Keynote Address
Using Chemistry of Proppants and Fluids to Optimize Hydraulic Fracturing Performance

Glenn S. Penny, Ph.D
Director of Technology MENA and Asia
Flotek Industries FZE

Providing Quality and Service to the Global Oilfield
Evolution of Hydraulic Fracturing

17 March 1949
Duncan, OK
1st fracturing by Halliburton for Stanolind Oil Co.

Present

Source: Montgomery & Smith 2019

Keynote • Fluids and Proppants • Glenn Penny Flotek Industries
Shale Fracturing headlines are often taken by mechanical and physical methods to increase performance: Volume, rate well position

Shale “Waterfrac Volumes” seismic work shows the fracture network length grows with volume. Average is 24,000 bbl or 1 million gal per frac with 10 to 12 fracs.
Better Rates? - What Works?

Closer Well Spacing and Simul Fracs

Better Primary & Secondary Frac Intersection to Wellbore.

Selecting Perfs based on potential not average distance.

We are going to look at the Chemistry of the fluid and Proppant to see what matters

Fluid additive selection needs to take into account:

- Tubulars and pumping rate and pressures
- TDS of water being used
- Percentage of clays.
- Potential generation of fines both siliceous and organic
- Acid solubility
- Need viscoelasticity for proppant transport
- Microbiological activity – need compatible biocides
- Potential for scale generation – may need scale inhibitor
- Problem with recovering injected fluids
Friction Flow Loop Data
Comparison of 1.0 gpt of Cationic Friction Reducers
4% NaCl, 7% KCl, or 7% (wt) CaCl₂
Tubing dimension - 1/2" OD - 0.402" ID
Flow Rate: 5 gpm

Selection of FR chemistry becomes important as TDS increases

SPE 119900  Kaufman and Penny “Critical Evaluation of Additives used is Shale Fracturing”
Shale column flow tests showing effectiveness of KCl and clay stabilizers in 20/40 sand and shale

Without stabilization the permeability drops Over 50% in less than 1 hr.

SPE 111063  Paktinat and Penny “Methods To Improve Fracturing of the Utica Shale”
Factors Influencing Proppant Performance

- Proppant Permeability vs type size and closure
- Influence of embedment, pressure cycling and multiphase non-Darcy Flow
- Frac fluid Damage
- Capillary Pressure in the proppant pack vs proppant type and size, closure and surfactant type and concentration
- Position of the lateral within the pack: Impact of fracture flow orientation on relative perm of pack
- Impact of gelling agents, surfactant type and concentration on the relative permeability profile vs proppant type and size and orientation: Rel perm of the pack correlates with production

Keynote • Fluids and Proppants • Glenn Penny Flotek Industries
Proppant types available

- Ceramic
  - Uniform size/shape enhances conductivity of proppant pack
- Silica sand
  - Broadly sized, irregular shaped, tightly packed grains reduce conductivity

Chinese proppant feedstock mixers
Proppant Selection vs Performance

Keynote • Fluids and Proppants • Glenn Penny Flotek Industries
Proppant Permeability vs size and closure at 250 F. Perm ranges from 100 Darcies for Ceramic to as low as 1 Darcy for 100 mesh at 10,000 psi.
Fracturing: Ceramic proppant fracture damage – embedment and diagenesis

Penny et al. StimLab Proppant Consortium
Residual Frac fluid Damage

- Many of the crosslinked fluids used today tend to leave 50 to 75% damage of the proppant pack.
- This can be alleviated with an aggressive breaker schedule which impacts proppant transport.
- As a result in the US mostly slick water fracs are pumped to maximize reservoir contact and minimize residual frac fluid damage.
- FR’s or PAM have some viscoelasticity that can contribute to proppant transport.
Impact of Embedment: Softer rocks lower conductivity of 1 lb/sq ft by 42%

<table>
<thead>
<tr>
<th>Closure Stress</th>
<th>CONDUCTIVITY (md-ft)</th>
<th>20/40Badger 1.0lb/sqft-250°F</th>
<th>20/40Badger 1.0lb/sqft-250°F</th>
<th>20/40 Lt Wt lb/sqft-250°F</th>
<th>20/40 Lt Wt 1.0lb/sqft-250°F</th>
</tr>
</thead>
<tbody>
<tr>
<td>psi</td>
<td></td>
<td>1.0lb/sqft-250°F</td>
<td>20/40 Lt Wt</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Youngs Mod E6 psi</td>
<td></td>
<td>2000</td>
<td>4000</td>
<td>6000</td>
<td>8000</td>
</tr>
<tr>
<td></td>
<td></td>
<td>5.00</td>
<td>2133</td>
<td>1429</td>
<td>543</td>
</tr>
<tr>
<td></td>
<td></td>
<td>1.00</td>
<td>1262</td>
<td>846</td>
<td>321</td>
</tr>
<tr>
<td></td>
<td></td>
<td>5.00</td>
<td>3456</td>
<td>2856</td>
<td>2041</td>
</tr>
<tr>
<td></td>
<td></td>
<td>1.00</td>
<td>2011</td>
<td>1662</td>
<td>1188</td>
</tr>
<tr>
<td></td>
<td></td>
<td>2000</td>
<td>4000</td>
<td>6000</td>
<td>8000</td>
</tr>
<tr>
<td></td>
<td></td>
<td>189</td>
<td>112</td>
<td>1195</td>
<td>695</td>
</tr>
<tr>
<td></td>
<td></td>
<td>75</td>
<td>44</td>
<td>704</td>
<td>410</td>
</tr>
<tr>
<td></td>
<td></td>
<td>17</td>
<td>10</td>
<td>357</td>
<td>208</td>
</tr>
<tr>
<td>% Decline</td>
<td></td>
<td>41%</td>
<td>42%</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Decline in Conductivity with cycling from 8000 to 4000 psi at 250°F.
Multiphase non-Darcy Flow Conductivity Reduction Factor vs Bbl of Liquid produced per day. 20 Bbbl of liquid lowers effective conductivity another factor of 10.

50 ft high frac with 1 lb/sq ft at 8000 psi closure and 250 F
And 4000 psi res pressure

Keynote • Fluids and Proppants • Glenn Penny Flotek Industries
Impact of proppant diagenesis on productivity
(Weaver 2010)

Can be prevented by the addition of scale inhibitor
Estimation of Capillary Pressure in a proppant pack

\[ p_{cap} = \frac{2\sigma \cos \theta}{r} \]

\[ F_{cap} = \pi r_1^2 \sigma \left( 1 - \frac{r_1}{r_2} \right) \]

\[ p_{cap} = \frac{2 \times 72 \text{ dynes/cm} \times 1.0}{\sqrt{k \text{ Darcies} \times 0.987E - 8 \text{ cm} \times 6895}} \]
Capillary Pressure ($P_{cap}$) of proppant pack vs size and closure at 250 F: As high as 10 to 12 psi

In a 100 ft high frac as much as 1200 psi is required to mobilize water due to $P_{cap}$
Why is this important? Simulations of gas production at various $p_c$ show 2-3 fold increase in gas rate by decreasing $P_c$ in proppant from 10 psi down to 0-1 psi.

- $p_c = 0$ psi
- $p_c = 5$ psi
- $p_c = 10$ psi
- $p_c = 20$ psi
Surfactant Selection becomes extremely Important

- Surfactants lower the cap pressure in the pack
- Conventional surfactants lower surface tension of water from 72 to 33 dynes/cm
- At reservoir conditions of 250 F surface tension is 44 without surfactant and 18 with conventional surfactants
- However adsorption is a big issue in the pack and formation
- Formulating into a CnF insures keeping the Pc low
Patented Complex nano Fluid (CnF®)

CnF® technology combines surfactants and solvent in a nanoscopic structure

10-20 nm droplet
Heads out tails in the solvent

Can add other components to the nano droplet
– Shale Stabilizers
– Demulsifiers
– Foamers, asphaltene paraffin solvents inhibitors

• CnF® has been applied in several applications
  – Drilling: Drilling Fluid Cleanup
  – Fracturing, Acidizing
  – Remediation
  – IOR/EOR

http://quatemol.sourceforge.net
Advantages of CnF over common Surfactants

1. CnF liquid liquid interface means the surfactant is less likely to adsorb on the invaded matrix. This means more surfactant is available at the oil/water or gas water interface as the treating fluid enters the reservoir.

2. This allows invaded fluid to be displaced at half of the pressure increasing rel perm to gas.

AE=Alcohol Ethoxylate
FS=Fluor surfactant
NP=nonylphenol
Ethoxylate

Keynote • Fluids and Proppants • Glenn Penny Flotek Industries
Cleanup and Load Recovery in Transverse Horizontal Fractures is Affected by Gravity, Viscous, and Capillary Forces

Flow downward, co-current at any rate, assisted by gravity. Lower Sw, better recovery and gas perm.

Possible water coning around well causing further damage?

Flow upward, co-current at high rates, counter-current at low rates, hindered by gravity. Higher Sw, poor load recovery, and low gas perm.

Keynote • Fluids and Proppants • Glenn Penny Flotek Industries
GRAVITY Fluid Recovery Results 30/50 sand and ceramic
With and without 2 gpt CnF in 20 in long by 1 in diameter column

Saturation increases toward bottom of pack

Keynote • Fluids and Proppants • Glenn Penny Flotek Industries
Downward Flow \% Water left in a 20 in column vs proppant size with water, conventional surfactant and CnF

As much as 90\% of the Water is left in the pack With 100 mesh Leaving rel perm<0.1
The data is modeled using a mobility ratio with Pcap to calculate fractional flow of water and gas and rel perm vs orientation.
Pcap Entry pressure = 0-1 psi
20/40 Ceramic

Flow through entire pack
30-40% Sw

Keynote • Fluids and Proppants • Glenn Penny Flotek Industries
Pcap Entry pressure = 4 psi
40/70 Sand

40% water blocked
Intermittent flow

Saturation of Displaced Phase [-]

Normalized Position [-]

Time Step [s]
- 1451.41
- 2755.79
- 3905.62
- 4623.33

Keynote • Fluids and Proppants • Glenn Penny Flotek Industries
Pcap Entry pressure = 10 psi
Mix of 40/70+ 100 mesh

90% water blocked
Channel flow
Upflow % Water left in 20 in column vs proppant type with water conventional surfactant and CnF

As much as 80% of the Water is left in the pack Leaving rel perm<0.2
Conversion of water saturation to relative permeability to gas

![Graph showing the conversion of water saturation to relative permeability to gas.](image)
Complex Nanofluid
4X better than no surfactant

Conventional Surfactant
2X better than water alone

Water

SPE 119152 Penny et al

Krg vs Conductivity, Surfactant & Transverse Frac Wellbore Position

Glenn Penny Flotek Industries
Example of landing and perforating to keep frac Growth above the wellbore
Field Validation and proppants and fluids \textit{with} RPI®

Data normalized for $kh$, Amount of proppant
Pressure Draw down

Jim Crafton Performance Sciences Inc
SPE 123280

Keynote • Fluids and Proppants • Glenn Penny Flotek Industries
Fracturing: Normalized Production with and without CnF® on Shale Gas Production vs proppant. CnF wells produce 2 to 3 times more gas than conventional surfactants. Higher conductivity proppants are even better.

Data indicates
Keep 100 mesh as low as possible <10% of total proppant

SPE 119152 Penny et al
To compare the lab data to the field data, it must be converted to reservoir conditions

\[ P_{\text{cap (res)}} = P_{\text{cap (lab)}} \times \frac{\sigma \cos \theta \text{(res)}}{\sigma \cos \theta \text{(lab)}} \]

- Assume contact angle is constant with temperature
- The interfacial tension of water and air in the lab is 72 dynes/cm, while it is 44 dynes/cm at 250\(^\circ\) F and in brine.
- This provides a ratio of 0.6
- And a change to relative permeability of about 1.3
- The adjusted relative permeability versus conductivity relationship nicely follows the trend of the normalized field production vs. conductivity
Normalized field production vs lab rel perm adjusted for temperature and wellbore position shows the range field data possible based on wellbore position.

SPE 119152 Penny et al
Conclusions

• The permeability and capillary pressure of proppants in the fracture has been calculated from permeability at reservoir conditions of time at stress and temperature and with embedment, cycling, frac fluid damage and non-Darcy flow

• Frac fluid selection based on water quality and shale stabilization are important to ultimate well productivity

• The relative permeability to hydrocarbon can range from 0.05 to 0.8 depending on the permeability, capillary pressure, surfactant and wellbore position

• The production of 240 wells was normalized based on reservoir quality, drawdown and treatment stages and sizes. Production and effective fracture length shows a clear dependence on the conductivity of the proppant placed in low permeability shale reservoirs
Conclusions

• There is a **7-fold increase** in production and effective fracture length with 20/40 or better proppants vs. 100 mesh with common surfactants.

• There is a **30-fold benefit** between 100 mesh and 20/40 or better when surfactant formulated into a complex nano-fluid is employed at 0.15% or greater.

• The relative permeability in upward and downward column tests vs. proppant type is useful in predicting the production range to be expected with various additives in transverse horizontal fractures vs. wellbore position.
Thank You / Questions