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

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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
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)

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

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

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

The fracture width is controlled by the fracture net pressure

\[ w = f(P_{net}) \]
### Damage Model

![Diagram showing external and internal filter cakes and non-bridging solids](image)

<table>
<thead>
<tr>
<th>Condition</th>
<th>External filter cake</th>
<th>Internal filter cake</th>
<th>Non-bridging solids</th>
</tr>
</thead>
<tbody>
<tr>
<td>High velocity (&gt;10 cm/min interstitial)</td>
<td>$d_{soild} &gt; 33% d_{pore}$</td>
<td>$33% &gt; d_{soild} &gt; 14% d_{pore}$</td>
<td>$d_{soild} &lt; 14% d_{pore}$</td>
</tr>
<tr>
<td>Low velocity (&lt;2 cm/min interstitial)</td>
<td>$d_{soild} &gt; 33% d_{pore}$</td>
<td>$33% &gt; d_{soild} &gt; 7% d_{pore}$</td>
<td>$d_{soild} &lt; 7% d_{pore}$</td>
</tr>
</tbody>
</table>

(Bennion et al. 1996)

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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)

\[ R_s = R_{\text{int}} + R_c - \left[ \ln \left( \frac{R_d}{r_w} \right) / \left( 2\pi h K \right) \right] \]

- Where:
  - \( R_{\text{int}} \) is the internal filter cake
  - \( R_c \) is the external filter cake
  - \( R_d \) 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

\[ C = OIW \times \frac{0.14}{2.1} \]  

(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.

@FRAC2D results exhibit the behavior shown in SPE 94606

Field data presented in SPE 94606
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

### Input Data

<table>
<thead>
<tr>
<th>Reservoir Prop</th>
<th>Layer L1</th>
<th>Layer L2</th>
<th>Layer L3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Depth (mid layer)</td>
<td>16,925 ft</td>
<td>16,932.5 ft</td>
<td>17,027 ft</td>
</tr>
<tr>
<td>Reservoir Temp</td>
<td>180°F</td>
<td>180°F</td>
<td>180°F</td>
</tr>
<tr>
<td>Thickness</td>
<td>30 ft</td>
<td>35 ft</td>
<td>45 ft</td>
</tr>
<tr>
<td>Porosity</td>
<td>0.27</td>
<td>0.28</td>
<td>0.30</td>
</tr>
<tr>
<td>Permeability</td>
<td>407 md</td>
<td>529 md</td>
<td>687 md</td>
</tr>
</tbody>
</table>

### Formation Properties

<table>
<thead>
<tr>
<th>Reservoir Prop</th>
<th>Layer L1</th>
<th>Layer L2</th>
<th>Layer L3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Young's Modulus</td>
<td>0.165 M psi</td>
<td>0.12 M psi</td>
<td>0.12 M psi</td>
</tr>
<tr>
<td>Poisson's Ratio</td>
<td>0.25</td>
<td>0.28</td>
<td>0.28</td>
</tr>
<tr>
<td>Min. Horizontal Stress</td>
<td>9,500 psi</td>
<td>10,200 psi</td>
<td>10,200 psi</td>
</tr>
<tr>
<td>Particle Concentration</td>
<td>5 ppm</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Average Particle Diameter</td>
<td>5 microns</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Particle Density</td>
<td>2.3 gm/cc</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Injection Rate</td>
<td>25,000 BPD</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

### Flow Distribution

![Fraction of Flow into Layers vs Injection Time](image1)

### Fracture Lengths

![Fracture Lengths vs Injection Time](image2)

Fracture from the first day

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 $\sigma_{\text{min}}$** = 0.8 psi/ft
- **TSS** = 5 ppm
- **$\Delta T$** = -60 psi
- **OIW** = 10 ppm
- **Poisson Ratio** = 0.24
- **$E_{\text{shale}}$** = 55,000 psi
- **$E_{\text{sand}}$** = 85,000 psi
- **Sand Linear Coefficient of Thermal Expansion** = $6.5 \times 10^{-6}$
- **Shale Linear Coefficient of Thermal Expansion** = $4.5 \times 10^{-6}$
- **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

<table>
<thead>
<tr>
<th>Formation Parameters</th>
<th>Layer 1</th>
<th>Layer 2</th>
<th>Layer 3</th>
<th>Layer 4</th>
</tr>
</thead>
<tbody>
<tr>
<td>$K$, md</td>
<td>2000</td>
<td>1000</td>
<td>4000</td>
<td>8000</td>
</tr>
<tr>
<td>$h$, ft</td>
<td>15</td>
<td>60</td>
<td>40</td>
<td>10</td>
</tr>
<tr>
<td>$\sigma_{\text{min}}$, psi/ft</td>
<td>0.6</td>
<td>0.55</td>
<td>0.58</td>
<td>0.6</td>
</tr>
<tr>
<td>Top, ft</td>
<td>9415</td>
<td>9510</td>
<td>9620</td>
<td>9700</td>
</tr>
<tr>
<td>Bottom, ft</td>
<td>9430</td>
<td>0570</td>
<td>9660</td>
<td>9710</td>
</tr>
<tr>
<td>Pressure, psi/ft</td>
<td>0.445</td>
<td>0.445</td>
<td>0.445</td>
<td>0.445</td>
</tr>
</tbody>
</table>
Scenario 1: Matrix injection w/ no damage confirms flow partitioning

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 Injection Rate

<table>
<thead>
<tr>
<th>Formation Parameters</th>
<th>Layer 1</th>
<th>Layer 2</th>
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<th>Layer 4</th>
</tr>
</thead>
<tbody>
<tr>
<td>K, md</td>
<td>2000</td>
<td>1000</td>
<td>4000</td>
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<tr>
<td>h, ft</td>
<td>15</td>
<td>60</td>
<td>40</td>
<td>10</td>
</tr>
<tr>
<td>σ_{min}, psi/ft</td>
<td>0.6</td>
<td>0.55</td>
<td>0.58</td>
<td>0.6</td>
</tr>
<tr>
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<td>0.445</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Layer 1</th>
<th>Layer 2</th>
<th>Layer 3</th>
<th>Layer 4</th>
</tr>
</thead>
<tbody>
<tr>
<td>Kh % of total</td>
<td>9.1%</td>
<td>18.2%</td>
<td>48.5%</td>
</tr>
<tr>
<td>Q % of total</td>
<td>9.3%</td>
<td>19.1%</td>
<td>48.2%</td>
</tr>
</tbody>
</table>
Scenario 2: Distributed Damage

<table>
<thead>
<tr>
<th>Formation Parameters</th>
<th>Layer 1</th>
<th>Layer 2</th>
<th>Layer 3</th>
<th>Layer 4</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>K, md</strong></td>
<td>2000</td>
<td>1000</td>
<td>4000</td>
<td>8000</td>
</tr>
<tr>
<td><strong>h, ft</strong></td>
<td>15</td>
<td>60</td>
<td>40</td>
<td>10</td>
</tr>
<tr>
<td><strong>σ_{min}, psi/ft</strong></td>
<td>0.6</td>
<td>0.55</td>
<td>0.58</td>
<td>0.6</td>
</tr>
<tr>
<td><strong>Top, ft</strong></td>
<td>9415</td>
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<td>9620</td>
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</tr>
<tr>
<td><strong>Bottom, ft</strong></td>
<td>9430</td>
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</tr>
<tr>
<td><strong>Pressure, psi/ft</strong></td>
<td>0.445</td>
<td>0.445</td>
<td>0.445</td>
<td>0.445</td>
</tr>
</tbody>
</table>

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

<table>
<thead>
<tr>
<th>Formation Parameters</th>
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<th>Layer 2</th>
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<th>Layer 4</th>
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<td>$h$, ft</td>
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<td>60</td>
<td>40</td>
<td>10</td>
</tr>
<tr>
<td>$\sigma_{\text{min}}, \text{psi/ft}$</td>
<td>0.6</td>
<td>0.55</td>
<td>0.58</td>
<td>0.6</td>
</tr>
<tr>
<td>Top, ft</td>
<td>9415</td>
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</tr>
<tr>
<td>Pressure, psi/ft</td>
<td>0.445</td>
<td>0.445</td>
<td>0.445</td>
<td>0.445</td>
</tr>
</tbody>
</table>

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

<table>
<thead>
<tr>
<th>Formation Parameters</th>
<th>Layer 1</th>
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<th>Layer 3</th>
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<tbody>
<tr>
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<td>Pressure, psi/ft</td>
<td>0.445</td>
<td>0.445</td>
<td>0.445</td>
<td>0.445</td>
</tr>
</tbody>
</table>

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

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.

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Scenario 5 : Damage with Constrained Surface Pressure

<table>
<thead>
<tr>
<th>Formation Parameters</th>
<th>Layer 1</th>
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<td>$h$, ft</td>
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<td>10</td>
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<tr>
<td>$\sigma_{\text{min}}, \text{ psi/ft}$</td>
<td>0.6</td>
<td>0.55</td>
<td>0.58</td>
<td>0.6</td>
</tr>
<tr>
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</tr>
<tr>
<td>Pressure, psi/ft</td>
<td>0.445</td>
<td>0.445</td>
<td>0.445</td>
<td>0.445</td>
</tr>
</tbody>
</table>

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-fractures 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

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