Fracture fluids main functions

- Open the fracture
- Transport proppant

**Desirable features:**

1. Compatible with the formation and reservoir fluids
2. Provide good fluid loss control
3. Exhibit low friction pressures
4. Stable, break & clean rapidly
5. Economical
Fracture fluids history

Pre-1950s  oil-based
1950s      water-based with GUAR
1969       First crosslinked GUAR (with 10% oil)
1970s      HPG gelling agent

Currently

- 70% of treatments are water-based
- 25% are energized
- 5% are oil-based
Fracture fluids

**Water-based fluids**

**Advantages:**
- low cost,
- high performance,
- ease of handling

**Disadvantages:**
- water sensitive formations,
- damage due to polymers

**Polymers** – to viscosify fluids

1. **GUAR** – high molecular weight, long-chained sugars...natural (6-10% residue)
2. **HPG** – chemically-treated guar, cleaner (2-4% residue)
3. **HEC** – cellulose derivatives
**Crosslinkers** - to increase viscosity of fluid at higher temperatures (alternative to increasing polymer loading, but expensive)

<table>
<thead>
<tr>
<th></th>
<th>Borates</th>
<th>Titanate &amp; Zirconium</th>
</tr>
</thead>
<tbody>
<tr>
<td>Crosslinking</td>
<td>Fast</td>
<td>Controlled</td>
</tr>
<tr>
<td>Reversible</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>Shear degradation</td>
<td>No</td>
<td>Sensitive</td>
</tr>
<tr>
<td>Temp limit</td>
<td>&lt; 225 F</td>
<td>&lt; 325 F</td>
</tr>
<tr>
<td>Friction</td>
<td>High</td>
<td>Delayed system</td>
</tr>
<tr>
<td>PH</td>
<td>8-10 required</td>
<td>Variable</td>
</tr>
</tbody>
</table>
• An increase in T or pH will accelerate the crosslink reaction
• If crosslinking is too rapid then higher friction pressure and shear degradation occurs.
• If crosslinking too slow then proppant may settle in wellbore
• Desirable to have crosslink time = fluid time in wellbore
• Dual crosslink system
  – Fast to ensure adequate viscosity at perfs
  – Slow ensures viscous fluid in fractures
Fracture fluids

Oil-based fluids

Advantage:
– Application to water sensitive formations

Disadvantages:
– Costly
– Environmental and safety concerns
– Quality of gels is poor and residue is high
Foamed fluids

• Addition of CO$_2$ or N$_2$ to base fluid
• Foam Quality – volume of frac fluid that is foam
  – Range is 60 to 90 quality foam to be stable and have sufficient viscosity
  – Typical is 70 quality
**Foamed fluids**

**Advantages:**
- Improved flowback/cleanup performance
- Good proppant transport
- Low fluid loss thus applicable to sensitive formations
- CO\(_2\) enhances solubility of oil. Also, CO\(_2\) has higher density thus lower surface treating pressures.
- Nitrogen is less dense, however requires less to create foam, thus reduction in material costs.

**Disadvantages:**
- Costs
- Operational
- Sand concentration limit
<table>
<thead>
<tr>
<th>Fracture fluids additives</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Buffers</strong> - maintain pH</td>
</tr>
<tr>
<td><strong>Bactericides</strong> - prevent viscosity loss due to bacterial degradation</td>
</tr>
<tr>
<td><strong>Stabilizers</strong> - enhances stability of gels at higher temperatures</td>
</tr>
<tr>
<td><strong>Breakers</strong> - polymers break at defined temperature...need chemical breaker if temperature below this defined temperature.</td>
</tr>
<tr>
<td><strong>Surfactants</strong> - promotes formation of foams and promotes cleanup of fracturing fluid in the fracture</td>
</tr>
<tr>
<td><strong>Clay stabilizers</strong> - control formation of clay swelling and migration</td>
</tr>
<tr>
<td><strong>Fluid loss additives</strong> – reduce excessive fluid loss, thus minimize premature screenout. Types: silica flour, emulsions</td>
</tr>
</tbody>
</table>
### Fracture fluids additives

**Example**

SBHT: 130° F

**Frac Fluid Additives**

<table>
<thead>
<tr>
<th>Amount per 1000 gallons</th>
<th>Additive</th>
<th>Reason</th>
<th>Liq Powd</th>
<th>Pmix</th>
<th>Fly</th>
</tr>
</thead>
<tbody>
<tr>
<td>2 gals</td>
<td>M117</td>
<td>KCL</td>
<td>x</td>
<td></td>
<td>x</td>
</tr>
<tr>
<td>7.9 gals</td>
<td>J-877</td>
<td>Base gel; guar (35#)</td>
<td>x</td>
<td>x</td>
<td></td>
</tr>
<tr>
<td>1 gal</td>
<td>F-75N</td>
<td>Surfactant; nonionic</td>
<td>x</td>
<td>x</td>
<td></td>
</tr>
<tr>
<td>0.3 lbs</td>
<td>M-275</td>
<td>Bactericide; add before water</td>
<td>x</td>
<td>x</td>
<td></td>
</tr>
<tr>
<td>1.2 lbs</td>
<td>L-10</td>
<td>Borate crosslinker</td>
<td>x</td>
<td>x</td>
<td></td>
</tr>
<tr>
<td>0.5 gal *</td>
<td>U-28</td>
<td>Activator; 9.5-11 Ph Sys.</td>
<td>x</td>
<td></td>
<td></td>
</tr>
<tr>
<td>6.4 lbs *</td>
<td>J-479LT</td>
<td>Controlled release persulfate</td>
<td>x</td>
<td>x</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>brkr-Ramp down from Pad to 10#</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1-3 lbs *</td>
<td>J-218</td>
<td>Live persulfate breaker: 0.1 lbs/1000 pad thru 3#, Ramp up from 4#-10# stages</td>
<td>x</td>
<td>x</td>
<td></td>
</tr>
</tbody>
</table>
Fracture fluids mixing

- **Batch**
  - Mixed together on surface
  - Bactericide, polymer, salt, clay stabilizer...
  - Crosslinker is borate

- **Fly**
  - Mixed while job is pumping
  - Crosslinker is Titanate
  - Sodium Hydroxide to raise pH for borate crosslinkers
  - Breakers, fluid loss additives

** quality assurance vs cost
Fracture fluids design criteria

1. Formation temperature and fluid rheology
2. Treatment volume and rate
3. Type of formation
4. Fluid loss control requirements
5. Formation sensitivity to fluids
6. Pressure
7. Depth
8. Type of proppant
9. Fluid Breaking requirements
Fracture fluids

Definition: Science of the deformation and flow of matter

Most important variable... **viscosity** = f(γ, T, t, C)

Effect of temperature on the viscosity of a 40 lbm/1000 gal HPG solution (SPE Monograph Vol 12, 1989)
Newtonian Fluids

\[ \tau \{ \text{shear stress} \} = \mu_a \{ \text{apparent viscosity} \} \times \dot{\gamma} \{ \text{shear rate} \} \]

Apparent viscosity is constant
Non-Newtonian Fluids

Fracturing fluids typically follow the power law model, thus apparent viscosity is dependent on shear.

Significant in proppant transport and friction

\[ \tau = k \dot{\gamma}^n \]

where

- \( k \) = consistency index indicative of the pumpability of the fluid
  \{lb_f-sec^n/ft^2\} or \{47,900 Eq. cp\}/\{lb_f-sec^n/ft^2\}

- \( n \) = power index indicating the degree of non-Newtonian characteristics
Non-Newtonian Fluids

- Measure in lab with concentric, cylindrical viscometers...obtain n’ and k’.

- n = n’

\[
k_{slot} = k' \left(\frac{2n + 1}{3n}\right)^n
\]

\[
k_{pipe} = k' \left(\frac{3n + 1}{4n}\right)^n
\]
Non-Newtonian Fluids

- Drag reducing non-Newtonian fluids require correlations involving several experimentally determined parameters.
- Bowen’s relation:

\[
\tau_w = \frac{d \Delta p f}{4 L} = A d b \left( \frac{8v}{d} \right)^s
\]

- where \( A \{\text{lb}_f \cdot \text{sec}^s/\text{ft}^{2+b} \} \), \( b \), and \( s \) are the required experimental constants.
Fracture fluids

Fluid Loss/Leakoff

- Detrimental because it decreases the efficiency of the treatment
- Process
  - Filter cake – deposition of polymer or particulates
  - Filtrate invasion
  - Uninvaded zone

Uninvaded zone

$\Delta p_v$ is fracture wall interface pressure differential and $\Delta p_c$ is invaded zone to reservoir pressure differential.
Fracture fluids

Fluide Loss/Leakoff

Lab-derived

a. Viscosity-controlled mechanism
   - Applies to filtrate invasion
   - Corresponds to ideal case, i.e., no filter cake and minimum resistance between filtrate and reservoir fluids

\[ C_v = 0.0469 \sqrt{\frac{k \phi \Delta p_c}{\mu_f}} \left\{ \frac{ft}{\sqrt{\min}} \right\} \]

- \( k \) - effective formation permeability, D
- \( \phi \) - porosity
- \( \mu_f \) - fracturing fluid viscosity, cp
- \( \Delta p_c \) - differential pressure across the face of the fracture, psi; \( p_f - p_r \)
Fracture fluids

b. Compressibility-control mechanism

- Fluid filtrate has similar flow properties to reservoir fluids
- Reservoir total compressibility affects pressure

\[
C_c = 0.0374 \Delta p_c \sqrt{\frac{k c_t \phi}{\mu_r}} \left\{ \frac{\text{ft}}{\sqrt{\text{min}}} \right\}
\]

- \( \mu_r \) - reservoir fluid viscosity, cp
- \( c_t \) - total reservoir compressibility, psi\(^{-1}\)
Fracture fluids

Fluid Loss/Leakoff

c. Wall-building mechanism

- Cake building is proportional to volume passed through surface

\[ C_W = \frac{0.0164m}{A_f} \left\{ \frac{ft}{\sqrt{\text{min}}} \right\} \]

- \( m \): slope of filter loss curve (cc/min \( 1/2 \)) obtained from static filtration test
- \( A_f \): filter area, cm\(^2\)

Pressure differential correction,

\[ m_{act} = m \left( \frac{\Delta p_{act}}{\Delta p_L} \right)^{1/2} \]

where \( \Delta p_L \) is differential pressure of filtration test.
Fracture fluids

Temperature correction for titanate HPG gel,

\[
C_{w,corr} = \frac{C_w @ 80^\circ F}{\sqrt{\mu_w @ T_{res}}}
\]

Valid until thermal degradation occurs...~200 deg F for 30lb\textsubscript{m}/1000 gal loading
Static filtration test

Dynamic filtration tests are available but complex.

Volume Lost (static) < Volume Lost (Dynamic)
Fracture fluids

Fluid Loss/Leakoff

d. Combining Fluid loss coefficient, $C_T$
   i. Harmonic average...flow in series

$$\frac{1}{C_T} = \frac{1}{C_v} + \frac{1}{C_c} + \frac{1}{C_w}$$

*assumes fixed boundary between two regions

ii. Pressure balance

$$\{\text{fracture to formation}\} = \{\text{fracture wall to interface}\} + \{\text{interface to reservoir}\}$$

$$\Delta p_T = \Delta p_v + \Delta p_c$$

$$C_T = \frac{2C_cC_vC_w}{C_vC_w + \sqrt{C_w^2C_v^2 + 4C_c^2C_v^2 + 4C_c^2C_w^2}}$$
e. Leakoff volume

i. When $C_w$ dominates

$$V_{\text{leakoff}} = V_{sp} + 2C_w \sqrt{t} \quad \{\text{volume/unit area}\}$$

where,

$$V_{sp} = \frac{b_{\text{int}}}{A_f}$$

units usually defined as gals/ft$^2$

ii. When $C_{vc}$ dominates

$$V_{\text{leakoff}} = C_T \ast \sqrt{t}$$
Fluid loss comparison between foamed fluids and conventional crosslinked gels (SPE Monograph Vol 12, 1989)
Fracture fluids

Example:

Calculate the fracturing fluid coefficient for the data given below:

- formation effective permeability = 15 md
- formation porosity = 9 %
- formation fluid viscosity = 1.5 cp
- oil compressibility = $11 \times 10^{-6}$ psi $^{-1}$
- oil saturation = 0.61
- gas compressibility = $530 \times 10^{-6}$ psi $^{-1}$
- gas saturation = 0.12
- wtr compressibility = $3 \times 10^{-6}$ psi $^{-1}$
- slope of filtration curve = $1.4$ cc/min $^{1/2}$
- filter area = $22.8$ cm$^2$
- filtration test differential pressure = 1000 psi
- fracturing treating pressure = 5500 psi
- reservoir pore pressure = 2100 psi
- fracturing fluid viscosity @ reservoir = 2.8 cp.
**Field Derived** from pressure decline analysis

\[
C_T = \frac{m_p \beta_s}{r_p \sqrt{t_p E'}} \left\{ h_f \begin{array}{c} \text{PKN} \\ 2x_f \end{array} \begin{array}{c} \text{KGD} \end{array} \right\}
\]

where

- \( m_p \) - slope of \( pw \) vs. \( G(\Delta T_D) \) plot
- \( \beta_s \) - represents pressure gradient in fracture during closure

\[
\beta_s = \frac{2n + 2}{2n + 3 + a} \quad \text{PKN}
\]

\[
\beta_s = 0.9 \quad \text{KGD}
\]

- \( a \) - degree of reduction in viscosity from the wellbore to the fracture tip
  - \( a = 0 \) constant viscosity profile
  - \( a = 1 \) linearly varying viscosity

- \( r_p \) - ratio of permeable formation thickness (\( h_n \)) to fracture thickness (\( h_f \))
- \( t_p \) - pumping time
- \( E' \) - plain strain modulus = \( E/(1-v^2) \)
- \( P_w \) - well pressure
Conversion of Laboratory Data to a Field Leakoff Coefficient

1. Use a lab-derived spurt loss and $C_w$ that is characteristic of the fluid package and for a specific formation permeability and temperature.

   Most common...

2. Use a simulator to handle multiple fluid parameters

3. Use a model to account for variable downhole conditions
Comparison of Laboratory and Field Leakoff Coefficients

Observation: In general, $C_{\text{field}} > C_{\text{Lab}}$