“Some Elements of Developing Ductile Shales: Description, Completions, Fracturing and Production”

Caney Town Hall Webinar

Tuesday, April 28th 10am CST
First in a series of Webinars under DE- FE-0031776

- Welcome & Introduction by Mileva Radonjic
- Presentation by George King
- During presentation attendees are encouraged to submit comments via the comment panel.
- We hope time allows for a live Q&A, however, if not written responses will be provided post webinar.
- Participants to include: DOE; NETL; Continental; OSU; OGS; Pittsburgh & Core labs
- Stay tuned for the May Town Hall Webinar - details to come

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*Background image is SEM Micrograph of Caney Shale courtesy of OSU*
George E. King, P.E. – CV Highlights

• 49-year veteran of the upstream Oil & Gas Industry
• Degrees in Chemistry (OSU), Chem. Eng. & Petroleum Eng. (U of Tulsa)
• 28 Years with Amoco Production Research – field research on workovers, fracturing, underbalance perforating, acidizing, coiled tubing, foam fluids, sand control, water sensitive formations, training.
• 9 years with BP-Amoco and BP – Distinguished Advisor, annular pressure control, innovation trainer, sand control reliability for deep water
• 1 year with Rimrock – startup company in Barnett Shale – refining shale fracturing in multi-fractured horizontal wells
• 9 years with Apache – shale completions, fracturing, training
• 2 years consulting: DOE Geo-Thermal, well integrity, sand control, shale completions, well control, frac hits, failure analysis.
Technical Accomplishments

• Technical accomplishments include 95 technical papers,
• Advances in sand control, underbalance perforating, foam fluids, shale fracturing, well Integrity during fracturing
• Industry and Academia
  • 1985 - SPE Distinguished Lecturer on foam,
  • 1999 - SPE Completions Course Lecturer on horizontal wells
  • 1992 SPE Technical Chairman of Annual Meeting,
  • 1988-98 - adjunct professor at U of Tulsa (completions & fracturing)
• Awards:
  • 2015 SPE Distinguished member,
  • 2012 Engineer of the Year from Society of Professional Engineers – Houston Region,
  • 2004 Society of Petroleum Engineers’ Production Operations Award
  • 1997 Amoco Vice President’s Award for technology.
Some Elements of Developing Ductile Shales: Description, Completions, Fracturing and Production

George E. King, P.E.
April 28, 2020
GEK Engineering PLLC
Advisor to OSU’s DOE-Funded Ductile Shale Project
Oklahoma State University
Outline of the Talk

1. Ductile shale description
2. Where is the oil and gas in ductile shales
3. How do oil and gas move through shales
4. Impact of net pressure changes and stress
5. Fracturing Ductile Shale
6. Completion Methods
7. Production
8. Ductile Shale Development overview
Effect of hydraulic fracturing on gas production in shale?

Three Curves:

- **Red** – Historical gas production from a MFHW well in core area of Haynesville.
- **Blue** – Simulated gas production rate from Model with 400 nano-Darcy matrix (no frac)
- **Green** - Simulated gas production rate from Model with 100 nano-Darcy matrix (no frac)

Fig. 5–Impact of shale matrix permeability on horizontal well gas production.

Decline over time – Multiple Shales with Same Decline Shape – Flush Production & Slow Recharge or Flaw Paths Closing With Pressure Reduction?

Impacting Factors
- Matrix Perm
- Fluid Viscosity
- Reservoir Pressure
- Drawdown Speed
- Brittle or Ductile
- Proppant type/vol
- Nat. Fracs

Average production profile for major U.S. Shale plays (Borrowed from Baker Hughes).
Well Known North American Ductile Shales

• **Haynesville (gas)** ~700 TCF, northern Louisiana & East Texas. Depth ~10,000 ft), BHT is 175 C, 350 F, and high pressure ~0.9 psi/ft. IP (24 hr) to 20+ mmscf/d. Gas requires treating to remove CO2 and H2S.

• **Fayetteville (gas)** ~13 bcf, central Arkansas, Depths 1400 to >4000 ft. Pressure ~ 0.4 psi/ft,

• **EagleFord (deep gas & shallow oil)** – 400 mile long x 50+ miles wide from northeast Mexico to NE Tx. Much higher carbonate percentage, ( to~70% in S. Texas, becoming shallower & more shaly to NW. High% carbonate creates mixed brittle and ductile sections.

• **Caney** – southeastern Oklahoma along a common shale belt with Fayetteville, Woodford and Caney
Sweetspot fairway of North American shale plays - with total estimated (red) and producible (white) hydrocarbons in place.
Shale Components – one view

• Brittle shales – easier initiation/propagation of hydraulic fracture - require little or no plastic deformation.

• Ductile shales tend to oppose fracture propagation – fracture closure (& healing) more likely.

• Silica and carbonate-rich shales exhibit brittle behavior while clay-rich shales “tend” to be ductile.

• Organic shale Petrophysical studies assume lithology is dominated by a few minerals, however, well logs are affected by mineral & pore structure variation.

What causes ductility? Mostly soft materials in the formation – clays, chalks, weak sands, etc.

• “The clay content has to be less than 40% for a successful shale play (DMITRE, 2012b; McKeon, 2011).

• However, evaluation criteria in China refer to clay contents less than 30% (Zou, 2013).

• Increasing clay content leads to increasing ductility of shale, which is beneficial in terms of forming a better seal to trap the gas within the reservoir, but not in terms of hydraulic fracturing, as the shale will tend to self-heal.

• As the hydraulic fluid is injected, the permeability will be further reduced due to clay content as the coherence of the matter is high, leading to a reduction in the extraction potential.”

Shales – Ductility and Brittleness

• Shear failure occurs when loading creates shear stresses that exceed shear strength.

• Fracturing is controlled by the ductility or brittleness of the material.

• Deformation can be brittle or ductile depending on shale properties and effective confining stress.

• Brittle deformation is characterized by dilation (becoming larger or wider) with sudden failure at a well-defined peak shear strength, followed by strain softening reduction to a residual shear strength.

• Brittle response can be accompanied by formation of distinct shear failure surfaces.

• Ductile response usually produces less defined peak shear strength (and strain softening), with more diffused and large deformations and less distinct shear failure surface.

Figure 2: Ternary diagram highlighting the six organic-rich shales falling within different lithofacies. Notice the Eagle Ford and Niobrara are more carbonate dominated. The Bakken is more siliceous. Generally, all six organic-rich shales contain mixed mudstone facies (Ternary diagram modified from Diaz et al., 2012).
Clay Impacts

Mineralogy and Clay Speciation of select Wolfcamp samples at Fasken Ranch 36-1

Brittle content: 70%

Modified from Allix et al. (2010)

Delaware Basin Petroleum Systems, Javie et al., 2017
Table 2: Average volumetric concentrations (in fraction of solid volume) of various minerals from XRD analysis performed in 8 wells with core samples in the Haynesville and Barnett shales. Main minerals are present in the form of $V_{\text{quartz}}$, $V_{p-\text{feldspar}}$, $V_{\text{calcite}}$, $V_{\text{illite}}$, $V_{\text{chlorites}}$, $V_{\text{mix}}$, and $V_{\text{kaolinite}}$. Accessory minerals include $V_{\text{feldspars}}$, $V_{\text{dolomites}}$, $V_{\text{ankerites}}$, $V_{\text{pyrites}}$, and $V_{\text{fluorapatite}}$.

<table>
<thead>
<tr>
<th>Mineral</th>
<th>Haynesville Shale</th>
<th>Barnett Shale</th>
</tr>
</thead>
<tbody>
<tr>
<td>Quartz ($V_{\text{quartz}}$)</td>
<td>0.268</td>
<td>0.369</td>
</tr>
<tr>
<td>Potassium feldspar ($V_{p-\text{feldspar}}$)</td>
<td>0.004</td>
<td>0.021</td>
</tr>
<tr>
<td>Plagioclase feldspar ($V_{\text{feldspar}}$)</td>
<td>0.073</td>
<td>0.050</td>
</tr>
<tr>
<td>Calcite ($V_{\text{calcite}}$)</td>
<td>0.203</td>
<td>0.131</td>
</tr>
<tr>
<td>Dolomite ($V_{\text{dolomite}}$)</td>
<td>0.013</td>
<td>0.031</td>
</tr>
<tr>
<td>Ankerite ($V_{\text{ankerite}}$)</td>
<td>0.013</td>
<td>0.012</td>
</tr>
<tr>
<td>Pyrite ($V_{\text{pyrite}}$)</td>
<td>0.020</td>
<td>0.031</td>
</tr>
<tr>
<td>Fluorapatite ($V_{\text{fluorapatite}}$)</td>
<td>0.018</td>
<td>0.015</td>
</tr>
<tr>
<td>Kerogen ($V_{\text{kerogen}}$)</td>
<td>0.055</td>
<td>0.086</td>
</tr>
<tr>
<td>Illite ($V_{\text{illite}}$)</td>
<td>0.233</td>
<td>0.092</td>
</tr>
<tr>
<td>Chlorite ($V_{\text{chlorite}}$)</td>
<td>0.055</td>
<td>0.048</td>
</tr>
<tr>
<td>Mixed layer illite/smectite ($V_{\text{mix}}$)</td>
<td>0.035</td>
<td>0.110</td>
</tr>
<tr>
<td>Kaolinite ($V_{\text{kaolinite}}$)</td>
<td>0.010</td>
<td>0.004</td>
</tr>
<tr>
<td>Main minerals</td>
<td>0.877</td>
<td>0.804</td>
</tr>
<tr>
<td>Accessory minerals</td>
<td>0.068</td>
<td>0.110</td>
</tr>
<tr>
<td>Kerogen</td>
<td>0.055</td>
<td>0.086</td>
</tr>
</tbody>
</table>

My Comment - Mineral analysis by itself, is less important than the overall rock fabric.

Rock fabric - porosity, mineral type, location and structure, grain bonding, fissures, fractures and stresses are most important.

Fig. 13—SOM of Strait wells. The KPI map is outlined in the thin black rectangle. Blue circles indicate regions of higher production. Red rectangles indicate regions of lower production.

Where to spot Frac Stages – one opinion

Fig. 9—Lateral staged by grouping “like” rock. Starting from the bottom, Track 1 is gamma ray, Track 2 is the lithology log, Track 3 is the stress log and Track 4 is the generated clusters. Vertical lines indicate plug depths.

Drawdown Production Control

• In the early phase of cleanup, flow measurement and production in the ductile Haynesville wells, many wells were severely damaged or lost altogether by excessive drawdown during early production.

• The drawdown induced damage was directly correlated to high drawdown pressure differential, softness of the rock, and the very high initial reservoir pressures.

• Diligent control of cleanup and production drawdown is absolutely essential to preserve natural fracture and hydraulic fracture networks.

• Common damage of excessive drawdown include unpropped fracture closing, proppant embedment, proppant crushing & fines migration.

Brittle and Ductile Behaviors Under Stress

Fig. 2—(a) Elastic and plastic parts of deformation or energy obtained from a single-stress cycle: loading/unloading; (b) graph comparing typical stress/strain curves for brittle and ductile materials. Brittle failure causes fracture at lower strain levels, whereas material absorbs less energy (shaded area) and there is a significant drop from peak to residual. Conversely, ductile failure shows significant plastic strain. December 2015 SPE Journal
Flow Path – Matrix

The fabric of productive shales does have channels of higher permeability than the very fine-grained material of the matrix.

The key to production is maximizing contact with these flow channels.
Look for the Gas Shows

- Gas Show
- Quantity
- Ratio of gasses
- Corresponding GR
- Other logs (CNL, Density) to help assess TOC
- Density for Brittleness
- Resistivity for water saturation and salinity
- ROP (rate of penetration)
- Is it a hot shale or a natural fracture?

The objective is to align the perf clusters with natural fractures.
Mineralogy Effects on Porosity

Clay has ultra-low porosity. Thermally mature organic material often has a high porosity and may be surrounded by higher porosity and permeability rock.

Bed-parallel microfractures may be found, and some researchers believe that microfractures are created by volume expansion.

Scanning electron image showing (a) the distribution of organic matter (OM) and clay in a shale gas sample (after Bertonecchello et al. (2014)), and (b) CT-scan image of a similar sample, showing bed-parallel natural fractures.
Relative Adsorption of Gases

Langmuir (absolute) adsorption isotherms for single-component gases obtained from dataset of Hartman et al. (2011). The isotherms are provided courtesy of Chad Hartman.
Free and Adsorbed Gas
Remember – these are average numbers

Variation in Marcellus due to depth, maturity, thickness and TOC.
Rock Creep with Time

Rock fabric deformation – creep may be several hundredths to several tenths of an inch of borehole diameter over a few months.

Figure 2—Rock Creep Under Load for three shale types
From (Sone & Zoback, Geophysics v78, no. 5)

Stress Changes Along the Wellbore

3D seismic interpretation by Rich and Ammerman, illustrating significant differences in seismic attributes between toe and heel of the lateral.

In their analysis, the natural fractures are parallel to fracture propagation in the toe. In the heel, the natural fractures are oriented perpendicular to hydraulic fracture direction.

An alternate interpretation is that the differences between $\sigma_{\text{min}}$ and $\sigma_{\text{max}}$ are decreasing in the heel and are in the range that both fracture sets could grow and complexity is developed.
Clay Damage

• Will clay create a problem? Depends on clay type, form, location, what fluids are flowing and Insitu stresses.


Reactivity of Clays

Biggest factors are contact area & location.

<table>
<thead>
<tr>
<th>Mineral</th>
<th>Typical Area (M²/g)</th>
<th>Cation Exchange Capacity (Meq/100 g)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sand (up to 60 microns)</td>
<td>0.000015</td>
<td>0.6</td>
</tr>
<tr>
<td>Kaolinite</td>
<td>22</td>
<td>3 - 15</td>
</tr>
<tr>
<td>Chlorite</td>
<td>60</td>
<td>10 - 40</td>
</tr>
<tr>
<td>Illite</td>
<td>113</td>
<td>10 - 40</td>
</tr>
<tr>
<td>Smectite</td>
<td>82</td>
<td>80 - 150</td>
</tr>
</tbody>
</table>

Size ranges for clays depend on deposit configuration. CEC’s affected by coatings and configurations.
How Does Oil Move Through Shale?


Source: Conoco-Phillips shale
Fabric Implications

Woodford Shale – gas does not bleed out of the matrix uniformly despite the macroscopic homogeneity

Bustin, 2009
How Many Fractures are Contributing?

Production highest from frac stages in areas of faulting – stress changes – natural fracs open?

Effect on Proppant Packed Fracture Flow Capacity in Ductile Chalk Core as Net Pressure Increases – *(soft elements affect structure)*

All tests used 20/40 mesh sand proppant.

Note that the fracture with 0.1” thickness of proppant declined much faster as net pressure was increased.

Approx. embedment in soft chalks is ½ of a proppant grain, so embedment reduced flow space in the 0.1” pack by 1/3rd, while one proppant layer loss for the 0.25” pack is ~1/7th of capacity and the loss in the 0.4” pack is about 1/10th over the pressure range in the tests.

From Where Does the Production Come?
(Kinetix-Intersect Modeling)

• Variable recovery after 30 years of production,
• 8.9% - near-wellbore dynamic nano-darcy region,
• 2% - inter-hydraulic fracture,
• 1.7% external feeder regions for shale oil producer
• ~ 2/3 total hydrocarbons from near-wellbore & fracs,
• Remaining 1/3 by external feeder region.
• Variable recovery factor & press depletion are basis for Enhanced Oil Recovery (EOR) techniques.

Hydraulic Fracture Simulations by Modeling

• Classic hydraulic fracturing simulators based on Linear-Elastic Fracture Mechanics (LEFM):
  • Convenient to use, (but limited in shales)
  • Provide reasonable predictions for brittle formations,
  • Fail to predict fracturing pressures (e.g., breakdown, extension) and geometry (e.g., frac width and length), in formations that undergo plastic failures (e.g., ductile shales, soft chalks and poorly consolidated sands).

Fracture Initiation and Propagation

- Fracture propagation in ductile formations can introduce a significant plastic deformation around the fracture due to shear failure.
- A fracture will propagate when the energy-release rate in the “process zone” reaches a critical value.

The cohesive zone is a region ahead of the crack tip that can be characterized by microcracks that are the result of damage evolution created by changing stress (pressure, tensile failure or shear).

Fracture Extension in Ductile Formations

Fig. 4—Cohesive zone embedded along the fracture path (modified from Chen et al. 2009).

Lower Caney barriers to downward frac growth

Fig. 17: Log of the Cometti displaying model results that show lithofacies of siliceous organic mudstones (black bars), carbonate mudstones (blue bars) siliceous mudstones (yellow bars), low organic mudstones (grey bars) (see Fig. 6 for legend). Also, see the corresponding favorable fracture zones (green bars) as opposed to potential fracture barriers (red bars) within both the Caney and False Caney. Note the significant thick barriers in the lower Caney that serve as containment for fractures induced into the sparse favorable zones of the upper Caney section.
## An Opinion on Comparison of MFHW Completion Types

<table>
<thead>
<tr>
<th>Completion Factor</th>
<th>Plug &amp; Perf</th>
<th>Pkr. &amp; Sleeve</th>
<th>CT Shifted Sleeve</th>
</tr>
</thead>
<tbody>
<tr>
<td>Early Expense (before drilling)</td>
<td>Low</td>
<td>High</td>
<td>Moderate</td>
</tr>
<tr>
<td>Lead Time (order from mfr.)</td>
<td>Low</td>
<td>High</td>
<td>Moderate</td>
</tr>
<tr>
<td>Casing/pkr run-tofrac time</td>
<td>Moderate</td>
<td>Moderate</td>
<td>Moderate</td>
</tr>
<tr>
<td>Landing accuracy Importance</td>
<td>Low</td>
<td>High</td>
<td>Moderate</td>
</tr>
<tr>
<td>Frac screenout occurrence</td>
<td>Low</td>
<td>Moderate?</td>
<td>Low</td>
</tr>
<tr>
<td>Potential for most frac entry points</td>
<td>Highest</td>
<td>Lowest</td>
<td>Moderate</td>
</tr>
<tr>
<td>Potential for missing stages</td>
<td>Low</td>
<td>Moderate</td>
<td>Low</td>
</tr>
<tr>
<td>Time between fracs</td>
<td>Moderate (2 hr)</td>
<td>Short (min.)</td>
<td>Short</td>
</tr>
<tr>
<td>High frac rates possible</td>
<td>Highest</td>
<td>Lowest</td>
<td>Moderate</td>
</tr>
<tr>
<td>Potential for missed stages</td>
<td>Low</td>
<td>Moderate?</td>
<td>Low</td>
</tr>
<tr>
<td>Gauge hole critical</td>
<td>Yes</td>
<td>Low</td>
<td></td>
</tr>
<tr>
<td>Isolation quality btw frac stages</td>
<td>Moderate</td>
<td>Low</td>
<td>Moderate</td>
</tr>
<tr>
<td>Proppant placement accuracy</td>
<td>Low</td>
<td>High</td>
<td>High</td>
</tr>
<tr>
<td>Equipment required during frac</td>
<td>Wireline Unit</td>
<td>None</td>
<td>Coiled Tubing Unit</td>
</tr>
<tr>
<td>Cleanout potential</td>
<td>High</td>
<td>Low</td>
<td>High</td>
</tr>
<tr>
<td>Workover Potential</td>
<td>High</td>
<td>Low</td>
<td>High</td>
</tr>
<tr>
<td>Flowback cntrl &amp; entry shut-off</td>
<td>Low</td>
<td>Low</td>
<td>High</td>
</tr>
<tr>
<td>Field Knowledge of Technique</td>
<td>High</td>
<td>Moderate</td>
<td>Moderate</td>
</tr>
<tr>
<td>Freeze-up avoidance</td>
<td>Low</td>
<td>High</td>
<td>Moderate</td>
</tr>
<tr>
<td>Potential for refracs</td>
<td>High</td>
<td>Low</td>
<td>High</td>
</tr>
<tr>
<td>All -in - Cost</td>
<td>Lowest</td>
<td>Mod/High</td>
<td>High</td>
</tr>
</tbody>
</table>

Source: George King, MFHW School Slides
Plug and Perf – Cemented Casing

60 to 100 fractures along one wellbore create rock contact areas over 700,000 square feet each, + opening natural fractures → about 10 million+ square feet of contact.
Packer and Sleeve – Open Hole

![Diagram of Packer and Sleeve – Open Hole](image)

- A larger, later stage ball that is being pumped into a sleeve and will open the next port for fracturing.
- The as-drilled open hole may vary slightly in diameter in the best of conditions.
- The balls that shift the sleeves must pass through the “upper” sleeves, thus the first ball dropped may be very small.
- Tubing, sleeves & packers are run as a single assembly. Tubing size is smaller than casing used in PNP completions.
- Swellable, Mechanical, or Inflatable Packer set in the open hole.
- Fracture Stage Length.
- Shiftable (movable) sleeve that open a port for fracturing when a dropped ball lands in the sleeve.
A recent high importance change - Hydraulic Diversion & Extreme Limited Entry (XLE)

• Number of perfs controls amount of hydraulic diversion when full injection rate reached.

• Achieving diversion while inj. rate is building to design rate requires diversion by other methods.

• Diversion by perforations involves number, diameter and flow efficiency of perfs

• Perf friction first seen when ratio of rate to perfs > 0.5 bpm/perf, but diversion begins when rate reaches at least 1.0 bpm/perf. Common today - effective diversion at 2.0 to 2.5+ bpm/perf?

• XLE - New data suggests hydraulic diversion with 100 mesh sands at 8 bbl/min/perf – resembles pin-point injection.
### Effect of Proppant Embedment

Table 2—Baseline Conductivity and Proppant Embedment at 2,000 and 7,500 psi of Stress

<table>
<thead>
<tr>
<th>Stress (psi)</th>
<th>Baseline Conductivities (md-ft.) @ 0.9 Damage Factor</th>
<th>Embedment – Change in Propped Fracture Width</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>100 Mesh</td>
<td>40/70 White Sand</td>
</tr>
<tr>
<td>2,000</td>
<td>7.2</td>
<td>16.4</td>
</tr>
<tr>
<td>7,500</td>
<td>0.7</td>
<td>4.3</td>
</tr>
<tr>
<td>Loss of Fracture Conductivity %</td>
<td>-91%</td>
<td>-74%</td>
</tr>
</tbody>
</table>
What is the difference?
- Larger/consistant prop size
- Better stability of ceramics
- Better strength of ceramics

What is the problem?
Cost
- sand $0.06 to $0.10 per lb.
- Ceramics ~$0.35 to ~$0.50/lb
Average Cumulative BOE per 1000 ft. of Lateral – Micro-proppant

Figure 16—Woodford (SCOOP) averaged cumulative BOE/1000 foot of lateral for 7 MP wells and 12 offset wells

Figure 24—Increasing proppant per lateral foot shows increase in the total propped surface area.
Fracture Modeling – “All Models are Wrong, But Some are Useful” - British statistician George E. P. Box

Where is the Proppant & is it Effective?

Proppant Conductivity – Not What We Think

Comparison between proppant baseline conductivity and "downhole" conductivity for 40/80 LWC, 40/70 RCS and 40/70 white sand proppants at Eagleford shale reservoir conditions (Bazan 2012)


Effect of More Proppant – best 3 months and best 12 months – Eagle Ford – Gas Window

Figure 16—Average of the best 3 months and 12 months of gas production and volume of sand per lateral foot in the Eagle Ford formation, Texas (Gas window).

Proppant – Eagle Ford - Oil Window Results

Figure 17—Average of the best 3 months and 12 months gas production and volume of sand per lateral foot in the Eagle Ford formation, Texas (Oil window).

Haynesville – More Prop – More Gas

Figure 20—Average of the best 3-month gas production and volume of sand per lateral foot in the Haynesville formation, Texas.

Is the fracture half empty or half full? Yes. And that is the problem.

“Because of the combination of near-well saturation and inertial flow, the pressure gradient increases to more than 2 psi/ft at the wellbore, but is less than 0.02 psi/ft ten feet beyond the well, where velocity and inertial effects are very low.” (Barree, et.al., 2014)
Does adding more frac stages really help?

Is it a case of diminishing returns?

Production vs. stage count

and

Production per stage vs stage count.
Choices of Frac Fluids

• The choice of frac fluid is set by the formation.

• Considerations:
  • Formation Sensitivity
  • Ability to breakdown & initiate a fracture,
  • Need to penetrate & open natural fracture system,
  • Ability to place the proppant,
  • Need to build a very large frac contact area,
  • Efficiency of load fluid recovery & minimum damage,
  • Fluid recycling and disposal where necessary,
  • Economics
Pumping the Frac

- LT: Limit Test
- FIT: Formation Integrity Test
- LOP: Leak-Off Test
- FBP: Formation Breakdown Pressure
- FPP: Frac Propagation Pressure
- ISIP: Instantaneous Shut-In Pressure
- FCP: Fracture Closure Pressure
Parts of the Frac

- **Rate, usually held constant**
- **Surface Pressure** – need to calculate net pressure (corrected for friction and proppant) may rise or fall. BHP much better.
- **Proppant loading** – usually 0.25 lb/gal to 3 lb/gal
- **Lost a Pump** for a few seconds
- **Press rise during the flush due to cutting proppant**
- **Friction Effect**
- **ISI P**
- **Leakoff**
- **Pad Slurry Flush**

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**Graph Description**

- **Barnett Shale**
- **Frac Breakdown**
- **Shut-in at end of flush**
- **Rate, bpm & Loading, ppa**
- **Wellhead Shut-in**

**Axes**

- **Pressures, psi**
- **Elapsed Time, min.**
- **Rate, usually held constant**
- **Steping Rate up by small steps**
- **Lost a Pump for a few seconds**
- **Press rise during the flush due to cutting proppant**
- **Proppant loading – usually 0.25 lb/gal to 3 lb/gal**
- **ISI P**
- **Leakoff**

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**Graph Details**

- **Pad**
- **Slurry**
- **Flush**
Conclusions from Literature & Experience

• Knowledge of Rock Fabric and Stresses are critical Information.
• Even Ductile rocks have a high variance.
• Land the lateral in the highest quality formation.
• Variance in mineralogy & stress along the laterals must set frac points.
• Use the best frac technology for the stimulation (Fluids and Proppant)
• Control the drawdown on cleanup and production.
Questions?