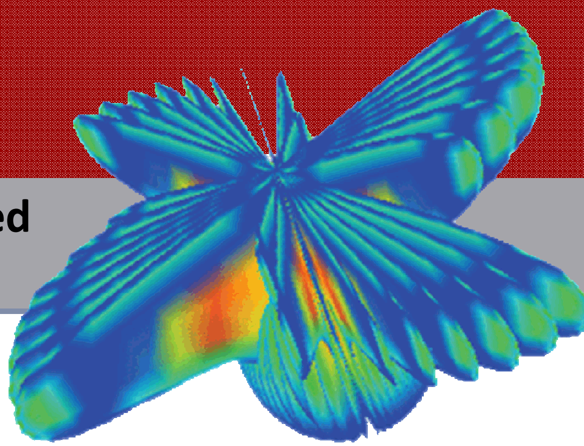
An Advanced, Integrated Simulator for Management of Produced Water Re-injection in Multilayer Vertical or Horizontal Wells



Salaheldin Elkatatny
Ahmed Farid
Ibrahim Mohamed
Omar Abou-Sayed
Ahmed Abou-Sayed

Outline

- Introduction
- Objectives
- General Description
- Validation
- Case Studies
- Conclusions

Introduction

- Produced water re-injection (PWRI) is the safest and most economical method for disposal of produced water in the oil industry
- In addition to oil field brines, plant waste solutions containing such diverse components as acids, caustics, inorganic salts, and hydrocarbons are routinely injected into the ground in the oilfield
- Waste waters are a mixture of many different streams
  1. Produced water
  2. Cooling tower blowdown
  3. Boiler water blowdown
  4. Ion exchange bed regeneration stream
  5. Filter backwash
  6. Cleaning solutions (acids, caustic, detergents)
  7. Corrosion inhibitors and biocides

Introduction

- The key issues that affect the management of the PWRI are:
  1. Injection regime
     A. Matrix injection
     B. Fracture injection
  2. Formation damage:
     A. Solids
     B. Bacteria
     C. Oil carried within the injected produced water
  3. Constrained pumping pressure at the wellhead

Objective

The objective of this study is to build a simulator that can:

- Handle injection in multilayered formation for vertical and horizontal wells under matrix and/or fractured regimes
- Account for the damage that results from solids, bacteria, and oil in the injected water
- Simulate injection under constant flow rate, and under constant surface pressure
- Handle the change of the minimum horizontal stress for each fracture due to the stress shadow caused by the other fractures as they propagate in case of multi-fractured horizontal well

General Description

Inputs:

- Well Data:
  - wellbore radius
  - tubing length roughness, ID
- Injection Parameters:
  - injected fluid temperature
  - injection rate
  - injection time
  - injected fluid rheological data
- Completion Data:
  - perforation top and bottom
- Formation Mechanical Properties
- Reservoir Properties:
  - Reservoir P & T
  - Porosity & Permeability,
  - Zone Deviation
  - Thickness,

Outputs:

- Flow rate distribution between the layers.
- Wellhead pressure (WHP), Bottom Hole Pressure (BHP), and Injectivity Index (II)
- Flow for both matrix and fracture injection.
- Fracture length with consideration of poro-elastic and thermo-elastic effects.

Fracture Initiation Model

The fracture initiation is controlled by the following equation (Perkins and Gonzales 1985)

$$P_{iwf} \geq \sigma_1 + \sqrt{\frac{\pi U E}{2(1-v^2)r_w}}$$

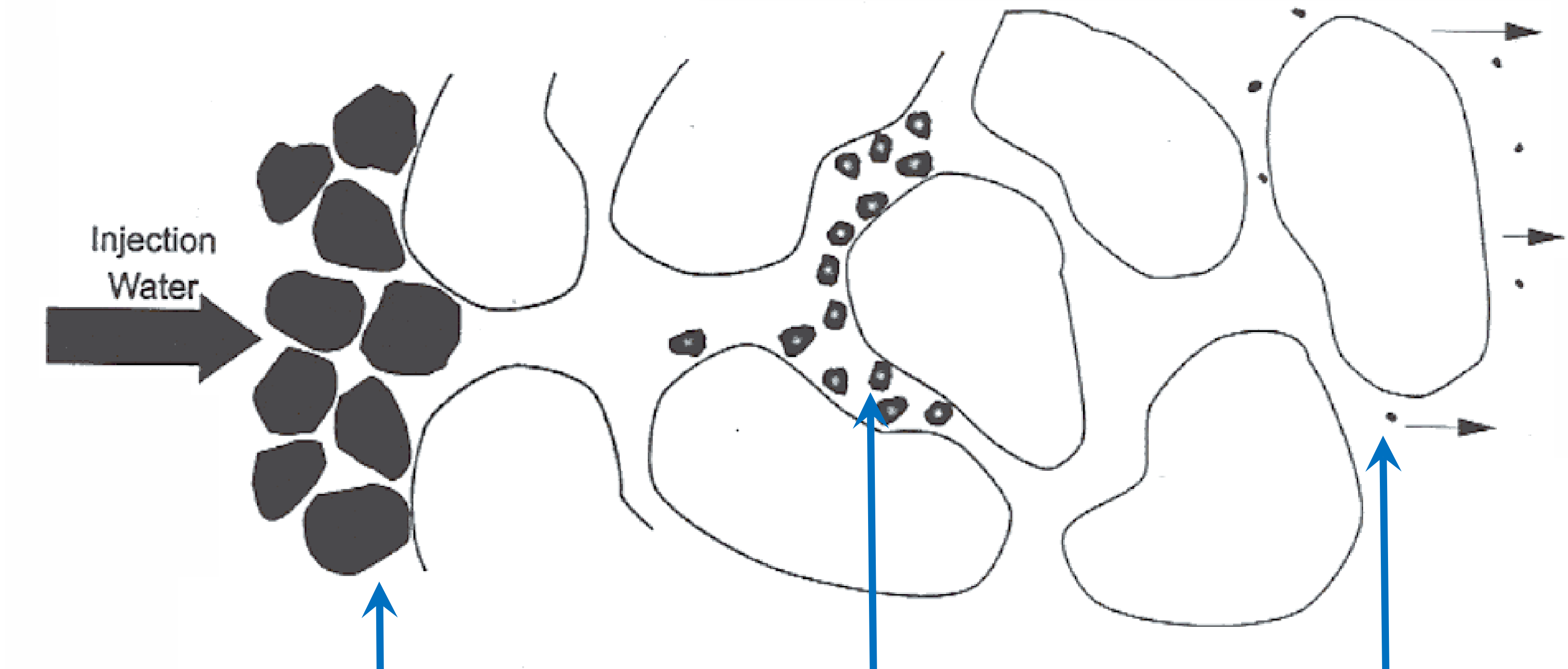
The fracture propagation is controlled by the following equation (Perkins and Gonzales 1985)

$$p_1 = \sigma_1 + \sqrt{\frac{\pi U E}{2(1-v^2)r_f}}$$

The fracture width is controlled by the fracture net pressure

$$w = f\left(P_{net}\right)$$

Damage Model



	External filter cake	Internal filter cake	Non-bridging solids
High velocity (>10 cm/min interstitial)	$d_{soild} > 33\% \ d_{pore}$	$33\% > d_{soild} > 14\% \ d_{pore}$	$d_{soild} < 14\% \ d_{pore}$
Low velocity (<2 cm/min interstitial)	$d_{soild} > 33\% \ d_{pore}$	$33\% > d_{soild} > 7\% \ d_{pore}$	$d_{soild} < 7\% \ d_{pore}$

(Bennion et al. 1996)

Damage Model

- The pressure increase due to skin damage around the wellbore is calculated by :

$$\Delta P_s = i_w \mu_w R_s$$ (**Prasad et al. 1999**)

$$R_s = R_{\text{int}} + R_c - \left\lfloor \ln(R_d / r_w) / \ (2\pi hK) \right\rfloor$$

- Where:
  - R_{int} is the internal filter cake
  - Rc is the external filter cake
  - Rd is the damaged radius ft

Porosity Reduction Model for Oil in Water (OIW)

the oil in water will be converted to the equivalent solid concentration and considered as a solid behavior

$$C = OIW * 0.14/2.1 \qquad \textbf{(PEA 23)}$$

where

C is the equivalent solid concentration of oil in water, ppm

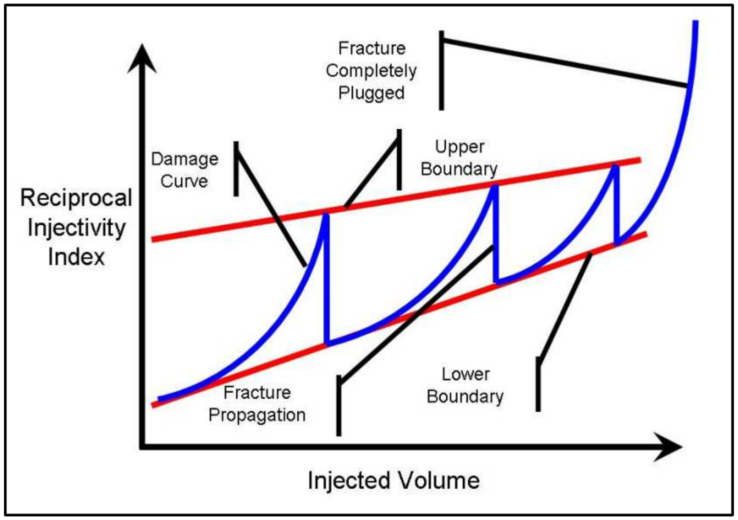
OIW is Oil in water concentration, ppm

Abou-Sayed, et.al., SPE 94606
"A Mechanistic Model for Formation Damage and Fracture Propagation During Water Injection"

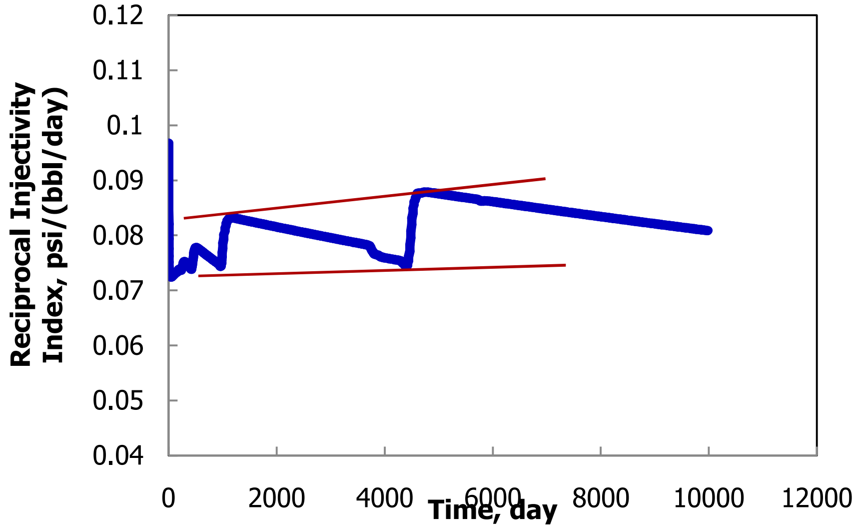
Two distinct processes alternate over well's life, resulting in a saw-toothed shape pressure-time (or rate-time) behavior:

1. Formation damage and fracture plugging, which causes a decrease in the injectivity index (II) and an increase in the required injection pressure until…
2. Fracture propagation occurs due to the increased pressure of injection. The propagation causes the II to spike suddenly as the required injection pressure decreases due to the increase in injection surface area and communication with the less damaged formation.

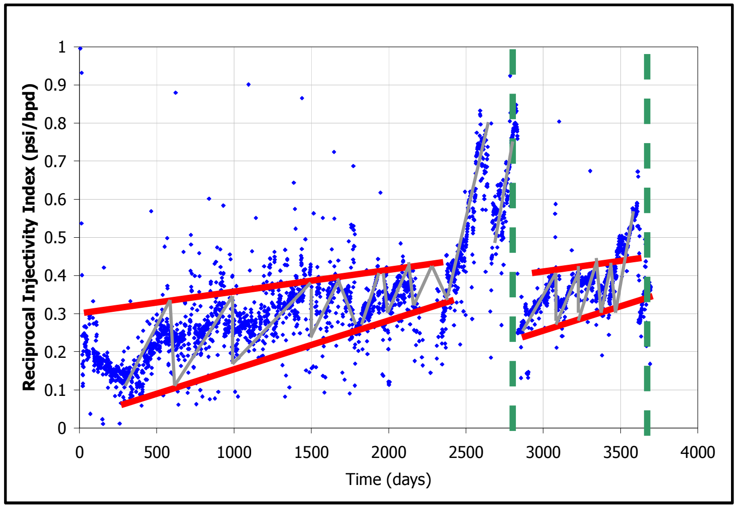
Choice of damage and fracture parameters can cause the boundary lines to be convergent, divergent, or parallel.



Characteristic behavior presented in SPE 94606



@FRAC2D results exhibit the behavior shown in SPE 94606



Field data presented in SPE 94606

Validation of @FRAC 2D

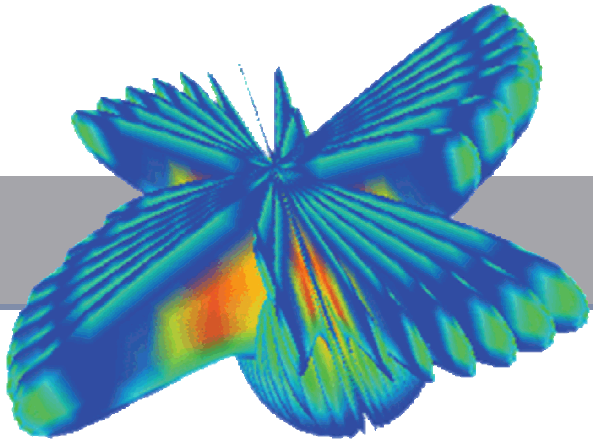
To validate the program, several cases were selected with published results in the literature.

- Sharma et al, REPSEA Produced Water Forum, 2006

- A client case was selected to illustrate
  1. Static matrix partitioning
  2. Multi-layer injection with “thief zones”
  3. Constrained surface pressure effect

- Horizontal well case to show the stress shadow effect on the fracture dimensions

Case Studies



Sharma, M. "Produced Water Reinjection," REPSEA Produced Water Forum, 2006

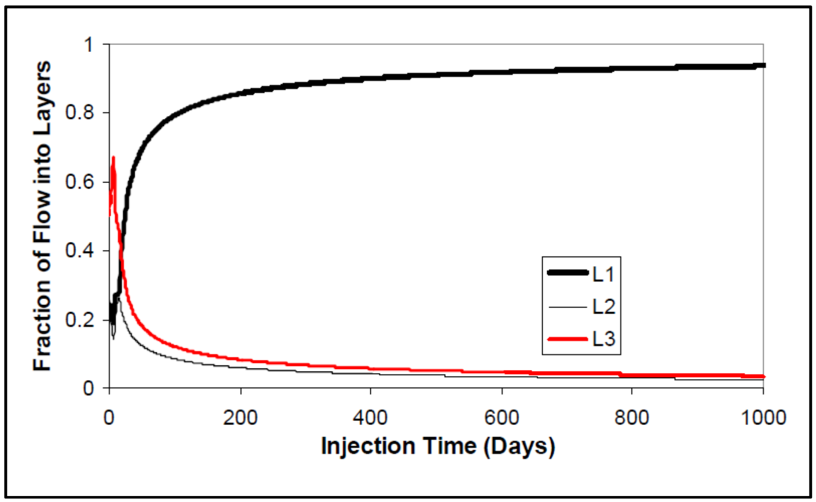
Reservoir Prop	Layer L1	Layer L2	Layer L3
Depth (mid layer)	16,925 ft	16,932.5 ft	17,027 ft
Reservoir Temp	180◦F	180◦F	180◦F
Thickness	30 ft	35 ft	45 ft
Porosity	0.27	0.28	0.30
Permeability	407 md	529 md	687 md

Input Data

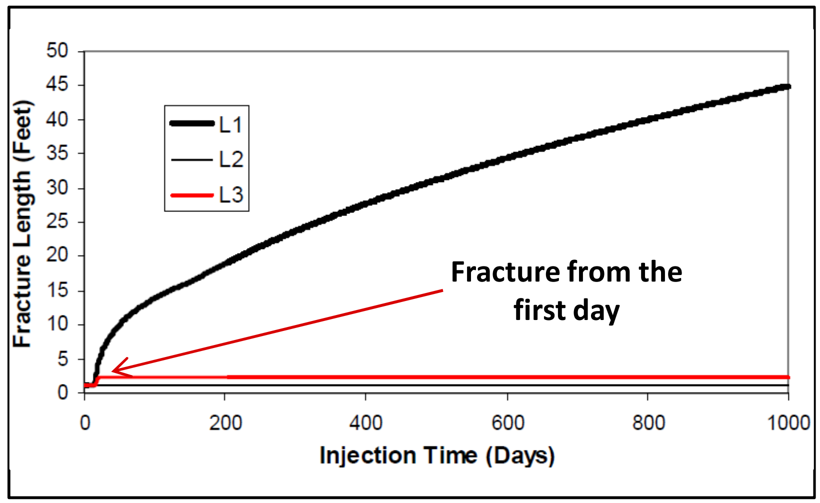
Reservoir Prop	Layer L1	Layer L2	Layer L3
Young's Modulus	0.165 M psi	0.12 M psi	0.12 M psi
Poisson's Ration	0.25	0.28	0.28
Min. Horizontal Stress	9,500 psi	10,200 psi	10,200 psi

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

Formation Properties

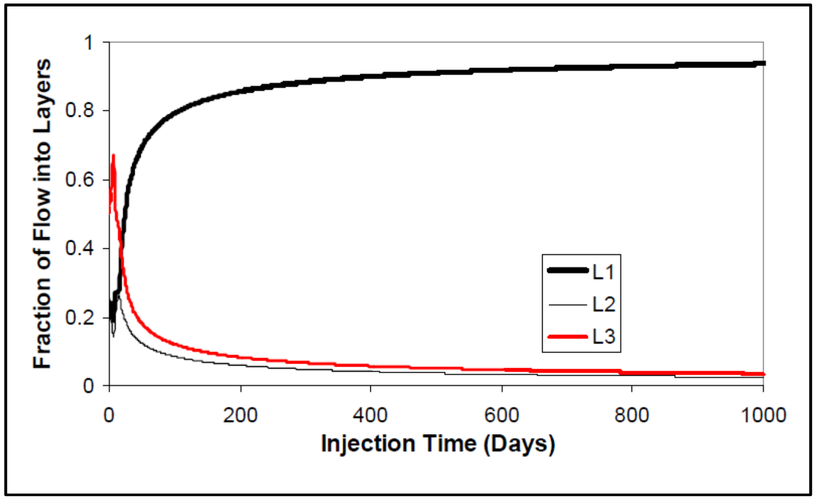


Flow Distribution

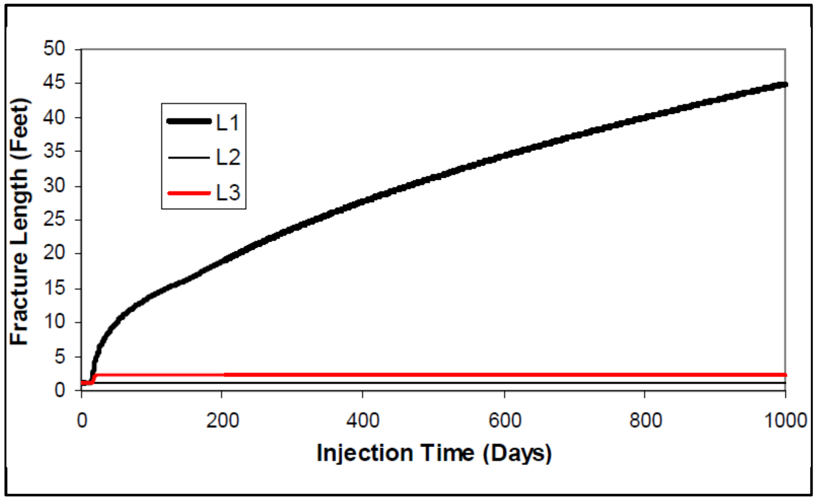


Fracture Lengths

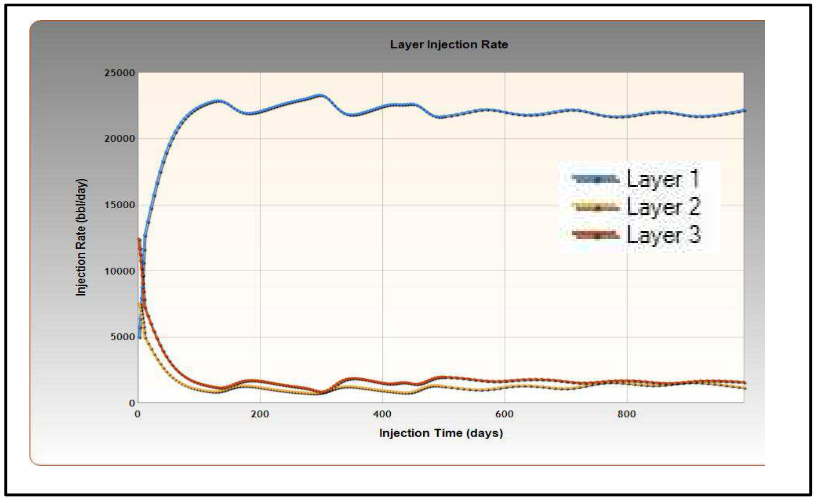
Sharma, M. “Produced Water Re-Injection,” REPSEA Produced Water Forum, 2006

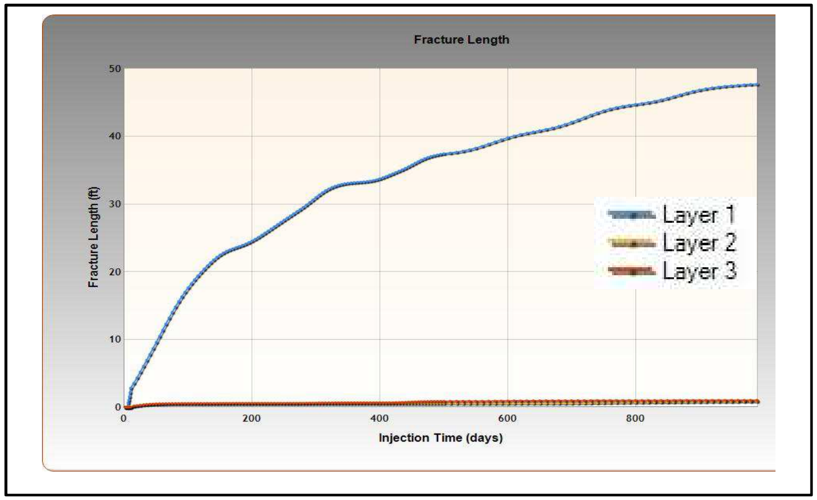


Flow Distribution



Fracture Lengths





@FRAC2D’s flow distribution, fracture lengths confirm reference case’s results

Client Case Input Data

Simulation parameters

Injection Time = 25 years
Injection Rate = 35,000 bpd
Tubing Head Pressure = 3,500 psi
Shale σ_{min} = 0.8 psi/ft
TSS = 5 ppm
ΔT = -60 psi
OIW = 10 ppm
Poisson Ratio = 0.24
E_{shale} = 55,0000 psi
E_{sand} = 85,0000 psi
Sand Linear Coefficient of Thermal Expansion = 6.5E^{-6}
Shale Linear Coefficient of Thermal Expansion = 4.5E^{-6}
Water Viscosity = 1 cp
Perforation length equal to the layer thickness
Fracture toughness = 1000 psi.sqrt-in.
Tubing ID = 6 inch
Tubing Roughness = 0.0001

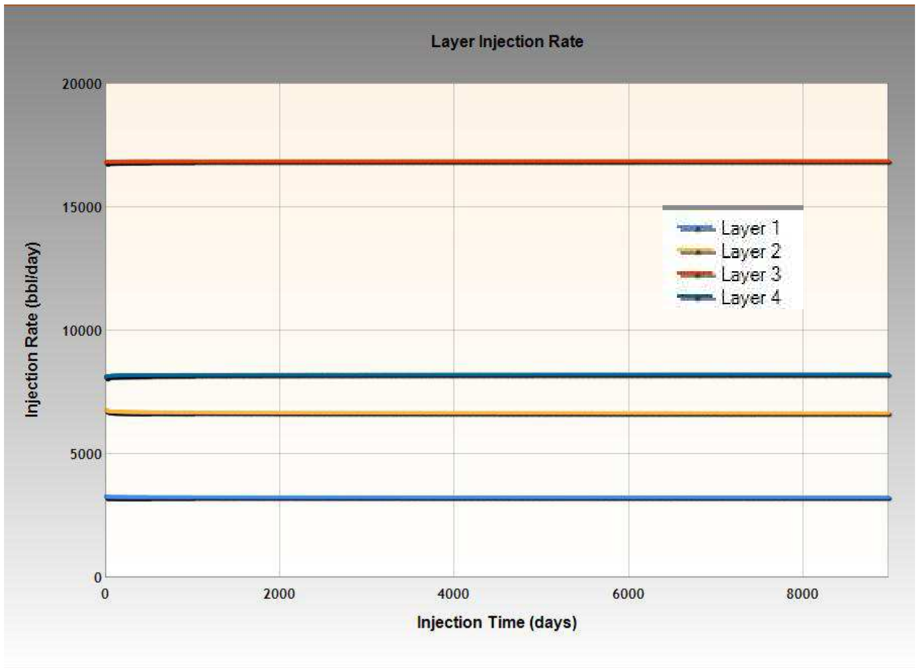
Formation Parameters	Layer 1	Layer 2	Layer 3	Layer 4
K, md	2000	1000	4000	8000
h, ft	15	60	40	10
σ_{min}, psi/ft	0.6	0.55	0.58	0.6
Top, ft	9415	9510	9620	9700
Bottom, ft	9430	0570	9660	9710
Pressure, psi/ft	0.445	0.445	0.445	0.445

Scenario 1: Matrix injection w/ no damage confirms flow partitioning

Formation Parameters	Layer 1	Layer 2	Layer 3	Layer 4
K, md	2000	1000	4000	8000
h, ft	15	60	40	10
σ_{min}, psi/ft	0.6	0.55	0.58	0.6
Top, ft	9415	9510	9620	9700
Bottom, ft	9430	0570	9660	9710
Pressure, psi/ft	0.445	0.445	0.445	0.445

Other parameters

- No Damage - Assume 100% of the injected solids pass through the formation
- No wellhead Restriction - Well head pressure = 3500 psi



As expected, in a case with no damage or fracturing, the flow distribution nearly mirrors the Kh distribution, save for the small effect of wellbore friction and the differing reservoir pressures which slightly decreases the flow to the deeper layers.

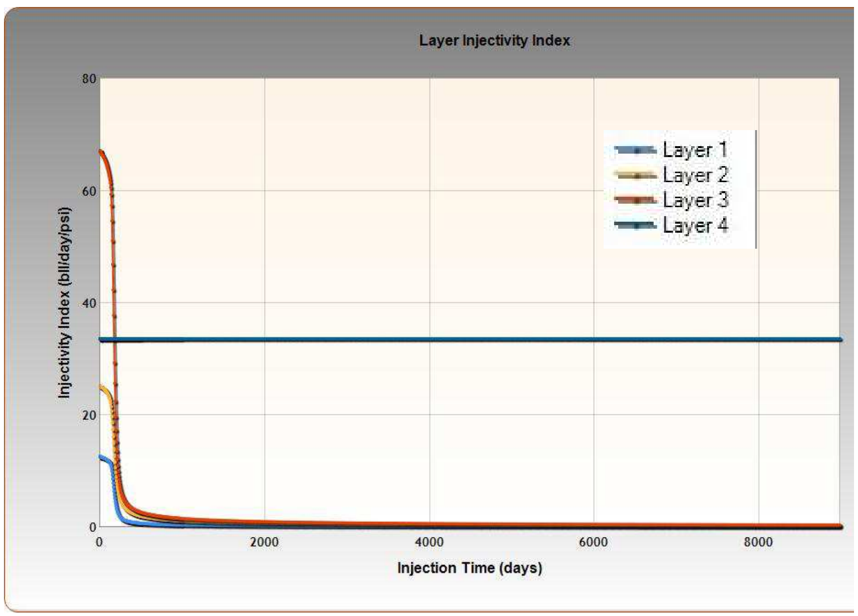
	Layer 1	Layer 2	Layer 3	Layer 4
Kh % of total	9.1%	18.2%	48.5%	24.2%
Q % of total	9.3%	19.1%	48.2%	23.5%

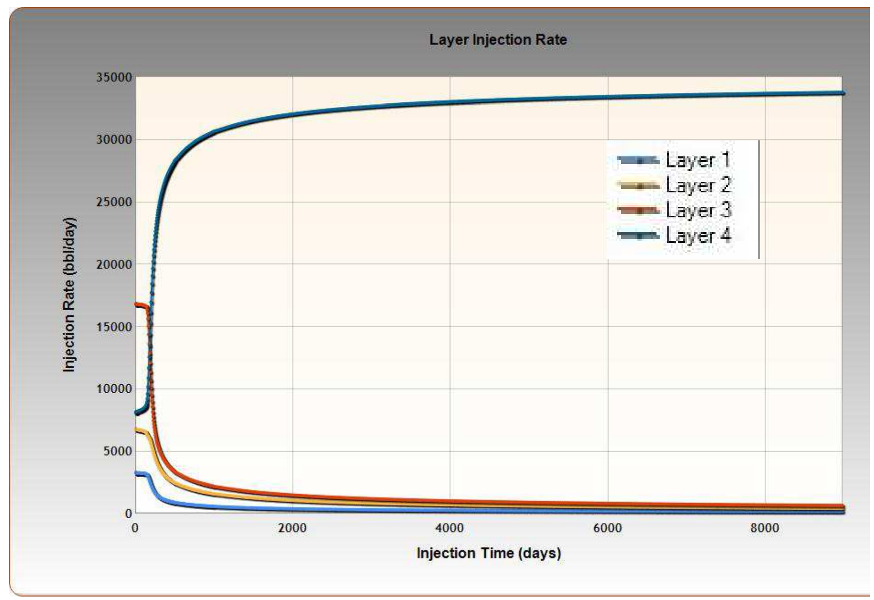
Scenario 2: Distributed Damage

Formation Parameters	Layer 1	Layer 2	Layer 3	Layer 4
K, md	2000	1000	4000	8000
h, ft	15	60	40	10
σ_{min}, psi/ft	0.6	0.55	0.58	0.6
Top, ft	9415	9510	9620	9700
Bottom, ft	9430	0570	9660	9710
Pressure, psi/ft	0.445	0.445	0.445	0.445

Other parameters

- Layer 1: Assume 80% of solids pass through
- Layer 2: Assume 60% of solids pass through
- Layer 3: Assume 90% of solids pass through
- Layer 4: Assume 100% of solids pass through
- Well head pressure = 3500 psi





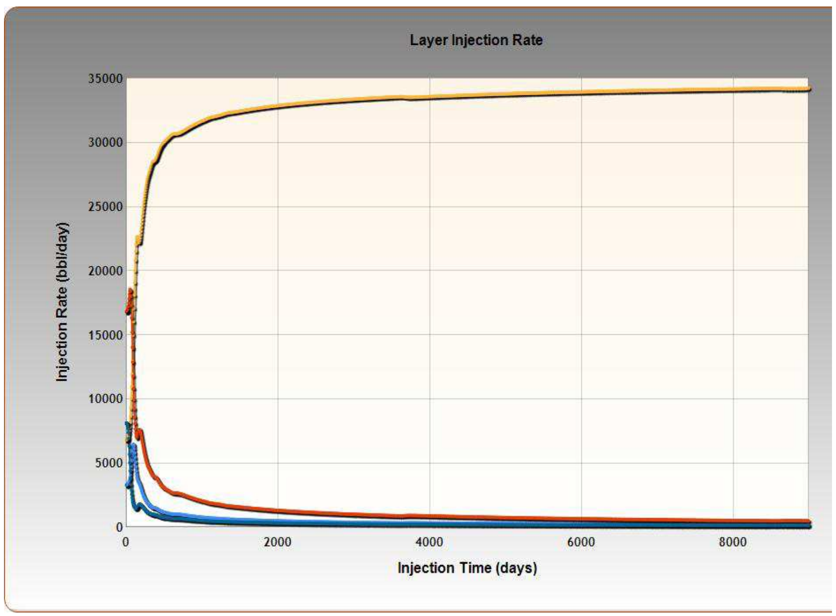
As damage accumulates, a non-damaging layer acts as a thief zone which accumulates all of the flow.

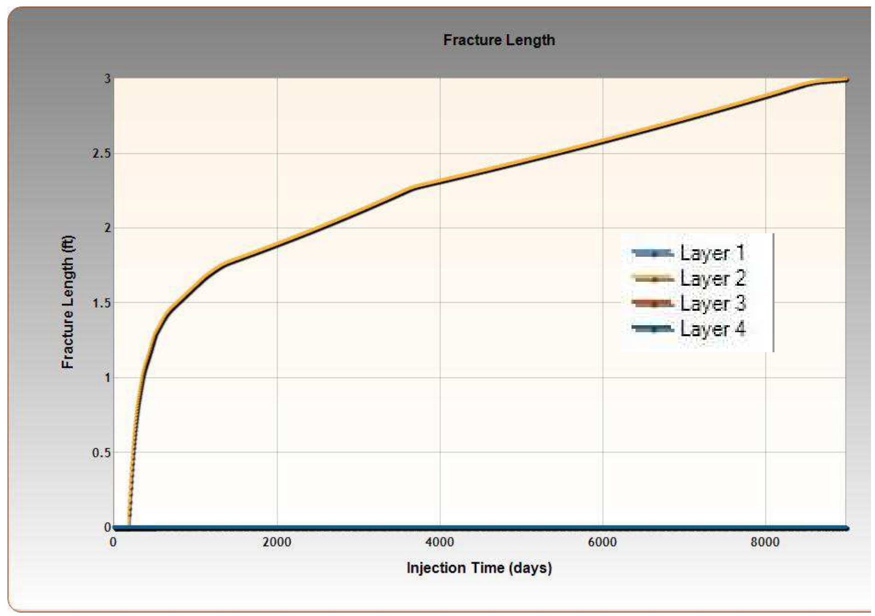
Scenario 3 : Formation Damage with Fracturing

Formation Parameters	Layer 1	Layer 2	Layer 3	Layer 4
K, md	2000	1000	4000	8000
h, ft	15	60	40	10
σ_{min}, psi/ft	0.6	0.55	0.58	0.6
Top, ft	9415	9510	9620	9700
Bottom, ft	9430	0570	9660	9710
Pressure, psi/ft	0.445	0.445	0.445	0.445

Other parameters

- Assume 80% of the injected solids pass through the formation
- Well head pressure = 3500 psi





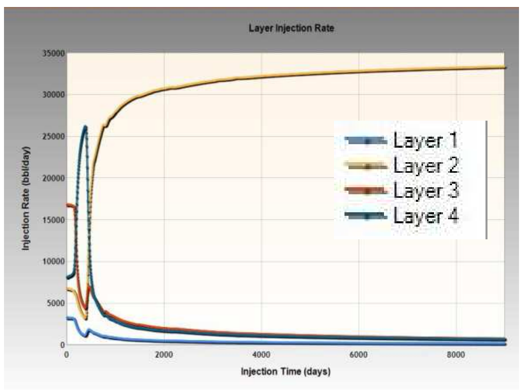
Once the first fracture opens up, the fractured layer (2) takes nearly all the flow.

Scenario 4 : Damage Distribution Sensitivity

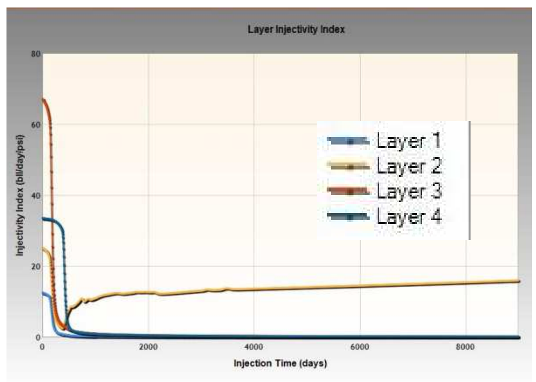
Formation Parameters	Layer 1	Layer 2	Layer 3	Layer 4
K, md	2000	1000	4000	8000
h, ft	15	60	40	10
σ_{min}, psi/ft	0.6	0.55	0.58	0.6
Top, ft	9415	9510	9620	9700
Bottom, ft	9430	0570	9660	9710
Pressure, psi/ft	0.445	0.445	0.445	0.445

Other parameters

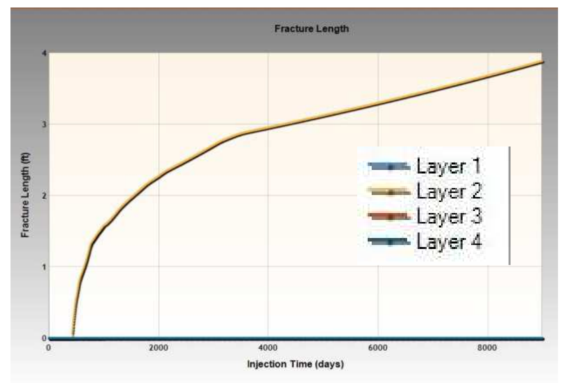
- Layer 1: Assume 80% of solids pass through
- Layer 2: Assume 60% of solids pass through
- Layer 3: Assume 90% of solids pass through
- Layer 4: Assume 99% of solids pass through
- Well head pressure = 3500 psi



Injection Rate



Injectivity Index



Fracture Length

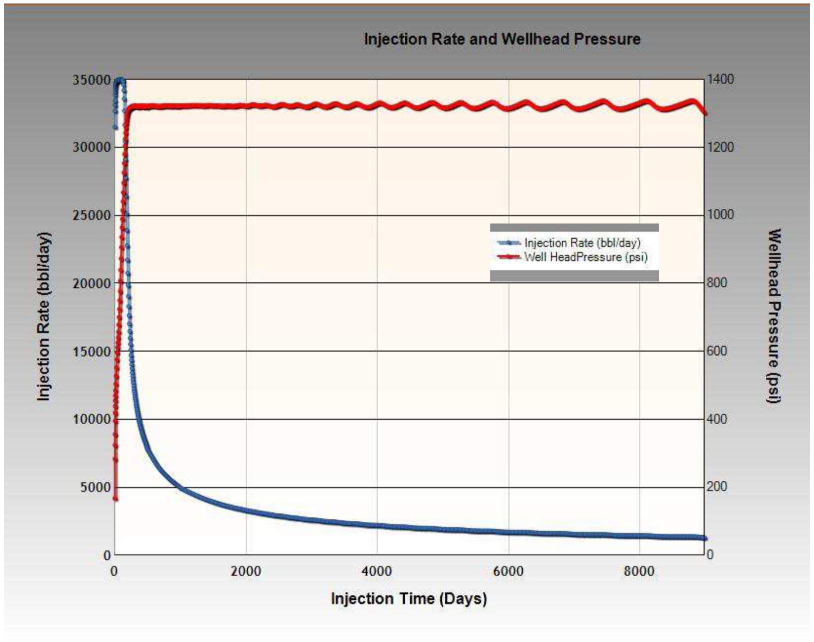
A sensitivity on the previous cases, this time with no non-damaging layers, shows a combination of the damage and fracture's affects on the flow distribution and injectivity index

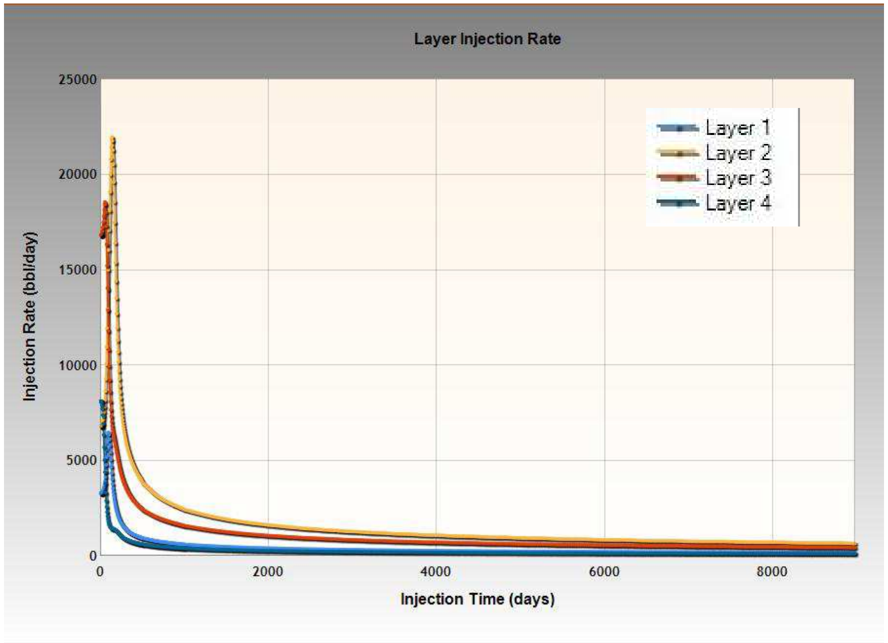
Scenario 5 : Damage with Constrained Surface Pressure

Formation Parameters	Layer 1	Layer 2	Layer 3	Layer 4
K, md	2000	1000	4000	8000
h, ft	15	60	40	10
σ_{min}, psi/ft	0.6	0.55	0.58	0.6
Top, ft	9415	9510	9620	9700
Bottom, ft	9430	0570	9660	9710
Pressure, psi/ft	0.445	0.445	0.445	0.445

Other parameters

- Assume 80% of the injected solids pass through the formation
- Well head pressure = 1350 psi

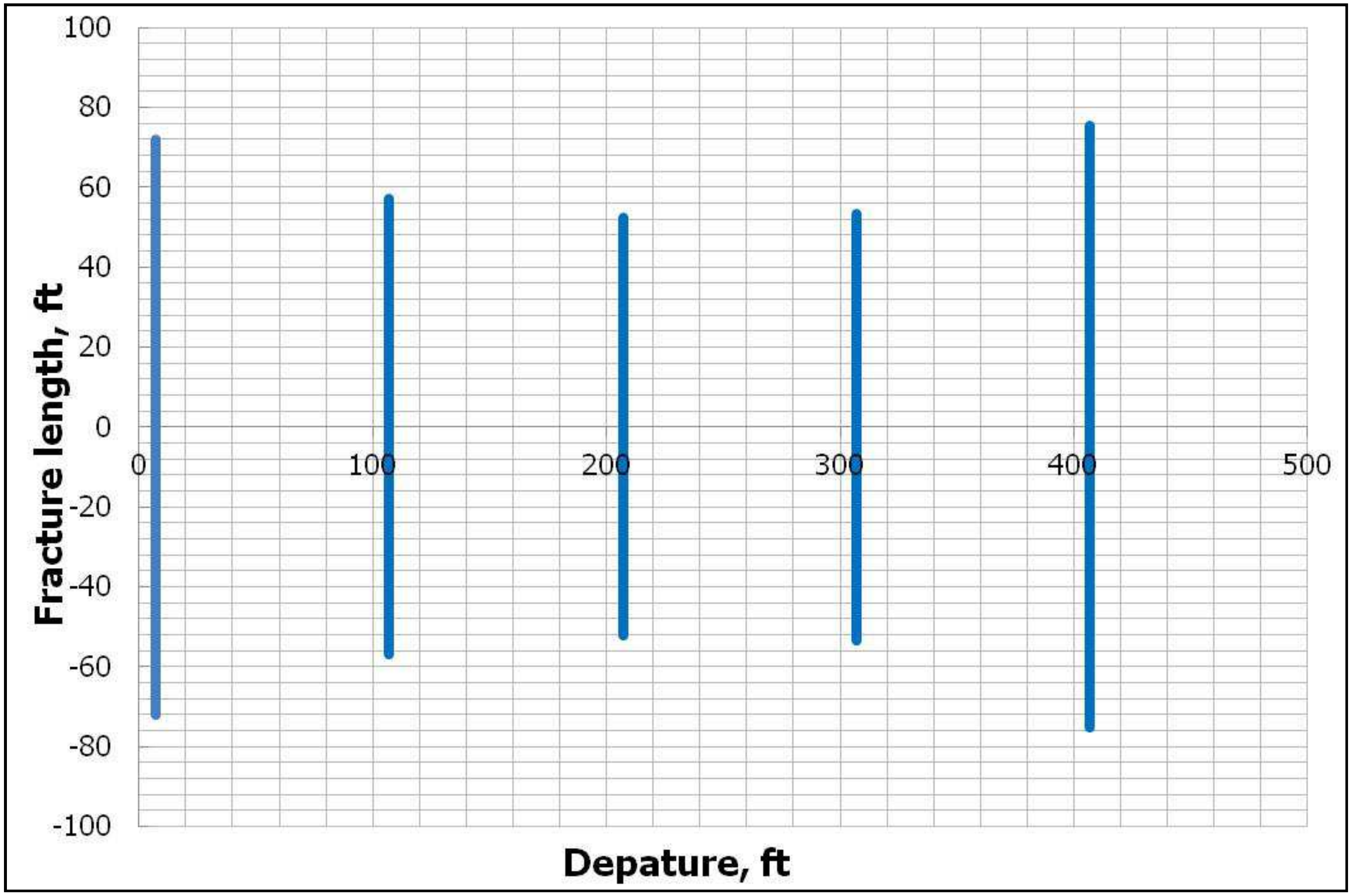




With the surface pressure restricted, the total flow rate decreases as the damage builds, then increases again as an open fracture reduces the restriction

Stress Shadow

In case of multi-fracures horizontal well, fractures near the tip and the hill of the horizontal well have longer fracture length than the fractures in the middle.



Conclusions

- **@FRAC 2D** is a hydraulic fracture and formation damage simulator used to analyze operations like horizontal shale multi-fracs, frac packs, Produced Water Re-Injection, etc.
- **@FRAC 2D** assesses formation damage caused by solids and solid settling, oil in water, and bacteria growth during both matrix and fractured injection.
- **@FRAC 2D** considers stress changes due to thermal and poro-elastic effects and models penetration depth to assure fracture containment within the injection horizon.
- **@FRAC 2D** applies broadly to contained or quasi-contained fractures including multi-perf, multi-zone and multi-layered injection, deviated, vertical or horizontal wells, history matching, or others.

Conclusions

- **@FRAC 2D** can be used to evaluate the impact of formation damage on long term injection processes, such as produced water re-injection or water flood.
- **@FRAC 2D** allows to define a constant injection rate or a constrained surface injection pressure and then view the resulting injection parameters.
- The model shows very good conformance to expected results from benchmark cases
- This allows the operator to understand the impact of injection fluid properties on injectivity, pump horsepower requirements, surface treatment needs, maximum disposal rates and volumes.

Thank You

Advantek International
3300 South Gessner Road, suite 257
Houston, Texas, 77063
713.532.7627
admin@advantekinternational.com
www.advantekinternational.com