Surface Area vs. Conductivity Type Fracturing Treatments in Shale Reservoirs

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Outline

• Objective
• Introduction
  – Surface area and Conductivity type fracture treatment
• Required testing to determine stimulation type in Shales
• Fracture treatment types and selection criteria guidelines
• Case history
• Conclusions
Objective

• Provide guidelines to choose between a surface area and a conductivity type fracture treatment in shales with case histories
  – Avoid costly trial and error approach
Introduction

• Shale Definition
  – Organic rich fine grained sedimentary rocks that contain a minimum of 0.5 wt% total organic carbon (TOC) with a mean grain size of less than 0.0625 mm

• Organic matter defines gas or oil shale
  – Crossplot of Hydrogen index vs. Oxygen index (Van Krevelen, 1961)
Introduction (contd..)
• Shale reservoir quality determines the economic potential of the play.
  – So, the first objective in developing a shale play is to understand the reservoir quality from cores and logs

• Then the challenge is to produce these shales economically.
• Shales have very low flow capacity
  – Requires some sort of stimulation to make them economically viable

• Since early 1990 a lot of work has been published on shale stimulation
  – Lancaster et al in 1992 presented the evolution of massive hydraulic fracturing in the Barnett shale
  – Shelley et al in 2008 investigated 393 Barnett shale well completions in their work.
    • They showed that it took 17 years in the Barnett shale to evolve from pumping crosslinked fluid systems to waterfracs
    • They also found out that waterfracs outperformed crosslinked fluid systems
    • Good and Bad
Operators in other shale plays are still attempting “Barnett type waterfracs” with mixed success.

Such mixed success shows that “Barnett type waterfracs” may not work in all shale plays.

In some shales (i.e. Barnett) “surface area” type frac treatments work well and others might need a conductivity type fracture treatment.

- Understand the reservoir and optimize the completions accordingly.
Introduction (contd..)

• Shale play evolution – a comparison to the development of CBM

• In this work, guidelines are provided to choose between the two types of fracture treatment.

• Guidelines based on
  – Core and log analysis
  – Fluid sensitivity tests
  – Brinell hardness test
  – Unpropped fracture conductivity test and
  – DFIT’s
Testing requirements to determine stimulation type

- **Capillary Suction Test (CST)**
  - Qualitative fluid sensitivity
- **Fluid sensitivity with ULPTA**
  - Quantitative
- **Brinell Hardness Test (BHN)**
  - Indicates whether the rock is hard or soft with and/or without fluid contact
  - Potential for embedment
- **Unpropped fracture conductivity test (UFCT)**
  - Determines the conductivity of the unpropped fracture
- **Diagnostic Fracture Injection Test (DFIT)**
  - Leakoff type, time to closure, PZS, PDL
Capillary Suction Time Test (CST)
Fluid Sensitivity with ULPTA

Salt Sensitivity Testing

Permeability, micro-darcy

Time, hours

6% NaCl
3% NaCl
Freshwater
Brinell Hardness Test (BHN)

\[ BHN = \frac{2F}{\pi D \left( D - \sqrt{D^2 - D_1^2} \right)} \]

Shale BHN Comparisons
Unpropped Fracture Conductivity Test (UFCT)

Eagle Ford Shale
Fracture Conductivity & Pressure Response

- 180 °F
- 105 μd-ft (7% KCl)
- 101 μd-ft (3% NaCl)
- 227 μd-ft (Gas)
- 2607 μd-ft (Hexane)
- 122 μd-ft (1% NaCl)
- 51 μd-ft (Fresh Water)

Conductivity (μd-ft), Rate (mL/min), Net Confining Stress (psi)

- Hexane
- 7% KCl
- 3% NaCl
- 1% NaCl
- Fresh Water
- Nitrogen
- NCS
- Conductivity
- Rate

CST Ratio

- 6% - 70 Mesh

Conductivity (μd-ft)

- 7% KCl
- 3% KCl
- 3% NaCl
- 5% NH4Cl
- Fresh Water
Diagnostic Fracture Injection Test (DFIT)

Haynesville Shale
G Function Derivative Analysis Plot

Mancos-SPE 123581

Gothic-SPE 123581
Fracture Treatment Type and Selection Criteria

- Two different types of fracture treatments were discussed (assuming that the shale reservoir characteristics have been analyzed and the potential exists)
  - Surface area and
  - Conductivity type
Surface Area Type Fracture Treatment

- “Barnett type waterfracs”
- Large volumes of water with small quantities of sand
- Majority of the sand used is either 100 mesh or 40/70 mesh sand
- Contact as much surface area as possible and create dendritic type fractures (residual unpropped fracture conductivity should be high)

<table>
<thead>
<tr>
<th>Fluid System</th>
<th>Clean Volume (gallons)</th>
<th>Proppant Concentration (ppg)</th>
<th>Proppant Type</th>
<th>Rate (bpm)</th>
<th>Proppant Total (lbs)</th>
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<td>15% FE Acid</td>
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<tr>
<td>15% FE Acid</td>
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<tr>
<td>FR Water</td>
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<td>FR Water</td>
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<td>Premium White-40/70</td>
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<td>25000</td>
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<tr>
<td>FR Water</td>
<td>100000</td>
<td></td>
<td></td>
<td>60</td>
<td>90000</td>
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</table>
Surface Area Type Fracture Treatment (contd..)

• Reason why these treatments have been successful is because the permeability of the created fracture is significantly higher than the matrix reservoir permeability.

• For example the permeability \((k, \text{ md})\) of a fracture with a certain width \((w, \text{ ft})\) is given by Craft and Hawkins as

\[
k = 7.7 \times 10^{12} w^2
\]

Permeability of a 1 mm (0.04 inches) wide fracture can then be estimated using this equation

\[
k = 7.7 \times 10^{12} \left(\frac{0.04}{12}\right)^2
\]

\[k \approx 85,555 \text{ darcies}\]
The objective of the surface area treatment is to create such dendritic fractures that can stay open under the varying stress conditions. The lower mesh proppants used in these fracture treatments are an attempt to keep these dendritic fractures open.
Surface Area Type Fracture Treatment (contd..)

- Selection Criteria:
  - good brittleness from the petrophysical analysis,
  - high BHN (dry & wet); potential for embedment is low,
  - high unpropped fracture conductivity
  - PDL or transverse storage type leakoff from DFIT and
  - G-time to closure can be high.
Conductivity Type Fracture Treatment

- “Conventional” type treatment

- More sand is pumped in conjunction with fluid to obtain higher residual dynamic conductivity.

- Generic hybrid type design is shown here

- Reservoir has to be conducive for such treatments.

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<th>Proppant Type</th>
<th>Rate (bpm)</th>
<th>Proppant Total (lbs)</th>
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<tr>
<td>Reactive Fluid Pad</td>
<td>5000</td>
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<td>FR Water Pad</td>
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<tr>
<td>FR water Pad</td>
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<td>0.5</td>
<td>Premium White-40/70</td>
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<td>90000</td>
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<tr>
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<td>Premium White-20/40</td>
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<td>60000</td>
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<td>4</td>
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<td>16000</td>
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<td>15</td>
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<td>216000</td>
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<td>288500</td>
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<td><strong>Conductivity Type Fracture Treatment (contd..)</strong></td>
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<td>--------------------------------------------------</td>
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<tr>
<td><strong>Selection Criteria:</strong></td>
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<tr>
<td>– good brittleness (or even ductility) from the petrophysical analysis,</td>
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<tr>
<td>– low BHN; potential for embedment is high,</td>
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<td></td>
<td></td>
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<tr>
<td>– low residual unpropped fracture conductivity</td>
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<tr>
<td>– DFIT leakoff type is not a limitation</td>
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<tr>
<td>– low or medium G-time to closure is a plus</td>
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</tbody>
</table>
Case History: Surface Area Type Fracture Treatment

- Barnett shale well in Johnson county, TX
- 4100 ft lateral length
- 8 fracture treatment stages
- Totals: 36,000 gallons of 15%FE acid, 3.8 million gallons of FR water and 720,000 lbm of 40/70 mesh proppant

![Graph showing average daily gas production rates over time.](image)
Case History: Conductivity Type Fracture Treatment

- Eagleford, Niobrara, Gothic and the Haynesville are all good examples for such treatment
- Eagleford has a dry BHN of 22, Gothic has 34 and the Haynesville has 18
- In comparison Barnett dry BHN value is 80
- Stegent et al (SPE 136183) presented the production from a conductivity type Hybrid fracture treatment in a Eagleford shale and compared it with offset wells that were stimulated with waterfracs (i.e. surface area type fracs)
Case History: Conductivity Type Fracture Treatment (contd..)

Production Comparison

Eagle Ford shale wells Peak monthly rate comparison (SPE 136183)
Case History: Conductivity Type Fracture Treatment (contd.)

- Gothic shale: 2 horizontal wells (Wells 2 and 3) and 1 vertical well (Well 4) production
  - Well 2: 2500 ft long, 8 stages with 1.75 million gallons of slickwater, 140,000 lbm of 100 mesh and 616,000 lbm of 30/50 mesh sand.
  - Well 3: 3200 ft long, 8 stages with 5 million gallons of slickwater, 600,000 lbm of 100 mesh and 1.25 million lbm of 40/70 mesh sand.
  - Well 4: completed with 480,000 gallons of slickwater, 114,000 lbm of 40/70 mesh sand and 84,000 lbm of 20/40 mesh sand.
• Gothic shale exhibits low BHN value (22 when compared to Barnett’s 80)
• Potential for embedment is high and so the lower mesh proppant will not help in the softer rock.
• Harder to keep the unpropped fractures open in softer rock like Gothic
• Requires a conductivity type frac
# Fracture Treatment Selection Criteria

<table>
<thead>
<tr>
<th>Testing Method</th>
<th>Fracture Treatment Type</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Surface Area</td>
</tr>
<tr>
<td>CST &amp; ULPTA</td>
<td>Needed for both fracture treatment types to select the correct fluid</td>
</tr>
<tr>
<td>Britteness</td>
<td>50% and above</td>
</tr>
<tr>
<td>BHN (dry)</td>
<td>~60 and above</td>
</tr>
<tr>
<td>UFCT</td>
<td>in the 1000's of μd-ft</td>
</tr>
<tr>
<td>DFIT</td>
<td>Pressure Dependent or Transverse Storage type leakoff is needed</td>
</tr>
</tbody>
</table>
Conclusions

• The “Barnett type waterfrac” is not the correct completion method for all shale plays.

• Shales are all different and based on their reservoir characteristics they require either a surface area type or a conductivity type fracture treatment.

• Clear guidelines and selection criteria are provided in this work to choose between these two types of fracture treatments in shales. It is important that these guidelines are satisfied in a combined manner when selecting the respective fracture treatment type.
  – Based on these guidelines, Gothic shale wells in the study area require conductivity type fracture treatments.

• A DFIT in conjunction with the other tests (especially UFCT) mentioned here is a useful tool to decide between these two types of fracture treatments.
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Questions ?