Formation Damage – Effects and Overview

• Where is the damage?
• How does it affect production?
Impact of Damage on Production

- Look at Effect of Damage
- Type of Damage
- Severity of Plugging
- Depth of Damage
- Ability to Prevent/Remove/By-Pass
Where is the Damage???

Idealized View

Wellbore  Damaged Zone  Undamaged Formation

Actual?

Wellbore

Fracture

High Perm Zone

Fluids follow the path of least resistance.
Horizontal Well Formation Damage Theories
Zone of Invasion - Homogeneous Case

Is damage evenly spread out along the well path or does it go down the highest permeability streaks?
Horizontal Well Formation Damage Theories
Zone of Invasion - Heterogeneous Case
Observations on Damage

1. Shallow damage is the most common and makes the biggest impact on production.

2. It may take significant damage to create large drops in production.

3. The problem, however, is that the highest permeability zones are the easiest to damage, and that can have a major impact on productivity.
The pressure drop around an unfractured wellbore shows the importance of the near wellbore on inflow. If this area is significantly damaged, the effect is immediately noticeable.
1. The most noticeable damage impacts the well in the first 30 cm or 12 inches of the formation.
2. The effect of the damage thickness compared with the amount of damage (as a percent of initial permeability). Only the most severe damage has a significant effect in a thin layer. (Darcy law beds-in-series calculation)
2. (continued) As the damage layer thickens and becomes more severe, the impact on production builds quickly.
3. Highest permeability zones are easiest to damage:

**Pore Size vs. Permeability**

\[ y = 1.3661x^{2.4865} \]

\[ R^2 = 0.982 \]

Large connected pores and natural fractures dominate the permeability of a formation.

The size of particles that can cause damage in these larger pores is larger than \(1/3^{rd}\) and smaller than \(1/7^{th}\). For a 8 micron pore, the small size would be 1 micron and less.
The Effect of Damage on Production

Rate = \( (\Delta P \times k \times h) / (141.2 \mu_o \beta_o s) \)

Where:

- \( \Delta P \) = differential pressure (drawdown due to skin)
- \( k \) = reservoir permeability, md
- \( h \) = height of zone, ft
- \( \mu_o \) = viscosity, cp
- \( \beta_o \) = reservoir vol factor
- \( s \) = skin factor

What are the variables that can be improved, modified or impacted in a positive way?
Productivity and Skin Factor

- \( \frac{Q_1}{Q_o} = \frac{7}{7+s} \)

Just an estimation, but not too far off between skin numbers of zero and about 15.

Where:

- \( Q_1 \) = productivity of zone w/ skin, bpd
- \( Q_o \) = initial productivity of zone, bpd
- \( s \) = skin factor, dimensionless
A better presentation of the damage from increasing skin factor. Skin only has an impact if the well can really produce the higher rate and the facilities can process it.
Example

- Productivity for skins of -1, 5, 10 and 50 in a well with a undamaged \((s=0)\) production capacity of 1000 bpd
- \(s = -1\), \(Q_1 = 1166\) bpd
- \(s = 5\), \(Q_1 = 583\) bpd
- \(s = 10\), \(Q_1 = 412\) bpd

- The best stimulation results are usually for damage removal and damage by-pass.
Another way of stating damage - Damage in a horizontal well – increasing skin makes the well behave like the drilled lateral was much shorter.
Damage Causes

• Obstructions in the natural flow path in the reservoir.
• “Pseudo” damage such as turbulence - very real effect, but no visible obstructions
• “Structural” damage from depletion – matrix compression, etc.
Flow Path Obstructions

- Scale, paraffin, asphaltenes, salt, etc.,
- Perforations – 12 spf w/ 0.75” / 1.9 cm holes only opens 2% of the casing wall.
- Tubing too small - too much friction
- Any fluid column in the well, even a flowing fluid column holds a backpressure on the well:
  - Salt water = 0.46 psi/ft
  - Dead oil = 0.36 psi/ft
  - Gas lifted oil = 0.26 psi/ft
  - Gas = 0.1 psi/ft (highly variable with pressure)
“Pseudo” Damage

• Turbulence
  – high rate wells
  – gas zones most affected

• Affected areas:
  – perfs (too few, too small)
  – Near wellbore (tortuosity)
  – fracture (conductivity too low)
  – tubing (tubing too small, too rough)
  – surface (debottle necking needed)
“Structural” Damage

• Tubular Deposits
  – scale
  – paraffin
  – asphaltenes
  – salt
  – solids (fill)
  – corrosion products
Perforation Damage

• debris from perforating
• sand in perf tunnel - mixing?
• mud particles
• particles in injected fluids
• pressure drop induced deposits
  – scales
  – asphaltenes
  – paraffins
Near Well Damage

• in-depth plugging by injected particles
• migrating fines
• water swellable clays
• water blocks, water sat. re-establishment
• polymer damage
• wetting by surfactants
• relative permeability problems
• matrix structure collapse
Deeper Damage

• water blocks
• formation matrix structure collapse
• natural fracture closing
Other Common Damages

• fines migration (increasing skin)
• water blocks
• scale
• emulsions
• paraffin and asphaltenes
• turbulence – rate dependent skin
• perf debris
• Initial damage from mud and DIF’s
Skin Components and Determination

• Total Skins ($s'$) = $S_o + S_{tp} + D \cdot Q$

Where:

$S_o$ = laminar skin
$S_{tp}$ = 2-phase skin
$D$ = rate dependent skin
$Q$ = rate
Skin Components and Determination

- Multi-rate tests $\Rightarrow S_o, S_{tp}, D$
- B/U Test $\Rightarrow$ total skin, $k$
- 2 B/U Tests $\Rightarrow S_o, D, k$
Cleaning Damage

• Most damage is removed by simple clean-up flow.
• How much drawdown?
• How long to flow it?
• How soon to flow it?
• To do it?
Root Causes of Residual Damage After Clean-up Flow....

• High perm formations less affected?
  
  – Major damage removers:
    • Flow Rate per unit area,
    • Flow Volume per unit area,
    • Pressure pulse?

• Drawdown per unit area – a control?
First Problem

We don’t understand cleanup by flow...

It’s a matter of flow rate and volume through a given area.
For the same pay thickness, a horizontal well or a fractured well may contact 100’s of times more pay zone area than a vertical well.

Clean-up flow is “diluted” by the length of interval open at once for cleanout.

A 10 ft pay in a vertical well w/ 6” diameter yields contact area of 16 ft²

A 1000 ft pay in a horizontal well w/ 6” diam. yields contact area of 1600 ft²

Now, think about the set drawdown – say 500 psi - per unit area, the velocity generated, and the total volume per area.
Which has the potential of cleaning up faster and more completely?

Vertical well - 500 psi dd and an inflow of 100 bbl/day/ft spread out over just 16 ft² will generate a clean-up flow of 110 gal per hour per ft.

5000 bpd

Horiz. Well – assume 5x more than vertical flow (typical) – would generate 5000 bpd, but spread over 1600 ft² – and release a clean-up flow of only 3 gal per hour per ft.
Second Problem

• We don’t understand damage.
  – How it got there
  – How it is removed.
  – How to prevent it.
  – What operations put the well’s productivity at risk.
Some examples of GOM skins versus md-ft

Note the increasing skin in higher conductivity wells – why? It should be easier to remove damage in higher perm formations. The key here is that turbulent (non-darcy or non mechanical) skins are nearly always higher in high capacity wells – especially gas.

There are many damage mechanisms, but few are permanent if we learn how to remove them.
Cleanup examples from Alaska wells – high losses into high PI wells, but……

![Fluid Loss Rate from Pre Workover PI - Alaska](image-url)

**Daily Loss, bbls**

**PI, bbls/day/psi**

3/14/2009

George E. King Engineering

GEKEngineering.com

SPE 26042
...there was actually little correlation with amount lost.
Of higher importance was whether the perfs were protected or not.
When perfs were protected, that was little risk of long term damage.
When the perfs were not protected, the well was damaged.
One very detrimental action was running a scraper prior to packer setting. The scraping and surging drives debris into unprotected perfs.

![Graph showing the effect of scraping or milling adjacent to open perforations. The graph compares the short-term and long-term change in PI for perfs not protected by LCM prior to scraping and perfs protected by LCM. The x-axis represents the percentage change in PI, ranging from -60 to 0. The y-axis represents the percentage change in PI. The graph shows that perfs not protected by LCM prior to scraping experience a greater decrease in PI compared to perfs protected by LCM.](image-url)
Sized particulates, particularly those that can be removed, are much less damaging than most polymers, even the so-called clean polymers.
Third Problem

• We don’t know enough about timing of damage removal.
  – Variety of causes
    • Polymer dehydration
    • Decomposition of materials
    • Adsorption, absorption and capillary effects

• Field data from Troika (100,000 md-ft) show initial flow improves PI, but later flow does not.
Deepwater Well Cleanup Lessons

• On initial cleanup, PI erratically increased as choke opened. Typical response was a decrease, as if well / flow path were loading up, then sharp PI increase, seemingly when the obstruction was unloaded.

• Little partly broken polymer recovered, but early load water recovery matched PI incr.

• Lower skins were linked to both sand flow before completion (sand surge removed damage), increased cleanup flow volumes (and drawdown) on initial cleanup, and more effective frac stimulations.
Deepwater Cleanup Lessons

• Wells cleaned up with increasing drawdown immediately following backflow start. Cleanup was increasing, measured by increasing PI, at the end of the first short cleanup periods prior to shut-in of the well.

• After initiation of production operations - after first cleanup flow, no further cleanup of damage was seen, regardless of drawdown. The reason is not known, but may be due to polymer adhering or cooking out?
Fourth Problem

• We don’t understand how damage impacts economic return.
An example of a completion method that minimizes damage.

- Perforating, but with enough underbalance to create the flow necessary to clean the perforations.
Look at some of the most common damage mechanisms. In some formations, a specific damage is very detrimental, while in another formation, the damage is insignificant.

<table>
<thead>
<tr>
<th></th>
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<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Mud Cake in Pay Zone</td>
<td>Formation Face</td>
<td>Moderate to Severe</td>
<td>Yes</td>
<td>Spurt Volume</td>
<td>Yes</td>
<td>Acids, Soaps, Enzymes</td>
</tr>
<tr>
<td>Mud Filt.</td>
<td>&lt;12”</td>
<td>Minor - mod.</td>
<td>No</td>
<td>No</td>
<td>No</td>
<td></td>
</tr>
<tr>
<td>Whole Mud Loss</td>
<td>Fractures and large vugs</td>
<td>Severe</td>
<td>Possible, Can help in few cases.</td>
<td>Depend on Cond. few cases similar</td>
<td>Yes, flow combined with solvent treatment</td>
<td>Few successful whole mud removals when vol. &gt; 200 bbls.</td>
</tr>
<tr>
<td>Cement Filtrate</td>
<td>&lt;12” into pay</td>
<td>Only if clay damage</td>
<td>No</td>
<td>No</td>
<td>No</td>
<td></td>
</tr>
<tr>
<td>Perforation Crush Zone</td>
<td>½” around perf</td>
<td>Moderate to Severe</td>
<td>Yes</td>
<td>4 to 12 gal/perf</td>
<td>Yes</td>
<td>Surge small zones into chamber, acids, pulses, fracs</td>
</tr>
<tr>
<td>Formation sand in perfs</td>
<td>perf tunnels</td>
<td>Most severe</td>
<td>Cleanup and reperf</td>
<td>Depends on initial &amp; later actions</td>
<td>Develop good perf and prepack actions</td>
<td></td>
</tr>
</tbody>
</table>
When looking at the range of skins, it is useful to know that some wells have high skins but are really restricted by other factors such as tubing flow limits, facility limits, etc., and are not really limited by the skins.

<table>
<thead>
<tr>
<th>Type of Damage</th>
<th>Skin range</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mud Cake in Pay Zone</td>
<td>+5 to +300, +15 is typical</td>
<td>Mud skin is usually shallow and has more impact when turbulence and non-darcy skin problems are most severe. Mud cake is usually by-passed by perforating.</td>
</tr>
<tr>
<td>Mud Filtrate</td>
<td>+3 to +30</td>
<td>Filtrate usually recovered by steady flow and time. Related to relative perm effects. This is usually a short lived problem (1 to 3 weeks)</td>
</tr>
<tr>
<td>Whole Mud Loss (in pay zone)</td>
<td>&gt;+50</td>
<td>Options depend on mud volume lost. Enzymes, solvents and acids for small volumes (&lt;10 bbls). Sidetrack if over 1000 bbls. Low solids mud can be removed by concentrating on viscosifier destruction or dispersment.</td>
</tr>
<tr>
<td>Cement Filtrate</td>
<td>+10 to +20</td>
<td>Very shallow clay problems. Perforate with deep penetrating charges to get beyond. Use leakoff control on cement.</td>
</tr>
<tr>
<td>Perforation Crush Zone</td>
<td>+10 to +20</td>
<td>Perf small intervals underbalanced. Isolation packer breaksown, explosive sleeve breakdown (very simple) - must be accomplished prior to gravel packing.</td>
</tr>
<tr>
<td>Formation sand in perfs</td>
<td>&gt;+50</td>
<td>Most severe typical damage - cleanout and recompletion required</td>
</tr>
</tbody>
</table>
Table 3: Completion Efficiency Factors (Stracke, SPE 16212)  Shown as a percent of wells in each bracketed completion efficiency range.

<table>
<thead>
<tr>
<th>Factor</th>
<th>100-75%</th>
<th>75-50%</th>
<th>50-25%</th>
<th>25-0%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Underbalance perf w/ surge chamber</td>
<td>26</td>
<td>26</td>
<td>26</td>
<td>23</td>
</tr>
<tr>
<td>Perforate and wash perfs</td>
<td>25</td>
<td>40</td>
<td>19</td>
<td>15</td>
</tr>
<tr>
<td>Underbalance perf w/ surge chamber + wash perfs</td>
<td>71</td>
<td>14</td>
<td>14</td>
<td>0</td>
</tr>
<tr>
<td>Surge Vol &lt; 4 gal/ft</td>
<td>23</td>
<td>19</td>
<td>35</td>
<td>23</td>
</tr>
<tr>
<td>Surge Vol &gt; 4 gal/ft</td>
<td>43</td>
<td>29</td>
<td>14</td>
<td>14</td>
</tr>
<tr>
<td>Surge differential &lt; 1000 psi</td>
<td>27</td>
<td>24</td>
<td>24</td>
<td>24</td>
</tr>
<tr>
<td>Surge differential &gt;1000 psi</td>
<td>19</td>
<td>27</td>
<td>31</td>
<td>23</td>
</tr>
<tr>
<td>Drilling overbalance &lt;300 psi</td>
<td>15</td>
<td>48</td>
<td>19</td>
<td>19</td>
</tr>
<tr>
<td>Drilling overbalance &gt;300 psi</td>
<td>31</td>
<td>31</td>
<td>23</td>
<td>16</td>
</tr>
<tr>
<td>Drilling overbalance &gt;1000 psi</td>
<td>27</td>
<td>31</td>
<td>23</td>
<td>19</td>
</tr>
<tr>
<td>Completion overbalance &lt;300 psi</td>
<td>25</td>
<td>39</td>
<td>25</td>
<td>12</td>
</tr>
<tr>
<td>Completion overbalance &gt;300 psi &lt; 600 psi</td>
<td>21</td>
<td>36</td>
<td>21</td>
<td>21</td>
</tr>
<tr>
<td>Completion overbalance &gt;600 psi</td>
<td>47</td>
<td>21</td>
<td>5</td>
<td>26</td>
</tr>
</tbody>
</table>

This data is difficult to understand unless the attention is focused at those factors which deliver the most wells in the 100% to 75% efficiency range, e.g., underbalance perf w/surge chamber and wash perfs.
Notice that underbalance perforating at high underbalance (which causes flow) delivers a perforation that is from 40% to nearly 300% larger than the other methods of perforating.

**Table 4: Perforation Tunnel Volume Following Perforating at Different Conditions (Regalbuto and Riggs, SPE PE, Feb 1988)**

<table>
<thead>
<tr>
<th>Pressure Differential</th>
<th>Hole Volume, perforated</th>
<th>Hole Volume, perforated/surged</th>
</tr>
</thead>
<tbody>
<tr>
<td>Overbalanced, 500 psi, no surge</td>
<td>18 cc</td>
<td></td>
</tr>
<tr>
<td>Balanced perforated, no surge</td>
<td>31 cc</td>
<td></td>
</tr>
<tr>
<td>Underbalanced perforated, 500 psi</td>
<td>20 cc</td>
<td>42 cc</td>
</tr>
<tr>
<td>Balanced perforated, delayed 1000 psi surge</td>
<td>31 cc</td>
<td>48 cc</td>
</tr>
<tr>
<td>Underbalanced perforated, 1000 psi</td>
<td>50 cc</td>
<td>75 cc</td>
</tr>
</tbody>
</table>
Back to over-all damage – What is it?

• Divide the well into three parts:
  – Inflow: area from reservoir to the wellbore
  – Completion potential: flow to surface
  – Surface restrictions: chokes, lines, separators.

• Basically, anything that causes a restriction in the flow path decreases the rate and acts as “damage.”
Differential pressure, $\Delta P$, is actually a pressure balance

$\Delta P = 700$ psi drawdown pressure

Where does the $\Delta P$ come from?

- 10,000 ft
- 4600 psi

$\Delta P =$ $4600$ psi reservoir pressure
- $-2600$ psi flowing gradient for oil
- $-150$ psi press drop
- $-100$ psi through the choke
- $-25$ psi through the flow line
- $-10$ psi through the separator
- $-15$ psi through downstream flow line
- $-1000$ psi sales line entry pressure

Column Densities:
- Gas = 1.9 lb/gal = 0.1 psi/ft = $1000$ psi in a 10,000 ft well
- Dead oil = 7 lb/gal = 0.364 psi/ft = $3640$ psi in a 10,000 ft well
- Fresh water = 8.33 lb/gal = 0.433 psi/ft = $4330$ psi in a 10,000 ft well
- Salt water = 10 lb/gal = 0.52 psi/ft = $5200$ psi in a 10,000 ft well
- Gas cut flowing oil = 5 lb/gal = 0.26 psi/ft = $2600$ psi in a 10,000 ft well
The first step.....

• For the purposes of this work, consider the flow connection between the reservoir and the wellbore as the primary but not the only area of damage.

• Now, is it “formation damage” or something else that causes the restriction?
Some sources of the “damage” in the reservoir-wellbore “connection”

• Wetting phases (from injected or “lost” fluids)
• Debris plugging the pores of the rock
• Polymer waste from frac and drilling fluids
• Compacted particles from perforating
• Limited entry (too few perforations)
• Converging radial flow – wellbore too small
• Reservoir clay interactions with injected fluids
• Precipitation deposits (scale, paraffins, asphaltenes, salt, etc)

Note that not all are really formation damage – How do you identify the difference?
And some restrictions – in very high perm wells – is the casing and the very limited amount of open area that perforations create.

Data comparing cased and perforated skin with skins from open hole completed wells from Algeria.
Identification of Damage.

• How good are you at deductive reasoning?
  – Identifying the cause and source of damage is detective work.
    • Look at the well performance before the problem
    • Look at the flow path for potential restrictions
    • Look to the players:
      – Flow path ways
      – Fluids
      – Pressures
      – Flow rate
What is Completion Efficiency?

• A measure of the effectiveness of a completion as measured against an ideal completion with no pressure drops.

• Pressure drops? – these are the restrictions, “damage”, heads, back-pressures, etc. that restrict the well’s production.
Look again - The Effect of Damage on Production

\[
\text{Rate} = \frac{(\Delta P \times k \times h)}{(141.2 \ \mu_o \ \beta_o \ s)}
\]

Where:

- \( \Delta P \) = differential pressure (drawdown due to skin)
- \( k \) = reservoir permeability, md
- \( h \) = height of zone, ft
- \( \mu_o \) = viscosity, cp
- \( \beta_o \) = reservoir vol factor
- \( s \) = skin factor
What changeable factors control production rate?

- Pressure drop – need maximum drawdown and minimum backpressures.
- Permeability - enhance or restore k? - yes
- Viscosity – can it be changed? – yes
- Skin – can it be made negative?

- These factors are where we start our stimulation design.
Formation Damage

• Impact
• Causes
• Diagnosis
• Removal/Prevention?

• Basically, the severity of damage on production depends on the location, extent and type of the damage. A well can have significant deposits, fill and other problems that do not affect production.
Conclusions

• Damage is usually shallow.
• Remove it or by-pass damage if it really causes a problem.
• Not every “damage” is in the formation.
• Not every drop in production is caused by damage.
• First, remove the pressure drops, everything else will take care of itself.