The Characteristic Flow Behavior of Low-Permeability Reservoir Systems

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Presentation Outline

● Orientation
● Properties of Reservoir Rocks:
  ■ Petrophysics Primer (review of Archie work).
  ■ Power Law Models for Permeability (low permeability systems).
● Non-Darcy Flow Behavior:
  ■ Historical Perspectives.
  ■ Current Perspectives.
● Characteristics of Low Permeability Reservoirs:
  ■ Effect of Clay Minerals.
  ■ Issues Related to Flow in Low Permeability Reservoirs.
● Hydraulic Flow Units:
  ■ Data Integration Work-Flows.
  ■ Reservoir Scaling.
● Tight Gas Reservoir Behavior:
  ■ Concept/Schematic of Elliptical Flow Behavior.
  ■ Performance of Fractured Wells in Low Permeability Systems.
● Conclusions and Recommendations
The Characteristic Flow Behavior of Low-Permeability Reservoir Systems

Properties of Reservoir Rocks

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Petrophysics: *Petrophysical Properties Map*

**Archie "Map" of Inter-relations of Petrophysical Properties (1950)!**

a. Systematic "mapping" of the inter-relation of petrophysical properties. Note that Archie observed that permeability was "connected" to saturation, porosity, and electrical properties — but the relationship was vague, as it remains today.

b. Crossplot of permeability to porosity (average trends) — used to imply that porosity and permeability have some type of functional relationship. Obviously, this remains a topic of considerable discussion.

**Petrophysics: Archie $k$-$\phi$-$F$ Relations**

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

<table>
<thead>
<tr>
<th>Porosity Model:</th>
<th>Permeability Model:</th>
</tr>
</thead>
<tbody>
<tr>
<td>$F = \frac{R_o}{R_w} \left[ = \frac{a}{\phi^m} \right]$</td>
<td>$F = \frac{R_o}{R_w} \left[ = \frac{A}{k^B} \right]$</td>
</tr>
</tbody>
</table>

**Equating the models:**

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

**Solving for $k$:**

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

*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: Power Law Permeability Relations

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.

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: *Power Law Permeability Relations*

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**Pape et al Fractal Model for Permeability:**

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

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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).

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.

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**Petrophysics: Power Law Permeability Relations**

### Beard and Weyl Data:

<table>
<thead>
<tr>
<th>Sorting</th>
<th>Grain Size</th>
<th>$(d_i)$ (mm)</th>
<th>Average Permeability ($k_{avg}$) ($D$)</th>
<th>Porosity ($\phi$) (fraction)</th>
<th>$k_{avg}/d_i^2$ (D/mm$^2$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Extremely Well Sorted</td>
<td>Coarse</td>
<td>0.75</td>
<td>356.500</td>
<td>0.424</td>
<td>632.8</td>
</tr>
<tr>
<td>Very Well Sorted</td>
<td>Coarse</td>
<td>0.75</td>
<td>348.500</td>
<td>0.408</td>
<td>619.6</td>
</tr>
<tr>
<td>Well Sorted</td>
<td>Coarse</td>
<td>0.75</td>
<td>226.500</td>
<td>0.390</td>
<td>402.7</td>
</tr>
<tr>
<td>Moderately Well Sorted</td>
<td>Coarse</td>
<td>0.75</td>
<td>82.500</td>
<td>0.340</td>
<td>146.7</td>
</tr>
<tr>
<td>Poorly Sorted</td>
<td>Coarse</td>
<td>0.75</td>
<td>34.000</td>
<td>0.307</td>
<td>60.4</td>
</tr>
<tr>
<td>Very Poorly Sorted</td>
<td>Coarse</td>
<td>0.75</td>
<td>10.500</td>
<td>0.279</td>
<td>18.7</td>
</tr>
<tr>
<td>Extremely Well Sorted</td>
<td>Medium</td>
<td>0.375</td>
<td>89.000</td>
<td>0.424</td>
<td>622.9</td>
</tr>
<tr>
<td>Very Well Sorted</td>
<td>Medium</td>
<td>0.375</td>
<td>86.000</td>
<td>0.408</td>
<td>611.6</td>
</tr>
<tr>
<td>Well Sorted</td>
<td>Medium</td>
<td>0.375</td>
<td>57.000</td>
<td>0.390</td>
<td>405.3</td>
</tr>
<tr>
<td>Moderately Well Sorted</td>
<td>Medium</td>
<td>0.375</td>
<td>21.000</td>
<td>0.340</td>
<td>149.3</td>
</tr>
<tr>
<td>Poorly Sorted</td>
<td>Medium</td>
<td>0.375</td>
<td>9.000</td>
<td>0.307</td>
<td>64.0</td>
</tr>
<tr>
<td>Very Poorly Sorted</td>
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<td>0.375</td>
<td>1.750</td>
<td>0.279</td>
<td>12.4</td>
</tr>
<tr>
<td>Extremely Well Sorted</td>
<td>Fine</td>
<td>0.1875</td>
<td>22.500</td>
<td>0.424</td>
<td>640.0</td>
</tr>
<tr>
<td>Very Well Sorted</td>
<td>Fine</td>
<td>0.1875</td>
<td>21.500</td>
<td>0.408</td>
<td>611.6</td>
</tr>
<tr>
<td>Well Sorted</td>
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<td>0.1875</td>
<td>14.200</td>
<td>0.390</td>
<td>403.9</td>
</tr>
<tr>
<td>Moderately Well Sorted</td>
<td>Fine</td>
<td>0.1875</td>
<td>5.250</td>
<td>0.340</td>
<td>149.3</td>
</tr>
<tr>
<td>Poorly Sorted</td>
<td>Fine</td>
<td>0.1875</td>
<td>—</td>
<td>0.307</td>
<td>—</td>
</tr>
<tr>
<td>Very Poorly Sorted</td>
<td>Fine</td>
<td>0.1875</td>
<td>—</td>
<td>0.279</td>
<td>—</td>
</tr>
<tr>
<td>Extremely Well Sorted</td>
<td>Very Fine</td>
<td>0.09375</td>
<td>5.550</td>
<td>0.424</td>
<td>631.5</td>
</tr>
<tr>
<td>Very Well Sorted</td>
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<td>0.09375</td>
<td>5.400</td>
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</tr>
<tr>
<td>Well Sorted</td>
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<td>0.09375</td>
<td>3.550</td>
<td>0.390</td>
<td>405.9</td>
</tr>
<tr>
<td>Moderately Well Sorted</td>
<td>Very Fine</td>
<td>0.09375</td>
<td>—</td>
<td>0.340</td>
<td>—</td>
</tr>
<tr>
<td>Poorly Sorted</td>
<td>Very Fine</td>
<td>0.09375</td>
<td>—</td>
<td>0.307</td>
<td>—</td>
</tr>
<tr>
<td>Very Poorly Sorted</td>
<td>Very Fine</td>
<td>0.09375</td>
<td>—</td>
<td>0.279</td>
<td>—</td>
</tr>
</tbody>
</table>

### Morrow Data: (selected)

<table>
<thead>
<tr>
<th>Well</th>
<th>$(d_i)$ Grain Size (mm)</th>
<th>Average Permeability ($k_{avg}$) ($D$)</th>
<th>Porosity ($\phi$) (fraction)</th>
<th>$k_{avg}/d_i^2$ (D/mm$^2$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>0.084</td>
<td>0.01510</td>
<td>0.184</td>
<td>2.14</td>
</tr>
<tr>
<td>C</td>
<td>0.082</td>
<td>0.00460</td>
<td>0.174</td>
<td>0.68</td>
</tr>
<tr>
<td>C</td>
<td>0.190</td>
<td>0.16400</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>0.50</td>
</tr>
<tr>
<td>D</td>
<td>0.155</td>
<td>2.23750</td>
<td>0.297</td>
<td>92.30</td>
</tr>
<tr>
<td>D</td>
<td>0.128</td>
<td>1.10800</td>
<td>0.290</td>
<td>67.63</td>
</tr>
<tr>
<td>D</td>
<td>0.138</td>
<td>0.71450</td>
<td>0.263</td>
<td>37.52</td>
</tr>
<tr>
<td>B</td>
<td>0.160</td>
<td>1.12550</td>
<td>0.319</td>
<td>43.96</td>
</tr>
<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 $k/d_i^2$ versus $\phi$ — extraordinary agreement given data quality (note slope $\approx 8$).

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Petrophysics: *Power Law Permeability Relations*

![Diagram of Permeability Correlation](image)

**a. Correlation plot of calculated versus measured permeability. — East Texas (US) tight gas example.**

**Correlation relation for this case.**

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

\[ c = c_{\text{max}} \exp[-c_1\phi^2 S_w^2 c^2] \]

**b. Log-log correlation plot of \( k \) versus \( \phi \). The correlation function yields an envelope.**

**c. Correlation plot of depth versus log(\( k \)). Correlation appears to be excellent.**

[From: Siddiqui and Blasingame (2008) — Work in Progress.]
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Non-Darcy Flow Behavior

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Non-Darcy Flow: Historical Perspectives

a. Fancher et al — this was the first systematic attempt to validate Darcy's law, and consider extensions for high-velocity flow.

b. Firoozabadi and Katz — Schematic of low and high velocity flow regimes (for visualization).

c. Cornell and Katz — this work provided a "unified" solution for high-velocity by employing the Forchheimer relation.

Non-Darcy Flow: Current Perspectives

Questions: (Huang and Ayoub)
1. What is the applicable range of the Forchheimer equation for describing non-Darcy flow?
2. What are the flow regimes and behaviors beyond the Forchheimer regime?
3. Are these flow regimes relevant?

Issues:
- The Darcy and Forchheimer equations were developed empirically and validated using fluid mechanics. Will it ever be possible to characterize a porous media uniquely, at the micro- or nano-scale levels?
- Is the Forchheimer regime a limitation? (probably not, but more work is warranted)

Proposal: (Barree and Conway)
- The "Logistic Dose" equation is proposed to model the "apparent" permeability ($k_{app}$) variable.
- The "Logistic Dose" relation is empirically tuned to data.

$$k_{app} = k_{min} + \frac{(k_d - k_{min})}{(1 + R^F_E)E}$$

Where:
- $k_d$ = Darcy permeability.
- $k_{app}$ = Apparent permeability.
- $k_{min}$ = Minimum permeability.
- $R_E$ = Reynolds number.
- $E$ = Empirical constant.
- $F$ = Empirical constant.

The Characteristic Flow Behavior of Low-Permeability Reservoir Systems

Characteristics of Low Permeability Reservoirs

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Low $k$ Reservoirs: Influence of Clay Minerals

Legend: SEM Micrographs
A. (240X) Grains with clay overgrowths.
C. (600X) Microporosity and clay filling.
D. (1400X) Rosettes of chlorite (note illite deposition).

a. Severe influence of clay minerals in this reservoir system — production shown to be uniquely tied to reservoir quality and effectiveness of well stimulation.

b. Geology concept model for Hay Reservoir.

c. Note the poor production behavior of the (well) Hay Reservoir Unit No. 2. This well has been recompleted/re-stimulated, initial completion lasted less than 4 years.

Low $k$ Reservoirs: *Influence of Clay Minerals*

Three general types of dispersed clay in sandstone reservoir rock

a. Schematic diagrams of clay minerals occurring in "tight gas" reservoirs.

b. Crossplot of air permeability to porosity at 1000 psig. Note correlation with clay types.

Low $k$ Reservoirs: Influence of Clay Minerals

a. Schematic/semi-quantitative extension of Neasham work showing permeability-porosity relationship for clay-bearing sandstones. Should be extended for modern cases of very low porosity/micro-Darcy permeability.

b. Schematic illustrating distributions of detrital clays.

c. Schematic illustration of clay diagenesis as a function of burial depth.

**Low k Reservoirs: Tight Gas Basins (circa 1980s)**

**Comparison of Properties for Conventional and Tight Gas Reservoirs**

<table>
<thead>
<tr>
<th>Property</th>
<th>Conventional Gas Sandstone</th>
<th>Tight Gas Blanket and Lenticular Sandstone (LP Reservoir)</th>
<th>Tight Gas Blanket Silstone, Silty Shale (HP Reservoir)</th>
<th>Tight Gas Blanket Chalk (HP Reservoir)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Porosity (%)</td>
<td>14-25 +</td>
<td>3-12 +</td>
<td>&lt;25-45</td>
<td>Primary</td>
</tr>
<tr>
<td>Porosity Type</td>
<td>Primary (intergranular), some secondary</td>
<td>Common secondary (microvug), some intergranular</td>
<td>Dominantly primary, some secondary</td>
<td>Primary</td>
</tr>
<tr>
<td>Porosity Communication</td>
<td>Good to excellent short pore throat</td>
<td>Poor, relatively long, sheet or ribbonlike capillary system</td>
<td>Good, short pore throats, but gas flow impeded by clays, small size of pore, and high S_w</td>
<td>Excellent, but gas flow impeded by size of pore and high S_w</td>
</tr>
<tr>
<td>Relative Clay Content in Pores</td>
<td>Low</td>
<td>High to moderate</td>
<td>Low to high</td>
<td>Low</td>
</tr>
<tr>
<td>Geophysical Well-Log Interpretation</td>
<td>Generally reliable in low-clay-content reservoirs</td>
<td>Generally unreliable owing to very thin porous laminations and high water saturation</td>
<td>Fair, some problems with deep mud filtrate invasion</td>
<td></td>
</tr>
<tr>
<td>Water Saturation (%)</td>
<td>25-50</td>
<td>45-70 +</td>
<td>40-90 approximate</td>
<td>30-70 approximate</td>
</tr>
<tr>
<td>In-Situ Permeability to Gas (md)</td>
<td>1.0-500 +</td>
<td>0.1-0.0005</td>
<td>&lt;0.1</td>
<td>&lt;0.1</td>
</tr>
<tr>
<td>Capillary Pressure</td>
<td>Low</td>
<td>Relatively high</td>
<td>Moderate</td>
<td>Moderate to high</td>
</tr>
<tr>
<td>Reservoir Rock Composition</td>
<td>Abundant quartz, minor feldspar and rock fragments</td>
<td>Quartz (60-90%), common rock fragments and some detrital feldspar and mica; may have carbonate cement</td>
<td>Quartz, feldspar, rock fragments, and clays; may have carbonate cement</td>
<td>Silt-size calcium carbonate microfossils, minor clay and quartz</td>
</tr>
<tr>
<td>Grain Density (g/cm³)</td>
<td>2.65</td>
<td>2.65-2.74 + (average 2.68-2.71 in silstone)</td>
<td>Unknown; probably 2.65-2.70</td>
<td>2.71</td>
</tr>
<tr>
<td>Reservoir Pressure</td>
<td>Usually normal to underpressured</td>
<td>May be underpressured or overpressured</td>
<td>Underpressured</td>
<td>Underpressured</td>
</tr>
<tr>
<td>Recovery of Gas In Place (%)</td>
<td>75-90</td>
<td>&lt;15-50 estimated low for individual reservoirs</td>
<td>Unknown; probably low 30-50 +</td>
<td></td>
</tr>
</tbody>
</table>

b. Tight gas reservoir basins and areas in western United States (circa 1980).

c. Schematic of "blanket" and "lenticular" sands, including gas and water distributions. Reservoir quality controlled by deposition and diagenesis.

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Low $k$ Reservoirs: Basin-Centered Gas (circa 2000)

a. Schematic diagram of a basin-centered gas accumulation, the overpressure zone is mapped and correlated with the depth-pressure chart.

b. Known and potential basin-centered gas accumulations in the United States (circa 2000).

c. Schematic of "direct" and "indirect" basin-centered gas accumulations — note that the gas is trapped below the water.

"Permeability Jail" Concept (attempt to explain water-blocked gas production)

(a) Illustrative example of "permeability jail" concept for a stratigraphic trap with high capillary pressure behavior.

(b) Comparison of concept models for "traditional" and low permeability reservoir rock. \textit{Implies that gas flow in low permeability systems is dominated by capillary pressure effects.}

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Hydraulic Flow Units
(Integration of Reservoir Scales)

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Petrophysical Integration Process Model

Reservoir Integration Process Model

- Reservoir Integration Process Model
  - Enhanced over previous process in terms of data integration and connection with reservoir modeling.
  - Emphasizes multiple analyses and overlapping data types to confirm flow capability.

Remaining Technical Challenges:
- Need for to create functional computational workflow/computer module so that tasks can be performed sequentially and simultaneously.
- Need to resolve reservoir scales — for example, petrophysical measurements and the results of well test analyses.

Other Pitfalls:
- This is not an inexpensive proposition — data must be acquired early and often, particularly production data.
- Can not avoid expenditure on petrophysical data (core, logs, etc.) — tasks can be targeted, but not eliminated.

Reservoir Scale Issues: Haldersen Schematics

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

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

The Characteristic Flow Behavior of Low-Permeability Reservoir Systems

Tight Gas Reservoir Behavior
(Elliptical Flow Behavior)

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Elliptical Flow: Elliptical Flow (circa 1980)

Linear Flow (Early to Intermediate Times)

Elliptical Flow (Intermediate to Late Times)

Pseudoradial Flow (Late Times)

Single-Well Elliptical Drainage Pattern

Multi-Well Elliptical Drainage Pattern

a. (Thompson) At the micro-Darcy permeability scale, it is VERY unlikely that pseudoradial flow will ever exist. The elliptical pattern is more likely.

b. (Roberts) The concept of single and multiple well elliptical drainage patterns has long been and assumption for tight gas development.

Elliptical Flow: **Elliptical Flow Models (Basics)**

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**Extension of "Riley" Elliptical Flow Model — Finite-Acting Reservoir Case**


**Comparison Using Cinco and Samaniego’s Type Curves**

b. Riley solution for compared to conventional solution for finite conductivity fracture case.


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a. Fracture modeled as an ellipse — Riley solution (infinite-acting reservoir).

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Elliptical Flow: Production Decline Type Curves

a. Elliptical flow type curve solution — low fracture conductivity case.

b. Elliptical flow type curve solution — high fracture conductivity case.

c. Schematic of the elliptical boundary model for a single well.

d. Match of production data functions ("Mexico" Gas Well) — elliptical flow type curve solution.

Elliptical Flow: Numerical Solution

a. Pressure profile at 0 year (0 hr).
b. Pressure profile at 1 year (8768 hr).
c. Pressure profile at 5.59 years (49,010 hr).
d. Pressure profile at 9.26 years (81,200 hr).
e. Pressure profile at 18.44 years (161,700 hr).
f. Pressure profile at 44.10 years (386,600 hr).

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Summary, Conclusions, and Recommendations

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Conclusions and Recommendations

- Petrophysical data are critical elements of a reservoir description for a low permeability system.
- Non-Darcy flow models are largely empirical, but may also be sufficient for application purposes.
- The effect of clay in a low permeability gas reservoir should never be ignored/neglected.
- Tight gas/shale gas basins are well-known (North America), but are (historically) slow to develop.
- Integrated reservoir descriptions are necessary for the exploitation of low permeability gas reservoirs — tie geology and reservoir performance.
- Fractured wells in low permeability reservoirs will produce elliptical flow patterns for the (essentially) the productive life of the well.
- We need to improve our understanding of "scale effects" in low permeability reservoirs (geology?).
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End of Presentation

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