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
<table>
<thead>
<tr>
<th>Era</th>
<th>Type</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pre-1950s</td>
<td>oil-based</td>
</tr>
<tr>
<td>1950s</td>
<td>water-based with GUAR</td>
</tr>
<tr>
<td>1969</td>
<td>First crosslinked GUAR (with 10% oil)</td>
</tr>
<tr>
<td>1970s</td>
<td>HPG gelling agent</td>
</tr>
</tbody>
</table>

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

**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
- CO₂ enhances solubility of oil. Also, CO₂ 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
Fracture fluids

- Buffers - maintain pH
- Bactericides - prevent viscosity loss due to bacterial degradation
- Stabilizers - enhances stability of gels at higher temperatures
- Breakers - polymers break at defined temperature...need chemical breaker if temperature below this defined temperature.
- Surfactants - promotes formation of foams and promotes cleanup of fracturing fluid in the fracture
- Clay stabilizers - control formation of clay swelling and migration
- Fluid loss additives – reduce excessive fluid loss, thus minimize premature screenout. Types: silica flour, emulsions
## Fracture fluids

### Example

<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>x</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>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

- **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

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

Apparent viscosity is constant
Fracture fluids

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:

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

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

• Detrimental because it decreases the efficiency of the treatment

• Process
  – Filter cake – deposition of polymer or particulates
  – Filtrate invasion
  – Uninvaded zone

\[ \Delta p_v \text{ fracture wall interface pressure differential} \]
\[ \Delta p_c \text{ invaded zone to reservoir pressure differential} \]

• where \( \Delta p_v \) is fracture wall interface pressure differential and \( \Delta p_c \) is invaded zone to reservoir pressure differential.
Fracture fluids

**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; \(p_f - p_r\)
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\(^{-1}\)
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.
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
      
      \[
      \Delta p_T = \Delta p_v + \Delta p_c
      \]

      \[
      C_T = \frac{2C_cC_vC_w}{C_vC_w + \sqrt{C_w^2C_v^2 + 4C_c^2(C_v^2 + C_w^2)}}
      \]
Fracture fluids

**Fluid Loss/Leakoff**

e. Leakoff volume

i. When $C_w$ dominates

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

where,

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

units usually defined as gals/ft$^2$

ii. When $C_{vc}$ dominates

$$V_{\text{leakoff}} = C_T \sqrt{t}$$
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:

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>formation effective permeability</td>
<td>= 15 md</td>
</tr>
<tr>
<td>formation porosity</td>
<td>= 9 %</td>
</tr>
<tr>
<td>formation fluid viscosity</td>
<td>= 1.5 cp</td>
</tr>
<tr>
<td>oil compressibility</td>
<td>= 11 \times 10^{-6} \text{ psi}^{-1}</td>
</tr>
<tr>
<td>oil saturation</td>
<td>= 0.61</td>
</tr>
<tr>
<td>gas compressibility</td>
<td>= 530 \times 10^{-6} \text{ psi}^{-1}</td>
</tr>
<tr>
<td>gas saturation</td>
<td>= 0.12</td>
</tr>
<tr>
<td>wtr compressibility</td>
<td>= 3 \times 10^{-6} \text{ psi}^{-1}</td>
</tr>
<tr>
<td>slope of filtration curve</td>
<td>= 1.4 \text{ cc/min}^{1/2}</td>
</tr>
<tr>
<td>filter area</td>
<td>= 22.8 cm^2</td>
</tr>
<tr>
<td>filtration test differential pressure</td>
<td>= 1000 psi</td>
</tr>
<tr>
<td>fracturing treating pressure</td>
<td>= 5500 psi</td>
</tr>
<tr>
<td>reservoir pore pressure</td>
<td>= 2100 psi</td>
</tr>
<tr>
<td>fracturing fluid viscosity @ reservoir</td>
<td>= 2.8 cp.</td>
</tr>
</tbody>
</table>
Viscosity-controlled mechanism, $C_V$

$$C_V = 0.0469 \sqrt{\frac{k \phi \Delta p_c}{\mu_f}} \left\{ \frac{ft}{\sqrt{\text{min}}} \right\}$$

$k = 0.015$ D

$\phi = 0.09$

$\mu_f = 2.8$ cp

$\Delta p_c = p_f - p_r = 5500 - 2100 = 3400$ psi

$C_V = 0.0600$ ft/sqrt(min)
Compressibility-control mechanism, $C_c$

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

$\mu_r = 1.5 \text{ cp}$

$k = 0.015 \text{ D}$

$\phi = 0.09$

$\Delta p_c = p_f - p_r = 5500 - 2100 = 3400 \text{ psi}$

$c_t = S_o c_o + S_w c_w + S_g c_g + c_f \{\text{psi}^{-1}\}$

$$= 71.1 \times 10^{-6} \text{ psi}^{-1}$$

$C_c = 0.032 \text{ ft/sqrt(min)}$
Wall-building mechanism, $c_w$

$$C_w = \frac{0.0164m}{A_f} \left\{ \frac{ft}{\sqrt{\text{min}}} \right\}$$

$m = 1.4 \ (\text{cc/min}^{1/2})$

$A_f = 22.8 \ \text{cm}^2$

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

$m_{act} = 4.76 \ (\text{cc/min}^{1/2})$

$$C_w = 0.0034 \ \text{ft/sqrt(min)}$$
Combining Fluid loss coefficient

i. combined viscosity-compressibility coefficients

\[ C_{vc} = \frac{2C_c C_v}{C_v + \sqrt{C_v^2 + 4C_c^2}} \]

\[ C_{vc} = 0.026 \text{ ft/sqrt(min)} \]

ii. Plus wall building coefficient

\[ C_T = \frac{2C_c C_v C_w}{C_v C_w + \sqrt{C_w^2 C_v^2 + 4C_c^2 \left( C_v^2 + C_w^2 \right)}} \]

\[ C_T = 0.003 \text{ ft/sqrt(min)} \]

\[ C_c = 0.032 \text{ ft/sqrt(min)} \]

\[ C_v = 0.0600 \text{ ft/sqrt(min)} \]

\[ C_w = 0.0034 \text{ ft/sqrt(min)} \]

\[ C_{vc} = 0.026 \text{ ft/sqrt(min)} \]
Leakoff volume after 60 minutes exposure to fracture fluid

i. When $C_w$ dominates

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

\[ = 0 + 2 \times 0.0034 \frac{\text{ft}}{\sqrt{\text{min}}} \times \sqrt{60 \text{ min}} \]

\[ = 0.053 \text{ ft} \times 7.48 \frac{\text{gal}}{\text{ft}^3} \]

\[ = 0.40 \frac{\text{gal}}{\text{ft}^2} \]

ii. When $C_{vc}$ dominates, then $C_T \simeq C_{vc}$

\[ V_{\text{leakoff}} = C_T \sqrt{t} \]

\[ = 1.51 \text{ gal} / \text{ft}^2 \]
Fracture fluids

Example
A given fracturing fluid was tested in a filter press with an area of 22.8 cm$^2$ at 1000 psig and the following data recorded,

<table>
<thead>
<tr>
<th>Time (min)</th>
<th>Filtrate Volume (cc)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>4</td>
</tr>
<tr>
<td>4</td>
<td>6</td>
</tr>
<tr>
<td>16</td>
<td>10</td>
</tr>
<tr>
<td>25</td>
<td>12</td>
</tr>
<tr>
<td>30</td>
<td>13</td>
</tr>
</tbody>
</table>

This fracturing fluid is to be used in a 6000 ft. well with a static bottom hole pressure of 2200 psig. From previous fracture jobs in the area, the fracture gradient has been found to be 0.65 psi/ft.

Find:
The fracturing fluid coefficient
The fluid efficiency for a treatment volume of 30,000 gals and an injection rate of 30 bpm.
The fracture area if average width is given to be 0.27 in.
The fracture length if fracture height is 100 ft.
1. Calculate $C_w$

$$C_w = \frac{0.0164m}{A_f} \left\{ \frac{ft}{\sqrt{\text{min}}} \right\}$$

$m = 2.006 \text{ (cc/min}^{1/2}\text{)}$

$A_f = 22.8 \text{ cm}^2$

$C_w = 0.00144 \text{ ft/min}^{1/2}$

Correction for $\Delta p$

$P_{\text{static}} = 2200 \text{ psi}$

$P_f = 6000(0.65)=3900 \text{ psi}$

$m_{\text{act}} = 2.615 \text{ (cc/min}^{1/2}\text{)}$

$C_w = 0.00188 \text{ ft/min}^{1/2}$
Fracture Area

- fracture is uniform width
- Flow of fracture fluid into formation \( (q_L) \) is linear & \( \perp \) to fracture face
- Average velocity into formation \( f \)(exposure time)
- The velocity function is constant, but the initial time varies with the time the fluid reaches the given point
- Pressure in fracture = sandface injection pressure (no fracture friction)

\[
A(t) = \frac{q_i \bar{w}}{4\pi C^2} \left[ e^{x^2} \text{erfc}(x) + \frac{2x}{\sqrt{\pi}} - 1 \right]
\]

where

\[
x = \frac{2C\sqrt{\pi t}}{w}
\]
Fracture Area

\[ A(t) = \frac{q_i \overline{w}}{4\pi C^2} \left[ e^{\frac{x^2}{2}} \text{erfc}(x) + \frac{2x}{\sqrt{\pi}} - 1 \right] \]

where

- \( A(t) \) - the area of one fracture face, \( \text{ft}^2 = 2x_f h_f \)
- \( q_i \) - injection rate, \( \text{ft}^3/\text{min} \)
- \( \overline{w} \) - average width, \( \text{ft} \)
- \( C \) - total fluid loss coefficient, \( \text{ft/\text{min}}^{1/2} \)
- \( t \) - time, \( \text{min} \)
- \( \text{erfc}(x) \) - complementary error function

\[
\text{erfc}(x) = \frac{2}{\sqrt{\pi}} \int_x^\infty e^{-t^2} \, dt = 1 - \frac{2x}{\sqrt{\pi}} \left[ 1 - \frac{x^2}{1!3} + \frac{x^4}{2!5} - \frac{x^6}{3!7} + \ldots \right]
\]

\[ x = \frac{2C\sqrt{\pi t}}{w} \]
2. Calculate Fluid Efficiency

\[ \eta = \frac{V_f}{V_i} = \frac{\text{WA}(t)}{q_i t} \]

\[ \eta = \frac{1}{x^2} \left[ e^{x^2} \text{erfc}(x) + \frac{2x}{\sqrt{\pi}} - 1 \right] \]

\[ x = \frac{2C\sqrt{\pi t}}{w} = \frac{2(0.00188)\sqrt{\pi(23.8)}}{.27/12} = 1.445 \]

thus \( \text{erfc}(x) = 0.041 \) and \( \eta = 46\% \)
3. Calculate fracture area

\[ A(t) = \frac{\eta V_i}{w} = \frac{0.46(30,000)(0.1337)}{0.27/12} = 82,000 \text{ ft}^2 \]

4. Calculate fracture half length

\[ A = 2x_f h_f \]

\[ 82,000 = 2x_f (100) \]

\[ x_f = 410 \text{ ft} \]
Fracture fluids

Impact of spurt loss

\[ V_{sp} = \frac{b_{int}}{A_f} = \frac{1.9879 \text{cc}}{22.8 \text{cm}^2} \cdot \frac{\text{ft}}{30.48 \text{cm}} \cdot \frac{7.48 \text{gal}}{\text{ft}^3} = 0.021 \text{ gal/ft}^2 \]

\[ V_{leakoff} = V_{sp} + 2C_w \sqrt{t} \]

\[ = 0.021 + 2 \times 0.00188 \frac{\text{ft}}{\sqrt{\text{min}}} \times \sqrt{23.8 \text{ min} \times 7.48} \]

\[ = (0.021 + 0.137) \frac{\text{gal}}{\text{ft}^2} \]

\[ = 0.158 \frac{\text{gal}}{\text{ft}^2} \]

\[ \eta = ? \]

\[ A = ? \]
Fracture fluids

Field Derived from pressure decline analysis

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

where

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

\[
\beta_S = \frac{2n + 2}{2n + 3 + a}
\]

- \( a \) - 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, $C_{\text{field}} > C_{\text{Lab}}$