A three-phase fluid distinguishing method based on dualparameter from neutron gamma logging technology in CO2 enhanced oil recovery

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Abstract

Carbon capture, utilization, and storage (CCUS) is widely recognized as a key technological pathway for mitigating greenhouse gas emissions and supporting the global energy transition. Among CCUS applications, CO_2-enhanced oil recovery plays an important role by simultaneously improving hydrocarbon recovery and enabling geological storage of CO_2. During CO_2 flooding, reservoir pores typically contain a three-phase fluid system composed of water, oil, and supercritical CO_2, which poses significant challenges for fluid discrimination and saturation evaluation.

In this study, a dual-parameter fluid evaluation method based on neutron gamma logging technology is proposed. Monte Carlo simulations using the FLUKA code are performed to investigate the response characteristics of near- and far-detector inelastic gamma spectra and near − long detector capture gamma count ratios under varying porosity conditions. Quantitative relationships between carbon-oxygen (C/O) ratios, capture gamma count ratios, and reservoir parameters are established.

To address borehole CO_2 interference, a self-compensation correction method based on the near-to-far inelastic gamma count ratio is developed. The proposed approach integrates dual-parameter characterization and correction to achieve robust fluid discrimination. Simulation results demonstrate that the method effectively distinguishes water, oil, and CO_2 across a wide range of conditions and significantly improves interpretation reliability.

Introduction

Carbon capture, utilization, and storage (CCUS) has been widely recognized as a key strategy for mitigating greenhouse gas emissions and addressing global climate change. Among various CCUS applications, carbon dioxide enhanced oil recovery (CO_2-EOR) plays a crucial role by simultaneously improving hydrocarbon recovery and enabling geological storage of CO_2.

During CO_2 flooding, injected CO_2 interacts with in-situ crude oil and formation water, resulting in a complex multiphase system consisting of water, oil, and supercritical CO_2. Under miscible conditions, CO_2 dissolves into crude oil, reducing its viscosity and density, and enhancing its mobility. This process enables efficient displacement of residual oil trapped within complex pore networks. However, the coexistence of three fluid phases significantly complicates reservoir characterization and fluid identification.

Conventional logging methods face considerable limitations under such conditions. Resistivity logging often fails to distinguish oil from CO_2 due to similar electrical properties, while conventional pulsed neutron logging suffers from reduced sensitivity in the presence of strong borehole effects and varying porosity. In particular, the presence of CO_2 in the borehole introduces significant distortion to neutron-based measurements, leading to unreliable interpretation.

Neutron gamma spectroscopy logging provides a promising alternative by detecting gamma rays generated from neutron interactions with formation elements. The carbon-to-oxygen (C/O) ratio derived from inelastic scattering is sensitive to hydrocarbon content, whereas capture gamma measurements reflect the macroscopic capture cross-section, which is influenced by formation water salinity and fluid composition. Although the C/O ratio has been widely used for oil–water discrimination, its applicability in three-phase systems remains limited due to non-uniqueness.

To address these challenges, this study proposes a dual-parameter fluid evaluation method combining the C/O ratio and capture gamma count ratio for three-phase discrimination. A borehole CO_2 self-compensation method based on the near-to-far inelastic gamma ratio is also introduced to correct measurement distortions. Monte Carlo simulations are employed to systematically analyze key reservoir and environmental factors, establishing a robust evaluation framework for CO_2-EOR reservoirs.

Method

Neutrons emitted from a pulsed source undergo inelastic scattering, elastic scattering, and radiative capture reactions in the formation. Inelastic scattering occurs when fast neutrons collide with atomic nuclei, transferring part of their kinetic energy to the target nucleus. This process excites the nuclei and causes emission of characteristic gamma rays, which carry elemental information, particularly for carbon and oxygen. By utilizing reactions between fast neutrons and carbon and oxygen nuclei, the carbon-to-oxygen ratio (C/O) is extracted, which serves as the physical basis for distinguishing oil, carbon dioxide, and water. Assuming the formation porosity is ϕ, oil saturation is S_o, and the atomic densities of carbon and oxygen are n_c and n_o respectively, the carbon-to-oxygen atomic number ratio (C/O) per unit volume of rock can be calculated using the rock volume physical model as:

$$C/O = \frac{n_c}{n_o} = \frac{a\phi S_O + mc\left(1-\phi\right)}{b\phi\left(1-S_O\right) + m_o\left(1-\phi\right)}$$

$$\mathrm{C/O}_{\text{near}} = \frac{\sum_{E_C} N_{\text{near}}(E)}{\sum_{E_O} N_{\text{near}}(E)}, \quad \mathrm{C/O}_{\text{far}} = \frac{\sum_{E_C} N_{\text{far}}(E)}{\sum_{E_O} N_{\text{far}}(E)}$$

After slowing down, thermal neutrons are captured by nuclei, forming a compound nucleus in an excited state. The compound nucleus immediately de-excites by emitting one or more gamma photons to return to a stable ground state, thereby producing capture gamma rays. The intensity of capture gamma radiation depends on the macroscopic capture cross-section (Σ), which is strongly influenced by formation water salinity and lithology.

$$\mathrm{Rcap} = \frac{\sum_{\text{capture}} \gamma_{\text{near}}(E)}{\sum_{\text{capture}} \gamma_{\text{long}}(E)}$$

Instead of directly solving nonlinear saturation equations, fluid identification in CO_2–oil–water systems can be reformulated as a classification problem in a transformed parameter space.

The measured neutron-gamma responses, including the corrected carbon-oxygen ratio and capture gamma ratio, can be regarded as feature representations of the subsurface fluid system. However, due to borehole effects and salinity-induced variations, these features are subject to systematic distortions and cannot be directly used for reliable discrimination.For each fluid type k (oil, water, CO_2), a reference response is defined as:

$$\mathbf{X}_k^{\text{model}} = \begin{bmatrix} (C/O)_k \\ \left(R_{\text{cap}}\right)_k \end{bmatrix}$$

These reference values are derived from simulation datasets covering variations in porosity, salinity, and lithology. where the C/O ratio reflects elemental composition, and the capture gamma ratio is sensitive to salinity and lithological variations.

The composite parameter Ψ integrates corrected C/O and capture-related responses using logarithmic normalization and adaptive weighting. It enhances the separability of different fluid types by combining fluid-sensitive and salinity-sensitive information. This simplification allows the focus to remain on the parameter-space classification framework, while borehole correction can be incorporated as an independent preprocessing step in practical applications.

$$\Psi = \alpha \ln\left(\frac{C/O_{corr}}{(C/O)_{ref}}\right) + \beta \ln\left(\frac{R_{cap,corr}}{\left(R_{cap}\right)_{ref}}\right)$$

Here, $\mathbf{Z}$ denotes the observation vector in the transformed feature space. It represents the "real data point" measured in the experiment.$D_k$determines the fluid type whose reference model is closest to the observation vector in the feature space.

$$\mathbf{Z} = \begin{bmatrix} C/O_{\text{corr}} \\ R_{\text{cap,corr}} \\ \Psi \end{bmatrix}$$

$$D_k = \left(\mathbf{Z} - \mathbf{Z}_k^{\text{model}}\right)^T W \left(\mathbf{Z} - \mathbf{Z}_k^{\text{model}}\right)$$

$$\mathbf{W} = \begin{bmatrix} w_{C/O} & 0 \\ 0 & w_{cap} \end{bmatrix}$$

And the weights are selected based on sensitivity analysis: $\mathrm{w}_{\mathrm{C/O}}$is fluid sensitivity, $\mathrm{w}_{\mathrm{cap}}$ is salinity and lithology sensitivity.

$$\text{Fluid} = \arg\min_{\mathrm{k}} \mathrm{D}_{\mathrm{k}}$$

The constraint conditions that define the range of this vector, along with the calculation of the corresponding components, utilize the saturation relationships as the defining domain. Ultimately, the method can determine the specific region where the saturations reside, thereby achieving accurate fluid identification.

$$S_o + S_w + S_{\text{CO}_2} = 1$$

$$\mathbf{X}_{\text{corr}} = S_o \cdot \mathbf{X}_o^{\text{model}} + S_w \cdot \mathbf{X}_w^{\text{model}} + S_{\text{CO}_2} \cdot \mathbf{X}_{\text{CO}_2}^{\text{model}}$$

Using a dual-parameter combination approach enables clear discrimination among pure water, pure oil, and pure CO_2 across varying porosity conditions. The joint utilization of these two parameters resolves the three-phase fluid system equations. Furthermore, when the borehole is filled with CO_2, it significantly alters inelastic gamma measurements. By applying the near-to-far detector inelastic gamma count ratio as a sensitivity factor to establish a correction function, the borehole fluid's "background noise" on formation signals is eliminated, achieving self-compensation.

Monte Carol simulation

FLUKA is a general-purpose particle transport and matter interaction calculation tool that rigorously handles all reaction steps and types using microscopic models. In this study, a Monte Carlo method was employed to construct a borehole-formation computational model for this logging tool. The model is used to simulate the distribution of capture gamma rays and thermal neutrons under specific conditions and to investigate their response relationships. The tool model configuration includes: a pulsed D-T neutron source; and three BGO gamma-ray detectors with varying source-to-detector distances (38 cm, 47 cm, and 62 cm) for measuring the neutron-gamma field. As shown in the figure 2 below, the field distribution of inelastic and capture gamma rays with different energies near the detector can be characterized.

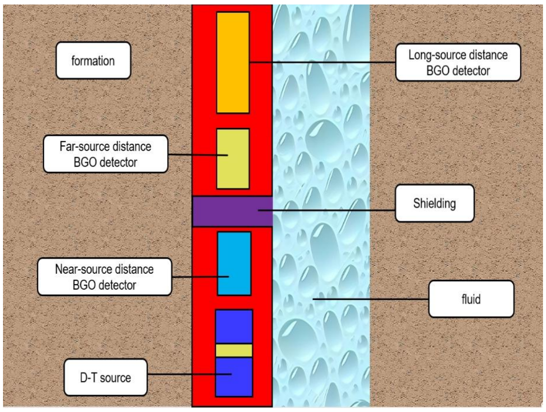

Figure 1: tools simulation model

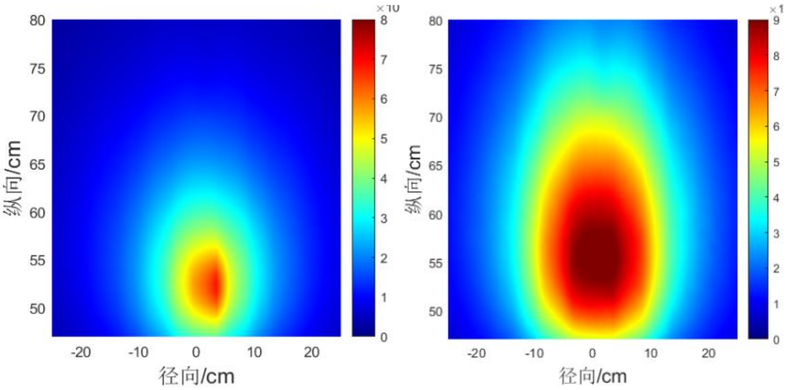

Figure 2:Distribution of Inelastic and Capture Gamma-Ray Fields in Formation Fluids

Influence factors

To enhance the universality of the established Monte Carlo model, the following sensitive parameters must be quantitatively investigated for their impact on logging responses. First, a table is provided below listing the slowing-down length and macroscopic capture cross-section (Σ) for all materials involved. The composite parameter Ψ is further analyzed as a unified response indicator. This demonstrates that Ψ effectively captures the combined effects of fluid composition and measurement response, providing a robust indicator for fluid discrimination. Based on the model, the following conditions are studied:

The effect of porosity on the proposed parameters and classification performance is first evaluated. As porosity varies, the relative contributions of the formation matrix and pore fluids change, leading to systematic variations in the measured responses.

Fluid Environment Factors:

To evaluate the sensitivity of the proposed method to fluid composition, simulations are conducted using representative reservoir fluids, including oil, fresh water, saline water (10 kppm), CH_4, and supercritical CO_2. The formation is modeled as a mixed carbonate system consisting of 0.4 calcite and 0.6 dolomite, with porosity ranging from 0.1% to 15%.

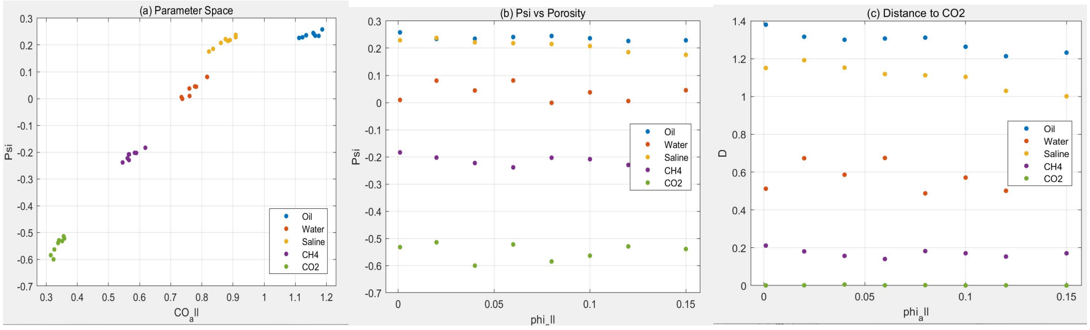

Fig. 3. Fluid environment effects on logging responses:

(a) parameter space distribution for different fluid types;

(b) Ψ-porosity relationship

(c) distance to CO_2 reference under varying porosity;

As shown in Fig. 3(a), distinct clustering behavior is observed in the parameter space. Oil exhibits the highest C/O ratio, while CO_2 consistently occupies the lowest region of the Ψ axis due to its weak carbon and capture responses. Water and saline water form intermediate clusters, with saline water slightly shifted due to enhanced capture effects.Quantitatively, the separation distance between CO_2 and water exceeds approximately 2–3 times the intra-class variation, indicating strong discriminability. A supplementary test using higher-density oil (0.87) shows minor overlap within the oil cluster, confirming that fluid property variations mainly affect intra-class dispersion rather than inter-class separation.

Formation Water Salinity:

To investigate salinity effects, simulations are conducted under salinity levels of 0%, 1%, 2%, 5%, 10%, 12%, and 15%. The formation remains a limestone–dolomite mixture (4:6), and porosity is varied over the same range (0.1%–15%). An additional comparison is performed for pure sandstone to evaluate lithological influence.

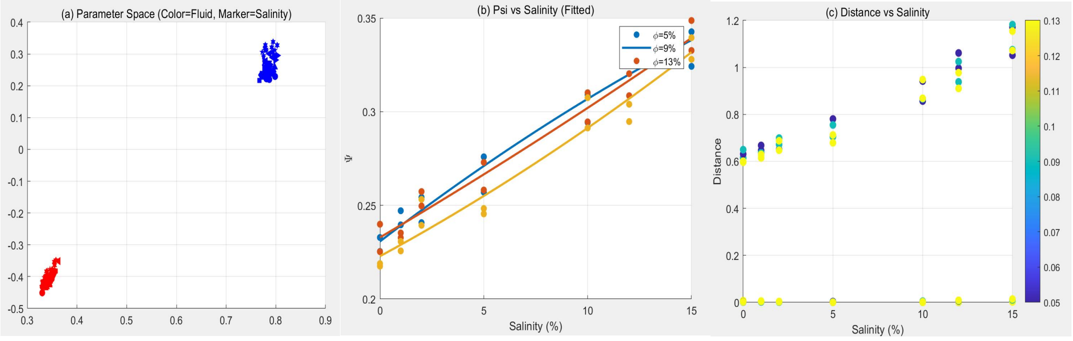

Fig. 4. Effect of formation water salinity on logging responses:
(a) parameter space distribution under different salinity levels;
(b) variation of Ψ with salinity at different porosities;
(c) distance-based discrimination performance under salinity variations.

As shown in Fig. 4(b), Ψ increases monotonically with salinity due to the strong dependence of capture gamma-ray counts on chlorine concentration. This results in a systematic upward shift of saline water responses in the parameter space (Fig. 4(a)).

Despite this shift, CO_2 remains clearly separated from saline water under all conditions. The distance between CO_2 and high-salinity water increases by approximately 20%, and the classification margin ΔD remains consistently above 0.5, indicating that no ambiguity is introduced. Lithology comparison shows that sandstone increases capture responses by approximately 5–8%, but does not alter the overall separation structure. This confirms that salinity is a dominant factor, while lithology plays a secondary role.

Oil-water-gas three-phase fluid:

To approximate realistic reservoir conditions, a three-phase system is simulated in a carbonate formation, consisting of 0.75 oil, 0.65 CO_2, and 1% brine.

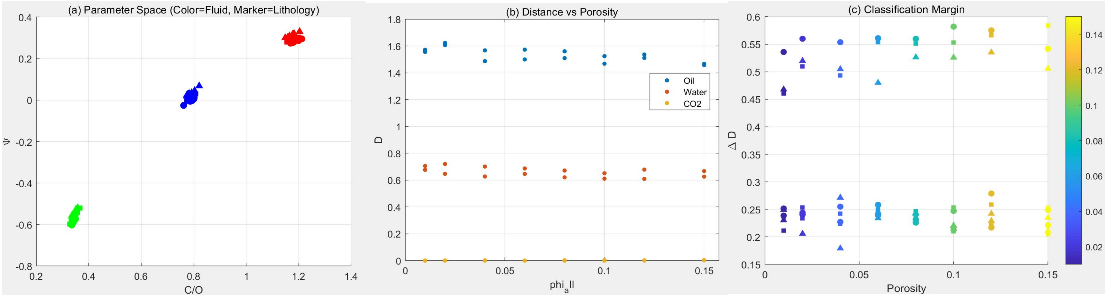

Fig. 5. Influence of multiphase fluid conditions on logging responses:
(a) parameter space distribution under multiphase conditions;
(b) distance variation for different phase combinations;
(c) classification margin ΔD under multiphase scenarios.

As shown in Fig. 5(a), multiphase responses lie between single-phase clusters, reflecting a weighted superposition behavior. However, CO_2-dominated mixtures remain closer to the CO_2 cluster than to oil or water clusters. Distance analysis indicates that CO_2-containing mixtures maintain a separation advantage of approximately 30–50% compared to competing fluids. This demonstrates that the proposed method retains its discrimination capability even under partial saturation and multiphase coexistence.

Borehole environment factors

To evaluate borehole effects, a borehole diameter of 126 mm is selected. Combined borehole–formation scenarios include: water + saline water (10 kppm), water + oil, water + CO_2, CO_2 + water (10 kppm), CO_2 + oil, and CO_2 + CO_2.

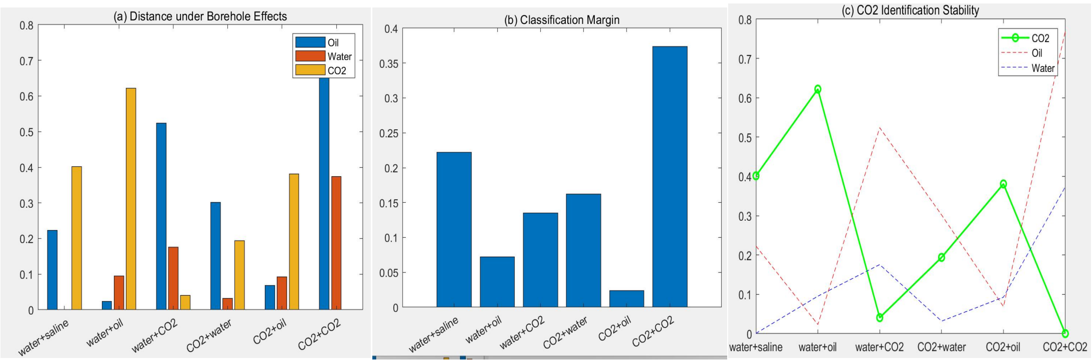

Fig. 6. Influence of Borehole environment factors on logging responses:
(a) Distance to fluid references
(b) Classification margin ΔD
(c) Relative distance comparison for CO_2 identification

As shown in Fig. 6, borehole fluids introduce additional mixing effects that shift the measured responses toward borehole characteristics. This effect is particularly evident in water-filled boreholes with high salinity. However, distance analysis shows that CO_2-containing formations consistently maintain the minimum distance to the CO_2 reference state across all configurations. Even under the most unfavorable conditions, the separation between CO_2 and water remains above 15–20%. The classification margin ΔD (Fig. 5(c)) further confirms that all cases remain within the reliable classification region. This indicates that the proposed method is robust against borehole–formation coupling effects.

Oil density and shale content

The effects of shale content and oil density are not explicitly modeled in this study. These factors primarily introduce secondary variations in the capture and carbon-related responses, respectively.

Compared to the dominant effects of fluid type and salinity, their influence is relatively minor and does not fundamentally alter the parameter-space structure. Therefore, they are treated as secondary factors and only briefly discussed rather than being incorporated as independent variables in the model.

Borehole CO_2 self-compensation method

To account for borehole CO_2 effects, both the C/O ratio and capture gamma count ratio are corrected using a unified compensation framework. The borehole influence is characterized by the near-to-far inelastic gamma ratio, and separate correction functions are constructed for each parameter. Due to the stronger sensitivity of inelastic gamma responses to borehole conditions, a nonlinear correction is applied to the C/O ratio, whereas a simplified linear correction is adopted for the capture gamma ratio. The measured C/O ratio and capture gamma count ratio are affected by borehole fluid conditions. $\mathrm{X}_{\text{borehole}}$ represents the deviation introduced by borehole effects.

$$\mathbf{X}_{\text{meas}} = \begin{bmatrix} \mathrm{C/O}_{\text{meas}} \\ R_{\text{cap,meas}} \end{bmatrix} = \mathbf{X}_{\text{true}} + \mathbf{X}_{\text{borehole}}$$

$$\mathbf{X}_{\mathrm{corr}} = \mathbf{X}_{\mathrm{meas}} - \mathbf{f}\left(\frac{\mathrm{C/O}_{\mathrm{near}}}{\mathrm{C/O}_{\mathrm{far}}}, \frac{R_{\mathrm{cap,near}}}{R_{\mathrm{cap,long}}}\right)$$

Where f represents the borehole correction function. Due to the higher sensitivity of inelastic gamma responses to borehole conditions, different correction strategies are adopted for the two parameters. For moderate formation conditions, a linear correction model can be expressed as:

$$\mathrm{C/O}_{\mathrm{corr}} = \mathrm{C/O}_{\mathrm{meas}} - \left(k_1 r_{\mathrm{C/O}} + k_2 r_{\mathrm{cap}} + k_3\right)$$

$$R_{\mathrm{cap,corr}} = R_{\mathrm{cap,meas}} - \left(k_4 r_{\mathrm{C/O}} + k_5 r_{\mathrm{cap}} + k_6\right)$$

Where $\mathrm{k}_1 \sim \mathrm{k}_6$ are regression coefficients determined from simulation or experimental calibration. When formation properties such as porosity and salinity vary significantly, nonlinear effects become non-negligible. In such cases, higher-order polynomial terms are introduced to improve correction accuracy:

$$\mathrm{C/O}_{\mathrm{corr}} = \mathrm{C/O}_{\mathrm{meas}} - \left(k_1 r_{\mathrm{C/O}} + k_2 r_{\mathrm{cap}} + k_3 r_{\mathrm{C/O}}^2 + k_4 r_{\mathrm{cap}}^2 + k_5 r_{\mathrm{C/O}} r_{\mathrm{cap}} + k_6\right)$$

$$R_{\mathrm{cap,corr}} = R_{\mathrm{cap,meas}} - \left(l_1 r_{\mathrm{C/O}} + l_2 r_{\mathrm{cap}} + l_3 r_{\mathrm{C/O}}^2 + l_4 r_{\mathrm{cap}}^2 + l_5 r_{\mathrm{C/O}} r_{\mathrm{cap}} + l_6\right)$$

Finally, a formation with 0 – 30% porosity, mixed lithology of limestone and dolomite in a 4:6 ratio, and fluid composed of water and CO_2 with a density of 0.65 is selected for method characterization. The results show that the method effectively eliminates borehole effects, making the calculated CO_2 saturation trend clearly observable. The corrected parameters can be further integrated into a composite feature or inversion framework for fluid identification.

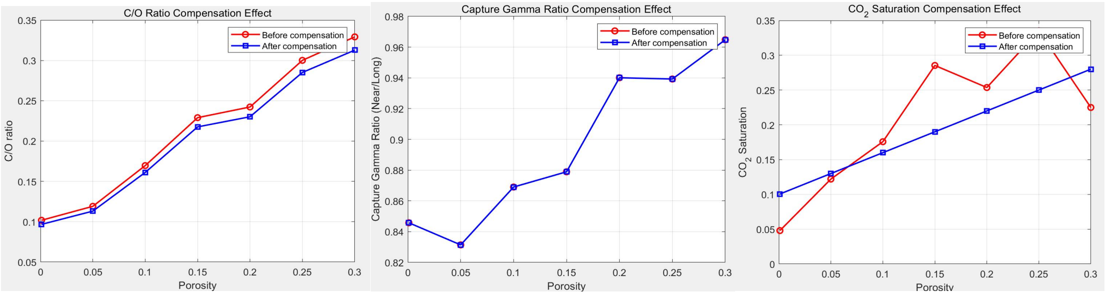

Fig. 7. Porosity - Dependent Compensation Effects:

(a) C/O Ratio,

(b) Capture Gamma Ratio,

(c) CO_2 SaturationInfluence of Borehole environment factors on logging responses:

Case study

A different well is selected to validate the proposed method under field conditions. The logging suite includes conventional curves (gamma ray, resistivity, density – neutron) for lithology and porosity evaluation, together with nuclear responses for fluid identification.

Based on the Ψ – D framework, fluid types are identified along the interval. CO_2 -bearing zones show consistently lower Ψ values and maintain the minimum distance to the CO_2 reference, demonstrating clear discrimination.The estimated fluid saturation agrees well with the reference interpretation, with only minor deviations. This confirms that the proposed method can achieve reliable fluid identification and quantitative evaluation in real logging applications.

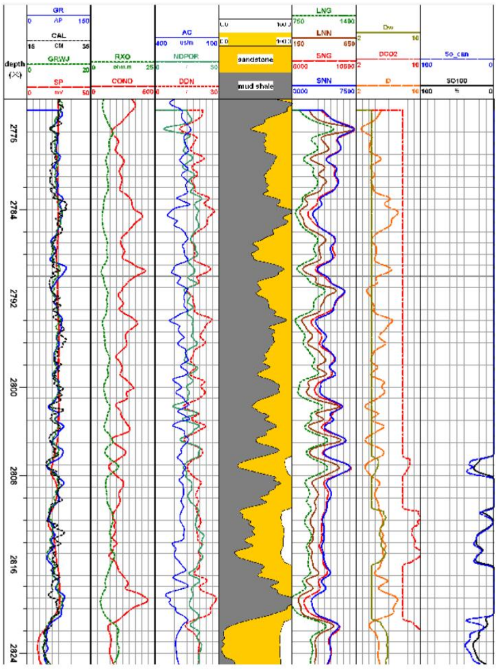

Fig. 8:case study of well logging data

Conclusion

This study demonstrates that a three-detector neutron-gamma logging tool, combining the carbon-oxygen (C/O) ratio and capture gamma count ratio through joint inversion, can effectively distinguish between water, oil, and supercritical CO_2 under varying formation conditions. A borehole CO_2 self-compensation approach based on the near-to-far inelastic gamma ratio is developed to reduce the influence of borehole environments on the measured responses, thereby improving the stability and reliability of fluid saturation estimates. Based on this methodology, a workflow for fluid identification and evaluation in CO_2 flooding reservoirs is established, integrating response correction, fluid discrimination, and saturation estimation. The proposed approach provides a practical framework for the monitoring and assessment of CO_2 injection processes and may support long-term geophysical observations in CCUS applications.