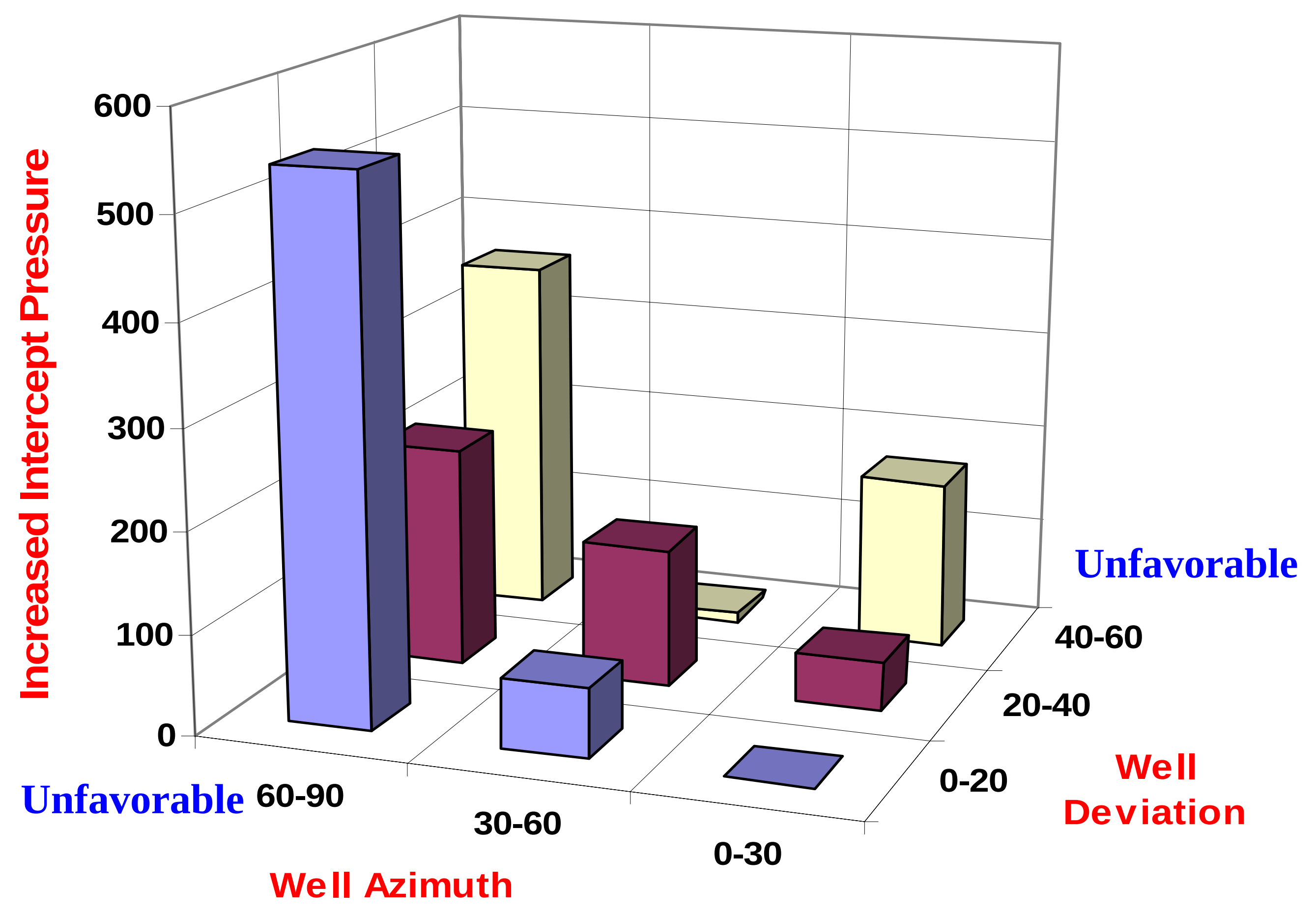
Performance Plot for Well H-09i

(From Martins et. al., 1994)



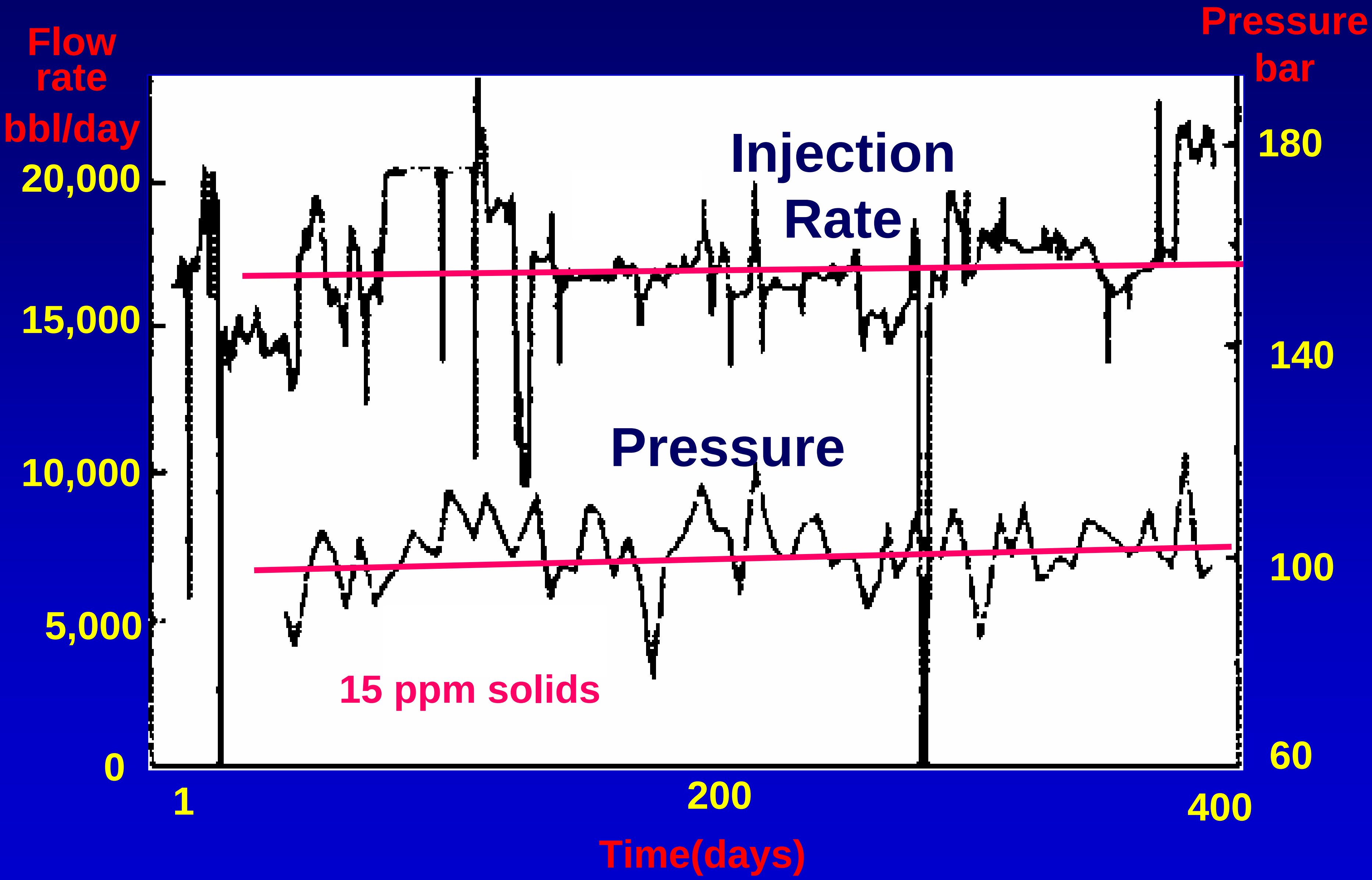
Effect of Well Azimuth and Deviation

(From Martins et. al., 1994)



Wytch Farm Field

Paige and Murray(1994)



Forties Field Experience

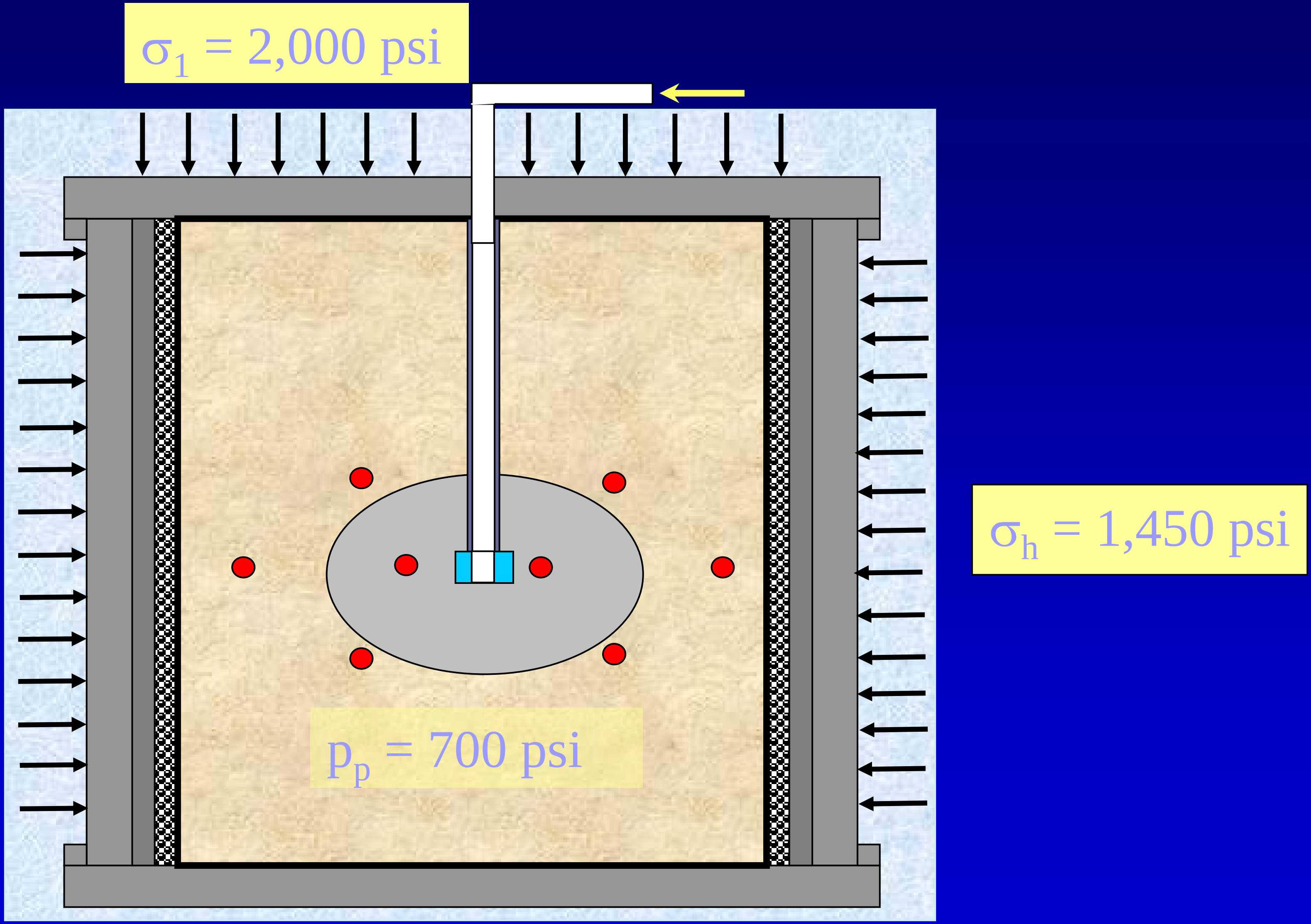
(1975-1996)

- 240,000 bbl of water injected in 1996.
- Core flow experiments indicated 90% reduction in injectivity over 6 months.
- Removal of fine filters had no adverse effects on injectivity of sea water.
- Injection of 50-1200 ppm oil and 5 to 50 ppm solids resulted in $I/I_o=0.7$ long term.

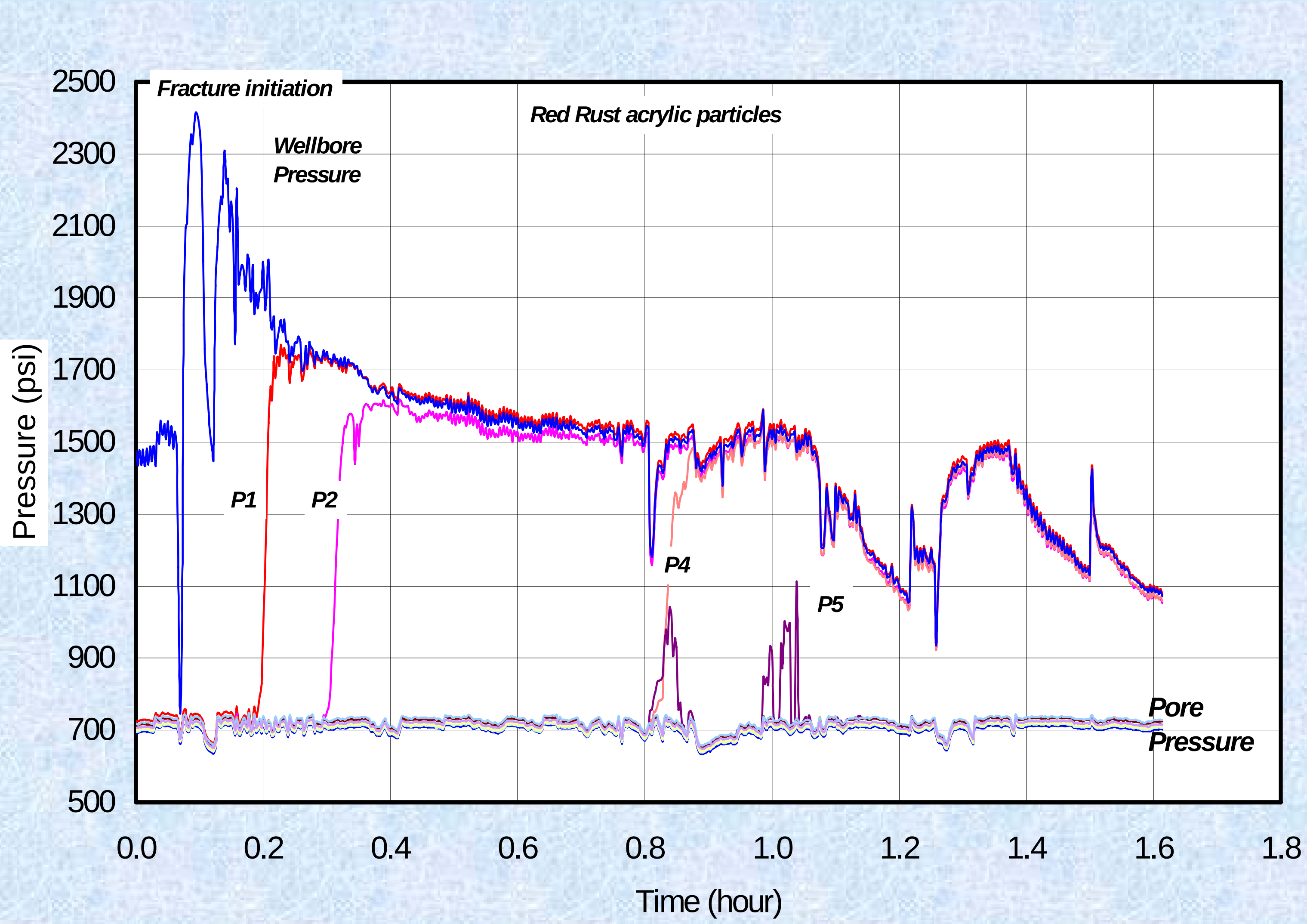
Ula, Magnus and Gyda Fields

- Removal of fine filters had no impact on injectivity.
- Hydraulic impedence testing on 50 injectors showed that they were all fractured.

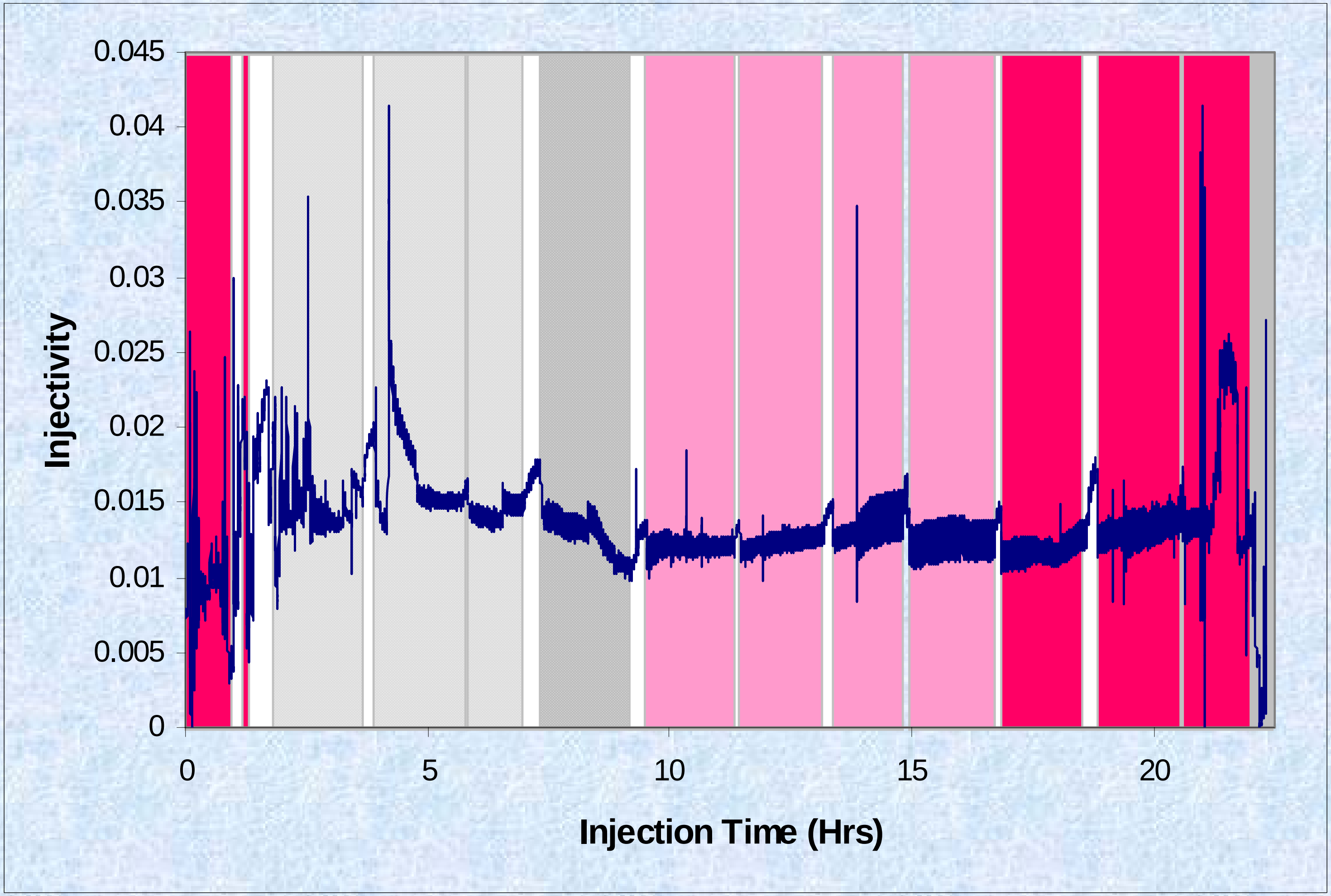
We have Tracked Fractures in Simulated Injection Wells



Pressure at Various Ports



Injectivity Remains Constant



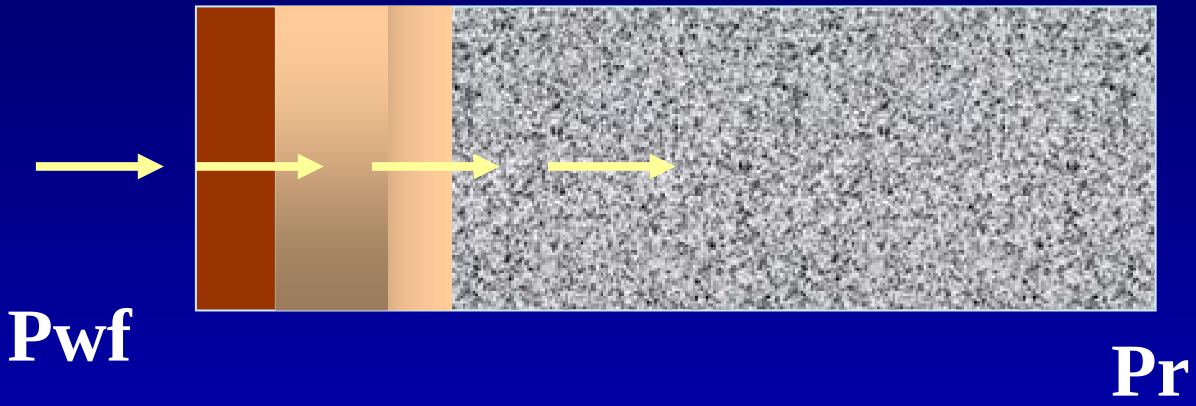
Lessons Learnt

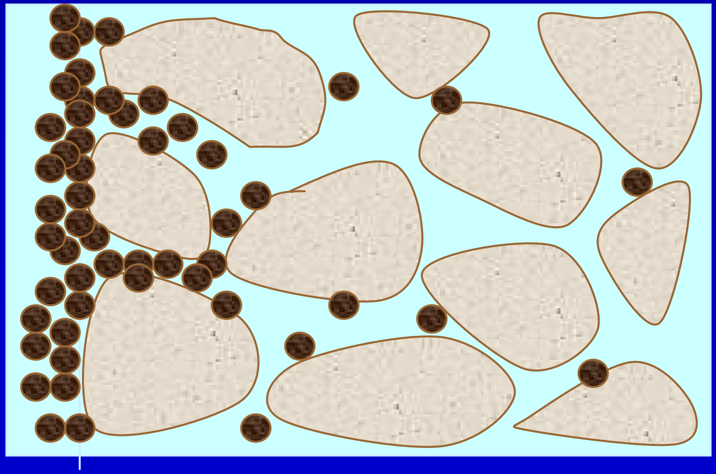
- Injectivity remains essentially constant (despite plugging by particles).
- The rate of fracture growth is closely related to particle trapping.
- Invasion depth from fracture face is shallow.
- Injected particles end up mostly at the fracture tip except when fracture is plugged.
- No fracture growth when clear brine is injected.

Unique Aspects of Injection Well Modeling

- Formation and fracture plugging
- Fracture propagation controlled by formation and fracture plugging
- Thermal stresses
- Pore pressure induced stresses
- Fracture geometry evolves with time
- Coupling to reservoir models

Particle Plugging





Filtration Equations

$$\frac{\partial(\phi c)}{\partial t} + u\frac{\partial c}{\partial x} + \frac{\partial D}{\partial t} = 0$$

$$\frac{\partial D}{\partial t} = \lambda\, uc$$

$$\lambda = 0.72 A_s N_{Lo}^{1/8} N_R^{15/8} + 2.4\times 10^{-3} A_s N_G^{1.2} N_R^{-0.4}$$

(Rajgopalan and Tien(1976))

Deposited Particles Reduce ϕ and k

$$\phi(x,t) = \phi_0 - D(x,t)$$

$$k = \frac{\phi^3}{5(1-\phi)^2}\frac{1}{S^2}\frac{1}{\tau}$$

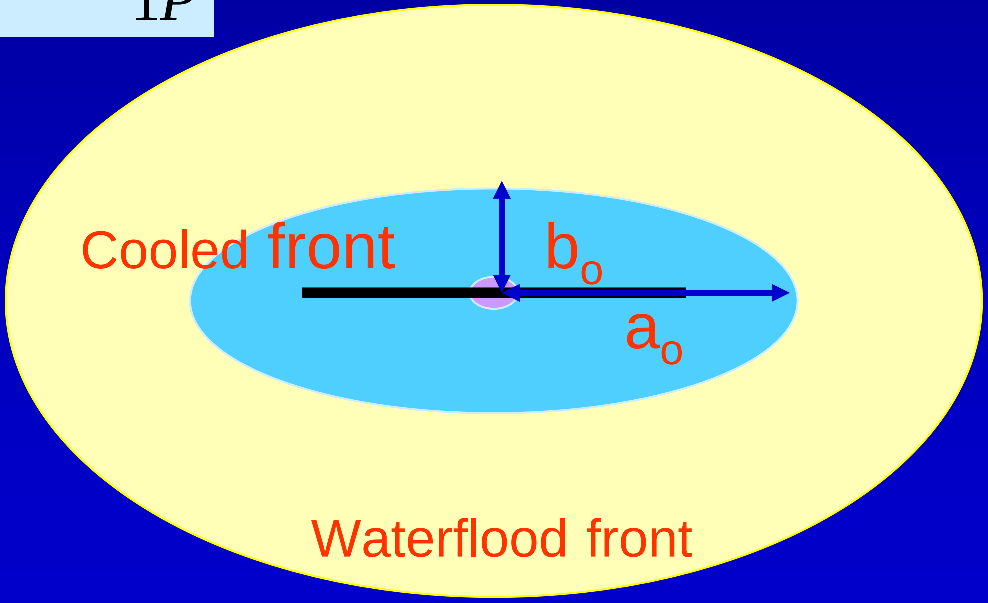
Thermal Stresses and Pore Pressure Effects

For Fracture propagation $P_{tip} > \sigma_1 + \sigma_{\mathrm{SE}}$

(Perkins & Krech (1968))

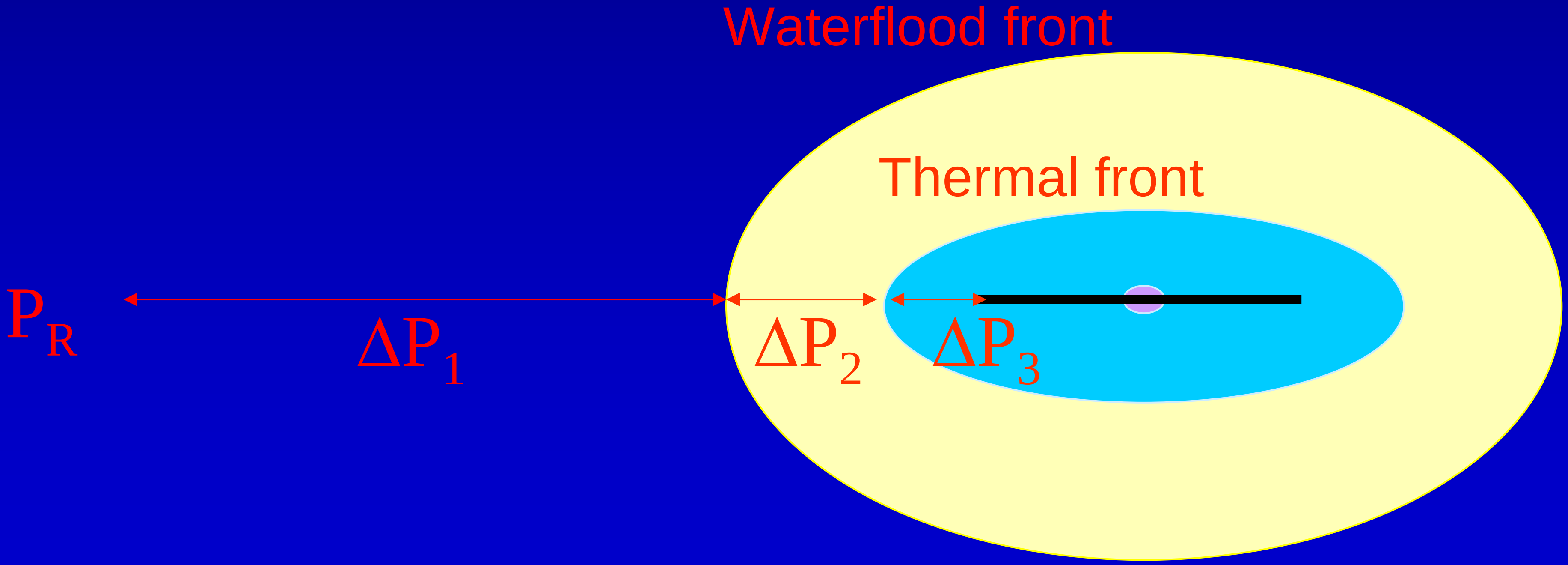
$$\sigma_1 = (\sigma_H)_{\min} + \Delta\sigma_{1T} + \Delta\sigma_{1P}$$

$$\frac{(1-\nu)\Delta\sigma_{1T}}{\beta E \Delta T} = \frac{(b_o / a_o)}{1 + (b_o / a_o)}$$

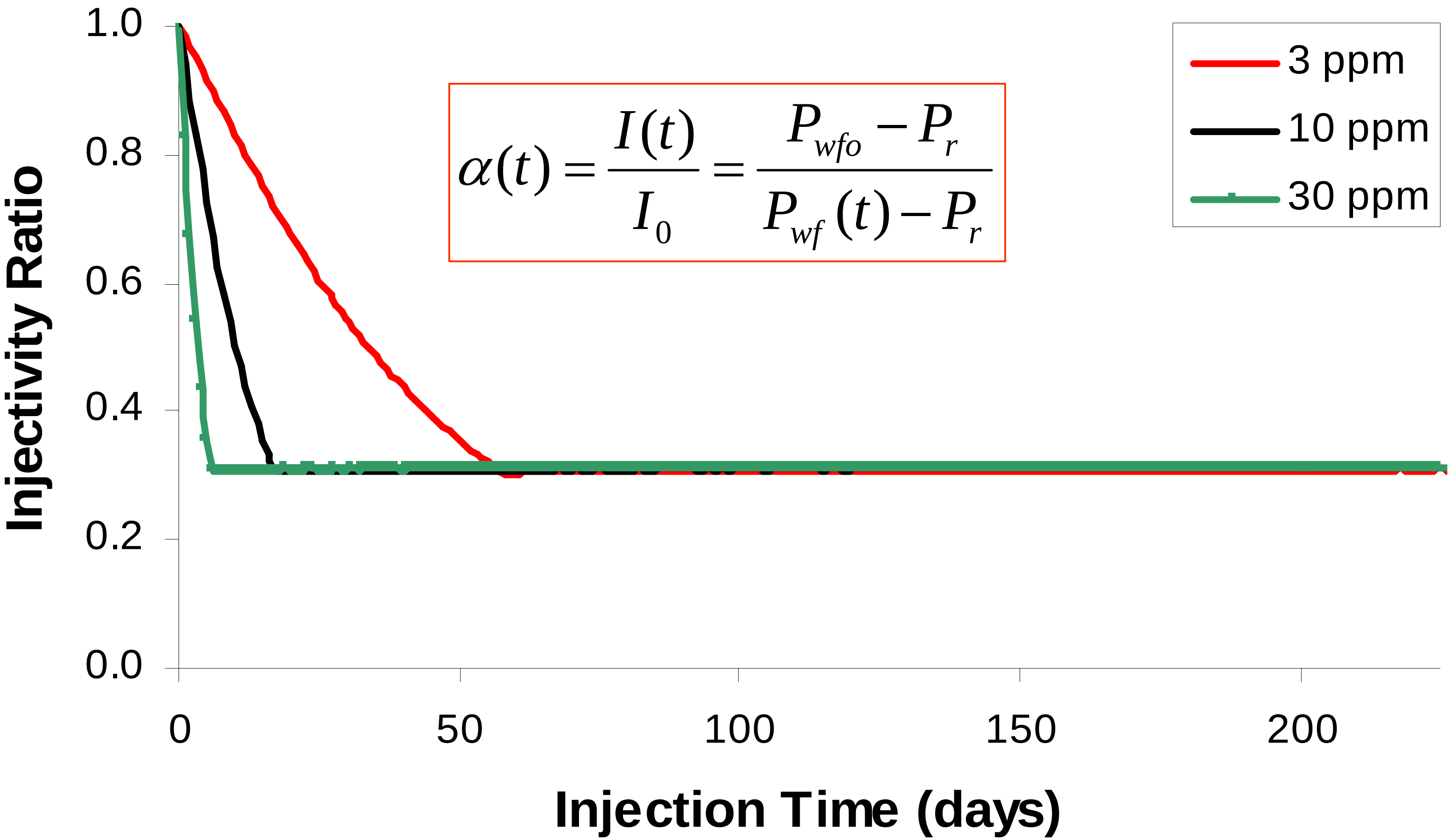


Flow Equations

$$P_{wf} = P_R + \Delta P_1 + \Delta P_2 + \Delta P_3 + \Delta P_s + \Delta P_f + \Delta P_p$$



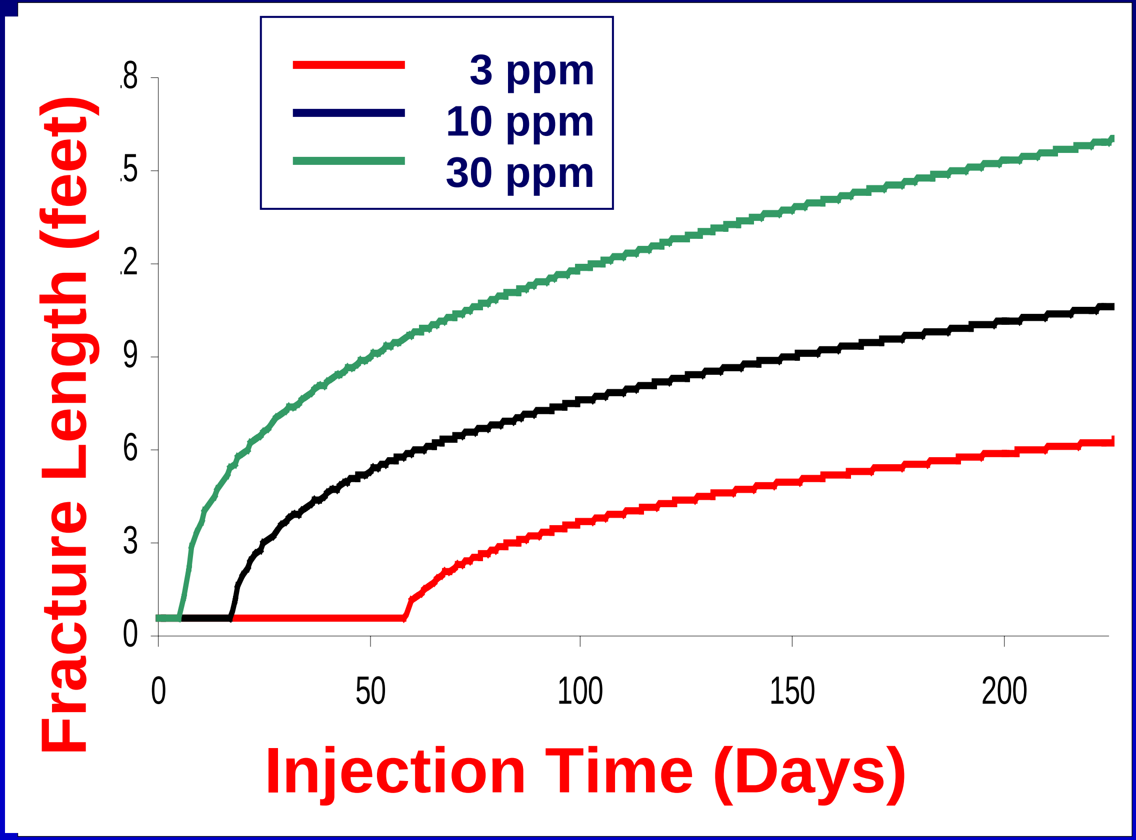
Effect of Injected Particle Concentration
(No Thermal Stresses, Swi=1)

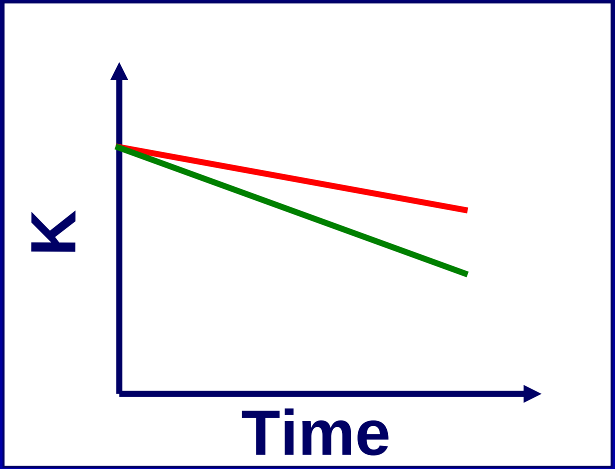


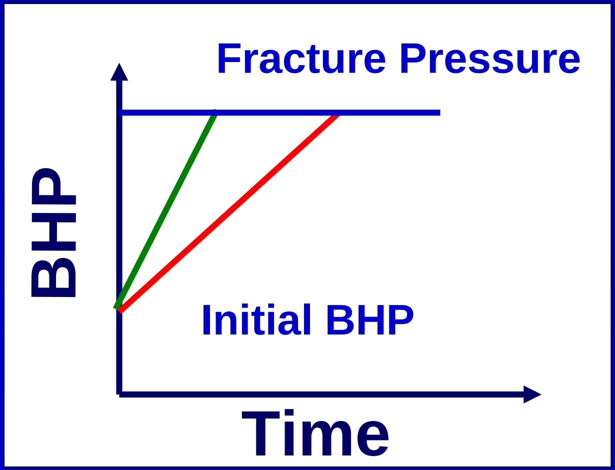
$$\alpha(t) = \frac{I(t)}{I_0} = \frac{P_{wfo} - P_r}{P_{wf}(t) - P_r}$$

Effect of Injected Particle Concentration

(No Thermal Stresses, Swi=1)

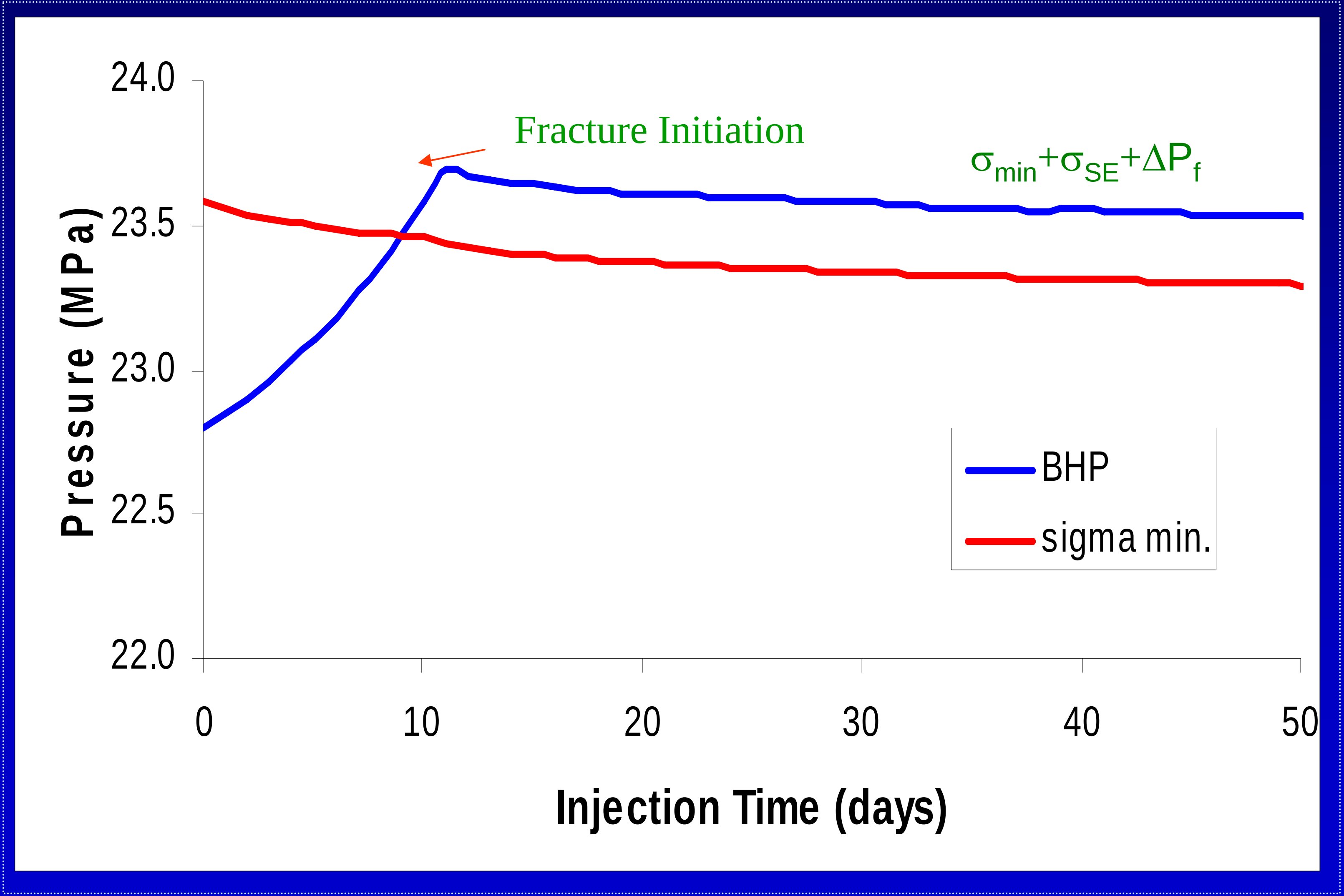






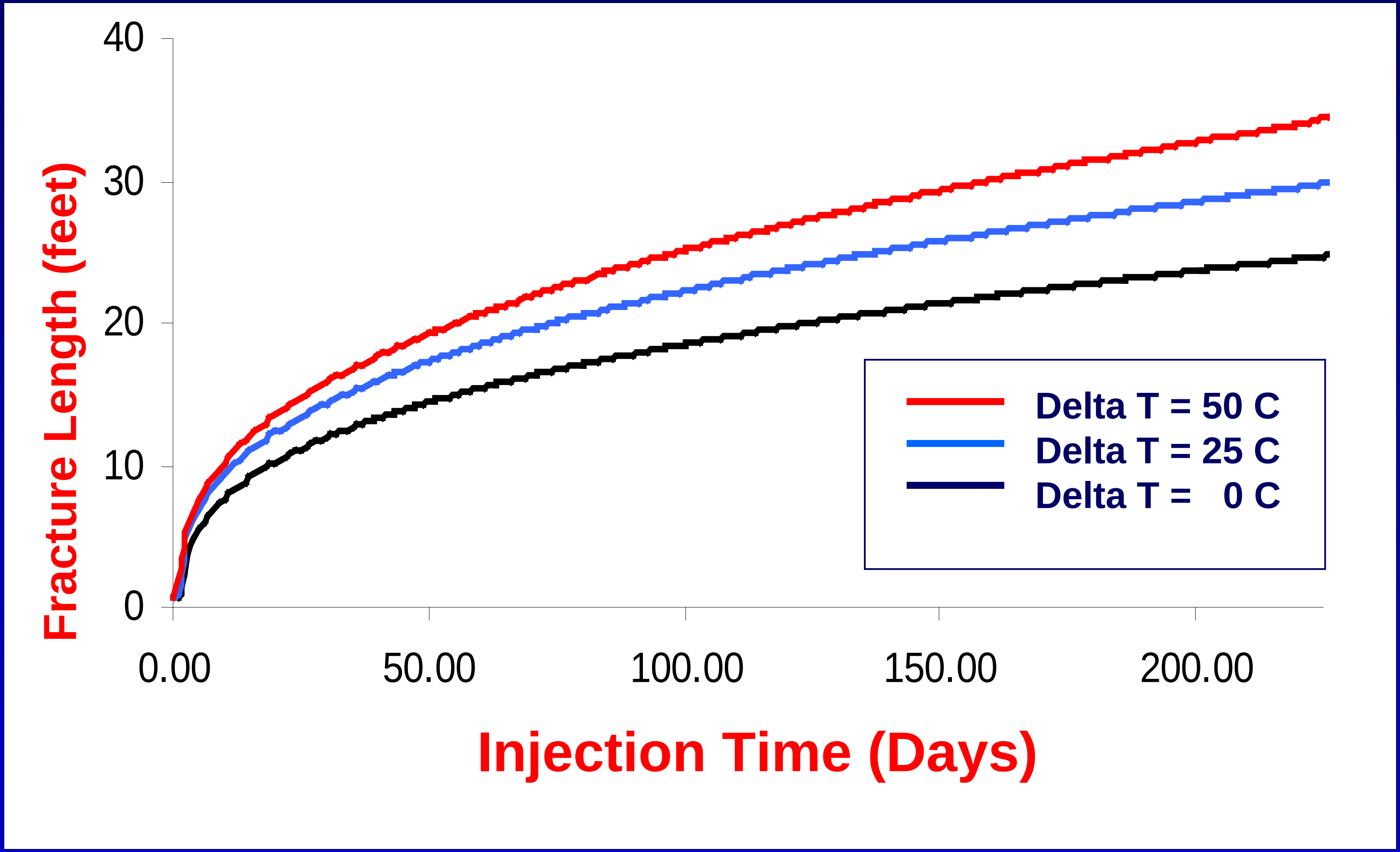
Anatomy of a Thermal Fracture

(ΔT=30 C, C_{inj}=100ppm)

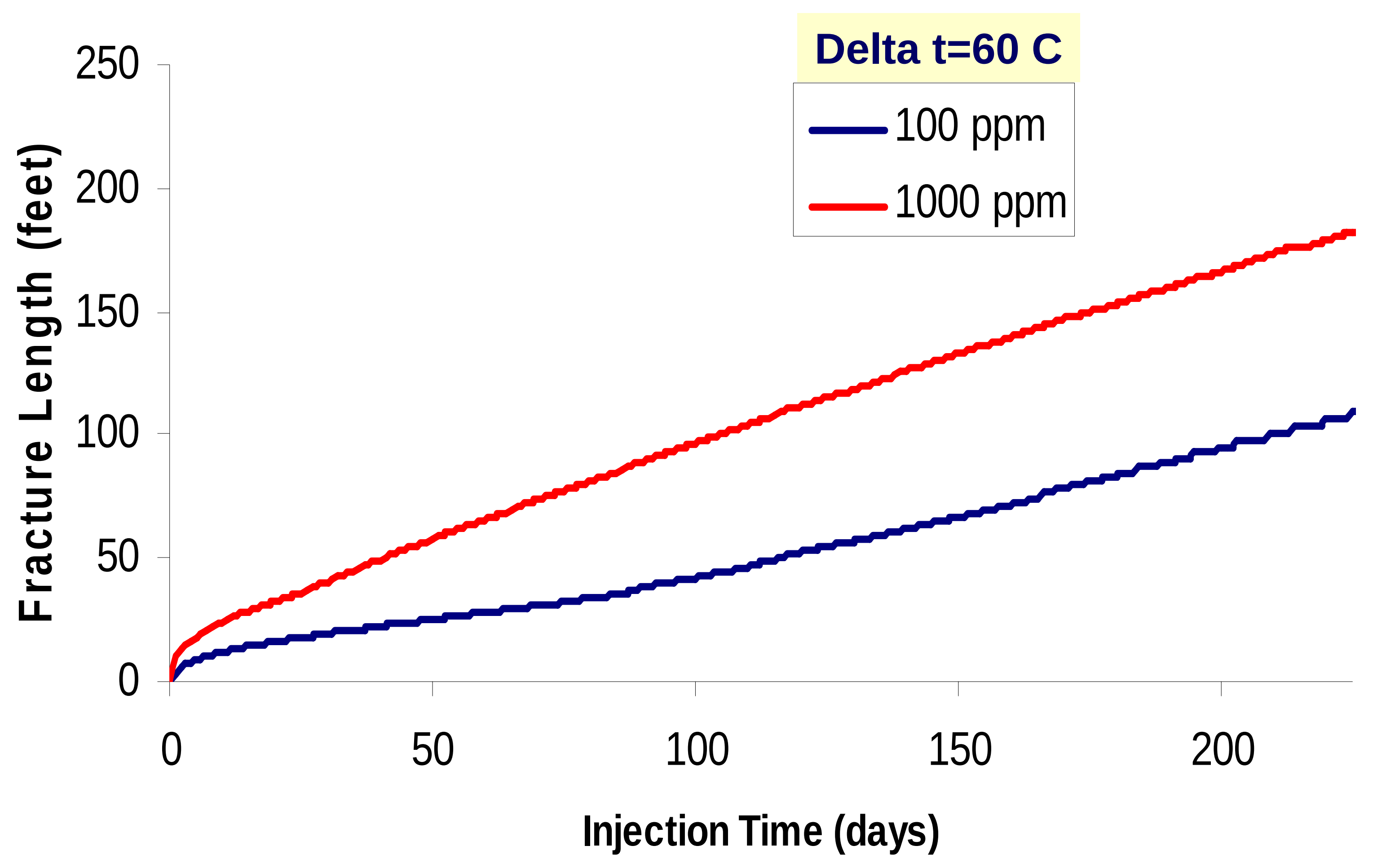


Effect of Thermal Stresses

(q=500m^3/day, S_{wi}=1)

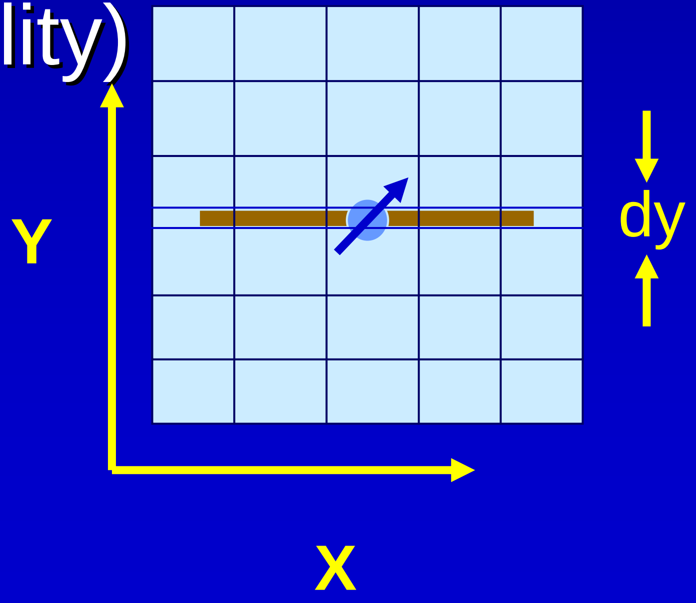


Thermal and Particle Plugging Effects



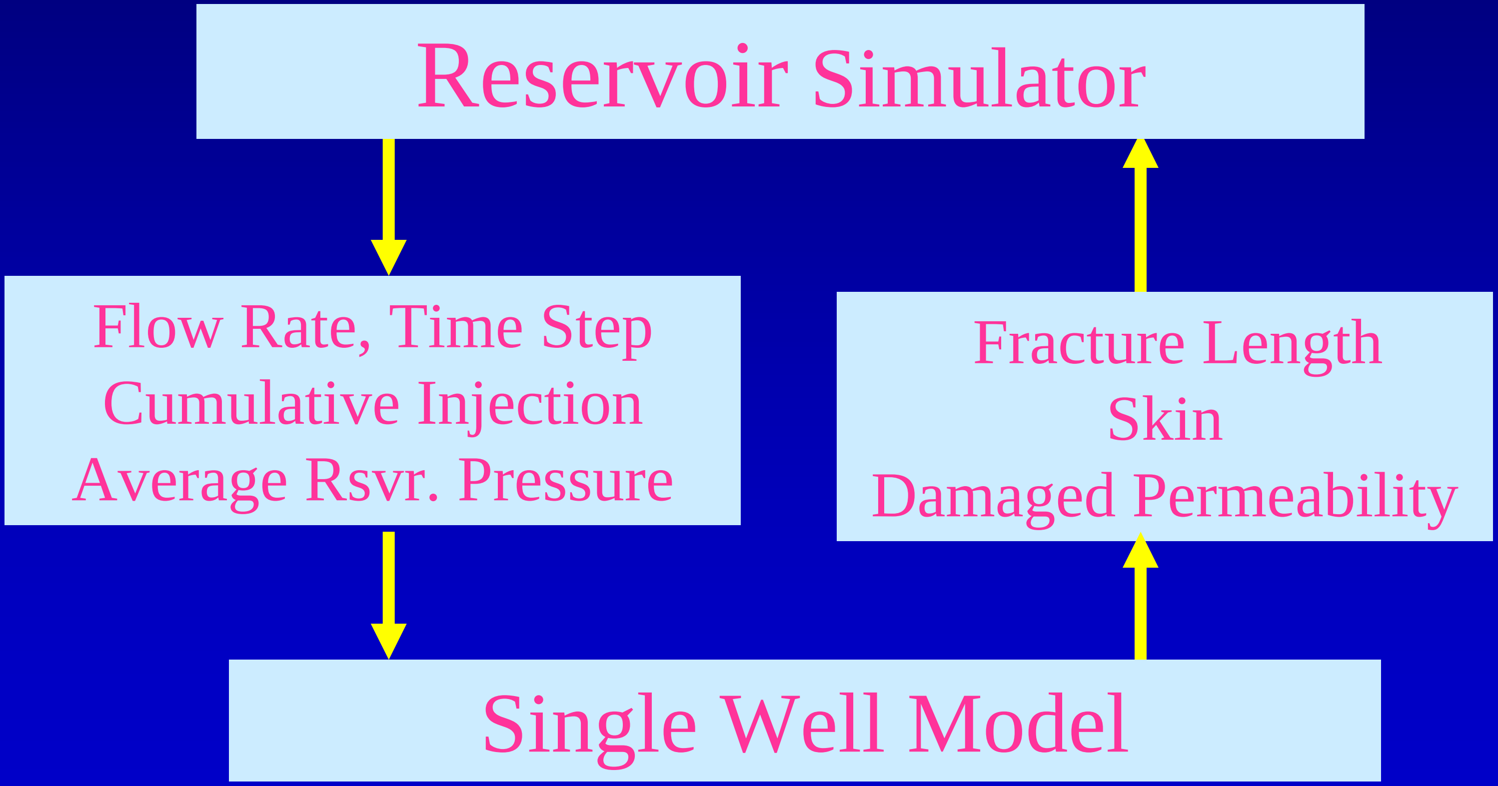
Coupling the Injector Model with a Reservoir Simulator

- The fracture length from the single well model is used to determine the grid blocks penetrated by the fracture
- Fracture is considered to be infinite conducting (high permeability)
- The permeability field is reset in the reservoir simulator



Our Approach

Phenomenological Decomposition



Reservoir Simulator

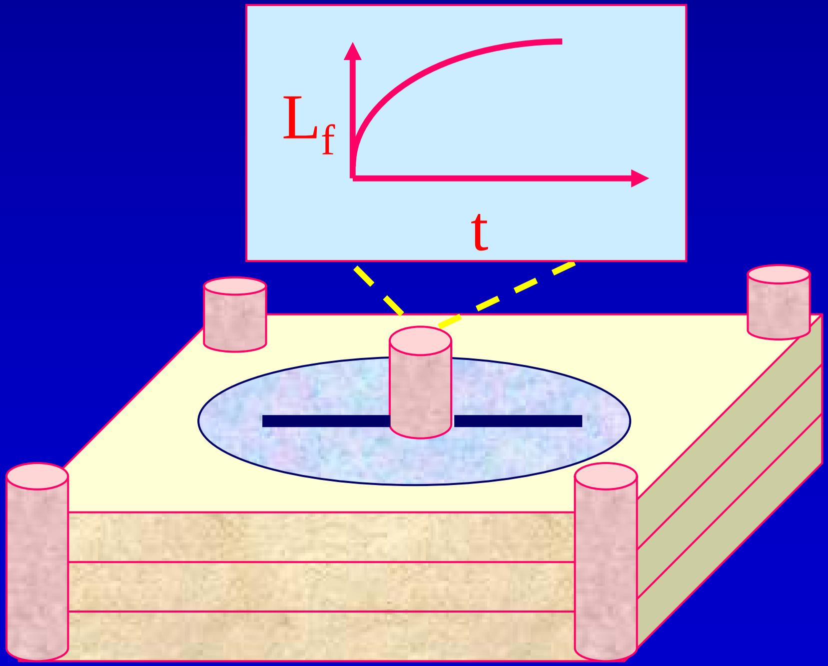
Flow Rate, Time Step
Cumulative Injection
Average Rsvr. Pressure

Fracture Length
Skin
Damaged Permeability

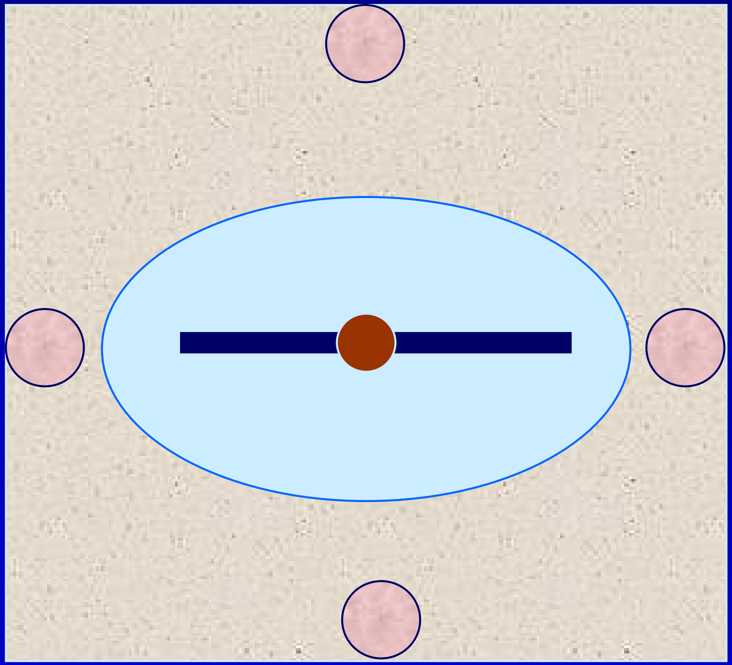
Single Well Model

Effect of Injection Well Fracturing on Reservoir Sweep (A Simple Example)

- Well positions in a five spot pattern
- No flow boundaries
- Compare oil recovery
  - fractured cases
  - unfractured cases



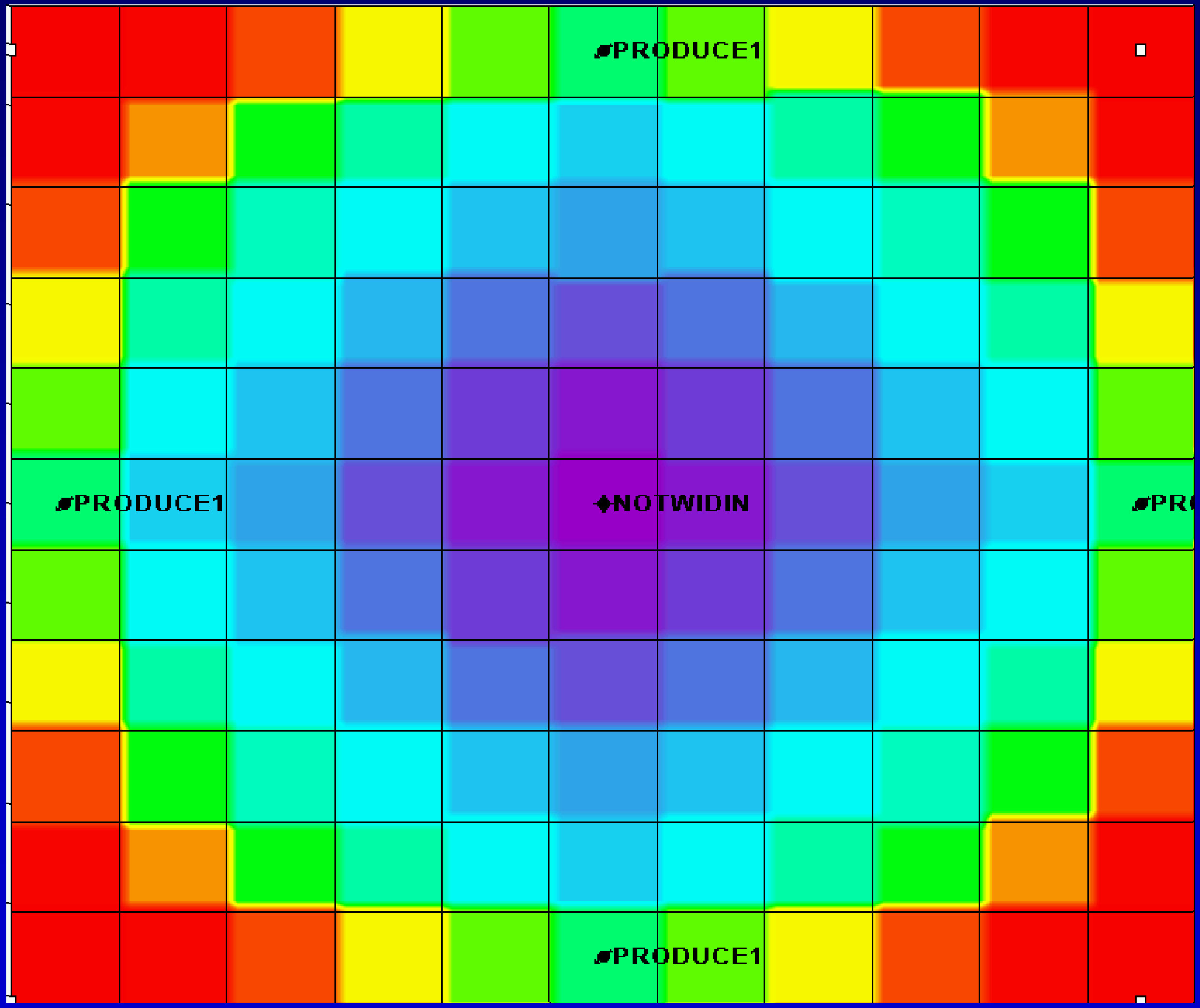
Configuration I



Fracture grows towards the producing wells

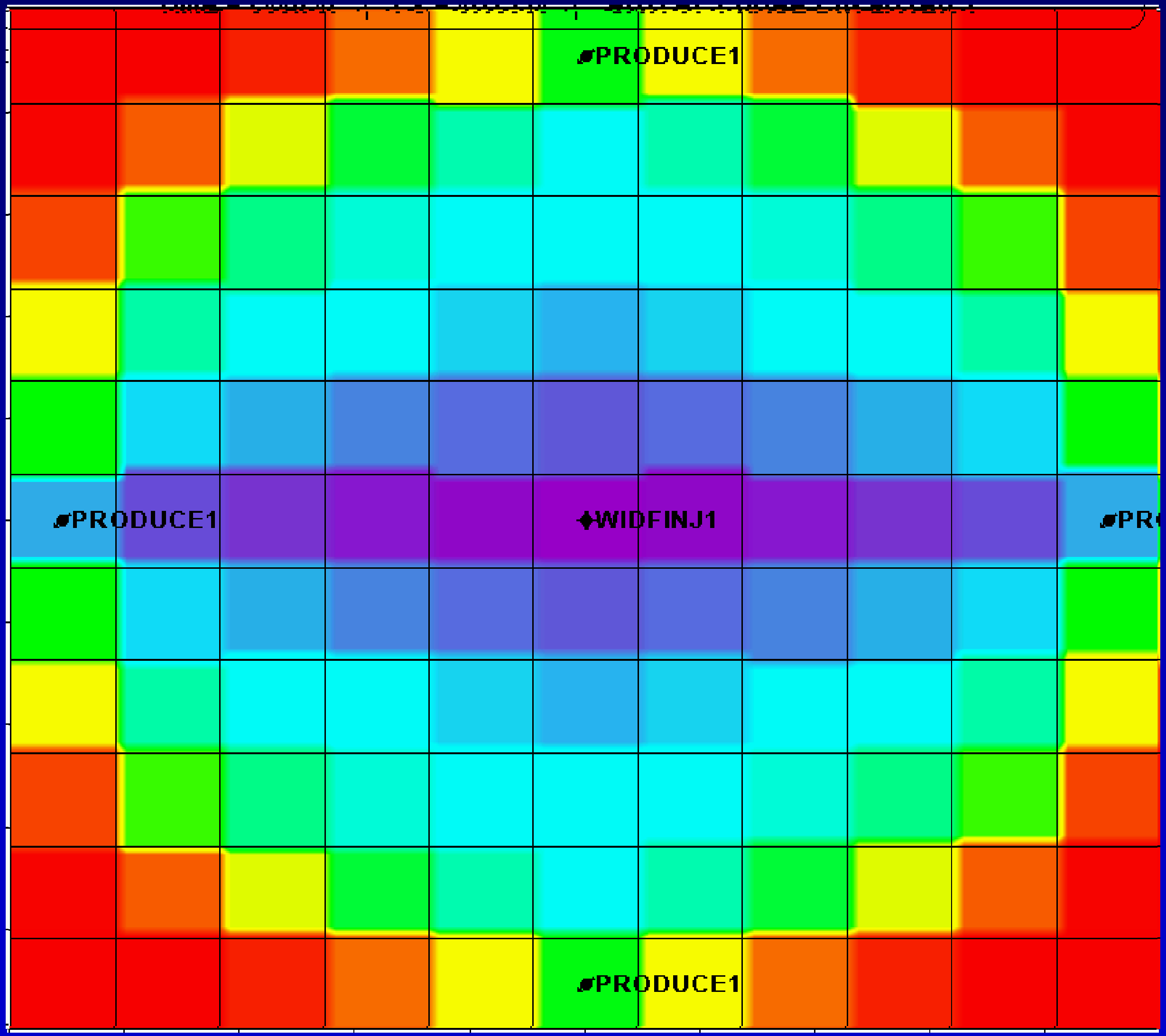
Unfractured Case

(Without Single Well Model)

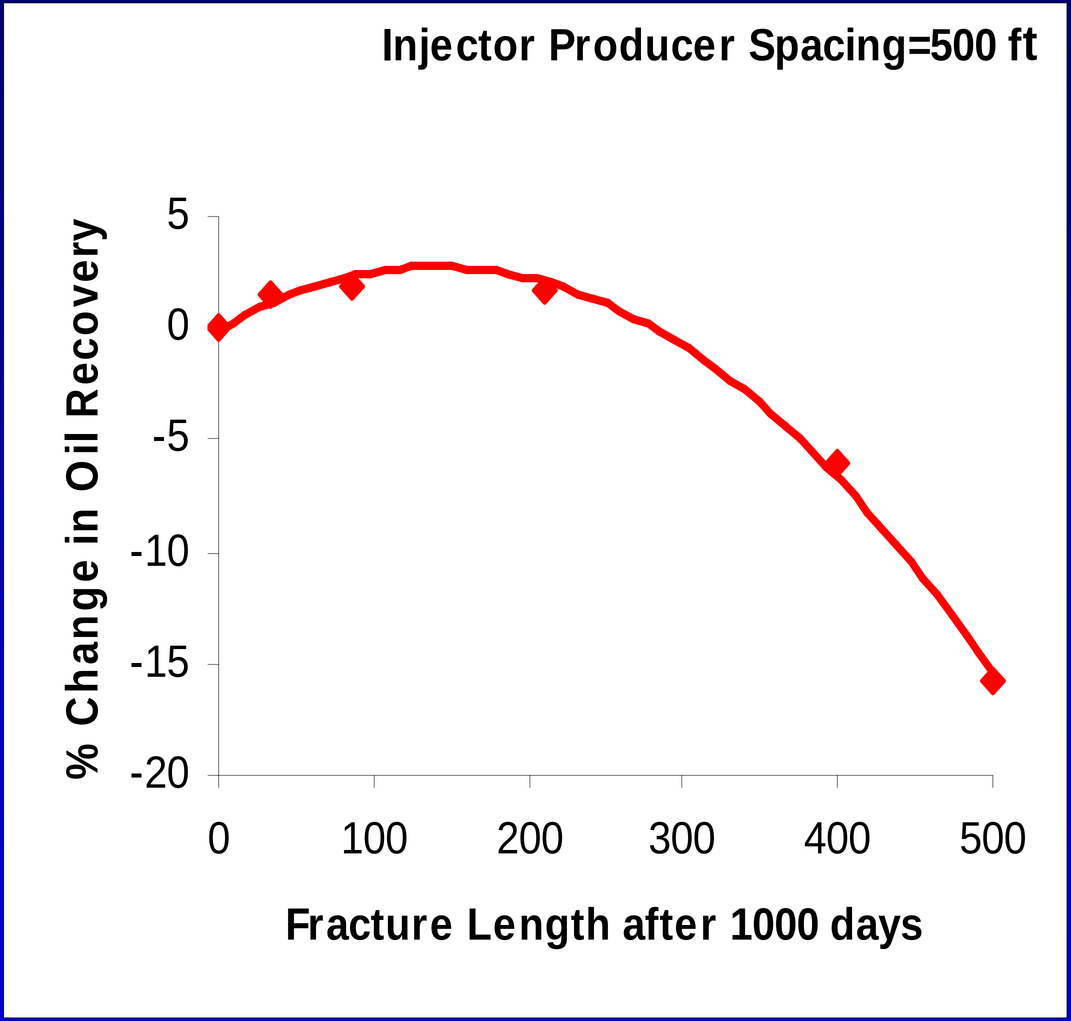


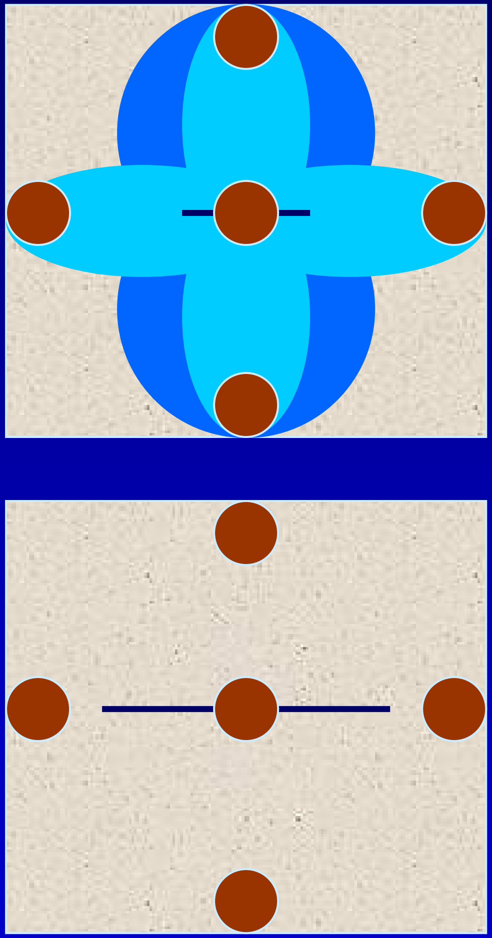
Fractured Case

(With Single Well Model)

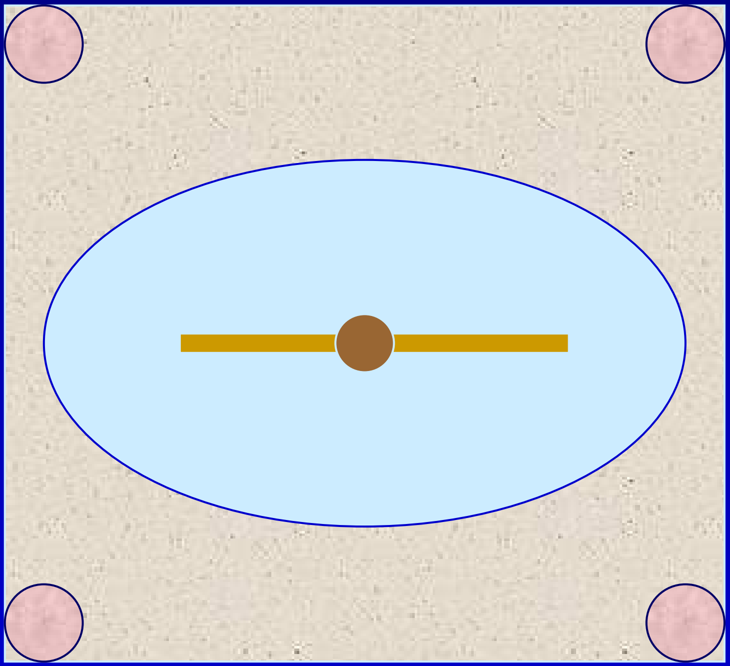


Effect of Fracture Length



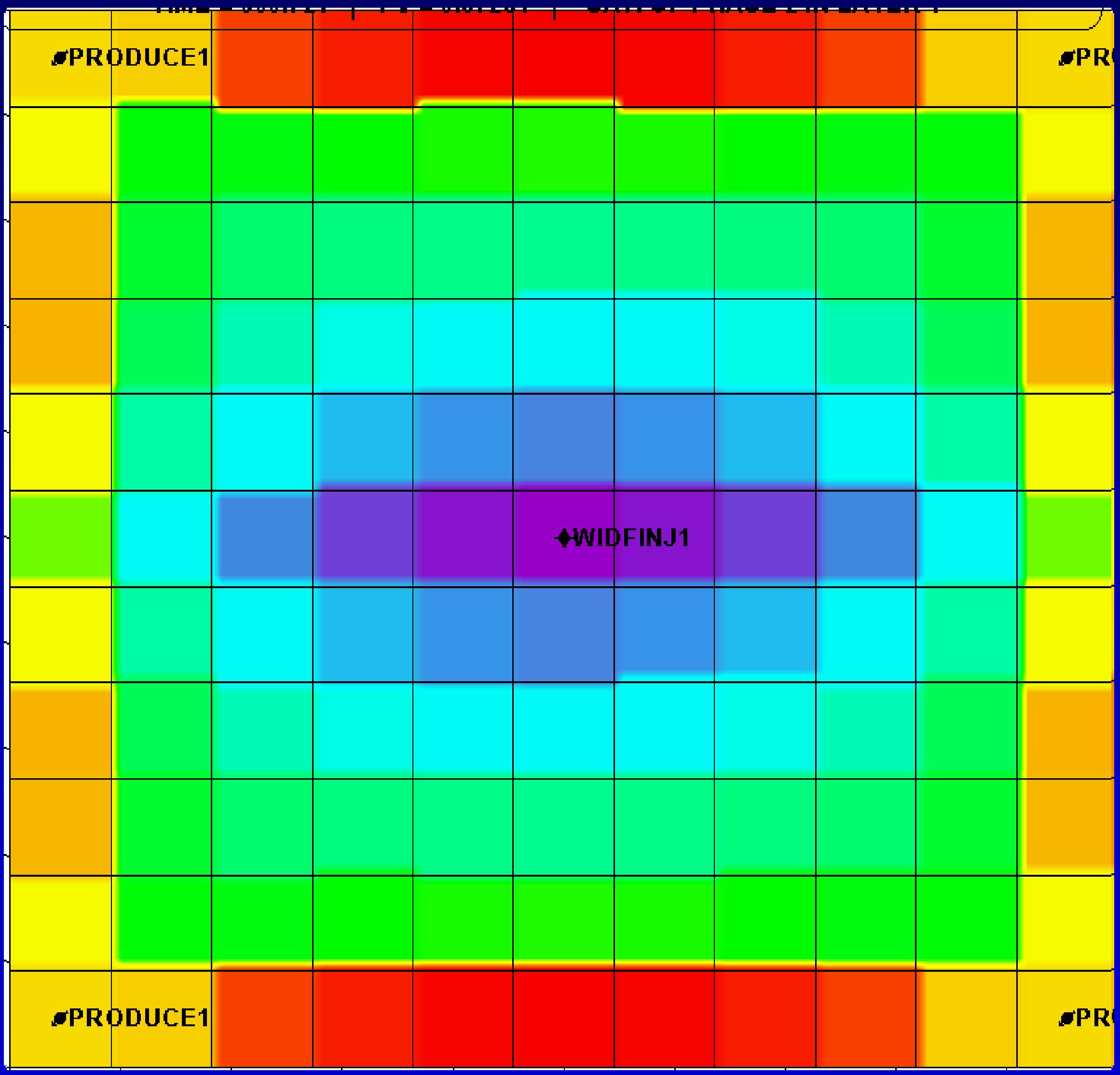


Configuration II

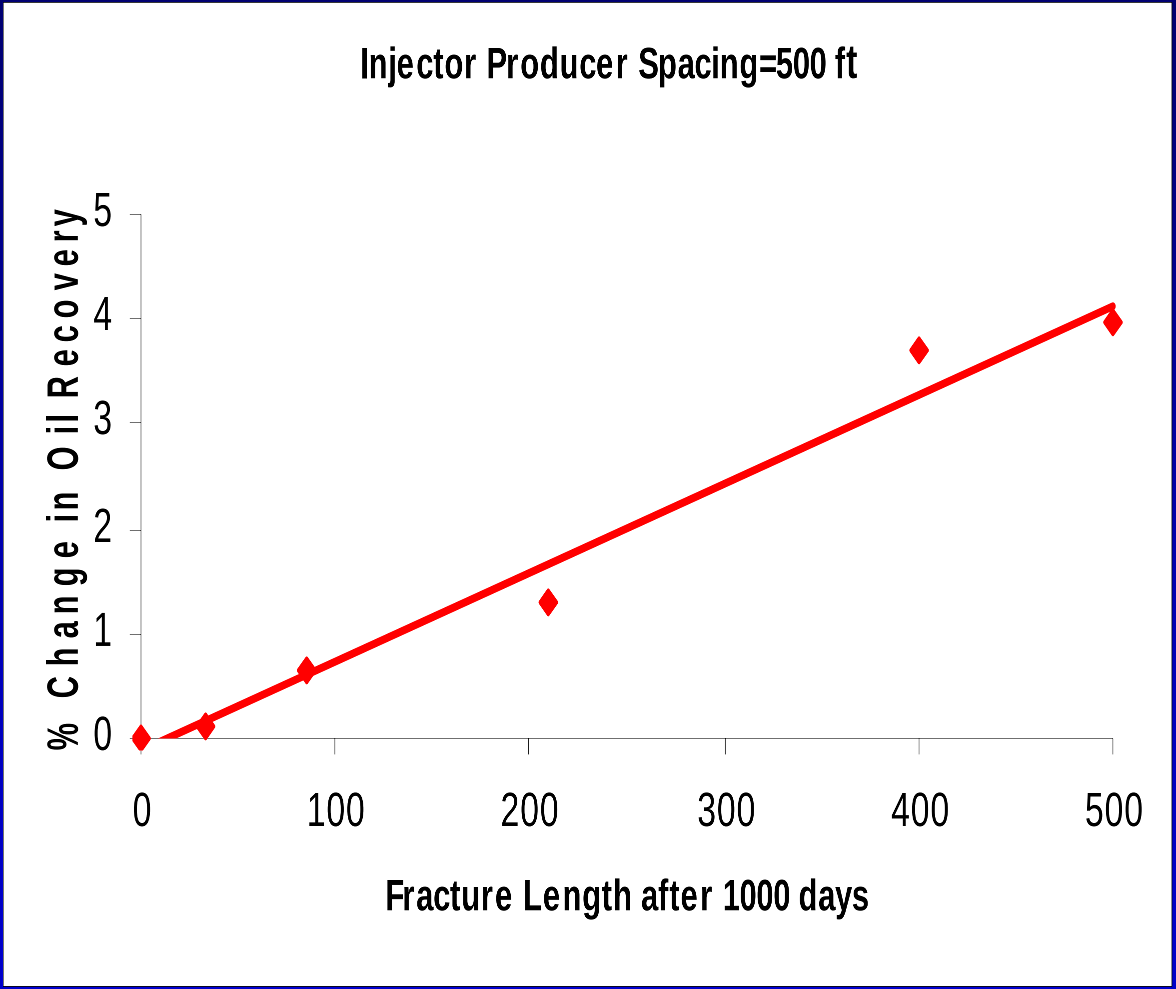


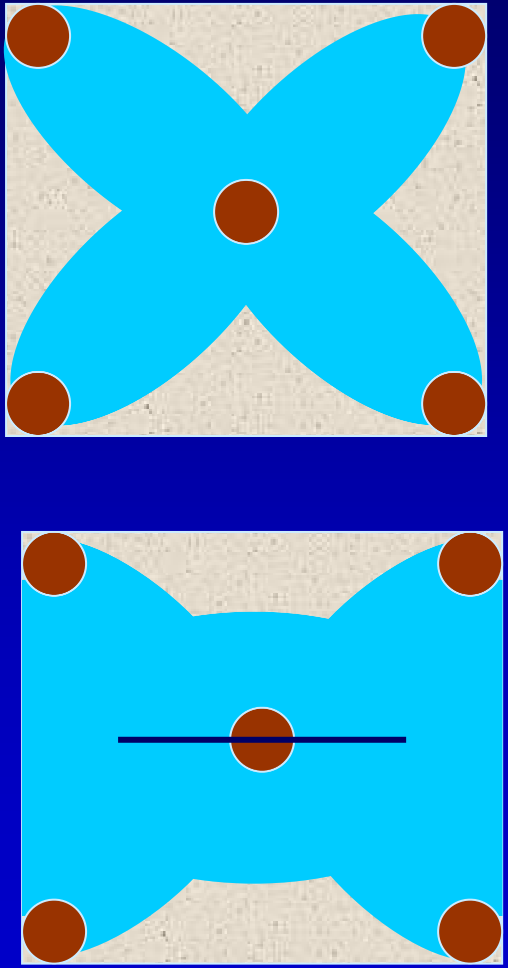
Fracture is oriented away from the wells

Fractured Case

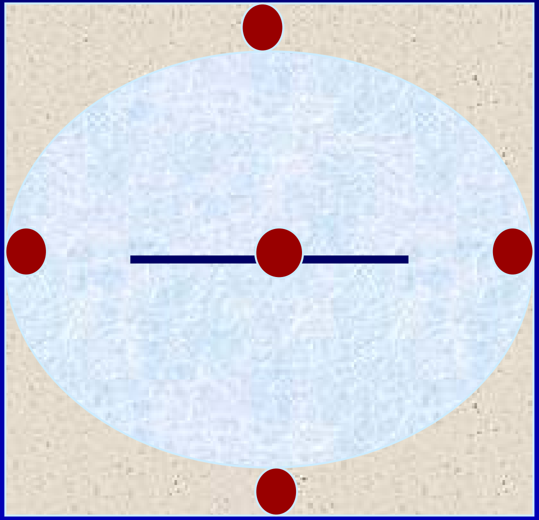


Effect of Fracture Length

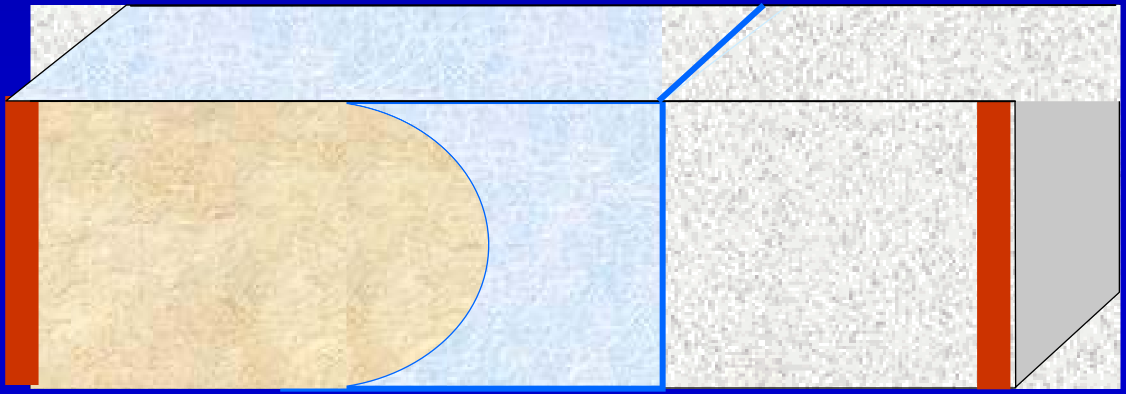




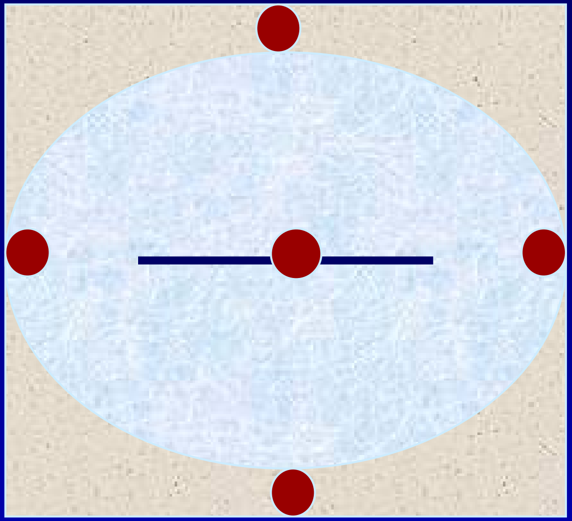
Effect of Heterogeneity



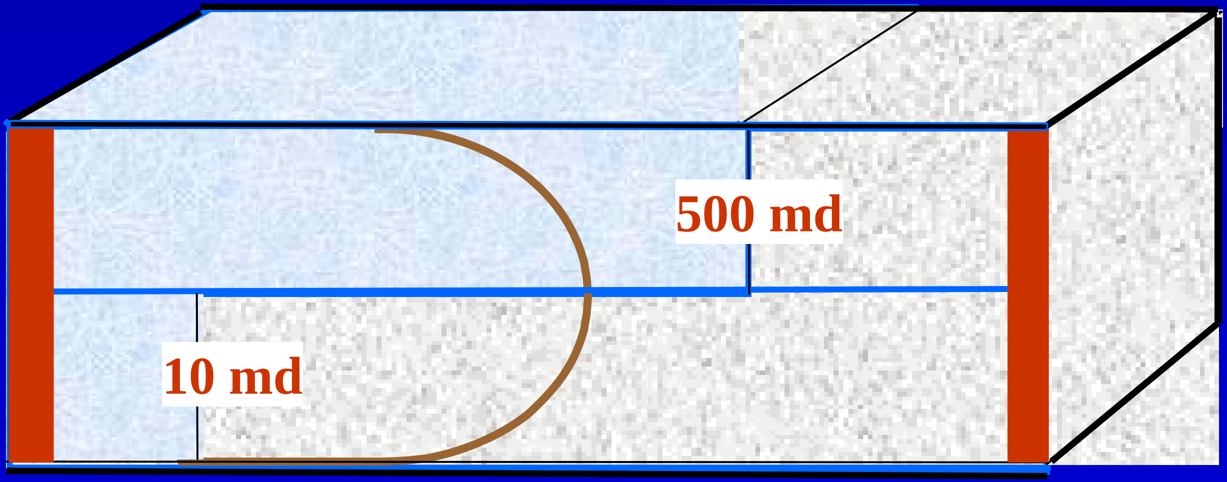
In homogeneous formations the fracture lags behind the waterflood front



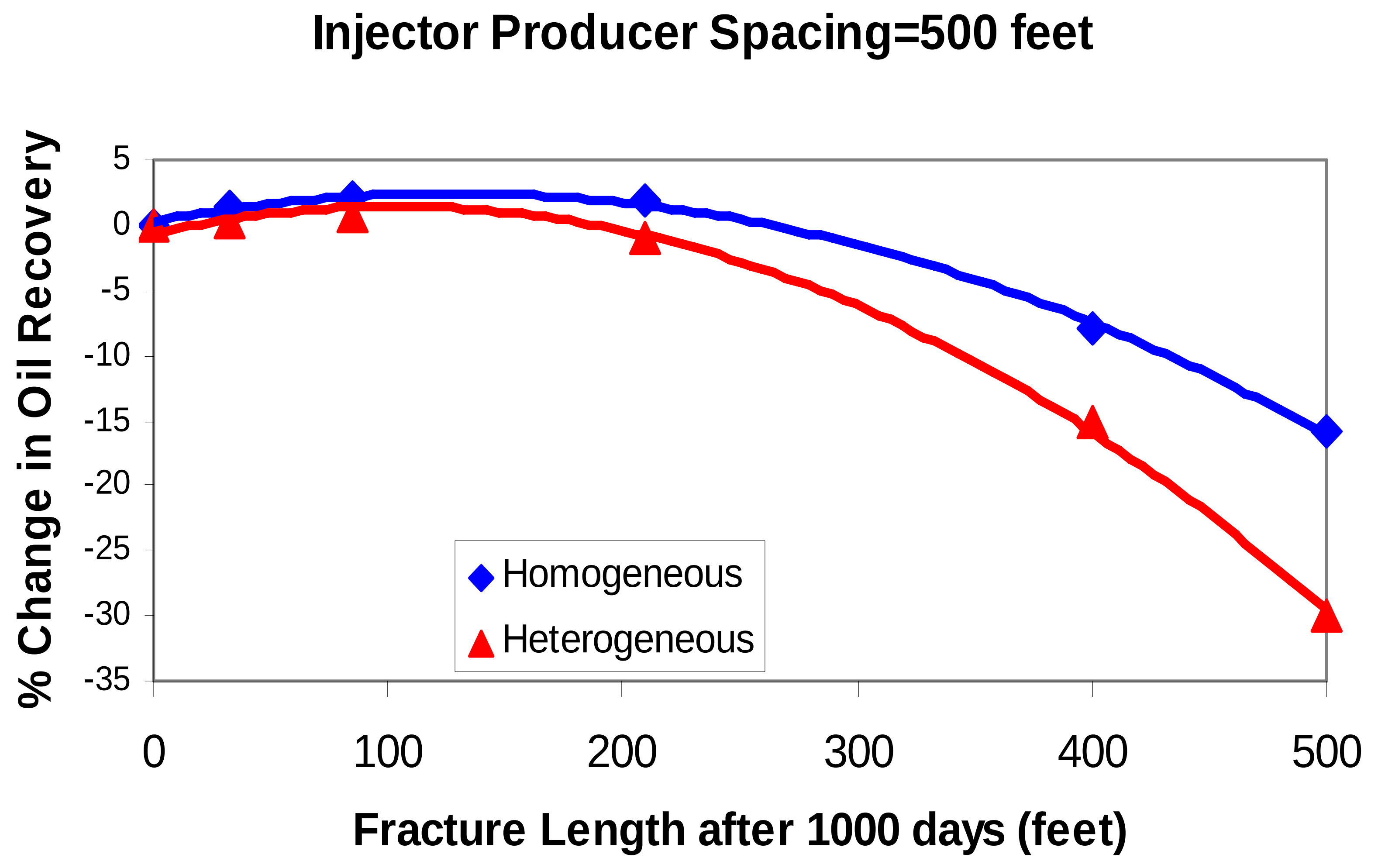
Effect of Heterogeneity



- In low permeability layers, the fracture may overtake the flood front
- More oil is bypassed in the low permeability layers



Effect of Heterogeneity



Injection into Multiple Layers

Offshore North America
Seawater Injection

Injection into Multiple Layers

Offshore North America

Seawater Injection

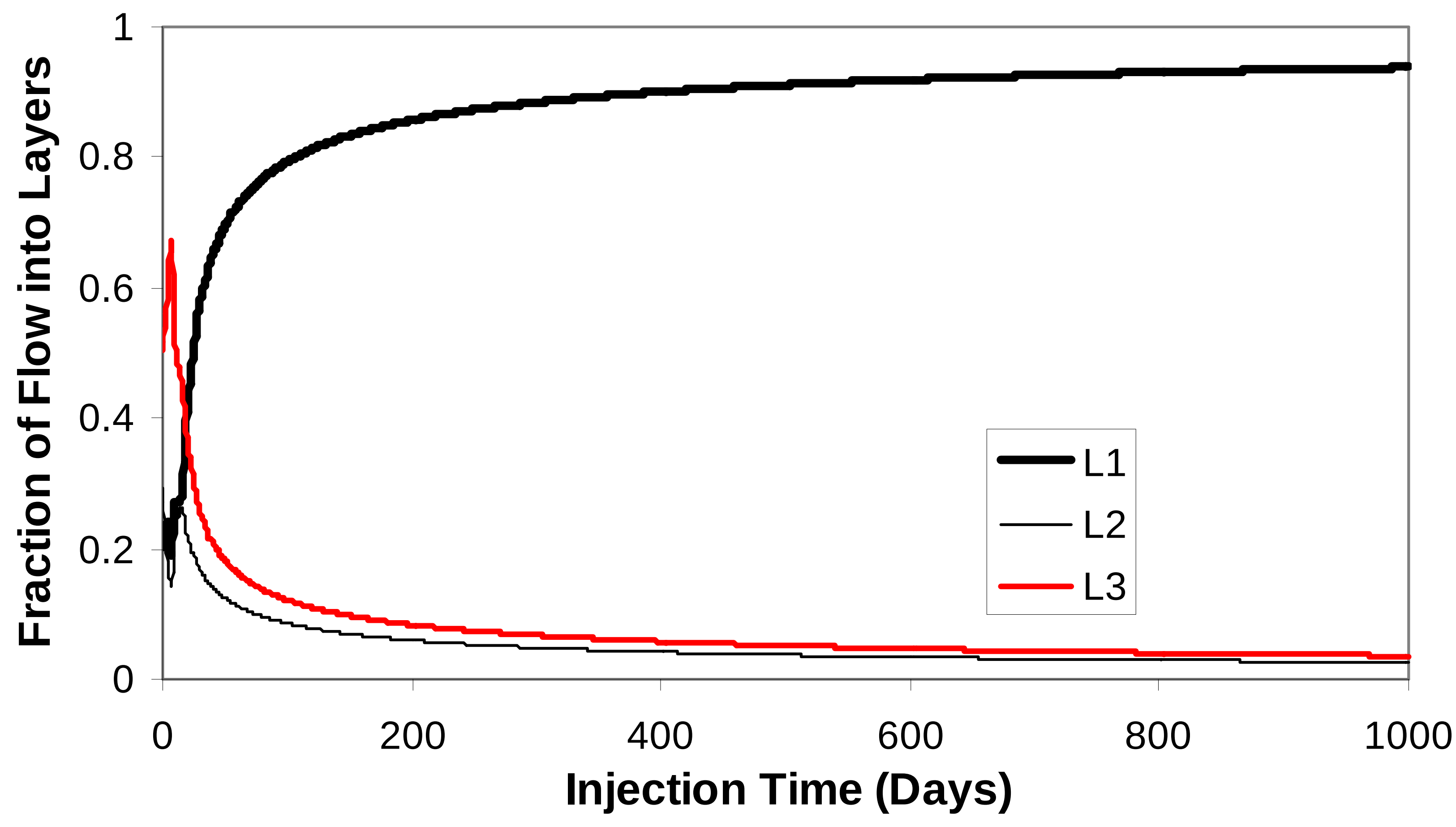
Reservoir Prop	**Layer L1**	**Layer L2**	**Layer L3**
Depth (mid layer)	16,925 ft	16,982.5 ft	17,027 ft
Reservoir Temp.	180 ^{o}F	180 ^{o}F	180 ^{o}F
Thickness	30 ft	35 ft	45 ft
Porosity	0.27	0.28	0.30
Permeability	407 md	529 md	687 md

Reservoir / Water Parameters

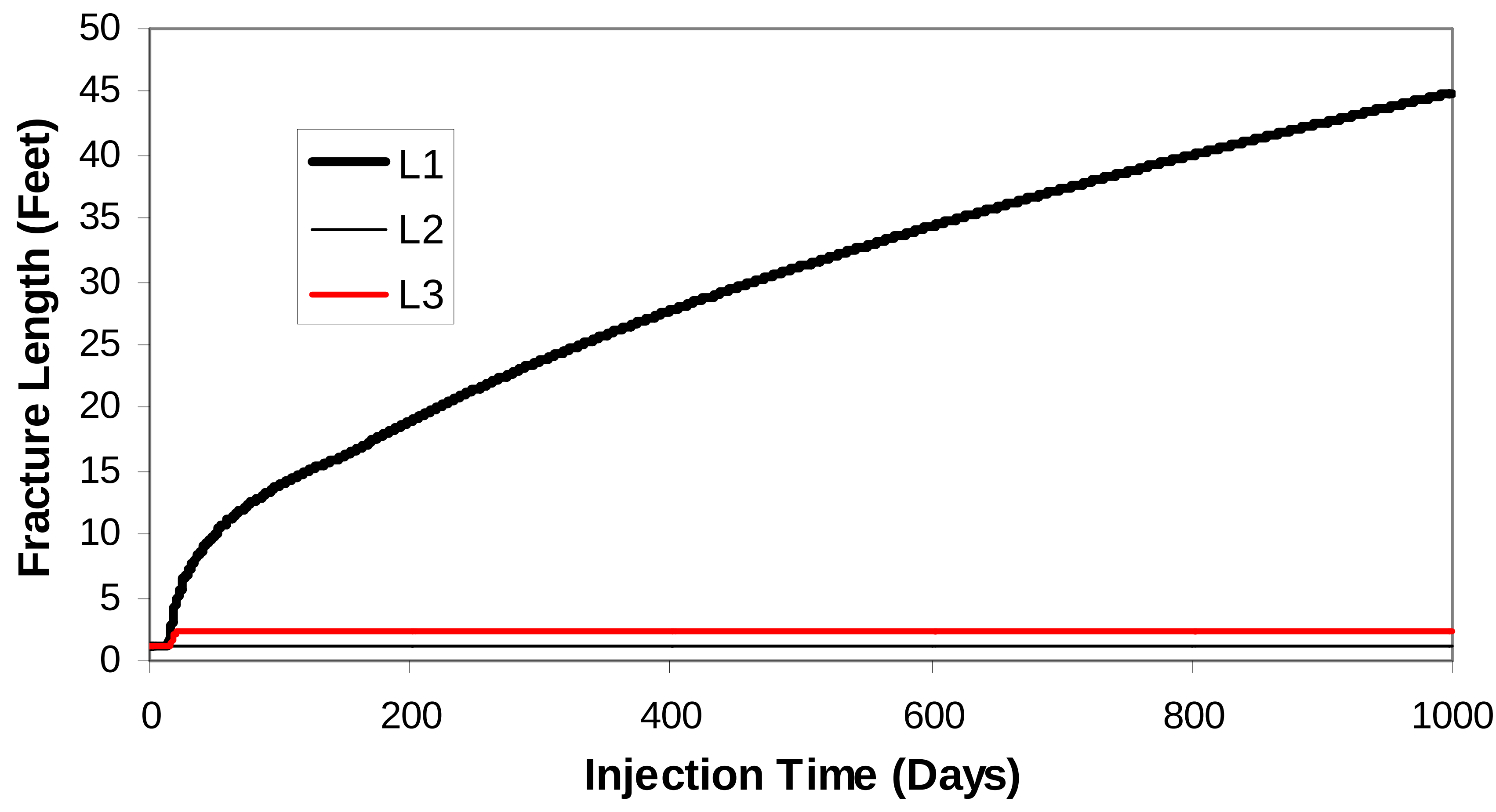
Rock Properties	**Layer L1**	**Layer L2**	**Layer L3**
Young’s Modulus	0.165 M psi	0.12 M psi	0.12 M psi
Poisson’s Ratio	0.25	0.28	0.28
Min.Horizontal Stress	9,500 psi	10,200 psi	10,200 psi

Particle Concentration	5 ppm
Average Particle Diameter	5 microns
Particle Density	2.3 gm/cc
Injection Rate	25,000 BPD

Flow into Each Layer



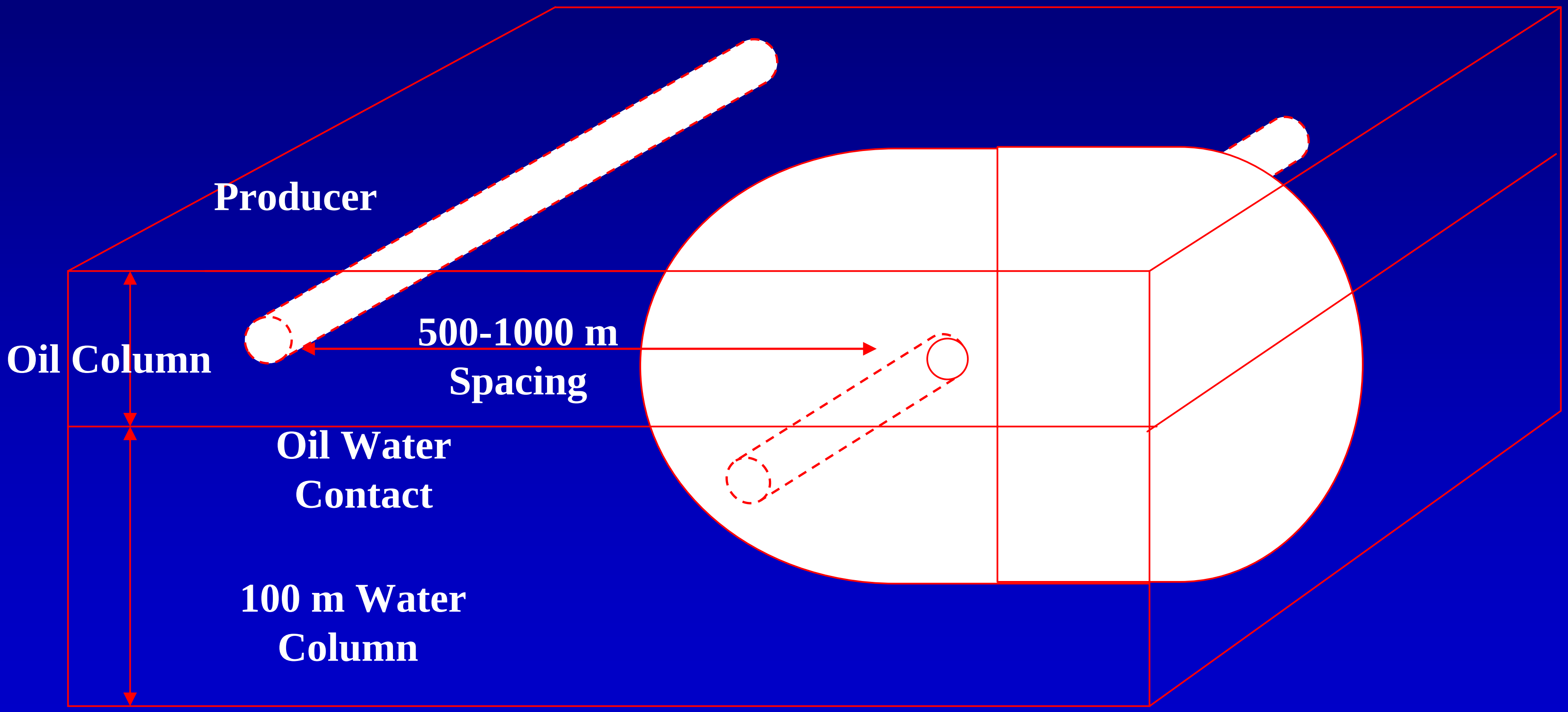
Fracture Lengths in Each Layer



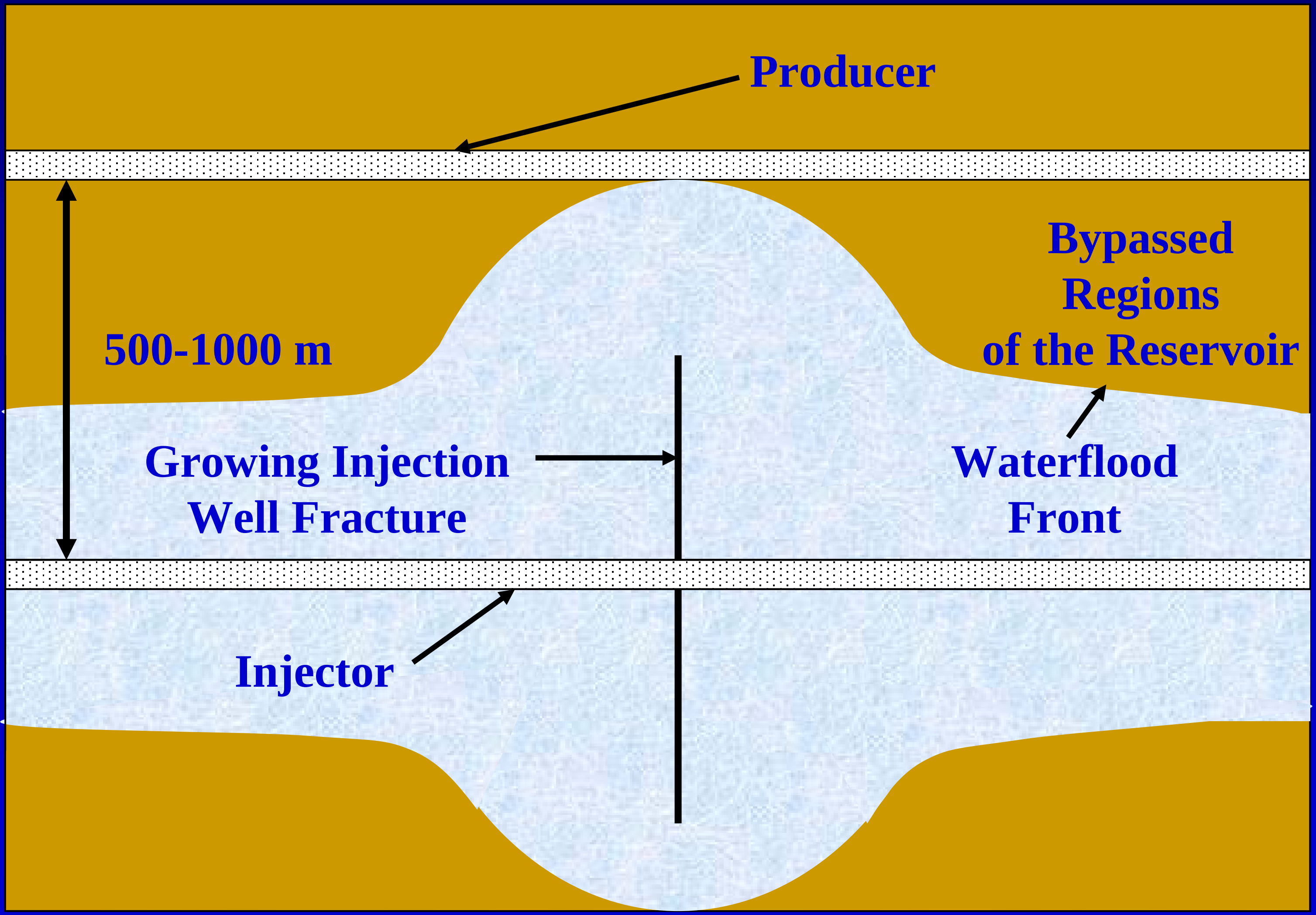
Injection into Multiple Zones
Challenges / Opportunities

- Single vs multiple injection strings.
- Conduct cost benefit analysis for flow control devices.
- Run models to understand the possibility of plugging and fracturing of different zones.
- This strategy can offer flexibility and control over where the water goes.

Effect of Fracturing Horizontal Injectors



Effect of Injection Well Fracturing on Oil Recovery



Water Re-Injection: Conclusions

- Controlled injector fracturing provides tremendous advantages
  - Improved reservoir sweep
  - Increased injection rates
  - Quicker payback time for waterfloods
  - Reduced water treatment costs
- Not recognizing injection well fracturing will cause major problems
- Accurate models and tools validated by laboratory and field data are needed to:
  - Keep fractures in-zone and of the desired length
  - Aid in facilities and completion design
  - Selecting injection patterns to maximize oil recovery

General Conclusions

- Better management of oilfield water is the key to oil & gas production economics in mature fields (both onshore and offshore)
- Water handling, treatment and re-injection is the single biggest operating expense for most operators.
- Subsurface injection of produced water is and will remain the disposal method of choice.
  - Subsurface separation is of very limited applicability
  - Sub-sea treatment is quite expensive and of limited use
- Technologies that aid in the economic handling of produced water are vital to both oil and gas production economics in the US both onshore and offshore. In order of economic impact:
  - Water re-injection technologies
  - Water shut-off, profile control, mobility control
  - Water treatment technologies for surface use

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- Kris Bansal
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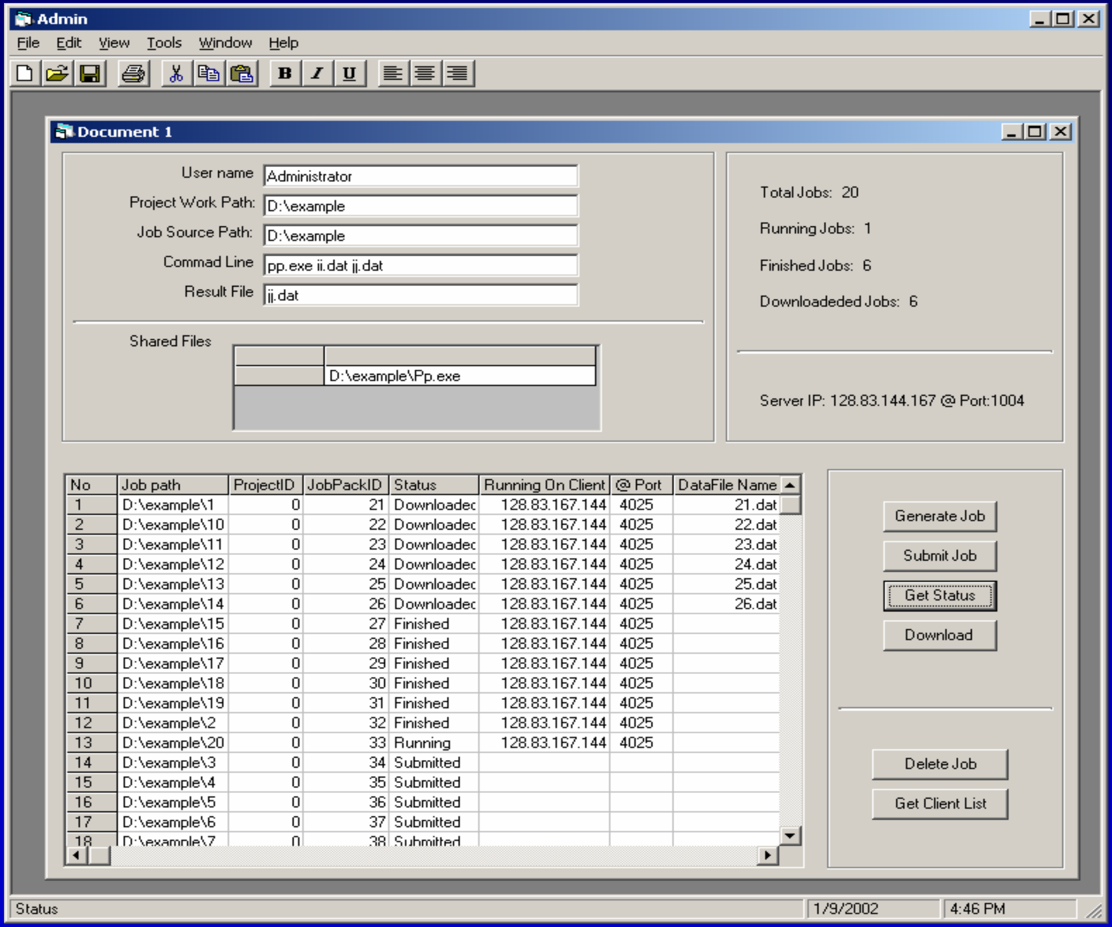
Acknowledgement

- This work was made possible by companies supporting the Injection Water Management JIP:
  - BHP,
  - ChevronTexaco,
  - ConocoPhillips,
  - Shell,
  - Statoil,
  - Total-Fina-Elf,
  - Petrobras.
- The State of Texas ATP program.

OPTIMA Administrative Tools



User name: Administrator
Project Work Path: D:\example
Job Source Path: D:\example
Commad Line: pp.exe ii.dat jj.dat
Result File: jj.dat

Shared Files: D:\example\Pp.exe

Total Jobs: 20
Running Jobs: 1
Finished Jobs: 6
Downloadeded Jobs: 6

Server IP: 128.83.144.167 @ Port:1004

No	Job path	ProjectID	JobPackID	Status	Running On Client	@ Port	DataFile Name
1	D:\example\1	0	21	Downloadec	128.83.167.144	4025	21.dat
2	D:\example\10	0	22	Downloadec	128.83.167.144	4025	22.dat
3	D:\example\11	0	23	Downloadec	128.83.167.144	4025	23.dat
4	D:\example\12	0	24	Downloadec	128.83.167.144	4025	24.dat
5	D:\example\13	0	25	Downloadec	128.83.167.144	4025	25.dat
6	D:\example\14	0	26	Downloadec	128.83.167.144	4025	26.dat
7	D:\example\15	0	27	Finished	128.83.167.144	4025	
8	D:\example\16	0	28	Finished	128.83.167.144	4025	
9	D:\example\17	0	29	Finished	128.83.167.144	4025	
10	D:\example\18	0	30	Finished	128.83.167.144	4025	
11	D:\example\19	0	31	Finished	128.83.167.144	4025	
12	D:\example\2	0	32	Finished	128.83.167.144	4025	
13	D:\example\20	0	33	Running	128.83.167.144	4025	
14	D:\example\3	0	34	Submitted			
15	D:\example\4	0	35	Submitted			
16	D:\example\5	0	36	Submitted			
17	D:\example\6	0	37	Submitted			
18	D:\example\7	0	38	Submitted			

Status | 1/9/2002 | 4:46 PM

- Allow the user to submit jobs and communicate with the server
- Provide application life-cycle control
- Provide the user with status of the various processes

Opportunities and Challenges

Challenges

- Design water handling and injection systems to reduce the cost of water injection.
  - Specify injection water quality, rates & pressures
  - Subsurface separation?
  - Subsea vs topsides
- The single well model can be used to address these challenges.

Opportunities

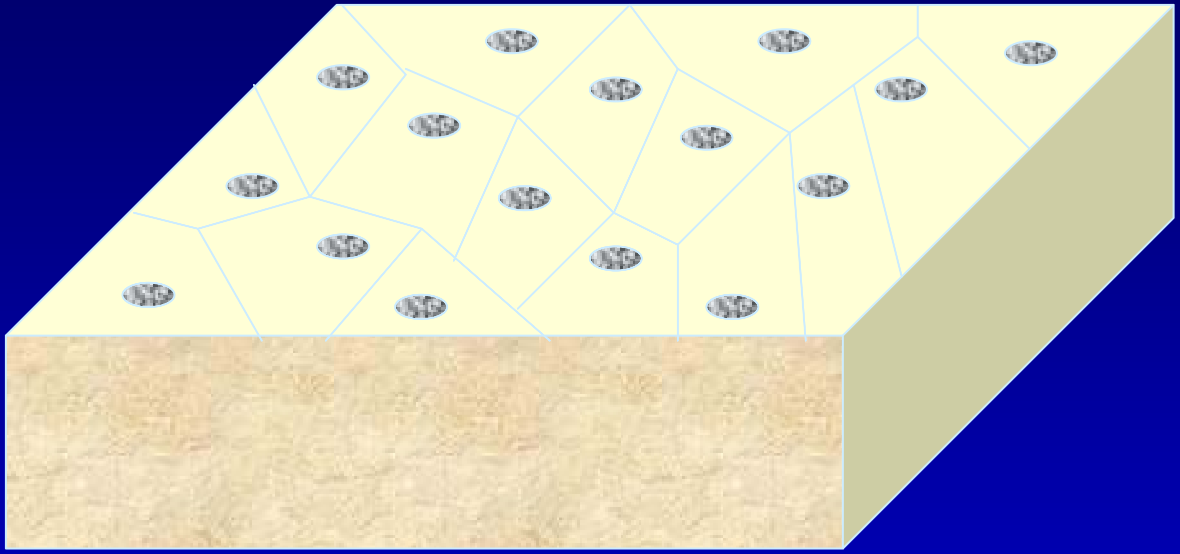
- Significant improvements in oil recovery.
- Cost reductions to improve production economics.

A Real Opportunity

Using Injection Well Fractures to Maximize Oil Recovery

Coupling Single Well Models with a Reservoir Simulator

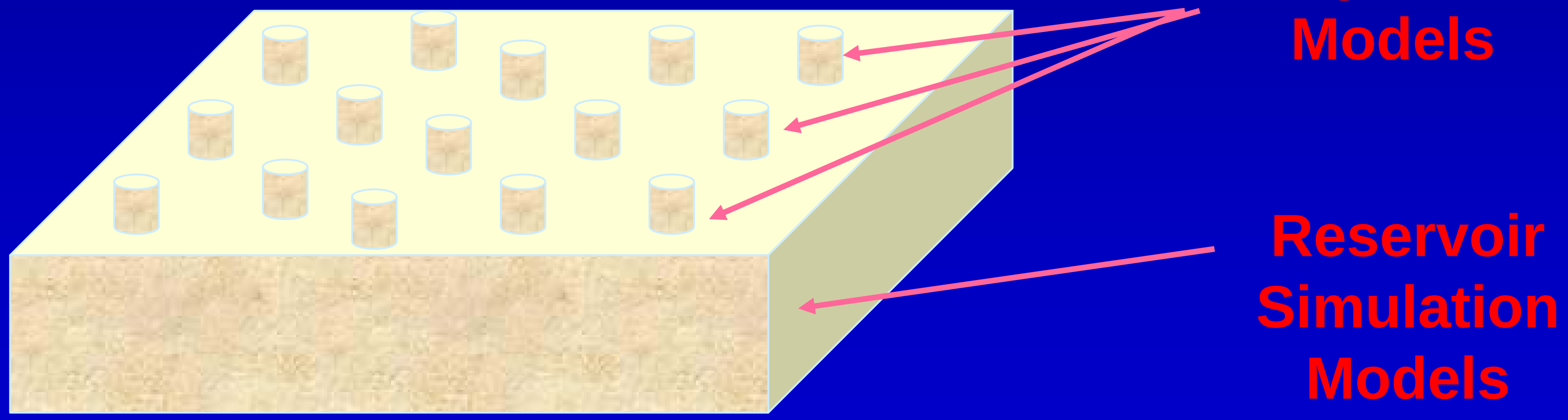
Traditional Domain Decomposition



- **Domain decomposition involves**
  - Breaking the reservoir into domains
  - Large volumes of data is exchanged between domains (unsuitable for distributed computing)

Phenomenological Decomposition

- **Decomposition based on problem physics**
  - Single Well Models
  - Reservoir Simulation Models



Single Well Models

Reservoir Simulation Models

Tight Gas Sands / Fracturing
The University of Texas at Austin

Water blocking in gas wells

Proppant Transport Models

Energized Fracs

Fractured Injectors

UTFRAC-3D

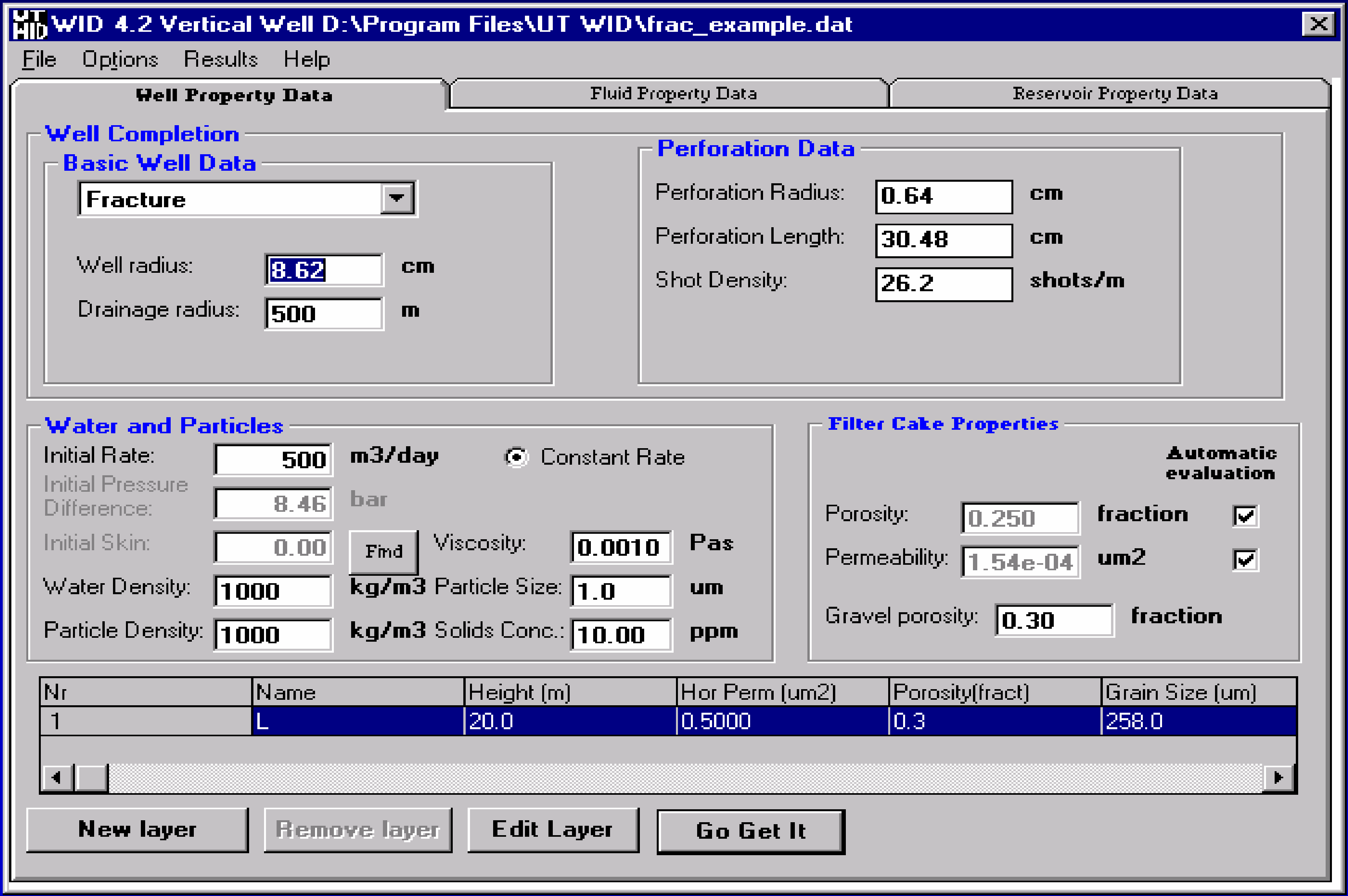
Proppant Transport Experiments

Re-fracturing

Fracturing Soft Sands

Case Studies

Single Well Model (WID 6.0)



WID 4.2 Vertical Well D:\Program Files\UT WID\frac_example.dat

Well Completion

Basic Well Data

Fracture

Well radius: 8.62 cm

Drainage radius: 500 m

Perforation Data

Perforation Radius: 0.64 cm

Perforation Length: 30.48 cm

Shot Density: 26.2 shots/m

Water and Particles

Initial Rate: 500 m3/day

● Constant Rate

Initial Pressure Difference: 8.46 bar

Initial Skin: 0.00

Viscosity: 0.0010 Pas

Water Density: 1000 kg/m3

Particle Size: 1.0 um

Particle Density: 1000 kg/m3

Solids Conc.: 10.00 ppm

Filter Cake Properties

Automatic evaluation

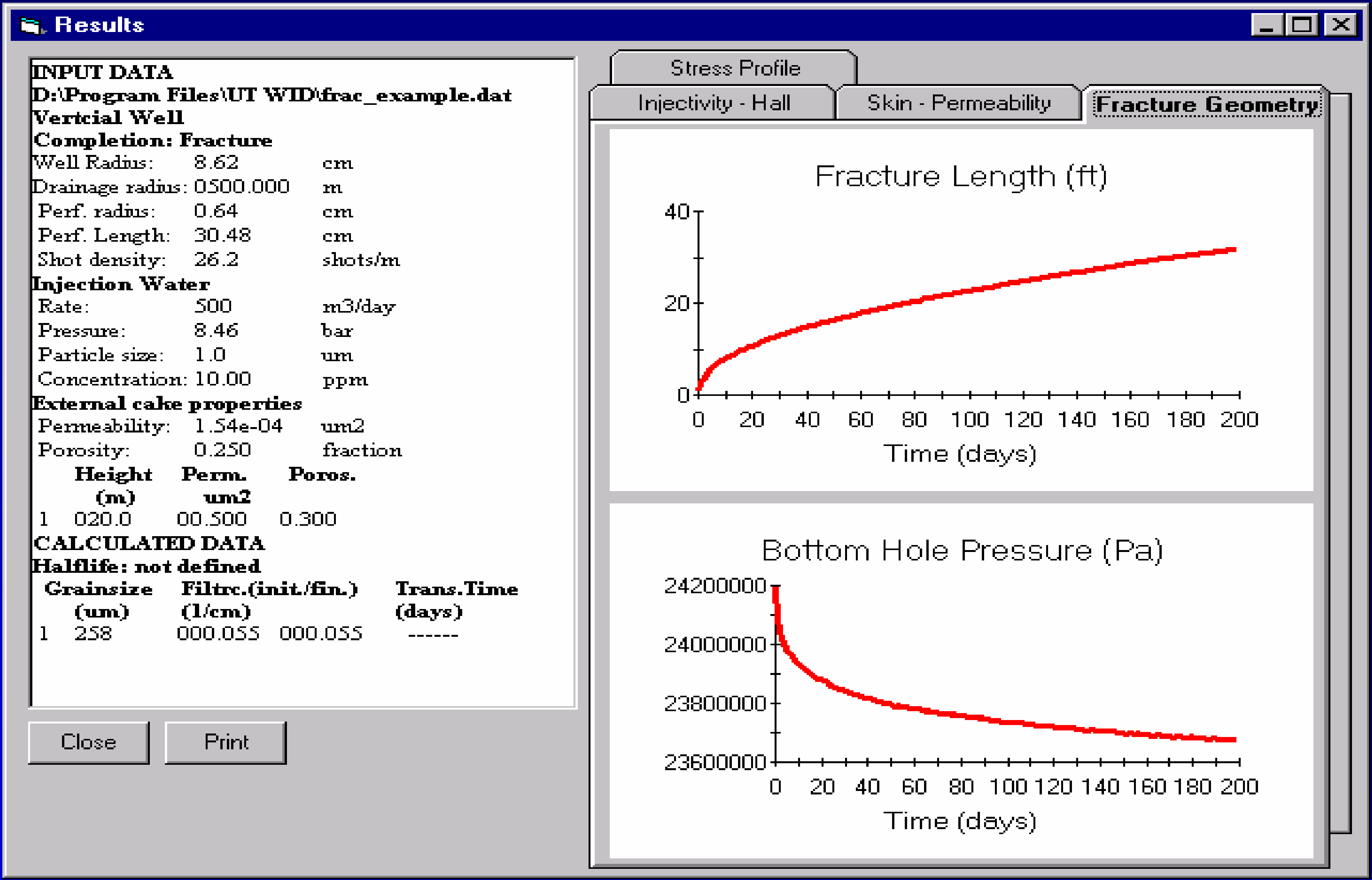
Porosity: 0.250 fraction ☑

Permeability: 1.54e-04 um2 ☑

Gravel porosity: 0.30 fraction

Nr	Name	Height (m)	Hor Perm (um2)	Porosity(fract)	Grain Size (um)
1	L	20.0	0.5000	0.3	258.0

Single Well Model (WID 6.0)



```
INPUT DATA
D:\Program Files\UT WID\frac_example.dat
Vertcial Well
Completion: Fracture
Well Radius:       8.62        cm
Drainage radius: 0500.000      m
 Perf. radius:     0.64        cm
 Perf. Length:     30.48       cm
 Shot density:     26.2        shots/m
Injection Water
 Rate:             500         m3/day
 Pressure:         8.46        bar
 Particle size:    1.0         um
 Concentration: 10.00          ppm
External cake properties
 Permeability:     1.54e-04    um2
 Porosity:         0.250       fraction
      Height    Perm.     Poros.
       (m)       um2
 1    020.0    00.500    0.300
CALCULATED DATA
Halflife: not defined
  Grainsize    Filtrc.(init./fin.)     Trans.Time
    (um)       (1/cm)                  (days)
 1    258      000.055    000.055       ------
```