Microseismic Frac Mapping: Moving Beyond the Dots from an Engineering Perspective

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Outline

- Microseismic 101
- A glance in the rear view mirror
- The engineer’s fracture diagnostics toolbox
- Why engineer’s use microseismic monitoring
- Microseismic technology advancements
- “Unconventionals” have changed the game
- What’s missing? – Moving Beyond the Dots
- Value addition opportunities
- What’s Next?
Microseismic 101

- Practice of listening to **passive**, microseismic activity caused by **hydraulic fracturing** (reservoir subsidence, and water, steam, or CO2 injection or sequestration).
- Microseisms are seismic energy emissions generated by shear slippages along weakness planes in the earth
- Passive Imaging is seismic without sources – receivers only

Objective:
- Detect and locate microseismic events in time and space.
- Measure characteristics of events (magnitude, source mechanism, etc.)
- Provide diagnostic information about the hydraulic fracture
1860 – Nitroglycerin injection used to stimulate shallow oil well in Pennsylvania (precursor to fracking?)

1947 - Stanolind Oil conducted the first experimental fracturing in the Hugoton field located in southwestern Kansas. The treatment utilized napalm (gelled gasoline) and sand from the Arkansas River. (1)

1949 - Halliburton conducted the first two commercial hydraulic fracturing treatments in Oklahoma (1)

1950’s through 1980’s – Numerous hydraulic fracturing pumping and diagnostics technology developments

1992 - Pinnacle Technologies introduced surface tilt frac mapping

Late 1990’s and early 2000’s – Pinnacle Technologies introduced downhole tilt and microseismic frac mapping

2003 - MicroSeismic, Inc. introduced surface microseismic frac mapping

2008 - MicroSeismic, Inc. introduced BuriedArray™ microseismic frac mapping

Over 1.1 million hydraulic fracture stimulation jobs in the past 6 decades

Less than 2% of these jobs monitored using frac mapping technology

### Stimulation Evaluation Tools

<table>
<thead>
<tr>
<th>GROUP</th>
<th>DIAGNOSTIC</th>
<th>MAIN LIMITATIONS</th>
<th>ABILITY TO ESTIMATE</th>
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<tr>
<td>Indirect</td>
<td>Net Pressure Analysis</td>
<td>Modeling assumptions from reservoir description</td>
<td>Length</td>
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<tr>
<td>Indirect</td>
<td>Well Testing</td>
<td>Need accurate permeability and pressure</td>
<td></td>
</tr>
<tr>
<td>Indirect</td>
<td>Production Analysis</td>
<td>Need accurate permeability and pressure</td>
<td></td>
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<tr>
<td>Indirect</td>
<td>Radioactive Tracers</td>
<td>Depth of investigation 1'-2'</td>
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<tr>
<td>Indirect</td>
<td>Temperature Logging</td>
<td>Thermal conductivity of rock layers skews results</td>
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<tr>
<td>Direct, near-wellbore</td>
<td>HIT</td>
<td>Sensitive to i.d. changes in tubulars</td>
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<tr>
<td>Direct, near-wellbore</td>
<td>Production Logging</td>
<td>Only determines which zones contribute to production</td>
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<tr>
<td>Direct, near-wellbore</td>
<td>Borehole Image Logging</td>
<td>Run only in open hole – information at wellbore only</td>
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<tr>
<td>Direct, near-wellbore</td>
<td>Downhole Video</td>
<td>Mostly cased hole – info about which perfs contribute</td>
<td></td>
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<tr>
<td>Direct, near-wellbore</td>
<td>Caliper Logging</td>
<td>Open hole, results depend on borehole quality</td>
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<tr>
<td>Direct, Far Field</td>
<td>Surface Tilt Mapping</td>
<td>Resolution decreases with depth</td>
<td></td>
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<tr>
<td>Direct, Far Field</td>
<td>DH Offset Tilt Mapping</td>
<td>Resolution decreases with offset well distance</td>
<td></td>
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<tr>
<td>Direct, Far Field</td>
<td>Microseismic Mapping</td>
<td>May not work in all formations</td>
<td></td>
</tr>
<tr>
<td>Direct, Far Field</td>
<td>Treatment Well Tiltmeters</td>
<td>Frac length must be calculated from height and width</td>
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</tbody>
</table>
Why engineer’s use microseismic monitoring

- Diagnostic tool to better understand hydraulic fracture geometry
  - Length
  - Height
  - Azimuth
  - Complexity
- Identify patterns of hydraulic fracture development
  - Zonal containment or lack thereof
  - Well to well or stage to stage overlap
- Geohazard avoidance
- Estimate stimulated reservoir volume
- Fracture treatment refinement
- Long-term field development optimization

Map View

Depth View

Zone breakout
• Stacked arrays
• Expanded arrays
• Fiber-optic wireline
Technology Advancements - Surface

FracStar® Array

- 1000+ channels of 1-C geophone strings, 6 phones per string
- Radial FracStar® array, 8-14 arms

- Array Type: Surface
- Duration: Temporary
- Coverage area: ~3 to 7 Sq. Miles
- Capabilities: Frac Monitoring
Buried Array™

- Array Type: Sub-Surface
- Duration: Permanent
- Coverage area: Hundreds of Sq. Miles
- Capabilities: Frac Monitoring, Reservoir Monitoring
- Buried: 50-300’
Technology Advancements - Processing

- Improved event detection capability and location accuracy
- Detailed source analyses – better understanding of how rock is breaking
Technology Advancements – Visualization

- Layered permeability distribution
- Average fracture aperture - ft
- Average fracture porosity - unitless
- Total fracture volume (ft³) – sum of fracture volumes in the model
- Stimulated reservoir volume (ft³) – volume of geocellular cubes that have fracture properties (the affected rock matrix)
Barnett widespread development began in 2003. Horizontal wells and hydraulic fracturing were the key enablers. Other unconventional plays followed on the heels of the Barnett at a rapid pace.
Rig Direction and Frac Stages

Market Overview

US Average Land Rig Count by Direction

- 2001: 1157 (69%), 1384 (24%), 1873 (7%), 1484 (51%)
- 2005: 1157 (69%), 1384 (24%), 1873 (7%)
- 2008: 1157 (69%), 1384 (24%), 1873 (7%)
- 2010 May: 1157 (69%), 1384 (24%), 1873 (7%)

Number of Frac Stages Per Well

- Bakken Shale
  - 2008: 12
  - 2009: 24
  - 2010E: 32
- Eagle Ford Shale
  - 2008: 11
  - 2009: 15
  - 2010E: 20
- Haynesville Shale
  - 2008: 12
  - 2009: 14
  - 2010E: 20

7/8/11 Update:
US Land – 1854, Horizontal – 1073
% of total - 58

- Production is increasingly moving towards horizontal wells with longer laterals to increase the surface area in a well
- Longer laterals are increasing the number of frac stages required and subsequently, the horsepower required

Source: Simmons and Company
Unconventionals are Changing The Game

Oil Field Services Market

- ~ 450% increase in pumping capacity since 2003
- Still growing at ~ 20-25% per year

- Even with the 24% growth of horsepower between 2009 and 2010, there is still demand for additional pressure pumping equipment
- As the amount of horsepower increases, there will be additional service opportunities for United
- United Holdings serves a number of the large oil field service companies

1) Greater than 20 companies
Source: Spears & Associates, "Drilling: Market Forecast"
Almost exclusively HW’s
Almost all wells require **hydraulic fracturing**
Long laterals (up to 10,000’)
More frac stages per lateral (>30)
  • Plug and perf capabilities extended
  • Packer and sleeve systems enhanced
High rate (>100 bpm), large volume (> 100,000 bbls/well), high proppant tonnage (> 4,000,000 lbs/well) fracs
24 hour frac operations (30+ stages/24 hrs)
“Factory” style multi-well pads and innovative frac sequencing
  • Zipper fracs
  • Simultaneous fracs
Result is significantly more data at a much faster pace
Operators (and service providers) are overwhelmed
Engineers are asking:
- What Does it Mean?
- How does it relate to production?
- What needs to be changed?

Determination of individual well fracture geometries, well orientation and well spacing requirements are no longer enough.

Must view and analyze as a “system”

Engineers want an integrated solution:
- Subsurface
  - Geophysics
  - Geology
  - Petrophysics
  - Geomechanics
- Completion
- Treatment
- Microseismic
- Production

View as System, not just individual wells
Particularly important for “factory” style multi-well pad applications

- Technical database
- Multivariate statistical analysis
- ID cause-and-effect relationships
- Key drivers for improved well and reservoir performance

- Microseismic data in frac models
- Net pressure behavior and relationship to microseismic and production results
- Use to help calibrate DFN/SRV models

- Microseismic data in simulators
- Use to help calibrate DFN/SRV models

- Subsurface
- Completion
- Pumping
- Microseismic
- Production

- Enhanced Engineering Analysis and Content

- Statistical Discovery

- Reservoir Simulation

- Frac Modeling

- Well and Stage Interaction Evaluation

- Value
What’s Ahead

- Continued R&D on event characterization to improve understanding of how the rock is breaking
- Improved understanding of “created” versus “effective” fracture geometry – “Where is the proppant?”
- Better understanding of how fracture geometry evolves during a treatment
  - Are we reactivating pre-existing fractures or creating new fractures or both?
  - Which is more prevalent?
  - How are stress changes that occur during fracture treatments driving and/or rerouting the fractures?
- Better understanding of the connectivity and flow properties of the hydraulic fracture network
What’s Ahead

- Reservoir Monitoring
  - Production, Haynesville
  - SAGD, Alberta
  - Water injection, Saudi Arabia
  - Compaction, North Sea
  - Production, North Sea
  - Cyclic Steam Injection, Alberta
  - CO₂ Injection, Wyoming
  - Gas Injection, Dubai
- Earthquake Monitoring
- Environmental Monitoring
- Integration of active and passive seismic
“The wise man must remember that while he is a descendant of the past, he is a parent of the future.” ~ Herbert Spencer

“You can’t have one foot in yesterday or one foot in tomorrow; you have to keep both feet in today and that’s how you get to tomorrow. “ ~ John Wooden