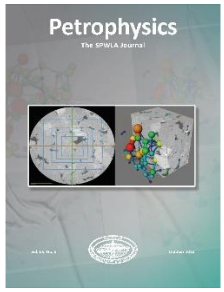

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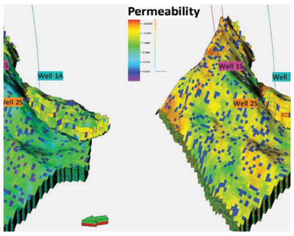
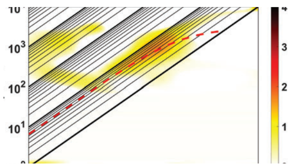


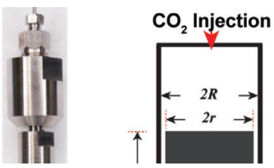
Akbar et al. **PAGES 924–938**

This study presents an integrated workflow that links special core analysis (SCAL) flow properties to pore geometry structure (PGS) rock types for improved reservoir characterization. Using a comprehensive SCAL database combined with data-driven and trend analyses, the method defines representative saturation functions for each rock type, including base-case, optimistic, and pessimistic bounds. The resulting rock types and relative permeability functions are fully suitable for full-field reservoir simulation, uncertainty assessment, and performance evaluation.



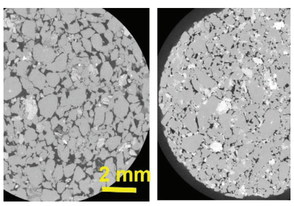
Ansaribaranghar et al. **PAGES 1073–1089**

Natural abundance ^{13}C MR relaxation times are sensitive to wettability changes in core plugs saturated with crude oil and brine. This hydrocarbon-specific, noninvasive readout enables reliable wettability assessment for special core analysis without the signal lifetime overlap that limits ^{1}H MR.



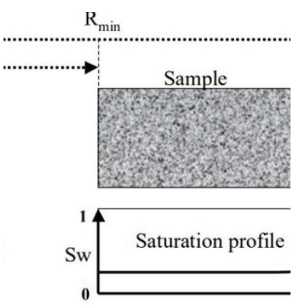
Chen et al. **PAGES 982–994**

This study evaluates CO_2 uptake measurement methods in source rock shales for geological carbon sequestration, showing that traditional adsorption techniques are ineffective for fluid-bearing source rocks. The high-field ^{13}C NMR spectroscopy method provides a robust and reliable method to measure the CO_2 uptake capacity in source rocks with in-situ fluids.



Faisal et al. **PAGES 996–1012**

This study demonstrates how digital rock physics (DRP) workflows, combined with fast pore-scale wettability characterization, enhance the accuracy of relative permeability predictions. By analyzing two sandstone lithotypes from the same well, the research identifies distinct mixed-wet models and shows their significant impact on flow simulations, underscoring the need for rapid wettability assessment in reservoir studies.



Fernandes et al. **PAGES 957–968**

This article provides a comprehensive review of primary drainage techniques in special core analysis (SCAL), highlighting their respective advantages, limitations, and the challenges they pose for accurately restoring reservoir conditions in laboratory settings. It introduces recent technological advances, including a novel hybrid drainage technique that optimizes sample preparation by reducing experimental artifacts and shortening test durations. The work serves as a valuable reference for engineers and researchers aiming to enhance the reliability of SCAL measurements and reservoir modeling, especially in the context of energy transition and CO_2 storage.

Halisch et al. **PAGES 1013–1031**

This study demonstrates how ionic dopants such as NaI, KI, or $BaCl_2$ can significantly alter electrokinetic rock properties, potentially biasing wettability interpretations in SCAL workflows. The observed zeta potential shifts reveal dopant-specific effects on surface charge behavior, emphasizing the value of electroacoustic screening as a diagnostic tool for dopant-induced wettability changes.

Karoussi et al. **PAGES 1043–1060**

The study investigates the wettability alteration phenomena in presalt carbonate reservoirs, which are primarily mixed-wet to oil-wet, that become more water-wet under modified seawater injection. The results provide evidence that seawater injection alters matrix wettability, leading to increased oil recovery and changes in water saturation dynamics. These findings improve understanding of how wettability alteration influences planning for future field developments that employ water injection for enhanced oil recovery.

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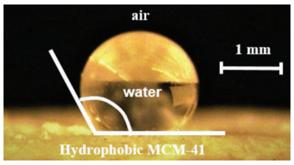
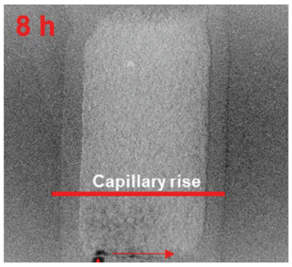


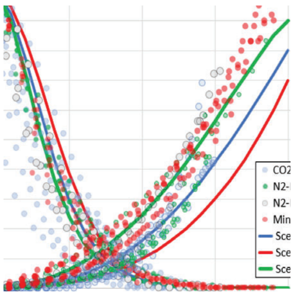
Nguyen et al. **PAGES 1061–1071**

This paper investigated how wettability controls the confined phase behavior of ethane in MCM-41 nanoporous materials. Hydrophilic surfaces promote stronger adsorption and earlier capillary condensation, especially in small pores and at elevated temperatures. These findings illustrate how tuning surface chemistry can optimize materials for gas storage and separation.



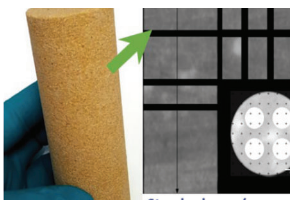
Nono et al. **PAGES 1032–1042**

This study introduces a new digital rock physics (DRP) protocol that restores reservoir rock wettability without using dopants, which are commonly and mandatorily added in traditional methods to enhance imaging contrast but can alter wettability. By comparing results from the new and old approaches on the same rock samples, the research highlights significant differences in wettability outcomes, which might impact pore network modeling results. It highlights the importance of removing dopants in wettability restoration protocols when focusing on DRP studies.



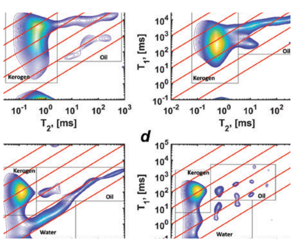
Schembre-McCabe et al. **PAGES 969–981**

This study presents a novel methodology for estimating CO_2/brine drainage relative permeability curves by utilizing analog two-phase systems, such as nitrogen/mineral oil, to address the scarcity and variability of direct CO_2/brine measurements. By aligning key dimensionless parameters—particularly viscosity ratio and capillary number—the authors demonstrate that analog systems can reliably replicate CO_2/brine flow behavior, supported by both experimental data and digital rock physics simulations. This analog-based approach offers a robust, uncertainty-aware framework to enhance predictive modeling in carbon storage applications where direct measurements are limited.



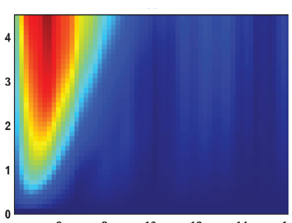
Youssef et al. **PAGES 939–955**

Using cutting-edge 3D X-ray µCT imaging and deep learning, the study demonstrates how to accurately predict permeability across multiple sandstone rock types. The deep residual network outperformed other models, demonstrating strong accuracy and generalization. Gray-level images further improved predictions, highlighting the potential of deep learning in digital rock characterization.



Zamiri et al. **PAGES 1090–1100**

^{13}C and ^{1}H magnetic resonance (MR) were used to quantify fluids and assess kerogen in mature and immature oil-rich shale samples. The ^{13}C MR improves confidence in the resolution and quantification of shale signal components by exploiting the absence of water signal in the ^{13}C response and generally longer ^{13}C relaxation times. In addition to fluid quantification, ^{13}C and ^{1}H MR measurements were combined to yield H/C ratios on the Van Krevelen diagram, indicating kerogen class and maturity.



Zamiri et al. **PAGES 1101–1117**

Traditionally, relative permeability (k_r) curves are estimated using numerical simulations of coreflood experiments and fitting the produced fluid volume and pressure drop data, assuming specific functional forms for the k_r curves. In this study, a method based on rapid saturation monitoring data was first validated using synthetic data. Experimentally, ^{23}Na MRI was then employed for in-situ saturation monitoring to derive model-free k_r curves. These curves were subsequently compared with those obtained from numerical simulation.