SPE Distinguished Lecturer Series
2001 - 2002

The ABC’s of Improving Production from Hydraulically Fractured Wells

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CARBO Ceramics Inc.
SPE DISTINGUISHED LECTURER SERIES
is funded principally
through a grant of the

SPE FOUNDATION

The Society gratefully acknowledges
those companies that support the program
by allowing their professionals
to participate as Lecturers.

And special thanks to The American Institute of Mining, Metallurgical,
and Petroleum Engineers (AIME) and individual SPE sections for their
contribution to the program.
Acknowledgements

- Carbo Ceramics Inc.
- Colleagues - Gulf Oil, ARCO Oil & Gas, ARCO Alaska, Colorado School of Mines
- Mike Vincent and Pat Handren
- My wife Joanie and children Chris, Julie and Jack.
Outline

• Fluid Flow in Porous Media
• Lab Testing of Proppants
  • “Darcy Flow” - viscous, laminar
  • “Inertial Flow” - non-Darcy conditions
  • “True Flow” - multiphase and non-Darcy
• Field Case Studies
• Conclusions
“The First Reservoir Engineer”

- The Inspector General of Bridges and Roads
- France, 1856
- What size filter is required to satisfy the drinking water needs of the city of Dijon?
- ..........

Henry Darcy
Darcy’s Experiment
Darcy’s Data

Discharge, Liters per Minute

Drop in Head Across Sand (Meters of Water)

First Series
October 29-November 2, 1855

Fifth Series
February 17-18, 1856
Darcy’s Equation

\[ Q = K \times \frac{(h_2 - h_1)}{L} \]

\[ \Delta \frac{P}{L} = \frac{\mu v}{k} \]

Applicable only with low fluid velocity

Typically valid for matrix flow distant from the wellbore
Forchheimer - 1901

- Recognized that fluid flow through porous media is a function of the square of the velocity.

\[ \Delta P/L = \mu \frac{v}{k} + \beta \rho v^2 \]

Applicable at realistic fracture flowrates

Typically required for fracture modeling and for radial flow in prolific non-stimulated wells
Flow Convergence in the Fracture

Surface Area of Reservoir exposed to one Frac Wing is length \( \times \) height \( \times \) 2 sides = \( \sim \) 20,000 ft\(^2\)

Cross Sectional Area = width \( \times \) height = \( \sim \) 1 ft\(^2\)

Velocity in the fracture is 20,000 times higher than in the formation!!

Width = 0.25 inches

Height = 50 ft

Length = 200 ft
Predicting Capacity of a Fracture

\[ \Delta P/L = \frac{\mu v}{k} + \beta \rho v^2 \]

\[ \Delta P/L = \frac{\mu v}{k} \]
Other Historical Studies

• C. M. White -1929
  - flowed liquids through coiled pipes, and found fluid inertia became important at Reynold’s numbers below 100.

• Ergun -1952
  - theoretical and experimental data confirm that the pressure drop through beds of granular solids are the sum of the viscous and kinetic energy losses.
  - Ergun equation is commonplace in calculations of heat and mass transfer to and from moving fluids.
• Claude Cooke - 1973 (SPE 4119)

- measured beta factors under stress for a variety of sand proppants
- verified that Beta factor is fluid independent
- recognized that fracture conductivity limits the production of wells
- case studies for wells making 1 to 10 MMSCFD showed that non-Darcy pressure drop can be 3 to 19 times higher than predicted with Darcy’s Law
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Ports for Measuring Differential Pressure
Temperature Port
Proppant Bed
Sandstone Cores
Flow Through Proppant Bed

Disassembled API Proppant Cell
Long Term Conductivity Cells
Example Proppant Conductivity Curve
Modified API RP-61 Procedure

Test Conditions: 2 lb/sq ft, 250°F, zero gel damage, YM = 5e6 psi, SLFrac 2001
Comparison of Viscous and Inertial Flow Effects - Dry Gas Well

Conditions: 20/40 Jordan Sand, 4000 psi stress, 50% gel damage, 50 ft frac height, 0.20 inch width, 1000 psi BHFP, SLFrac 2001

API Testing in laminar flow

This component controlled by $\beta$
Beta Factor

- A material property that can be experimentally measured for each proppant size and type.
- Essentially a measure of the tortuosity of the flowpath in the proppant pack.
- Beta can be reduced by:
  - High Initial Permeability (high perm equates to less tortuous flow path).
  - Tight Size Distribution (uniform pore size, and high porosity minimizes expansion/contraction losses).
  - High proppant sphericity (angularity is bad).
  - Smooth Proppant Surface
Forchheimer Equation

- \( \Delta P/L = \mu v / k + \beta \rho v^2 \)

- It may be linearized and rewritten as:
  \[
  Y = 1 / k_0 + \beta X
  \]

  where:
  \[
  Y = \Delta p/(L \mu v) \quad \text{and} \quad X = (\rho v/\mu)
  \]
  \( k_0 \) is the absolute permeability.
Example Forchheimer Plot

Test Conditions: 2 lb/sq ft, 6000 psi, 250°F, zero gel damage, YM = 5e6 psi, SLFrac 2001
Multiphase Flow Effects

- Multiphase flow should be considered in *most* wells.
- Even 1 or 2 bpd of condensate or water has a substantial impact on effective conductivity and production rate.
- BHFP and pressure in fracture body is typically below bubble point.
- Primary Causes: saturation changes, relative permeability effects, and increased complexity of non-Darcy flow regime (phase interaction).
Multiphase Flow in Proppant Packs

Increased Pressure Drop due to Mobile Liquid in Proppant Packs

Multiplier of Total Pressure Drop vs. Fractional Flow of Liquid

Source: Stim-Lab Proppant Consortium, Feb. 2001. 2.8 lb/sq ft CarboLite at 4000 psi stress, 550 Darcy reference perm. Multiplier is incremental to total pressure drop under non-Darcy conditions with dry gas. Equivalent rates from 50’ frac height at 2000 psi BHFP.
Impact of Multiphase Non-Darcy Flow
20/40 Proppants at 2 lb/sq ft, 6500 psi and 225 F
(Penny & Jin - SPE 30494)

Effective Conductivity (md-ft)

- API "Darcy Flow" Viscous Flow Conditions
- "Inertial Flow" With Non-Darcy Effects
- "True Flow" Multiphase and Non-Darcy Flow

Non-Darcy Test Conditions: 1 MMSCFD, 50 ft. frac height, 3000 psi BHFP, w/ and w/o 10 bwpd.
Impact of Multiphase Non-Darcy Flow
20/40 Proppants at 2 lb/sq ft, 6500 psi and 225 F
(Penny & Jin - SPE 30494)

Non-Darcy Test Conditions: 1 MMSCFD, 50 ft. frac height, 3000 psi BHFP, w/ and w/o 10 bwpd.
The Real World: How do we apply this information?

- Recognize that multiphase and non-Darcy flow effects dramatically reduce the effective conductivity of fractures.

- Additional conductivity reductions due to embedment and gel damage often result in actual fracture conductivity ranging from 1% to 5% of published reference values!

- Most fracture design tools disregard these effects.

- Adjustments must be made to the fracture design and production models to optimize the economic potential of the fracture treatment.
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Case Study #1
SPE 20707 & 24857
Kuparuk River Field, Alaska
Kuparuk River Field, Alaska
SPE 20707 & 24857

- 20 to 100 md in lower A Sand
- Fine sandstone with shale, quartz & ankerite cementation
- ~30 feet of pay at ~6000 ft TVD
- Stress on proppant = 3400 psi

Traditional thought was that these wells should not be fracture stimulated.

Unique data quality and quantity. Over 880 fracs, and over 200 refracs with multiple build up tests.
Evolution of Fracture Design - Kuparuk

- Initially, small “skin fracs” were pumped to frac past drilling damage.
- Average Flow Efficiency of 164% and $s = -1.6$
- No benefit found to pumping larger job sizes without increase in fracture conductivity
- Strong benefits achieved with:
  - higher permeability (lower Beta factor) proppants
  - the elimination of solid FLA’s; 100-mesh sand and silica flour
  - Improved fluids and Tip Screen Out (TSO) designs
- Five years of continual “learning” resulted in a doubling of production rates despite minimal benefit predicted with a Darcy flow model.
Kuparuk Proppant Parameters

For Proppants at 2 lb/sq ft

API Reference Conductivity (md-ft)

<table>
<thead>
<tr>
<th>Proppant</th>
<th>Conductivity</th>
</tr>
</thead>
<tbody>
<tr>
<td>20/40 Sand</td>
<td>0.00000</td>
</tr>
<tr>
<td>20/40 LWC</td>
<td>0.00025</td>
</tr>
<tr>
<td>16/20 LWC</td>
<td>0.00050</td>
</tr>
<tr>
<td>12/18 LWC</td>
<td>0.00075</td>
</tr>
<tr>
<td>20/40 LWC</td>
<td>0.00100</td>
</tr>
</tbody>
</table>

Beta (atm - sec^2/gram)

<table>
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<th>Beta</th>
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<tbody>
<tr>
<td>20/40 Sand</td>
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</tr>
</tbody>
</table>

SLFrac 2.21, 3400 psi stress, 150°F, 2.5e6 Modulus, 20% Gel Damage, 2 lb/sq ft
Impact of Multiphase Non-Darcy Flow
Kuparuk Formation

Effective Conductivity (md-ft)

API "Darcy Flow" Viscous Flow Conditions

"True Flow" Multiphase and Non-Darcy Flow

SLFrac 2.21, 3400 psi stress, 150°F, 2.5e6 Modulus, 20% Gel Damage, 2 lb/sq ft
Kuparuk Refrac Rates
SPE 24857

Phase I - GD 20/40 Sand (9 wells)
Phase II - GD/GW 20/40 LWC (27 wells)
Phase III - GD/GW 16/20 LWC (97 wells)
Phase IV - GW 12/18 LWC (52 wells)
Evolution of Kuparuk Frac Design
Relationship of Effective Conductivity to Rate

Predicted including non-Darcy and Multiphase Effects

Data: 3400 psi stress, 20% gel damage, YM of 2.5 mmpsi, 30 ft pay, 30 API oil at 650 scf/bbl, SLFrac 2.21
Kuparuk Well 2F-08
SPE 24857

Production from A Sand (bfpd)

Date

May-84 May-86 May-88 May-90 May-92 May-94 May-96 May-98 May-00

Original Fracture (20/40 Sand)
Refrac #1 (20/40 sand)
Refrac #2 (16/20 LWC)

Incremental Oil Exceeds 1,000,000 barrels
Incremental Oil exceeds 650,000 barrels
Kuparuk Well 2F-11
SPE 24857

Production from A Sand (bfpd)

Original Fracture (20/40 Sand)
Refrac #1 (20/40 sand)
Refrac #2 (16/20 LWC)

Incremental Oil Exceeds 1,000,000 barrels
Green River Basin, Wyoming

- Green River Basin wells consist of a stacked layer of reservoirs with 30 to 120 feet of productive interval.
- It is typical that the Frontier interval will be commingled with the deeper Bear River to get a commercial well.
Frontier Formation, Wyoming

- Permeability - .05 md
- Depth ~ 7800 ft
- Stress on Proppant ~ 5500 psi
- Reservoir Pressure - 2390 psi
- Net pay - 30 feet
- Fracture Geometry - 160’ X 500’ X .65#/sq ft
Wyoming - Green River Basin
Initial Production Rates vs Time

Phase 1
105k # sand

Phase 2 - increased sand volumes six-fold

Phase 3
235k# sand

Effective Decline for Sand Fracs

Phase 4 - replace sand with 270k# ISP

Phase 5 - back to sand as a “cost-saving” measure, 270-400 k#

Phase 6 - last drilling & sell field?

Chevron Frontier Wells, Wyoming
SPE 67299
Frontier Formation Proppant Parameters

SPE 67299

SLFrac July '98, 5460 psi stress, 150°F, 3.5e6 Modulus, 50% Gel Damage, 0.65#/sq ft
Impact of Multiphase Non-Darcy Flow
Frontier Formation - SPE 67299

Effective Conductivity (md-ft)

- API "Darcy Flow" Viscous Flow Conditions
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Frontier Formation Predicted Rates

104,000 lbs proppant, 0.65 lb/sq ft, 7750 ft, 0.75 psi/ft, 500 ft, 2 bldp
Predicted Vs. Actual IP Rates for Darcy and Non-Darcy Models

100% represents perfect prediction of initial rates
Predicted Vs. Actual IP Rates for Darcy and Non-Darcy Models

Ave Error for Darcy Model = +52%

Ave Error for Non-Darcy Model = +6%
Chevron Frontier Wells, Wyoming
SPE 67299

Wyoming - Green River Basin
Initial Production Rates vs Time

Initial Production Rate (MSCF/D)

Year

Phase 1
105k # sand

Phase 2 - increased sand volumes six-fold

Phase 3
235k# sand

Effective Decline for Sand Fracs

Phase 4 - replace sand with 270k# ISP

Phase 5 - back to sand as a “cost-saving” measure, 270-400 k#

Phase 6
324k# LWC
Subsequent Development

• Field has not been divested
• An additional 11 wells were drilled in 2000
• LWC fracs had an average IP of 2.34 MMscfd
• Eight wells being drilled in 2001
**SPE Papers Documenting Benefit of Increased Conductivity**

- **Over 70 SPE papers since 1973**

**28 Regions**
- Germany, North Sea, Australia, Colombia, Europe, Indonesia, Vietnam, West Africa, Norway, Malaysia, Venezuela, Siberia, Angola, China, Oman, Brazil, Wyoming, Texas, Iowa, Illinois, Colorado, Alaska, Appalachian, Oklahoma, Ohio, Gulf of Mexico, Louisiana, New Mexico

**• 44 Companies** (primary author’s affiliation)

**Oil wells, gas wells, lean and rich condensate**

- **Well Rates**
  - 1 to 25,000 bopd
  - 0.25-100 MMSCFD

- **Well Depths**
  - <3000 to 20,000 feet
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"In the past few years much consideration has been given to the evaluation of the effect of hydraulic fracturing on the productivity of wells........

........ Only little consideration has been given to the characteristics, and in particular the flow capacity, of the fracture itself and its effect on well production"
• Production rates from hydraulically fractured wells in a given reservoir are principally determined by the pressure drop in the fracture:
  - In gas wells this is dominated by the non-Darcy flow term ($\beta\rho v^2$) and multiphase effects.
  - For oil wells this is dominated by multiphase flow effects.

• Most completion engineers do not include these effects in their fracture design. This results in lower post-fracture production rates.
The ABC’s of Improving Production from Hydraulically Fractured Wells

**A**PI proppant conductivity tests were designed for use as a reference
“do not use these values for treatment design”

**B**eta factor of the proppant is the critical component for evaluating the necessary fracture conductivity

**C**ash flow improvement
The ABC’s of Improving Production from Hydraulically Fractured Wells

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