Natural Gas Engineering

Reservoir Petrophysics

Introduction to Geology

T.A. Blasingame, Texas A&M U.
Department of Petroleum Engineering
Texas A&M University
College Station, TX 77843-3116
+1.979.845.2292 — t-blasingame@tamu.edu
**Geology: Basic Porosity Types**

<table>
<thead>
<tr>
<th>FABRIC SELECTIVE</th>
<th>NOT FABRIC SELECTIVE</th>
</tr>
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<tbody>
<tr>
<td>INTERPARTICLE</td>
<td>FRACTURE</td>
</tr>
<tr>
<td>INTRAPARTICLE</td>
<td>CHANNEL*</td>
</tr>
<tr>
<td>INTERCRYSTAL</td>
<td>VUG *</td>
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<tr>
<td>MOLDIC</td>
<td>CAVERN*</td>
</tr>
<tr>
<td>FENESTRAL</td>
<td></td>
</tr>
<tr>
<td>SHELTER</td>
<td></td>
</tr>
<tr>
<td>GROWTH — FRAMEWORK</td>
<td></td>
</tr>
</tbody>
</table>

* Cavern applies to man-sized or larger pores of channel or vug shapes.

**Fabric Selective:**
- Porosity (and permeability) are functions of deposition and diagenesis.

**Not Fabric Selective:**
- Fractures, etc.
- Porosity and permeability may (or may not) be a function of deposition and diagenesis.

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**Fig. 2.13**—Classification of pores and pore systems in carbonate rocks (after Choquette and Pray¹¹).
Geology: Basic Porosity Types — Sandstones

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**Features:**
- Note intergranular porosity ("conventional reservoir concept).
- Clays can cause significant degradation of porosity.

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Geology: Sandstone Depositional Systems

a. Various sandstone depositional sequences — note the "transport" system evolves basinward.

From: Reservoir Sandstones — Berg (1986).

b. These schematics illustrate similarity in depositional processes and also give insight into heterogeneity.

Sandstone Reservoirs:
- Depositional sequences are well-established/accepted.
- Turbidite reservoirs are probably of most current interest.
Carbonate Reservoirs: Permeability/Porosity Character

- Porosity and permeability often weakly correlated in carbonates.
- Permeability in carbonates most often dependent on diageneric processes.

a. Crossplot of permeability versus porosity (logarithmic scales). Includes particle size as a variable.

b. Permeability-porosity profiles for various carbonate depositional sequences.
Petrophysics: Effect of Small-Scale Heterogeneities

- **Weber Example Core:**
  - Laminated Aeolian sandstone.
  - Thin beds (<1 cm) are common.
  - Some laminations have zero permeability (influence on vertical flow?).

- **General Considerations:**
  - Core-scale heterogeneities may or may not affect overall reservoir performance (depends on continuity).
  - Attempts to correlate small-scale heterogeneities are likely to fail, except for isolated samples.

- **Issues:**
  - How do such features affect:
    - Pressure transient behavior (well test time scale events)?
    - Pseudosteady-state behavior (production time scale events)?
  - Solutions for increasing reservoir exposure? (hydraulic fracturing?)

Permeability Comparison: Santa Barbara Field (Venezuela)

- Major conclusion is that these data due not appear to be correlated.
- High permeability values probably "overweigh" $k_{\text{log mean}}$ estimate.
- $k_{\text{PTA}}$ values higher than $k_{\text{WPA}}$, but we have only 3 (three) $k_{\text{PTA}}$ values.
Reservoir Scale Issues: *Halderson Schematics*

**Reservoir Scaling Issues**

- **NANO or ATTO**
- **MICRO**
- **MACRO**
- **MEGA**
- **GIGA**

a. (Haldersen) Four conceptual scales associated with porous media averages.

b. (Haldersen) Volume of investigation of a pressure build-up test and cross section indicating large-scale internal heterogeneities.

From: *Simulator Parameter Assignment and the Problem of Scaling in Reservoir Engineering* — Halderson (1986).
Geology/Petrophysics: Questions to Consider

Q1. Validity of correlations of petrophysical data?
A1. These will always be "local" correlations, difficult to extend or extrapolate across depositional systems.

Q2. Role of geology in PTA?
A2. Must consider geology in general, but particularly for cases where the following reservoir models are employed:
   - Linear sealing or leaky faults.
   - Bounded reservoir system.
   - Naturally fractured/dual porosity reservoir.
   - Multilayered reservoirs.

Q3. Correlation of \( k_{\text{core}} \) with \( k_{\text{PTA}} \)?
A3. Always a comparison of "apples and oranges" due to:
   - Sample size.
   - Saturation/mobility issues.

Q4. Effect of reservoir heterogeneity on PTA?
A4. Interesting question — volume-averaging appears to dominate the estimate of permeability obtained from PTA. Attempts to estimate permeability "distributions" will be non-unique and/or overly simplified.
Reservoir Petrophysics

Flow in Porous Media

T.A. Blasingame, Texas A&M U.
Department of Petroleum Engineering
Texas A&M University
College Station, TX 77843-3116
+1.979.845.2292 — t-blasingame@tamu.edu

Concept:
- "Tortuous paths"
- Darcy flow.

Concept:
- Perfect paths.
- Poiseuille flow.
- How to reconcile?

Figure 2: (A) - The complex geometry of solid surfaces which bound the flow domain.
(B) - Straight capillaric model.

Haldorsen, H.H.: "Simulator Parameter Assignment and the Problem of Scale in Reservoir Engineering."
Flow Concepts: Klinkenberg Effect

Liquid Flow:
- Governed by "viscous flow."
- Analog = Poiseuille flow.
- "Zero-slip" at wall concept.

Gas Flow:
- Molecules "slip" at wall.
- Gradient is lower than expected.
- Computed permeability higher.
- Results MUST be corrected.

Flow Concepts: High-Velocity Flow in Porous Media

An Analysis of High-Velocity Gas Flow Through Porous Media

Abbas Firoozabadi, Abadan Institute of Technology
Donald L. Katz, SPE-AIME, U. of Michigan

Fig. 1—Flow in a cylindrical conduit.

(a) Change of shape of fluid element.

(b) Longitudinal shear and longitudinal tension forces.

Fig. 2—Flow in an idealized pore.

(a) Low velocity

(b) Velocity higher

(c) Intermediate, transition

(d) High velocity, turbulent

Fig. 3—Idealized flow through alternating cross sections.
Flow Concepts: Klinkenberg Effect — $H_2$, Air, and $CO_2$

Issues:
- Smaller molecules = more severe Klinkenberg effect.
- The Klinkenberg effect can be derived and is a subset of "Knudsen Flow."

Permeability Constant of Core Sample "K" to Hydrogen, Air, and Carbon Dioxide at Different Pressures.

FIG. 4

Petrophysics: Low/Ultra-Low Permeability Issues (Nelson)

Simply Put:
- Molecules of fluid are on the same order of size as pores.
- Very different flow behavior than traditional "Darcy's Law."
- Also affects phase behavior (i.e., composition, density, temperature, and pressure relations).
- Definition of "unconventional" reservoirs.

Petrophysics: Permeability Characterization/Correlation

Permeability Characterization/Correlation:
- Permeability = \( f(\phi, \text{composition}, \text{texture}, \text{grain size}, \text{sorting}, \text{etc.}) \).
- Simplified correlations for permeability will only be of "local" use.


**Petrophysics:** \( k = a \exp[b \phi] \) (Schematic Trends)

**Sketched Trends:**
- Increase in porosity → increase in permeability (obvious).
- \( k = a \exp[b \phi] \)???
- This does not seem intuitive (statistics)?
- What about:
  \[ k = A \phi^B \]
- What about other variables?

**Petrophysics: \( k = a \exp[b \phi] \) (Archie Trends)**

- **Sketched Trends:**
  - Similar to previous schematic plot.
  - This is the "original" presentation by Archie (to the best of our knowledge, this is the first plot of \( \log(k) \) versus \( \phi \)).
  - There are many other variables:
    - Grain sizes
    - Sorting
    - Texture
    - Angularity
    - ...
  - These variables can not be directly quantified.

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**Archie, G.E.:** "Introduction to Petrophysics of Reservoir Rocks," *Bull.* AAPG (1950), 34, 943-961.
**Archie Results:**

- **Porosity:**
  \[ F = \frac{a}{\phi^m} \]
  - This result "makes sense" (i.e., volume of the room is proportional to the volume of the electrolyte).

- **Permeability:**
  \[ F = \frac{A}{k^B} \]
  - This result **DOES NOT** "make sense" (i.e., the size of the door is proportional to the volume of the room???).

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**Petrophysics: Archie k-\(\phi\)-F Relations**

![Graphs showing the relation of porosity and permeability to formation resistivity factor.](attachment:image.png)

**Figure 1.** Relation of porosity and permeability to formation resistivity factor for consolidated sandstone cores of the Gulf Coast.

**Figure 2.** Relation of porosity and permeability to formation resistivity factor, Nacatoch sand, Bellevue, La. Permeabilities below 0.1 millidarcy not recorded.
Petrophysics: Archie $k$-$\phi$-$F$ Relations

**a. Crossplot of formation (resistivity) factor versus permeability ($F = a/\phi^m$).**

**Porosity Model:**  
$$F = \frac{R_o}{R_w} \left[ \frac{a}{\phi^m} \right]$$

**Permeability Model:**  
$$F = \frac{R_o}{R_w} \left[ \frac{A}{k^B} \right]$$

**Equating the Models:**

$$\frac{a}{\phi^m} = \frac{A}{k^B}$$

**Solving for $k$:**

$$k = \left[ \frac{A}{a} \frac{\phi^m}{\phi} \right]^{1/B} = \alpha \phi^\beta$$

This exercise suggests that permeability and porosity are related by a power law relation — this observation is only true for uniform pore systems.

**b. Crossplot of formation (resistivity) factor versus permeability ($F = A/k^B$).**
Petrophysics: *Porosity-Permeability — Power Law Relation*

Legend: Thin Sections (photomicrographs)

A. Upper shoreface ($\phi = 0.207, k = 46.5 \text{ md}$) Vinton Cty, OH.
B. Lower shoreface ($\phi = 0.085, k = 3.43 \text{ md}$) Hocking Cty, OH.
C. Tidal channel ($\phi = 0.066, k = 0.0178 \text{ md}$) Carroll Cty, OH.
D. Tidal flat ($\phi = 0.053, k = 0.0011 \text{ md}$) Portage Cty, OH.
E. Fluvial ($\phi = 0.087, k = 15.3 \text{ md}$) Kanawha Cty, WV.
F. Estuarine ($\phi = 0.068, k = 0.0048 \text{ md}$) Preston Cty, WV.

a. Thin sections of Lower Silurian Sandstones, Appalachian Basin (US).

b. Appalachian samples — permeability is approximated as a power law function of porosity.

c. Attempt to correlate Morrow samples by deposition — similar to Appalachian samples.

Petrophysics: Fractal Model for Permeability (Pape)

a. Pape concept model plot — based on a fractal pore distribution. Some concern regarding the additive structure of the model (this seems to be a simplistic reduction of the fractal concept).

\[ k = a_1 \phi + a_2 \phi^2 + a_3 \phi^{10} \]

b. Legend for the Pape concept model plot. Note that there are several quite different data sets shown, yet the "structure" of the correlation appears consistent.

Petrophysics: *Influence on φ and k* (Unconsolidated Sand)

**Beard and Weyl Data:**

<table>
<thead>
<tr>
<th>Sorting</th>
<th>Grain Size</th>
<th>$d_{mean}$ (mm)</th>
<th>$k_{avg}$ Average Permeability (D)</th>
<th>$φ$ (Porosity fraction)</th>
<th>$k_{avg}/d^2$ (D/mm)$^2$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Extremely Well Sorted</td>
<td>Coarse</td>
<td>0.75</td>
<td>356.50</td>
<td>0.424</td>
<td>633.8</td>
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<tr>
<td>Very Well Sorted</td>
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<td>0.408</td>
<td>619.6</td>
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<tr>
<td>Well Sorted</td>
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<td>0.390</td>
<td>402.7</td>
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<td>0.307</td>
<td>60.4</td>
</tr>
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<td>0.424</td>
<td>632.9</td>
</tr>
<tr>
<td>Very Well Sorted</td>
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<td>86.00</td>
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<td>Well Sorted</td>
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<tr>
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<td>Very Fine</td>
<td>0.09375</td>
<td>—</td>
<td>—</td>
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</tr>
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<td>Very Fine</td>
<td>0.09375</td>
<td>—</td>
<td>—</td>
<td>—</td>
</tr>
</tbody>
</table>

**Morrow Data: (selected)**

<table>
<thead>
<tr>
<th>Well</th>
<th>Grain Size (mm)</th>
<th>$k_{avg}$ Average Permeability (D)</th>
<th>$φ$ (Porosity fraction)</th>
<th>$k_{avg}/d^2$ (D/mm)$^2$</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>0.084</td>
<td>0.1015</td>
<td>0.184</td>
<td>2.14</td>
</tr>
<tr>
<td>C</td>
<td>0.082</td>
<td>0.0046</td>
<td>0.174</td>
<td>0.66</td>
</tr>
<tr>
<td>C</td>
<td>0.190</td>
<td>0.1640</td>
<td>0.223</td>
<td>4.54</td>
</tr>
<tr>
<td>C</td>
<td>0.082</td>
<td>0.00335</td>
<td>0.179</td>
<td>0.59</td>
</tr>
<tr>
<td>D</td>
<td>0.155</td>
<td>2.23750</td>
<td>0.297</td>
<td>92.39</td>
</tr>
<tr>
<td>D</td>
<td>0.128</td>
<td>1.10800</td>
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<td>67.61</td>
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<tr>
<td>D</td>
<td>0.138</td>
<td>0.71450</td>
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</tr>
<tr>
<td>B</td>
<td>0.160</td>
<td>1.12250</td>
<td>0.319</td>
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<tr>
<td>B</td>
<td>0.120</td>
<td>0.29600</td>
<td>0.284</td>
<td>20.56</td>
</tr>
</tbody>
</table>

a. Data from Beard and Weyl, and Morrow et al. These are unconsolidated sand samples.

b. Log-log plot of $k/d^2$ versus $φ$ — extraordinary agreement given data quality (note slope ≈ 8).

From: 
**Correlation relation for this case.**

\[ k = a(\phi + c)^b \quad (b = 8) \]

\[ c = c_{\text{max}} \exp[-c_1 \phi c_2 S_w c_3] \]

Orientation:
- Possibly one of the most important sequences of experimental results in Petroleum Engineering.

Observations:
- Do you see "Darcy's Law?"
- Is it a good idea to formulate pressure drop as a "friction factor" for flow in porous media?
- What would you do?

Comment:
- Note that this approach is not perfect, ALL trends should overlay if the friction factor and Reynolds number are properly defined.
- Reformulate?
Petrophysics: Cornell-Katz Relation for High-Velocity Flow

Formulation:
- Cornell and Katz appear to have chosen appropriate definitions for Reynolds number and friction factor.
- Are all of these variables "measurable?"

Observations:
- Excellent conformance for all cases?
- The curved and flat portions are for "Forchheimer" flow (pressure gradient is proportional to velocity squared).

Comment:
- Non-linear, requires numerical solutions.

Reservoir Petrophysics
(End of Lecture)

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