

Numerical Modelling of CO₂ Injection and Trapping Mechanisms in Depleted Gas Reservoirs

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Abstract

Depleted gas reservoirs offer significant potential for permanent carbon dioxide (CO₂) storage while supporting enhanced gas recovery. However, predicting CO₂ migration and long-term containment requires robust numerical modelling of multiphase flow, reservoir heterogeneity, and trapping processes. This study examines the application of numerical modelling to CO₂ injection and trapping mechanisms in depleted gas reservoirs, focusing on structural, residual, solubility, and mineral trapping.

Numerical simulation provides a framework for evaluating CO₂ plume evolution, pressure distribution, injectivity, storage efficiency, and potential leakage pathways under varying reservoir conditions. Particular attention is given to reactive transport and long-term performance prediction, which are essential for understanding changes in reservoir properties and CO₂ behaviour over extended storage periods. The study further considers the influence of residual gas saturation, geological heterogeneity, permeability, porosity, and injection conditions on storage performance. Integrating multiphase-flow and reactive-transport modelling can improve prediction of CO₂ retention, enhance storage efficiency, and support safer and more reliable geological carbon storage in depleted gas reservoirs.

Keywords: CO₂ storage; depleted gas reservoirs; numerical modelling; CO₂ injection; trapping mechanisms; reactive transport; enhanced gas recovery.

1. Introduction

The increasing concentration of carbon dioxide (CO₂) in the atmosphere has strengthened the need for effective carbon capture and storage (CCS) technologies. Geological storage in depleted gas reservoirs has gained attention because these formations possess established pore spaces, proven hydrocarbon containment capacity, and existing geological information from previous exploration and production activities. They can also provide opportunities for combining CO₂ sequestration with enhanced gas recovery (Raza et al., 2018; Dumitrache et al., 2023).

CO₂ injection into depleted gas reservoirs involves complex multiphase interactions among CO₂, residual natural gas, formation water, and reservoir rock. The movement and distribution of

injected CO₂ are influenced by pressure, temperature, permeability, porosity, residual gas saturation, and geological heterogeneity. Numerical modelling provides an effective approach for predicting these processes, including CO₂ plume migration, pressure changes, injectivity, and storage capacity. Raza et al. (2018) showed that residual gas saturation can significantly influence CO₂ storage behaviour, while Dumitrache et al. (2023) demonstrated the usefulness of numerical reservoir simulation for evaluating underground CO₂ storage.

The long-term security of CO₂ storage depends largely on the effectiveness of different trapping mechanisms. These include structural, residual, solubility, and mineral trapping. The contribution of these mechanisms changes over time and is controlled by reservoir and fluid properties (Sun et al., 2020). Numerical simulation therefore plays an important role in evaluating how CO₂ migrates and becomes progressively immobilized within the reservoir. Recent studies have further applied numerical modelling to CO₂-enhanced gas recovery and sequestration in tight sandstone and heterogeneous shale reservoirs (Zhao et al., 2024; Hu et al., 2026).

Reactive transport modelling is also important for understanding long-term CO₂–fluid–rock interactions. Williams (2023) demonstrated the value of numerical reactive-transport modelling for predicting long-term reservoir performance and geochemical processes. Although the study focused on geothermal reservoirs, its modelling principles are relevant to assessing fluid movement and geochemical interactions associated with geological CO₂ storage.

Therefore, this study examines the numerical modelling of CO₂ injection and trapping mechanisms in depleted gas reservoirs, with emphasis on CO₂ migration, multiphase flow, reservoir pressure response, geological heterogeneity, trapping efficiency, and long-term storage security. Integrating conventional reservoir simulation with reactive-transport approaches can improve the prediction of CO₂ behaviour and support the safe and effective utilization of depleted gas reservoirs for geological carbon storage.

2. Numerical Modelling Framework for CO₂ Injection in Depleted Gas Reservoirs

Numerical modelling provides an important framework for understanding the behaviour of injected CO₂ within depleted gas reservoirs. Because CO₂ migration and trapping occur below the surface and involve interactions among multiple fluids and geological formations, numerical simulation can be used to predict reservoir responses under different injection conditions. The reliability of these predictions depends on accurate reservoir characterization, appropriate representation of multiphase flow, and consideration of fluid–rock interactions (Dumitrache et al., 2023).

2.1 Characterization of Depleted Gas Reservoirs

Accurate characterization of a depleted gas reservoir is a fundamental requirement for developing a reliable numerical model. Important properties include porosity, permeability, reservoir pressure, temperature, fluid saturation, and geological structure. These parameters determine the available pore volume, fluid-flow pathways, and capacity of the formation to accommodate injected CO₂. Residual gas saturation is particularly important because significant quantities of gas may remain after hydrocarbon production, thereby influencing the available pore space and CO₂ displacement behaviour (Raza et al., 2018).

Geological heterogeneity must also be incorporated into reservoir models because variations in permeability and porosity can create preferential pathways for CO₂ migration. Such variations may influence plume distribution, pressure development, and the efficiency of CO₂ trapping. Recent numerical studies have demonstrated the importance of representing heterogeneous formations when assessing CO₂-enhanced gas recovery and sequestration (Hu et al., 2026).

2.2 Numerical Simulation of CO₂ Injection

Numerical simulation of CO₂ injection involves representing the movement of CO₂ through the reservoir under multiphase-flow conditions. The model considers interactions between injected CO₂, residual natural gas, and formation water while accounting for changes in pressure and saturation. Simulation results can be used to predict CO₂ plume migration, injection performance, pressure buildup, and the spatial distribution of stored CO₂ (Dumitrache et al., 2023).

Injection rate and well conditions are important operational parameters in these simulations. Excessively high injection rates may produce rapid pressure increases and uncontrolled CO₂ migration, whereas lower rates may reduce injection efficiency. Numerical models therefore allow different injection scenarios to be evaluated before field implementation. In depleted gas reservoirs, simulation can additionally assess how injected CO₂ displaces remaining natural gas and contributes to enhanced gas recovery (Zhao et al., 2024).

2.3 Modelling CO₂–Reservoir Interactions

The interaction between injected CO₂ and the reservoir environment significantly affects storage performance. CO₂ properties change with pressure and temperature, influencing its density, viscosity, and mobility within the formation. At the same time, variations in porosity and permeability affect the pathways available for CO₂ movement. Numerical models can incorporate these factors to examine the distribution and evolution of the CO₂ plume throughout the reservoir.

The interaction between CO₂ and formation fluids is also important because CO₂ may dissolve into formation water and subsequently participate in geochemical reactions. These processes can

contribute to long-term CO₂ immobilization and alter reservoir properties. Numerical modelling therefore provides a means of investigating the combined effects of fluid movement and reservoir characteristics on CO₂ storage behaviour (Sun et al., 2020).

2.4 Reactive Transport and Long-Term Reservoir Behaviour

Reactive transport modelling extends conventional reservoir simulation by incorporating chemical interactions between CO₂, formation fluids, and reservoir minerals. These interactions can influence CO₂ dissolution, mineral precipitation, and changes in reservoir properties over extended periods. Consequently, reactive transport models are useful for evaluating the long-term stability and effectiveness of geological CO₂ storage.

Williams (2023) demonstrated the importance of numerical reactive-transport modelling for predicting long-term reservoir performance and understanding coupled fluid-flow and geochemical processes. Although the study focused on geothermal reservoirs, the modelling approach provides useful principles for assessing long-term CO₂–fluid–rock interactions in geological storage systems. Incorporating such processes can improve predictions of CO₂ behaviour beyond the initial injection period.

2.5 Model Calibration, Validation, and Uncertainty

Calibration and validation are essential for ensuring that numerical reservoir models provide realistic predictions. Calibration involves adjusting model parameters using available geological, pressure, production, and reservoir-performance data. The calibrated model can then be validated against independent observations or historical reservoir behaviour. This process helps reduce discrepancies between simulated and observed conditions.

Uncertainty remains an important challenge because reservoir properties are rarely known with complete accuracy. Variations in permeability, porosity, residual gas saturation, relative permeability, and geological connectivity can significantly affect predicted CO₂ migration and trapping. Sensitivity and uncertainty analyses can therefore be used to identify the parameters that have the greatest influence on simulation results. The incorporation of these analyses strengthens the reliability of numerical predictions and supports better decisions regarding CO₂ injection and storage.

Overall, numerical modelling provides a systematic approach for evaluating CO₂ injection and its behaviour within depleted gas reservoirs. Reliable simulations require accurate reservoir characterization, appropriate multiphase-flow representation, and consideration of CO₂–fluid–rock interactions. The inclusion of reactive transport processes, as highlighted by Williams (2023), can further improve predictions of long-term reservoir behaviour. Together, these modelling approaches provide a foundation for assessing CO₂ migration, storage capacity, trapping efficiency, and the overall suitability of depleted gas reservoirs for geological CO₂ storage.

3. CO₂ Injection Behaviour and Reservoir Response

The behaviour of CO₂ after injection is influenced by reservoir properties, fluid interactions, injection conditions, and geological heterogeneity. Numerical modelling provides an effective approach for examining these processes and predicting changes in pressure, fluid saturation, CO₂ migration, and gas recovery. Understanding the reservoir response is important for designing injection strategies that maximize storage efficiency while maintaining the integrity of the storage formation.

3.1 CO₂ Displacement of Residual Natural Gas

Depleted gas reservoirs commonly retain a quantity of natural gas after production. Injection of CO₂ can displace part of this residual gas and create an opportunity to combine CO₂ storage with enhanced gas recovery. The effectiveness of this displacement depends on reservoir pressure, permeability, fluid saturation, and the relative mobility of CO₂ and natural gas.

Raza et al. (2018) demonstrated that residual gas saturation can significantly affect CO₂ storage behaviour because the remaining gas occupies pore spaces that would otherwise be available for CO₂. Numerical simulation can therefore be used to estimate the extent of gas displacement and determine the quantity of CO₂ that can subsequently remain within the reservoir. The modelling of fluid movement and reservoir response is also important for understanding how injected fluids evolve over time (Williams, 2023).

3.2 Pressure Evolution and CO₂ Injectivity

CO₂ injection produces changes in reservoir pressure that depend on injection rate, permeability, pore volume, fluid properties, and the initial pressure of the depleted formation. Excessive pressure buildup may reduce injection efficiency and potentially affect caprock integrity. Numerical simulation allows different injection rates and pressure conditions to be assessed before field implementation.

Dumitrache et al. (2023) demonstrated the usefulness of numerical reservoir simulation for evaluating CO₂ storage and associated subsurface responses. Zhao et al. (2024) similarly used numerical simulation to examine CO₂ storage combined with enhanced gas recovery in depleted tight sandstone reservoirs. These approaches allow the relationship between injection conditions, pressure development, and storage performance to be evaluated.

Table 1. Key Parameters Influencing CO₂ Injection and Storage Performance in Depleted Gas Reservoirs

Parameter	Influence on CO ₂ Injection and Storage
Injection rate	Controls the rate of pressure buildup and plume expansion
Reservoir pressure	Influences CO ₂ density, mobility, and injection behaviour
Permeability	Determines the ease and direction of CO ₂ movement
Porosity	Controls the available pore volume for CO ₂ storage
Residual gas saturation	Influences pore-space availability and gas displacement
Temperature	Affects CO ₂ properties and fluid–rock interactions
Caprock properties	Controls containment and limits upward migration
Reservoir heterogeneity	Creates preferential pathways and uneven CO ₂ distribution

The interaction among these parameters means that changes in reservoir conditions can produce significant differences in predicted CO₂ migration and storage efficiency. Therefore, numerical models should incorporate realistic reservoir properties to produce reliable assessments.

3.3 CO₂ Migration in Heterogeneous Reservoirs

Geological heterogeneity strongly influences the movement and distribution of injected CO₂. Differences in permeability, porosity, and lithology may create preferential pathways through which CO₂ migrates more rapidly. This can result in uneven plume development, localized pressure changes, and variations in trapping efficiency.

Numerical modelling is particularly useful for identifying these preferential flow pathways and predicting the spatial distribution of CO₂ within heterogeneous formations. Hu et al. (2026) demonstrated the importance of accounting for reservoir heterogeneity when assessing CO₂-enhanced gas recovery and sequestration. In addition, the numerical modelling of coupled transport and reservoir processes provides a basis for evaluating changes in subsurface behaviour over longer periods (Williams, 2023).

3.4 Influence of Injection Conditions on Storage Performance

Injection rate, well location, injection duration, and pressure conditions can significantly influence the efficiency and safety of CO₂ storage. A high injection rate may accelerate plume migration and pressure buildup, whereas an appropriately controlled injection rate can promote more effective distribution of CO₂ within the available pore space.

Numerical simulation allows alternative injection scenarios to be compared and optimized before implementation. Zhao et al. (2024) showed the application of numerical modelling to evaluate CO₂ storage alongside enhanced gas recovery, while Hu et al. (2026) examined similar processes under heterogeneous shale reservoir conditions. Such simulations can help identify operating conditions that balance gas recovery, CO₂ storage capacity, and pressure management.

3.5 CO₂ Storage and Enhanced Gas Recovery

The integration of CO₂ storage with enhanced gas recovery provides an important potential benefit of injecting CO₂ into depleted gas reservoirs. As CO₂ enters the formation, it can displace remaining natural gas toward production wells, potentially increasing gas recovery while retaining a proportion of the injected CO₂ within the reservoir.

The effectiveness of this approach depends on reservoir characteristics, injection strategy, and the interaction between CO₂ and residual gas. Numerical modelling can estimate both additional gas recovery and the quantity of CO₂ retained within the formation. Zhao et al. (2024) and Hu et al. (2026) demonstrate the application of numerical approaches for evaluating these coupled storage and recovery processes.

In summary, CO₂ injection produces complex changes in fluid distribution, pressure, and reservoir behaviour. Factors such as residual gas saturation, injection rate, geological heterogeneity, and reservoir pressure must therefore be considered when assessing storage performance. Numerical modelling, including the long-term transport and interaction processes discussed by Williams (2023), provides an important foundation for predicting these responses and optimizing CO₂ injection into depleted gas reservoirs.

4. Numerical Assessment of CO₂ Trapping Mechanisms

The effectiveness of geological CO₂ storage depends on the ability of the reservoir to immobilize injected CO₂ through several physical and geochemical mechanisms. Numerical modelling provides a means of examining the development of these mechanisms over time and determining how reservoir properties influence CO₂ retention. The principal mechanisms considered in depleted gas reservoirs include structural, residual, solubility, and mineral trapping (Sun et al., 2020).

4.1 Structural and Stratigraphic Trapping

Structural and stratigraphic trapping is one of the primary mechanisms responsible for retaining CO₂ within geological formations. Following injection, CO₂ tends to migrate upward because of its buoyancy and may accumulate beneath impermeable caprocks or within structural closures. The effectiveness of this mechanism depends on caprock integrity, reservoir geometry, permeability distribution, and the density difference between CO₂ and formation fluids.

Numerical models can simulate the upward migration and accumulation of CO₂ and identify areas where the plume may become structurally contained. Sun et al. (2020) emphasized the importance of evaluating trapping mechanisms when assessing the storage potential of subsurface hydrocarbon-bearing formations. Accurate representation of geological structures is therefore essential for predicting the long-term containment of injected CO₂.

4.2 Residual or Capillary Trapping

Residual trapping occurs when CO₂ becomes immobilized within pore spaces as a result of capillary forces. During CO₂ migration, water may re-enter previously occupied pore spaces and disconnect portions of the CO₂ phase, leaving residual CO₂ that cannot easily move through the formation. This mechanism can substantially contribute to storage security because immobilized CO₂ is less likely to migrate beyond the storage zone.

The extent of residual trapping is strongly influenced by pore structure, wettability, saturation history, and residual gas saturation. Raza et al. (2018) demonstrated the importance of residual gas saturation in numerical assessments of CO₂ storage in depleted gas reservoirs. Numerical models can incorporate these parameters to estimate the quantity of CO₂ that becomes residually trapped following injection.

4.3 Solubility and Mineral Trapping

Solubility trapping occurs when injected CO₂ dissolves into formation water, reducing the mobility of the CO₂ phase. Over longer periods, dissolved CO₂ may participate in geochemical reactions with reservoir minerals and potentially form stable carbonate minerals through mineral trapping. These processes can progressively increase the permanence of geological CO₂ storage (Sun et al., 2020).

The relative importance of trapping mechanisms changes as the storage period progresses. The conceptual trend below illustrates how structural and residual trapping may be more significant during earlier stages, while solubility and mineral trapping can become increasingly relevant over longer periods.

Reactive transport modelling is particularly relevant when assessing solubility and mineral trapping because these processes involve interactions between CO₂, formation water, and reservoir minerals. Williams (2023) demonstrated the importance of numerical reactive-transport approaches for examining coupled transport and geochemical processes and predicting long-term reservoir performance. Applying similar modelling principles to CO₂ storage can improve the assessment of how dissolved CO₂ interacts with the reservoir environment over extended periods.

4.4 Numerical Prediction of Trapping Efficiency

Numerical simulation can be used to estimate the amount of CO₂ retained through different trapping mechanisms and evaluate how storage efficiency changes with time. Model outputs may include CO₂ saturation, plume distribution, dissolved CO₂ concentration, pressure evolution, and mineral alteration. These outputs allow different storage scenarios to be compared and provide information for assessing long-term containment.

The accuracy of these predictions depends on the quality of geological and fluid-property data used in the model. Reservoir heterogeneity, relative permeability, capillary pressure, and geochemical reaction rates can introduce uncertainty into estimates of trapping efficiency. Consequently, sensitivity analysis is necessary to determine which parameters have the greatest influence on predicted CO₂ retention.

4.5 Long-Term CO₂ Retention and Storage Security

Long-term storage security depends on the progressive immobilization of CO₂ and the integrity of the geological formation. Numerical models can extend beyond the injection period to investigate how CO₂ redistributes, dissolves, and potentially reacts with reservoir minerals. Williams (2023) highlighted the value of long-term numerical modelling for predicting changes within subsurface reservoirs, particularly where fluid transport and geochemical reactions occur simultaneously.

The integration of multiphase-flow and reactive-transport modelling therefore provides a more comprehensive approach to evaluating CO₂ storage security. Such an approach can help identify potential migration pathways, estimate long-term retention, and determine whether depleted gas reservoirs can provide stable conditions for geological CO₂ sequestration.

In sum, the numerical assessment of trapping mechanisms demonstrates that CO₂ storage is a dynamic process involving several complementary mechanisms. Structural and residual trapping can provide important initial immobilization, while dissolution and mineral reactions may contribute increasingly to long-term retention. Numerical and reactive-transport modelling, including the approach highlighted by Williams (2023), is therefore essential for evaluating the evolution and effectiveness of these mechanisms under realistic reservoir conditions.

5. Model Evaluation, Challenges, and Future Perspectives

The reliability of numerical modelling depends on how accurately the model represents the geological, fluid-flow, and geochemical conditions of the reservoir. Model evaluation, sensitivity analysis, and uncertainty assessment are therefore necessary for determining whether numerical predictions can adequately describe CO₂ injection, migration, and trapping. These processes also help identify the major limitations that must be addressed to improve long-term CO₂ storage assessments.

5.1 Model Calibration and Validation

Calibration involves adjusting numerical model parameters to achieve agreement between simulated results and available reservoir observations. Relevant data may include historical pressure, production behaviour, fluid saturation, permeability, and other geological properties. A calibrated model can subsequently be validated using independent observations to determine whether it can reproduce realistic reservoir behaviour.

Dumitrache et al. (2023) demonstrated the usefulness of numerical reservoir simulation for evaluating underground CO₂ storage, while Raza et al. (2018) highlighted the importance of accurately representing residual gas saturation when modelling CO₂ storage in depleted gas reservoirs. Proper calibration and validation are therefore essential for reducing discrepancies between simulated and actual reservoir conditions.

5.2 Sensitivity Analysis of Key Parameters

Sensitivity analysis determines how changes in individual reservoir or operational parameters affect model predictions. Important parameters include permeability, porosity, residual gas saturation, injection rate, reservoir pressure, temperature, and relative permeability. Identifying highly sensitive parameters helps researchers determine which uncertainties require greater attention during reservoir characterization.

For CO₂ storage, sensitivity analysis can also be used to evaluate changes in plume migration, pressure buildup, storage capacity, and trapping efficiency. Numerical studies of CO₂-enhanced gas recovery have shown that reservoir properties and heterogeneity can strongly influence predicted storage and recovery performance (Zhao et al., 2024; Hu et al., 2026).

5.3 Uncertainty in CO₂ Storage Modelling

Uncertainty is unavoidable in geological CO₂ storage because subsurface formations are heterogeneous and their properties cannot be measured at every location. Uncertainty in permeability, porosity, geological connectivity, residual gas saturation, and geochemical reaction rates can produce significant differences in predicted CO₂ migration and trapping.

Table 2. Key Modelling Parameters, Sources of Uncertainty, and Their Effects on CO₂ Storage Performance

Modelling Parameter	Major Source of Uncertainty	Potential Effect on CO ₂ Storage
Permeability	Spatial heterogeneity	Changes CO ₂ flow pathways and injectivity
Porosity	Geological variability	Influences available storage volume
Residual gas saturation	Limited reservoir data	Affects CO ₂ displacement and residual trapping
Injection rate	Operational uncertainty	Influences pressure buildup and plume expansion
Relative permeability	Experimental limitations	Affects multiphase CO ₂ movement
Caprock properties	Incomplete geological characterization	Influences containment and leakage risk
Geochemical reaction rates	Limited long-term data	Affects mineral trapping predictions

These uncertainties demonstrate the need for multiple simulation scenarios rather than relying on a single deterministic model. Williams (2023) emphasized the value of numerical modelling for predicting long-term reservoir performance where fluid transport and geochemical processes interact. Incorporating uncertainty into such models can provide a more realistic assessment of long-term CO₂ behaviour.

5.4 Challenges in Long-Term CO₂ Prediction

One of the major challenges in numerical CO₂ storage modelling is predicting reservoir behaviour over long periods. CO₂ migration, dissolution, mineral reactions, and changes in reservoir properties may continue for decades or longer after injection has stopped. The limited availability of long-term field observations makes it difficult to fully validate these predictions.

Another challenge is accurately representing coupled physical and chemical processes. Conventional multiphase-flow models may not adequately capture geochemical reactions, while reactive-transport models require additional geological and chemical data. Williams (2023) demonstrated the importance of considering coupled transport and geochemical processes when evaluating long-term subsurface reservoir performance.

5.5 Future Development of Numerical Modelling

Future numerical modelling approaches should increasingly integrate detailed geological characterization, multiphase-flow simulation, geochemical modelling, and uncertainty analysis. Improvements in computational capacity can also support higher-resolution reservoir models capable of representing complex geological structures and preferential CO₂ pathways.

The integration of CO₂ storage with enhanced gas recovery is another area requiring further numerical investigation. Studies by Zhao et al. (2024) and Hu et al. (2026) demonstrate the potential of numerical simulation for evaluating these combined processes. Advanced modelling approaches based on the reactive-transport principles discussed by Williams (2023) can further improve predictions of long-term CO₂ migration, dissolution, and mineralization.

5.6 Implications for Safe CO₂ Storage

Reliable numerical modelling can support decisions concerning injection rates, well placement, storage capacity, pressure management, and long-term containment. By identifying potential migration pathways and evaluating the contribution of different trapping mechanisms, numerical models can help reduce the risks associated with geological CO₂ storage.

The evaluation of numerical models shows that calibration, validation, sensitivity analysis, and uncertainty assessment are essential for producing reliable predictions. Challenges associated with geological heterogeneity, limited subsurface data, and long-term fluid–rock interactions remain significant. However, continued development of integrated numerical and reactive-

transport models, as demonstrated by Williams (2023), can strengthen the assessment of depleted gas reservoirs as secure and effective CO₂ storage formations.

6. Conclusion

Numerical modelling provides an effective approach for evaluating CO₂ injection, migration, and trapping in depleted gas reservoirs. The behaviour of injected CO₂ is influenced by reservoir pressure, permeability, porosity, residual gas saturation, injection conditions, and geological heterogeneity. Numerical simulation enables these factors to be assessed while providing predictions of CO₂ plume development, pressure response, storage capacity, and enhanced gas recovery potential (Raza et al., 2018; Zhao et al., 2024).

The long-term security of CO₂ storage depends on the combined contribution of structural, residual, solubility, and mineral trapping mechanisms. Numerical and reactive-transport modelling can improve understanding of how these mechanisms develop over time. Williams (2023) demonstrates the importance of numerical modelling for evaluating coupled transport and geochemical processes and long-term reservoir performance, principles that are relevant to assessing CO₂ storage behaviour in depleted gas reservoirs.

Overall, the integration of reservoir simulation, trapping-mechanism assessment, and reactive-transport modelling provides a comprehensive framework for evaluating depleted gas reservoirs as potential CO₂ storage formations. Further improvements in reservoir characterization, uncertainty analysis, and long-term modelling are necessary to enhance the reliability of CO₂ storage predictions and support the safe and efficient deployment of geological carbon storage.

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