Tracer-Guided Characterization of Dominant Pore Network and Implications on Permeability and Wettability in Shale*

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Abstract

Pore network characterization is an important aspect in unconventional reservoir evaluation. A common technique is using the scanning electron microscope (SEM). While application of this technique brings substantial advances in pore characterization in shales, understanding the connected pore network that dominates flow in shale samples is limited by using SEM alone because of small fields-of-view and lack of views of connectivity in 3D. In this research, a new technique integrating tracer imbibition, micro-CT imaging, and SEM imaging was developed to provide a “real” solution for multiscale imaging in shale. Tracer imbibition indicates pore connectivity; micro-CT imaging after tracer imbibition thus provides an overview of the connected pore network at the millimeter scale. With guidance from micro-CT images after tracer imbibition, a more accurate and detailed characterization of pore systems and related mineralogy can be conducted using higher-resolution SEM. Therefore, this integrated method provides a way of simultaneous viewing of the overall framework of the dominant pore network and details of the pores. The method was applied to five samples from Wolfcamp and Eagle Ford Formations. Results reveal the effectiveness of the new method by showing different patterns of distribution of the dominant pore network and different controlling mineralogy. Dominant porosity, estimated from grayscale analyses, displays a good correlation with permeability. This result indicates that dominant porosity is more relevant to permeability than total porosity. Results from imbibition tests and micro-CT imaging are compared with that from contact angle measurement. Important implication for wettability can be obtained from the comparison. Contact angle measurements characterize the surface wettability and the results are consistent with the imbibition behavior in microfractures, whereas local pore wettability is more complicated and is affected by local surrounding mineral phases or organic matter.

References Cited


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1. Bureau of Economic Geology, University of Texas at Austin
2. Argonne National Laboratory
Motivation

• SEM is an important technique for pore network characterization

• However, it is challenging to evaluate the “big picture” of the pore network using SEM alone

• It is also difficult to evaluate pore connectivity using SEM

≈10,000 SEM images are needed to fully describe a mm-scale sample

0.5 mm

2 mm

10 µm
Motivation

• The sessile drop method measures contact angle of the sample surface

• The contact angle may not represent pore wettability
  • Pore surface ≠ sample surface
An integrated technique of tracer imbibition and multi-scale imaging

- Tracer (CH$_2$I$_2$) imbibition + micro-CT + SEM/EDS
- CH$_2$I$_2$: an oil-phase tracer, non-polar
Samples from Wolfcamp and Eagle Ford Shale

<table>
<thead>
<tr>
<th>Sample</th>
<th>Formation</th>
<th>Depth (ft)</th>
<th>Mineralogy (XRD or XRF) facies</th>
</tr>
</thead>
<tbody>
<tr>
<td>W1</td>
<td>Wolfcamp</td>
<td>10773</td>
<td>Calcareous mudstone</td>
</tr>
<tr>
<td>W2</td>
<td>Wolfcamp</td>
<td>10486</td>
<td>Siliceous mudstone</td>
</tr>
<tr>
<td>W3</td>
<td>Wolfcamp</td>
<td>10505</td>
<td>Siliceous mudstone</td>
</tr>
<tr>
<td>E1</td>
<td>Eagle Ford</td>
<td>12308</td>
<td>Calcareous mudrock (marl)</td>
</tr>
<tr>
<td>E2</td>
<td>Eagle Ford</td>
<td>11943</td>
<td>Calcite-rich argillaceous mudrock</td>
</tr>
</tbody>
</table>

- Different or same lithofacies based on mineralogy
Results of Sample W1: Micro-CT

- Diameter of the “mini-plug” is 1.5 mm
- Micro-CT images have pixel resolution of 0.65 µm
- The difference image (oil – dry) shows areas with tracer imbibition
  - Lighter areas indicate tracer imbibition
  - Darker areas indicate no tracer imbibition
Tracer-Guided Comparison: Micro-CT vs. BSE

- Precisely aligned micro-CT and BSE images
- **The registered micro-CT image (tracer + dry) provides a guidance for further characterization with SEM**
Dominant Pore Network in W1

- Has evident grayscale contrast
- Has relatively **uniform** distribution **in mm-scale**
- Persists from bottom to top of the sample (5 mm)
Tracer-Guided Characterization of Pores and Local Mineralogy/Organic Matter

- Dominant pore type in W1 is **clay mineral pores**
- Which are distributed in “clay mineral clusters” between larger calcite and quartz grains
Tracer-Guided Characterization of Pores and Local Mineralogy/Organic Matter

- Dominant pore type in W1 is **clay mineral pores**
- Which are distributed in “clay mineral clusters” between calcite and quartz grains
Tracer-Guided Characterization of Pores and Local Mineralogy/Organic Matter

- Kerogen with no pores shows no tracer imbibition
- Organic-matter pores are not important in W1
The Integrated Method Facilitates Multi-Scale Characterizations of the Dominant Pore Network

- Dominant pore network in **mm-scale**
- Local mineralogy (**μm-scale**) surrounding the pores
- Pores (**nano-scale**) within the dominant pore network
Results of An Eagle Ford Shale Sample (E1)

- Dominant pore network has **layered distribution**
- The layers are coccolith-rich lens
- Dominant pore type is **interparticle pores** with **organic matter boundaries** between coccolith pieces
Pores without Tracer Imbibition in E1

- Many pores exist within bitumen and between clay minerals in forams
- No (evident) imbibition indicates poor connectivity of these pores
Permeability-Porosity Relationship

- Porosity and permeability were measured using a modified gas expansion method (Peng et al., 2019a)
- No correlation between matrix permeability and porosity
Samples with higher permeabilities show more tracer imbibition.

Dominant porosity can be estimated based on grayscale contrast in the micro-CT images and the measured total porosity (Peng et al., 2019b).
Improved Permeability-Porosity Relationship

- A **positive correlation** exists between **permeability** and **dominant porosity**
- This indicates dominant pores (relatively larger and more densely-distributed) are more relevant to flow
Surface, Pore, and Microfracture Wettability

- Contact angle using the sessile drop method of the oil is 86°, meaning the sample surface is neutrally-wet to oil (CH₂I₂).
- Tracer imbibition occurred in pores within coccolith layers → pores are oil-wet.
- The contradictory results indicate that surface wettability ≠ pore wettability in shale,
- which is because that the bulk mineralogy and surrounding mineralogy (or organic matter) of pores are different.
- However, surface wettability can be consistent with microfracture wettability.
Conclusions

• The integrated method of tracer imbibition and imaging provides a path for multiscale characterization of the dominant pore network in shale
  • The characterization provides new insights on pore network distribution in mm-scale, local mineralogy surrounding pores in μm-scale, and details of the dominant pores in nm-scale

• Dominant porosity is more relevant to permeability than total porosity

• Pore wettability is different from surface wettability in shale, whereas “fresh” microfracture wettability can be consistent with surface wettability
• Peng, S., B. Ren, M. Meng, 2019a, Quantifying the Influence of Fractures for More Accurate Laboratory Measurement of Shale Matrix Permeability using a Modified Gas Expansion Method, SPE Reservoir Evaluation & Engineering-Formation Evaluation, SPE-195570-PA


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Thank you for attention!
Questions?

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