Predicting Final Fracture Conductivity, Cleanup, and Production

R.D. Barree
Determination of Realistic Proppant Pack Conductivity

• Pack width determined by
  – Proppant concentration
  – Closure stress
  – Filter-cake and embedment

• Pack permeability determined by
  – Proppant size and strength
  – Packing and porosity
  – Regained permeability and gel clean-up
  – Non-Darcy and multiphase flow
Observed Pack Width for 20/40 Sand

White Sand (20/40) – 2#/ft²

Closure stress , psi

Width from published bulk density

Pack Width, inches

+/- 5% expected width error
Embedment and Spalling

Width loss from embedment only

Width loss from embedment and spalling or formation extrusion
Internal versus External Pack Widths

- External pack width determined by proppant density and loading
- External width affected by embedment
- Spalling causes an internal width loss
- Wall filter-cake is an internal width loss
Embedment and Spalling Lead to Internal Pack Width Loss
Variation in Measured Permeability for 20/40 White Sand

Permeability of 20/40 White Sand

+/- 15% error in perm measurements

Closure Stress, psi

Permeability, darcy
Change in Porosity with Packing

Fig. 1.—Unit cells of cubic (case 1) and rhombohedral (case 2) packing. (After Graton and Fraser, J. Geol.)

Fig. 2.—Pores of the unit cells of cubic (case 1) and rhombohedral (case 2) packing. (After Graton and Fraser, J. Geol.)
Estimates of Permeability from Porosity

- **Kozeny-Carman equation**\(^2\)
  \[
  k = \frac{d_m^2 \phi^3}{180 (1 - \phi)^2}
  \]
  Note: with \(d_m\) in microns \(k=\mu m^2\) and \(1 \mu m^2=1.01324\) darcy

- **Variance in perm with packing**\(^3\)
  - Minimum porosity for uniform spheres=25.95%
  - Maximum porosity for uniform spheres=47.64%

- **Slichter**\(^4\): \(K_{\text{max}}/K_{\text{min}}=7.5\)

- **Kozeny**\(^5\): \(K_{\text{max}}/K_{\text{min}}=11.5\)


Note: with \(d_m\) in microns \(k=\mu m^2\) and \(1 \mu m^2=1.01324\) darcy
### Conversion from US Mesh to Centimeters Diameter

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\[
y = 2.2988x^{-1.0874}
\]
Comparison of Calculated and Observed Pack Permeabilities

\[ \phi = 38.1\% \]
\[ \phi = 37.3\% \]
\[ \phi = 37.1\% \]
\[ \phi = 29.8\% \]
\[ \phi = 31.9\% \]
\[ \phi = 31.6\% \]
Effect of Porosity on Width for 2 lb/ft² CarboLite
Impact of Cyclic Stress Loading on Conductivity

Comparison of Shorterm vs longterm (50hr) after cycling from 8000 psi to 4000 psi (2 lb/sq ft at 250F)

Conductivity (md ft)

No of cycles

- 20/40 White sand
- 20/40 White sand 50hr
- 16/30 Precured RCS
- 16/30 Precured RCS 50hr
- 20/40 Lt. Wt. Ceramic
- 20/40 Lt. Wt. Ceramic 50hr
- 20/40 Int Wt. Ceramic
- 20/40 Int Wt. Ceramic 50hr

y = 4073.5x^{-0.0311}
y = 3575.3x^{-0.0449}
y = 1837.8x^{-0.0667}
y = 480.04x^{-0.1679}
Normalized Conductivity with Time at Stress for 40/70 PRC (Corrected Starting KfWf)
Possible Predictive Function for Normalized Time Slope with Stress
Impact on Well Performance of Variable Conductivity

- $P_i = 5000$ psia
- $k = 0.01$ md
- $\phi = 0.05$ V/V
- $\gamma_g = 0.65$
- $h = 50$ ft
- $x_f = 500$ ft
- Area = 100 acres
- $k_{wf} = 10$ md-ft
- $X/Y = 1$
- $P_{eb} = 350$ psia
- $D = 1.995$ inch
- $\varepsilon = 0.0023$
- $L = 9000$ ft
- $T_{wh} = 70 ^\circ F$

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Impact of Variable Conductivity on Well Cumulative Production

Cumulative Gas, BCF

Days on Production

Constant FCD
Variable FCD
# Analysis of Constant FCD Example

## Constant FCD Case

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<th>Parameter</th>
<th>Value</th>
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# Analysis of Variable FCD Example

## Variable FCD Case

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Volumetric OGIP = 1.74 BCF

Channel = 2087.1 ft Length = 2087.1 ft
Fluid Rheology Changes Frac Shape and Prop Distribution

- Fluid mobility decreases in areas of high prop conc and low shear.

Diagram:
- High-Leakoff
- Stagnant Fluid
Useful Conductivity May be Localized

Fracture Area = 1000 sq ft  Avg Stress = 5000 psi

Dens Propped Area = 100 sq ft  Prop Stress = 50,000 psi

Stress in Flow Channel is nearly zero.
Unsupported sand simulates “node” deposit. Load platen contacts sand at a point.

Low unstressed Poisson’s Ratio prevents lateral sand motion. Sand grains “lock” in place and crush at very low average stress.
Proppant Crushing Under “Uniform” Stress – 5000 psi
Proppant Crushing Under “Uniform” Stress – 5000 psi
Cleanup is a Recursive Process

- Cleanup is required to start fluid movement
- Fluid movement establishes a pressure gradient
- A minimum threshold pressure gradient is needed to start cleanup
- After initiation, cleanup improves with
  - High velocity, high Reynolds Number flow
  - Multi-phase flow
  - Large throughput volumes
- There is a maximum distance to which the drawdown can be transmitted
Persulfate Degradation in Cores at 150 °F

Solution: 2% KCl with 1 lb/1000 gal (120 mg/L) SP

- Sample A: 98% Quartz, 1% Dolomite, 1% Illite
- Sample B: 84% Quartz, 4% Feldspar, 3% Dolomite, 6% Illite, 1% Chlorite (Fe), 2% Kaolinite
- Sample C: 52% Quartz, 26% Feldspar, 5% Ankerite (Fe), 1% Dolomite, 11% Illite, 3% Chlorite (Fe), 2% Kaolinite

Pore Volumes Throughput vs. Persulfate Concentration (mg/L)

Legend:
- Sample A
- Sample B
- Sample C
- Control
- Linear (Sample A)
- Linear (Sample B)
- Linear (Sample C)
- Linear (Control)
Oxidizer Consumption

- Reservoirs are reducing environments
- Oxygen “uptake” capacity is large
- Iron bearing minerals are reactive
- Breaker tests are done in an oxygen rich environment
- Lab tests done without oxygen show different results
  - No spontaneous break with temperature
  - Very stable fluids
Zero Shear Viscosity of Guar at 250 °F
Polymer Concentrates During Leakoff and Closure

![Graph showing gel concentration factor vs. average number of proppants per gallon of gel. The graph indicates a decreasing trend in gel residue with increasing number of proppants.]
Retained Perm Determined by Gel Residue

![Graph showing the relationship between Retained Perm, % DP for Cleanup, psi/ft and #/Mgal Polymer Residue. The graph has a logarithmic scale on the y-axis and a linear scale on the x-axis. The data points indicate a decreasing trend of Retained Perm with increasing #/Mgal Polymer Residue.](image-url)
Initiation of Flow Can Require a Large dP

Dp to initiate flowing a 12 cp (1.75 ppt AP) Broken Fluid at low rate
35 ppt CMHPG + Zr + 10 ppt Gel Stab. + 1 ppt Oxidizer (pad) 1.75 ppt in Slurry
w/ 1.0 lb/sqft Precured Resin Coated Sand (static leakoff to 4000psi)
at 140F and 4000 psi Closure Stress

<table>
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<tr>
<th>Time (hr)</th>
<th>Temp (°F)</th>
<th>n'</th>
<th>K'</th>
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<td>0.72</td>
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Flowed 12cp partially broken gel
(1.75 ppt AP) (300 rpm at 140F)
Initial dP for Cleanup is Like a Threshold Pressure or Yield Point

- Fracture initially filled with gel residue
- Static fluid develops zero-shear viscosity of residue
- Cleanup initiation dP described by pseudo-capillary pressure function
Continued Cleanup with Brine Requires Excess Rate and Pressure Gradient

2% KCl flow after Partially Broken Gel Injection
35 ppt CMHPG + Zr + 10 ppt Gel Stab. + 1 ppt Oxidizer (pad), 1.75ppt in slurry
w/ 1.0 lb/sqft Precured Resin Coated Sand
Static leakoff to 4000 psi and Regain

---

Graph showing the results of the cleanup process with 2% KCl flow after Partially Broken Gel Injection. The graph includes data on flowing rate (mls/min), conductivity (md-ft), cumulative volume (liters), and differential pressure (psi/ft) over time (min). It indicates the start of 2% KCl regain after a 12cp broken gel flow with 1.85ppt AP and the start of gas flow.
Observed Cleanup can be Predicted With a Single Function of Ultimate Regained Perm

Predicted vs Actual Cleanup vs rho v/mu (combined)
Stabilized = 40 lb CMHPG+Zr + Stabilizer
Breaker = 35 lb CMHPG = Zr + Oxidizer

\[
\text{breaker} = (5 + (90\% - 5) / (1 + (\rho \nu / \mu)^{(90\% / 50)}))
\]

\[
\text{Stabilized} = (5 + (50\% - 5) / (1 + (\rho \nu / \mu)^{(50\% / 50)}))
\]
Conductivity Damage
Independent of Fluids (?)

- Non-Darcy flow effects
- Multiphase (relative permeability)
- Multiphase-non Darcy flow
  - Compounding the problem
- Capillary face damage
Forchheimer Non-Darcy Losses

Forchheimer equation:

\[- \frac{dp}{dx} = \frac{\mu v}{k} + \beta \rho v^2\]

where

\(\beta = \) the inertial coefficient
\(k = \) Darcy permeability
\(\mu = \) fluid viscosity
\(v = \) Darcy velocity, Q/A

\[- \frac{dp}{dx} = \frac{\mu v}{k} \left(1 + \frac{\beta k \rho v}{\mu}\right)\]
Non-Darcy Flow in a Propped Fracture

\[
k_{\text{eff}} = k_{\text{min}} + \frac{(1 - k_{\text{min}})}{(1 + R_e)^E}
\]

\[
R_e = \frac{\rho V}{\mu T}
\]

1.0 MMSCFD from 100’ H

\[K_{\text{min}} = 0.002\]

\[E = 0.89\]
Remaining Apparent Permeability Under Non-Darcy Flow Conditions

Non-Darcy Flow Effect for 100' Frac Height, 0.13" Width

Fraction of Darcy Perm Remaining

MSCF/D at 1000 psi BHFP, 90F

- Forch
- Sg=85%
- Kmin
Over what fracture height does the gas flow?

Calculations for 2000 psi BHFP at 250F
Wellbore Drawdown or Gravity Segregation Determines Flow Path

Free gas flows in segregated channel(?)

\[ S_g = S_{gc} \text{ in zone} \]

\[ S_w = 100\% \text{ below pay} \]
Multiphase Flow Damage Factor for Sand

Sand ND Corrected Krs

Maximum Flow Restriction At Fg=0.98
$K_{g\text{ eff}}$ on Iso-Saturation Lines
Estimating Actual Effective Conductivity and Fracture Length

- Account for proppant pack baseline conductivity
- Assume initial guess at pack cleanup and regained perm
- Calculate reservoir transient deliverability under specified drawdown
- Correct for multiphase flow and estimate prop-pack Reynolds number (Re)
- Calculate cleanup and non-Darcy effects based on fractional flow and Re
- Iterate on actual flow rate until convergence
Expressions of Fracture Effectiveness

- Conductivity = $k_f w_f$
- $F_{CD} = k_f w_f / (k X_f)$
- $C_r = k_f w_f / (\pi k X_f)$
- Effective infinite conductivity $X_f$ ($X_{eff}$):

$$X_{eff} = \frac{X_{flowing}}{1 + \left(\frac{FCD}{1.7}\right)^{-1.01}}$$

- Equivalent $R_{wa}$ for pseudo-radial flow
  - $R_{wa} = X_{eff} / 2$

- These are much more a function of pack cleanup and dynamic conductivity than of created (propped) length

What is $X_f$?
Maximum Clean-up Length for Various Pack Conductivity Values and Permeabilities
Effective Flowing Frac Length Model

• Calculate fracture conductivity (kfwf) including all damage and dynamic effects
• Calculate flowing fracture length (Xflow) from proposed model
• Calculate FCD from flowing length and damaged conductivity

\[ F_{CD} = \frac{k_f w_f}{k_r X_{flow}} \]

• Calculate effective infinite-conductivity length from FCD for use in outside models
Effective and Apparent Dynamic Fracture Length

\[
\frac{X_{\text{eff}}}{X_{\text{created}}} = \frac{1}{1 + \left(\frac{FCD}{1.7}\right)^{-1.01}}
\]
Infinite-Conductivity Length for a Created Length of 1000 ft
Predict-K Example: Inputs Derived from Pre-Frac Testing

- Pre-frac diagnostic injection test pumped down casing to obtain
  - Closure stress
  - Reservoir pressure
  - Estimated perm and kh

- Frac’d down casing
  - 30Q CO2/28# zirconate crosslinked water-based CMG fluid
  - 220,220# 20/40 White Sand placed at 1-6 PPG

- Predict post-frac production and compare to actual well performance
Frontier Example Processed Log Data

Net Pay=60’
Frontier Example Job Data

Graph showing time series data for various parameters:
- USER001 (psi)
- USER002 (psi)
- Slurry Rate (bpm)
- Sand Concentration (lb/gal)
- Bottomhole Proppant Conc (lb/gal)
- Calc'd BH Pressure (psi)
Frontier Example BHP G-Function

GohWin Pumping Diagnostic Analysis Toolkit
Minifrac - G Function

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![Graph showing G(Time) vs Pressure and Derivatives](image-url)

- **Bottom Hole Calc Pressure (psi)**
- **Smoothed Pressure (psi)**
- **Smoothed Adaptive 1st Derivative (psi)**
- **Smoothed Adaptive G*dP/dG (psi)**

---

Bottom Hole Calc Pressure (psi)
Smoothed Pressure (psi)
Smoothed Adaptive 1st Derivative (psi)
Smoothed Adaptive G*dP/dG (psi)
Results
- Reservoir Pressure = 6023.84 psi
- Transmissibility, $kh/\mu = 141.59427 \text{ md*ft/cp}$
- $kh = 3.48364 \text{ md*ft}$
- Permeability, $k = 0.0697 \text{ md}$
Final Predicted Proppant Concentration (lb/ft$^2$) After Frac Treatment

Avg Conc=0.79 lb/sqft, Xcreated=1100 ft
Actual Well Post-Frac Gas Rate

~1 MMSCF/D after 70 days
Baseline Conductivity

Proppant Conductivity

Conductivity vs Stress

WBU Baseline

© 2009
Dynamic Conductivity
(1000 MSCF/D, 520 psi BHFP)
Production Analysis Results

PREDICT-K
Production Report

Reservoir name: Frontier
Water production (bbl/mmmscf): 5,000
Maximum flow rate (Mscf/d): 10,000
Condensate yield (bbl/mmmscf): 10.00
Wellhead pressure (psi): 300.0
Original gas in place (MMSCF): 1065.7

Treatment: WBU Length = 1100
Prepant: Jordan Unimin 20/40
Prepant conc. (lb/sq ft): 0.793
Fluid: 26# Guar-Borate
Fracture half length (ft): 1100
Fracture height (ft): 160

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Comparison of Predict-K and Actual Rate
## GPA Analysis of Actual Production

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### Graph

- **Volumetric OGIP = 0.80 BCF**

- **Uniform Flux Fracture**
  - Rectangular
  - Consolidated Sandstone
Why does the PBU Length Differ from the Dynamic Producing Length?

Reservoir linear flow transient is outside the fracture.

Dynamic conductivity losses exist only during production.
Impact of Effective Xf on Drainage Area (Reservoir Dependent)

\[
y = 0.163x + 41.737 \\
R^2 = 0.3316
\]
Maximum Attainable Effective Xf Depends on:

- Reservoir permeability
- Frac fluid cleanup
- Producing water-cut and condensate yield
- Applied drawdown
- Created fracture length
- Average proppant concentration
- Applied closure stress
- Reservoir rock “hardness”

Effective frac length is usually much shorter than expected
Defining Optimum Fracture Length: Reservoir Example

- TVD = 12000 feet
- Net pay = 50 feet
- Permeability to gas = 0.01 md
- Porosity = 10%
- Fracture closure gradient = 0.75 psi/ft
- Condensate and water rates = 10 bbl/MM
- Gas price = $6.00/MSCF
- Oil price = $55.00/STB
- Discount rate = 20%
Example 1: 40 Acre Drainage (4:1) with Economics based on 5-Year Production
Example 2: 20 Acre Drainage (10:1 Channel) 5-Year Economics
Designing for Expected Conductivity

• Include major damage effects
  – non-Darcy and multiphase flow effects
  – non-uniform stress, prop crushing and traditional conductivity
  – channelized flow, saturation distributions and gravity override
  – fluid stability, breaker effectiveness, cleanup, flowback and post-treatment

• Integrate reservoir deliverability and pack damage to estimate effective producing frac length
Post-Job Analysis: A Critical Component to Design Optimization

• We must know what was achieved to improve the design

• Production analysis is still the best tool around
  – How the frac behaves during production pays for the treatment

• Collect the data!

• Do the work, or the design effort was wasted