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Exhaustive Review of CO_2 Sequestration in Depleted Hydrocarbon Reservoirs: Recent Advances, Challenges and Future Prospects

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Cite This: https://doi.org/10.1021/acs.energyfuels.4c03512 Read Online

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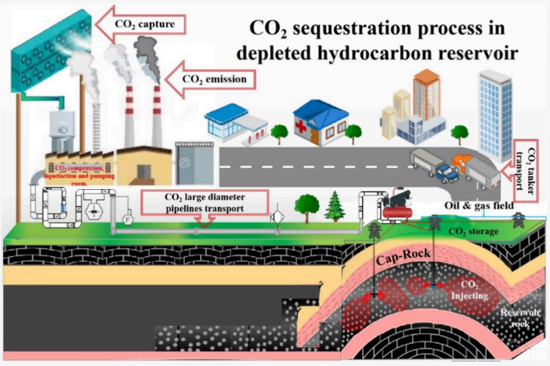
ABSTRACT: Aging or depleted hydrocarbon reservoirs (AHRs or DHRs) represent a promising alternative for CO_2 geo-sequestration compared to other geological formations, owing to their distinctive characteristics and the availability of pre-existing infrastructure. However, large-scale deployment faces complex, multidimensional challenges that require ongoing research to ensure optimal efficiency and safety. Despite notable progress in understanding the technical processes, significant techno-economic barriers remain. To overcome these obstacles, it is essential to adopt a critical and holistic analysis of existing studies while also exploring innovative approaches. Most recent reviews, though contributing significantly, have focused on specific aspects of CO_2 storage in these reservoirs, neglecting a systemic and multidimensional approach that integrates these various challenges into a single analysis. This fragmented approach leaves a gap in the literature, which may result in an incomplete understanding of the complex interactions between different factors, reducing the effectiveness of proposed solutions and limiting the ability to anticipate long-term impacts on the safety and sustainability of sequestration systems. Additionally, the rapid evolution of technology and scientific knowledge necessitates a constant update of studies related to sequestration in DHRs. Incorporating the latest technological innovations and methodological approaches is crucial to optimizing carbon capture and storage (CCS) processes, enhancing long-term safety, and adapting reservoir management strategies to increasing environmental and economic constraints. This review aims to address these gaps by providing a critical, comprehensive, and multidimensional analysis of recent advances while identifying persistent challenges. The integration of technical, economic, and environmental dimensions into a unified perspective offers a strategic global vision essential for guiding future research and supporting industrial applications. Furthermore, synthesizing the most recent developments and highlighting areas requiring further investigation, this study outlines a strategic roadmap for optimizing CO_2 sequestration in AHRs and DHRs, offering crucial insights for both research and industrial innovation.



1. INTRODUCTION

Climate change, characterized by rising average Earth temperatures due to human-generated greenhouse gases (GHGs), is impacting the planet causing rising sea levels, melting glaciers, extreme weather, and ecosystem disruptions.[1] This situation has garnered considerable attention from the scientific and international community, prompting urgent action to mitigate its impacts.

The Paris Agreement on Climate Change, ratified by 196 nations, seeks to restrict the increase in global temperatures to a level much below 2 °C, with a preference for 1.5 °C, in comparison to preindustrial levels.[2,3] Achieving this ambitious goal necessitates a drastic reduction in GHG emissions.[4,5]

Carbon dioxide (CO_2), considered the primary contributor to the enhanced greenhouse effect (accounting for approximately 80% of total GHG emissions (Figure 1A)),[6,7] is a crucial gas in the global warming process. Fossil fuels (Figure 1B) such as coal, oil, and gas,[8,9] primarily composed of hydrogen and carbon, are the primary source of its widespread presence.

The fight against climate change recognizes carbon neutrality, the act of equalizing CO_2 emissions and removals,[13,14] as a crucial objective.[15] In this situation, CO_2 geo-sequestration, which is the process of capturing and storing CO_2 released by human activities, looks like a promising technological solution.[16,17] It involves three main steps: capturing CO_2 at the source of emission, transporting it, and storing it in the right geological formations.[17,18] Noteworthy, the choice of capture method relies on the emission source, where "point source" and "diffuse source" refer to concentrated emissions from specific points (industries, power plants) and "diffuse source" refers to

Received: July 19, 2024
Revised: October 26, 2024
Accepted: October 28, 2024

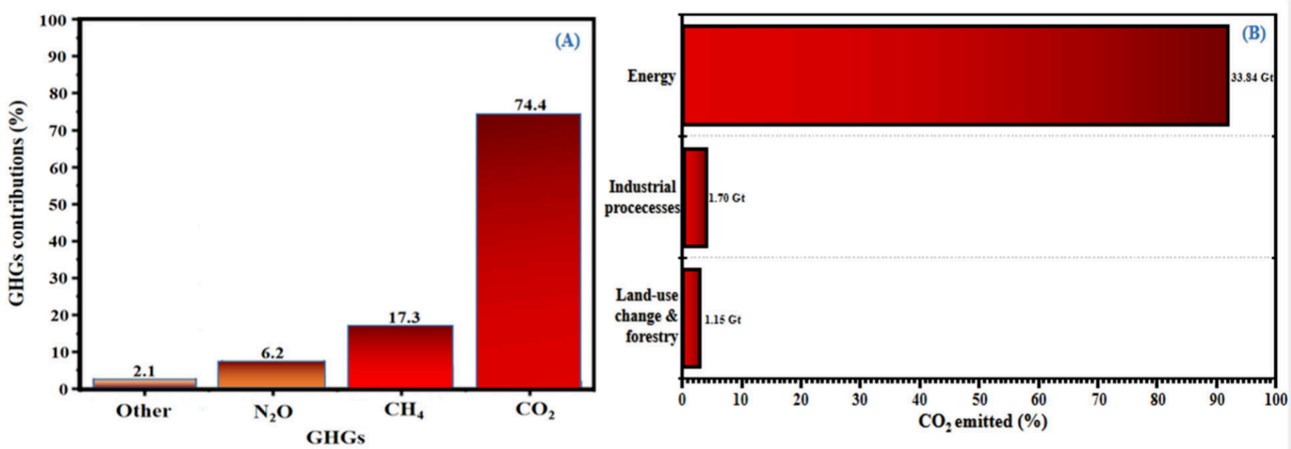


Figure 1. (A) GHG contributions to air pollution; (B) Global CO_2 emissions by sector. The global energy sector accounts for 92% of direct and indirect CO_2 emissions (Cumulative across available years). Data retrieved from refs 10−12. Available at https://www.wri.org/. Copyright 2024 Vigna L et al.

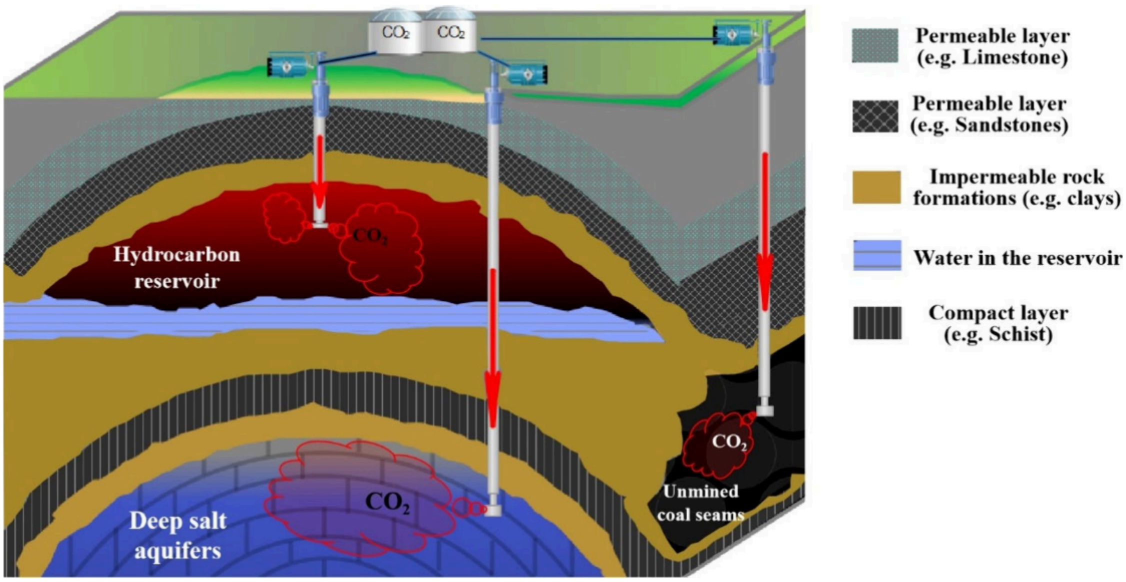


Figure 2. Overview of CO_2 geological storage options.

emissions dispersed over vast geographical areas (transportation, agriculture), respectively.[19,20] Transportation options include pipelines, ships, or trucks.[21,22] As for CO_2 storage, it can occur in depleted hydrocarbon (oil and gas) reservoirs (DHRs), deep saline aquifers (DSAs), or unmined coal seams,[23,24] as illustrated in Figure 2.

Among the various options available for geological storage, DHRs represent a particularly promising solution for CO_2 sequestration due to their favorable geological characteristics and the extensive experience accumulated in their management.[25] These reservoirs, which previously contained hydrocarbons, have demonstrated their ability to retain pressurized fluids over millennia, providing natural sealing conditions that significantly mitigate the risk of leakage.[26,27] Furthermore, their prior exploitation has facilitated the development of substantial expertise in reservoir characterization and management. Utilizing the existing oil and gas infrastructure can also drastically reduce capital expenditures associated with CO_2 storage projects.

Moreover, the injection of CO_2 into aging oil and gas reservoirs (AOGRs) enhances oil recovery, thereby optimizing energy resources while simultaneously providing a permanent site for CO_2 storage.[28,29] With an estimated global storage capacity ranging between 390 and 750 gigatons, these reservoirs have the potential to absorb nearly ten times the world's annual CO_2 emissions, making them a highly effective tool for mitigating climate change.[30] Thus, storing CO_2 in AOGRs or DHRs appears to be a highly practical and feasible approach to reducing carbon emissions.

However, despite these significant advantages, large-scale implementation of CO_2 sequestration in DHRs remains hampered by numerous multifaceted challenges that require ongoing research and in-depth elucidation to ensure the efficiency and safety of such projects.[31,32] Among these technical obstacles are the management of reservoir deformation due to prolonged CO_2 injection, the control of risks associated with fluid migration into unconfined zones, and uncertainties regarding geochemical reactions that may alter the porosity or permeability of reservoir rocks. These technical issues are

https://doi.org/10.1021/acs.energyfuels.4c03512
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Table 1. Summary of Recent Studies on CO_2 Sequestration in DOGRs

Reference	Main Subject	Contributions and Gaps
Bo Wei et al. (2023)[26]	CO_2 storage in depleted oil and gas reservoirs: A review	Reviews the storage capabilities of depleted oil and gas reservoirs, focusing on specific projects and their geological characteristics without integrating broader technical aspects of CO_2 injection or monitoring.
Han, et al. (2024)[38]	Review of CO_2 Fracturing and Carbon Storage in Shale Reservoirs	highlights the dual benefits of CO_2 fracturing for enhancing hydrocarbon recovery and facilitating carbon storage, offering valuable insights and real-world application data. However, it lacks specific case studies, sufficient assessment of environmental impacts, and detailed economic analyses and monitoring strategies needed for ensuring the long-term safety and effectiveness of CO_2 storage in shale reservoirs.
Heidarabad et al. (2024)[39]	Carbon Capture and Storage in Depleted Oil and Gas Reservoirs: The Viewpoint of Wellbore Injectivity	Examines the limited consideration of injectivity and storage capacities of specific depleted reservoirs, emphasizing isolated cases without discussing the multifaceted challenges associated with CO_2 sequestration.
Askarova et al. (2023)[40]	An Overview of Geological CO2 Sequestration in Oil and Gas Reservoirs	Presents an overview of geological CO_2 sequestration methods specifically in depleted oil and gas reservoirs, focusing on isolated technical case studies while not addressing integrated technical challenges.
Pavlova et al. (2022)[41]	Supercritical Fluid Application in the Oil and Gas Industry: A Comprehensive Review	Examines various applications of supercritical fluids, including CO_2 injection techniques for oil recovery, focusing on isolated technical cases rather than a broader analysis of all related issues.
Jones, A. C. (2022).[42]	Injection and Geologic Sequestration of Carbon Dioxide: Federal Role and Issues for Congress	Reviews the process of CO_2 injection in various oil fields but primarily addresses individual cases without a comprehensive analysis of long-term risks or integrated management strategies.
Kali et al. (2022)[43]	Techno-socio-economic analysis of geological carbon sequestration opportunities	Discusses geological storage methods using depleted hydrocarbon fields but focuses on specific case studies without integrating all relevant technical considerations.
Alam et al. (2022)[44]	Dual Benefits of Enhanced Oil Recovery and CO_2 Sequestration: The Impact of CO2 Injection Approach on Oil Recovery	Examines specific scenarios of CO_2 injection into depleted reservoirs for enhanced oil recovery, emphasizing isolated case studies rather than an integrated approach.
Parisio et al. (2020)[45]	Sinking CO_2 in Supercritical Reservoirs	Presents a novel approach to CO_2 storage by injecting it into supercritical reservoirs, allowing it to sink and reducing leakage risks. The study lacks a thorough exploration of critical technical challenges, such as induced seismicity, long-term stability, monitoring strategies, and environmental impacts, which are essential for assessing its practical viability and safety.

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compounded by the high costs of CO_2 capture, transport, and storage, as well as concerns related to safety and public acceptance,[33,34] which cannot be overlooked. In addition, often underdeveloped regulatory and policy frameworks add further complexity to the implementation of these projects. In this context, continued efforts to improve the efficiency, safety, and sustainability of CO_2 geo-sequestration are essential.

In recent decades, extensive research has been conducted to understand the mechanisms of CO_2 sequestration in DHRs. Recent studies, such as that of Vafaie et al. (2023),[35] have focused on the technical challenges of CO_2 injection into DHRs, including pressure management, rock deformation due to prolonged injection, leakage risk control, and more. Substantial progress has been made, particularly in the use of geochemical and geomechanical models to simulate interactions between CO_2, rocks, and fluids present in the reservoirs, as highlighted by Khan et al. (2024),[36] with notable case studies such as the Sleipner project in Norway and the Weyburn-Midale project in Canada. Nevertheless, many gaps remain and must be addressed to facilitate the identification of potential corrective strategies.

First, although recent studies have deepened the understanding of certain technical aspects, such as reservoir permeability and porosity, research on the optimization of injectivity and large-scale real-time monitoring is still developing. While CO_2 injectivity has been the subject of several studies, optimizing it in reservoirs with complex geological characteristics still requires advances, particularly to ensure homogeneous distribution of CO_2. Likewise, although advanced sensors, such as seismic sensors, have been integrated into pilot projects to monitor the evolution of CO_2 plumes in real-time, their large-scale deployment, especially in offshore or geologically heterogeneous environments, remains a technological and economic challenge. The impact of geological heterogeneities on CO_2 migration and distribution is also an active area of research, as these variations can significantly influence the behavior of injected CO_2. Technologies such as 4D seismic, which allows real-time visualization of fluid movements within reservoirs, have proven effective in certain onshore contexts. However, their large-scale application in more complex environments, such as offshore or highly heterogeneous reservoirs, still faces significant technical and financial constraints, requiring further innovations for widespread adoption.

Second, the majority of existing reviews, such as those summarized in Table 1, while making significant contributions, have focused on isolated aspects of CO_2 storage in DHRs. For instance, the study conducted by Al-Khulaidi et al. (2024),[37] provides an overview of how Carbon Capture, Use and Storage (CCUS) technologies can be integrated into gas recovery processes, highlighting current methodologies, challenges, and future research directions. However, one of the primary gaps in this study is its insufficient focus on long-term environmental impacts, the necessary monitoring strategies to ensure the safety and effectiveness of CO_2 storage, as well as the economic analyses. Other studies, meanwhile, discuss specific cases like trapping mechanisms or geochemical reactions in particular formations, without comprehensively addressing challenges related to aging infrastructure, managing heterogeneous reservoirs, or the long-term interactions between CO_2 and reservoir rocks. This leaves a gap in the literature regarding a systemic and multidimensional approach that integrates these various challenges into a single analysis.

It is pertinent to highlight a significant omission regarding the insufficient attention given to contemporary practical case studies, particularly in France with projects such as PYCASSO and GOCO2, as well as internationally. These pilot initiatives, while essential for assessing the true long-term impacts of CO_2 storage, are frequently overlooked by academic reviews, along with the long-term empirical evidence derived from these efforts. Such data is vital for understanding the stability of CO_2 in DHRs, evaluating environmental consequences over extended periods, and comprehending the economic ramifications of large-scale deployment. This gap limits the ability to formulate recommendations based on concrete, real-world experience, thereby underscoring the necessity to integrate these recent case studies into future analyses to validate and refine theoretical frameworks. The incorporation of these elements is crucial for providing a more holistic and pragmatic assessment of the feasibility and long-term risks associated with CO_2 geo-sequestration initiatives.

Furthermore, due to the continuous evolution of scientific knowledge and technological advancements, comprehensive reviews on CCS in DHRs require regular updates to remain relevant and reflect the latest innovations. It is, therefore, imperative to update the understanding of CCS in these reservoirs by incorporating the recent contributions of the scientific community, as well as technological and methodological innovations. Such updates are essential to improving the efficiency and safety of storage solutions, while also adjusting reservoir management strategies to new environmental and economic requirements. By making this knowledge more accessible, it will also facilitate its adoption by various stakeholders in the field.

Thus, this study aims to bridge these gaps by providing a comprehensive and multidimensional analysis of recent advancements in CO_2 sequestration within AOGRs and DHRs. Unlike previous reviews, this work explores not only the technical aspects of CO_2 injection and storage but also the specific challenges associated with offshore environments and geologically complex reservoirs, as well as economic, political, and social considerations. Furthermore, this manuscript examines site characterization technologies, the specific advantages of CO_2 storage in AOGRs and DHRs, and incorporates recent technological innovations such as the use of fiber optic sensors for real-time monitoring, water-CO_2 alternating injection (WAG) techniques to enhance injectivity, and advanced numerical modeling approaches to simulate fluid-rock interactions at various scales.

Additionally, this review addresses critical points often overlooked in the existing literature, including recent case studies both in France and internationally, as well as an analysis of long-term empirical data. These elements are essential for understanding the real-world impacts of sequestration projects. The article also highlights ongoing challenges related to the management of AHRs and long-term geochemical reactivity. Proposed approaches to enhance well integrity and improve reservoir monitoring include innovative solutions such as self-healing materials (granular hydrogels), coupled geomechanical modeling with real-time monitoring data, and the integration of artificial intelligence (AI) and machine learning (ML) technologies to enhance leak detection. Finally, this review emphasizes future perspectives on developing new reagents to accelerate CO_2 mineralization and strategies aimed at reducing long-term monitoring costs. The original contribution of this study lies in its ability to provide a comprehensive, structured,

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and up-to-date vision while clearly identifying areas where further research is necessary to overcome current obstacles and ensure the viability of large-scale sequestration projects.

Figure 3 presents a diagram that depicts the structural design of this work, or workflow.

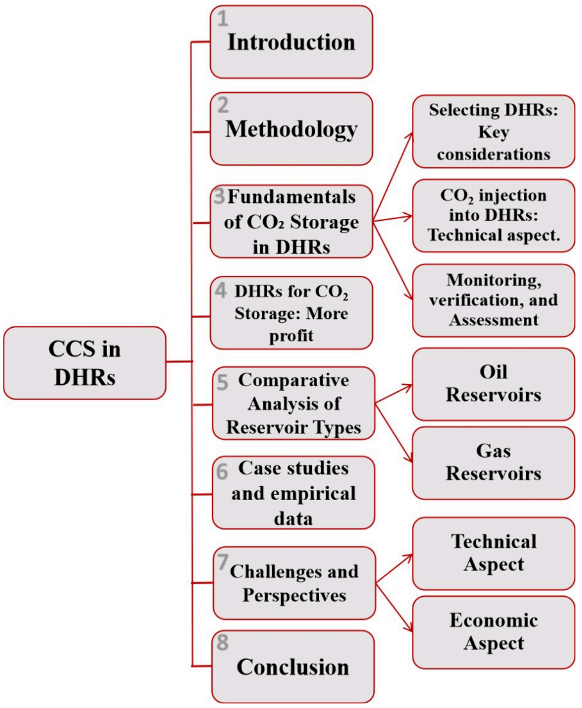

Figure 3. Flowchart illustrating the primary segments addressed in this study.

2. METHODOLOGY

A comprehensive review of CO_2 sequestration in hydrocarbon reservoirs was conducted using a rigorous methodology grounded in fundamental scientific principles. The approach involved tracing the history of CCS from its conceptual origins to recent technological advancements, which provided context for current challenges and opportunities. A meticulous examination of scientific literature, including publications, technical reports, and demonstration projects, allowed for the synthesis of current knowledge and identification of emerging trends. Information was collected and documented with precision, ensuring a thorough and accurate overview of the CCS field. Additionally, consultations with industry experts offered insights into recent developments, emerging challenges, and future trends, enhancing the review's practical relevance to industry stakeholders.

3. FUNDAMENTALS OF CO_2 STORAGE IN DHRS

Geological CO_2 sequestration, following its capture and transportation, plays a pivotal role in the CO_2 storage process, with the objective of securely and durably storing captured CO_2 within appropriate subsurface geological structures, not only to reduce greenhouse gas emissions in the atmosphere but also for potential future industrial applications.[46−48] Storage techniques encompass selecting the storage site, injecting CO_2 at significant depths underground where it is trapped by geochemical and geophysical mechanisms (such as dissolution in water, mineralization, capillary pressure, etc.),[46] and implementing monitoring, verification, and assessment procedures.

3.1. Selecting DHRs: Key Considerations.

Before commencing CO_2 storage, choosing an appropriate site is essential. Selecting a suitable DHRs for storage depends on several factors,[49] including storage capacity, distance from CO_2 sources, local regulations and proximity to transport infrastructures (Figure 4).[50,129]

Figure 4. CO_2 storage site selection criteria.

3.1.1. CO_2 Storage Capacity. This refers to the ability of the reservoir to store the captured CO_2 volume. Storage capacity is considered a key factor in DHRs selection and depends on various reservoir characteristics (porosity, permeability, temperature, pressure, water saturation, residual hydrocarbon saturation, interfacial tension, wettability, formation geometry, rock geochemical properties, geological integrity, trapping mechanisms, and geologic confinement and stability) and estimation methods.

3.1.1.1. Reservoir Characteristics. Porosity and Permeability. Porosity and permeability are fundamental characteristics for evaluating CO_2 storage capacity in DOGRs. These two properties directly influence the amount of CO_2 that can be stored and the ease with which it can migrate within the reservoir.[26] High-porosity reservoirs, such as sandstone and carbonate formations, offer greater storage capacity due to their larger pore volume.[25] A study by Rasool et al. (2023)[23] demonstrated that high porosities (greater than 20%) promote CO_2 retention and allow greater flexibility during injection. However, high porosity alone does not guarantee effective storage. The distribution and connectivity of the pores must also be optimized to allow controlled CO_2 migration within the reservoir.

Regarding permeability, it is crucial for the injectivity of CO_2. Low permeability can limit the injection rate, requiring higher injection pressures,[51] which could compromise reservoir stability. Conversely, excessive permeability, often caused by natural fractures or discontinuities in the reservoir, can increase the risk of leakage.[23] Pan Li et al. (2023)[52] conducted an experimental study on the effect of CO_2 storage on reservoir permeability and concluded that reservoirs with moderate permeability (between 10 and 100 millidarcys) are optimal for storage, as they allow smooth CO_2 migration without causing abrupt breakthroughs into unexpected areas.

However, a major challenge in DOGRs lies in the natural heterogeneities, such as local permeability variations due to fractures or geological faults. Zhong et al. (2019)[53] demonstrated that in heterogeneous reservoirs, permeability variability can lead to uneven CO_2 migration, requiring fine-scale modeling and regular monitoring to avoid leakage risks through more permeable zones.

In light of the above, it is clear that combining high porosity with adequate permeability is crucial to maximizing CO_2 storage efficiency. However, a detailed evaluation of the reservoir structure is necessary to ensure that these properties are favorable for safe long-term CO_2 retention.

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Temperature and Pressure. Temperature and pressure conditions within the reservoir directly influence the density and phase of the injected CO_2. When CO_2 is injected at pressures and temperatures above its critical point (73.8 bar and 31.1 °C) Figure 5, it enters a supercritical state, significantly improving its storage efficiency. In this state, CO_2 exhibits properties of both a gas and a liquid: low viscosity, which enhances its mobility through the reservoir pores, and high density, maximizing the volume of CO_2 that can be stored in a given space.[54,55]

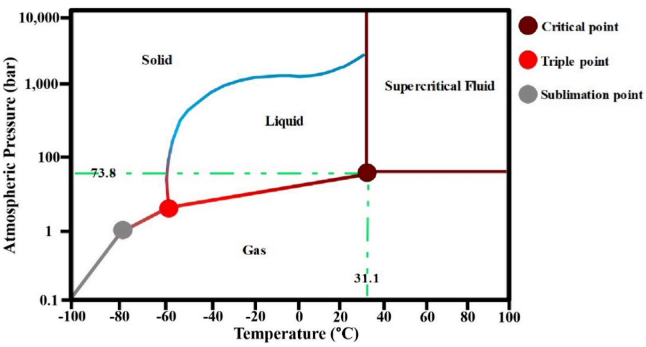

Figure 5. Phase diagram of CO_2 based on temperature and pressure, delimiting the boundaries between gaseous, liquid and supercritical states. Adapted with permission from ref 56. Copyright 2024 Elsevier

According to Parisio et al. (2020),[45] the density of supercritical CO_2 increases significantly under high pressure, which increases the volume stored in a given space. Reservoirs located at depths greater than 800 m generally offer optimal temperature and pressure conditions to maintain CO_2 in its supercritical phase. However, according to a study by Ma Shuying et al. (2023),[57] reservoirs at greater depths (over 3000 m) may present additional challenges, such as increased drilling and injection costs, and difficulties associated with monitoring and intervention in the event of a leak. At these depths, temperature and pressure may also impact the reservoir's mineralogical composition, leading to complex geochemical reactions with the CO_2.

On the other hand, reservoirs at shallower depths (less than 800 m) may not reach the required pressure and temperature conditions to maintain CO_2 in a supercritical phase. In this case, CO_2 remains in its gaseous or liquid form, reducing its density and storage capacity. Fang et al. (2023),[58] demonstrated that in such cases, CO_2 occupies a larger volume for the same mass, necessitating larger geological formations to store significant amounts of CO_2.

Another critical consideration concerns the impact of temperature and pressure variations on CO_2 migration. At lower pressures, CO_2 may become more mobile, increasing the risk of leakage through faults or fractures. At higher temperatures, geochemical reactions with the reservoir rock may occur more rapidly, which could either stabilize the CO_2 through mineral trapping or create migration pathways by altering the reservoir's permeability.

In summary, managing temperature and pressure conditions is essential to ensure effective CO_2 storage. Continuous monitoring and geophysical modeling are required to adjust injection strategies and ensure the long-term stability of storage.

Water and Residual Hydrocarbon Saturation. Water saturation in a reservoir is a key factor in determining CO_2 storage capacity, as it directly influences the distribution and mobility of injected CO_2. Reservoirs with high water saturation (aquifers) may reduce the available space for CO_2, thus limiting effective storage capacity. Conversely, reservoirs with low water saturation may potentially increase storage capacity but also raise the risks of uncontrolled CO_2 migration and leakage, as water helps stabilize and dissolve part of the CO_2.[31,59,60] Recent studies, such as those conducted by Singh et al. (2020),[61] have shown that in reservoirs with high water saturation, CO_2 injection induces a complex interaction between water and gas, where CO_2 can dissolve into the water, forming carbonic acid. This phenomenon contributes to long-term CO_2 stabilization through dissolution trapping. However, excessive water saturation can also decrease CO_2 mobility and limit its dispersion into the reservoir's porous zones, requiring more complex injection techniques, such as alternating water-CO_2 injection (WAG).

Regarding residual hydrocarbons, their presence in the reservoir can influence CO_2 behavior. Reservoirs containing significant amounts of residual hydrocarbons modify the wettability of the reservoir, potentially increasing the viscosity of CO_2 and reducing its displacement efficiency in the formation. A study by Hawthorne et al. (2018)[62] showed that residual hydrocarbons also affect CO_2 density, altering its interaction with the reservoir rock. Along the same lines, Lyu et al. (2024),[63] explored how residual gas mixtures, including hydrocarbons, influence CO_2 dissolution, trapping, and mass transfer dynamics. Their study demonstrates that the presence of residual hydrocarbons can hinder CO_2 dissolution and modify the overall density of the gas mixture, affecting its interaction with the reservoir rock and storage efficiency. Although these hydrocarbons may hinder storage capacity, they can also create synergies in enhanced oil recovery (EOR) projects, enabling the maximization of hydrocarbon recovery while sequestering CO_2.

In conclusion, accurate assessment of water and residual hydrocarbon saturation levels is essential for optimizing CO_2 injection strategies and maximizing storage capacity. The outcomes vary depending on the specific reservoir characteristics, requiring detailed modeling and continuous monitoring to avoid CO_2 losses and ensure effective long-term storage.

Formation Geometry. The geometry of the reservoir refers to the size, shape, and spatial extent of the geological formation into which CO_2 is injected. These characteristics have a direct impact on storage capacity, as well as the migratory behavior of CO_2 after injection.[61] Reservoirs with extensive surface areas and significant thickness generally offer greater storage capacity and better confinement potential.[64] Reservoirs with a structurally simple geometry, such as anticline formations (geological domes sealed by an impermeable caprock), are highly sought after for CO_2 storage, as their shape naturally limits lateral CO_2 migration and allows for effective confinement under the caprock.[65−67] However, a recent study by Rasool et al. (2023)[23] showed that even in these favorable structures, factors such as the presence of undetected faults or fractures can compromise long-term geological integrity.

In contrast, reservoirs with complex geometries, such as fault systems or compartmentalized reservoirs, require more detailed geophysical modeling to predict CO_2 migration. Fractured geological formations, for example, can allow CO_2 to migrate more rapidly toward the surface if the fractures are not properly sealed. A study by Zhang et al. (2023)[68] demonstrated that in reservoirs with complex geometry, controlled and gradual injection is necessary to avoid opening existing fractures, which could compromise CO_2 containment.

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Regarding reservoir size, reservoirs with a large lateral extent are ideal for storing large quantities of CO_2. The work of Meng et al. (2024)[64] suggests that formations with a wide surface area and significant thickness are capable of absorbing and distributing CO_2 more evenly, thereby reducing the risk of abrupt CO_2 breakthroughs through the caprock formations. However, in smaller or compartmentalized formations, CO_2 may quickly reach the reservoir boundaries, increasing the risk of local overpressure and leakage.

In conclusion, formation geometry is a key parameter in selecting reservoirs for CO_2 storage. A favorable geometry enables secure storage, while a complex geometry requires increased modeling and monitoring efforts to ensure long-term storage stability.

Interfacial Tension and Wettability. The interfacial tension between the injected CO_2 and the aqueous or petroleum phase present in the reservoir significantly influences the mobility and distribution of CO_2 within the reservoir.[69] As noted by Eyitayo et al. (2024)[70] in their experimental study, high interfacial tension can lead to the formation of small CO_2 droplets, limiting its dispersion and reducing the reservoir's storage capacity. Recent research by Heidarabad et al. (2024),[39] Zhang et al. (2023)[71] et Jeon et al. (2020)[72] has shown that reducing interfacial tension through the addition of surfactants or optimizing pressure and temperature conditions can improve CO_2 mobility in the reservoir pores, thereby enhancing gas distribution and increasing storage capacity.

Wettability refers to the tendency of reservoir rocks to be preferentially wetted by water or hydrocarbons, and it is crucial as it influences the capillary behavior of CO_2 within the reservoir pores.[73] In water-wet reservoirs, CO_2 tends to migrate less uniformly, potentially limiting its sequestration efficiency. However, in CO_2-wet reservoirs, the gas is distributed more homogeneously, facilitating more efficient storage. A recent study by Bruce Hill et al. (2021)[74] reviewed various trapping mechanisms, highlighting that reservoirs with partial CO_2 wettability allow for greater distribution and accumulation of the gas within the pores, optimizing residual trapping. However, reservoir wettability can be influenced by factors such as water salinity, rock mineralogy, and the presence of residual hydrocarbons.

Thus, understanding and adjusting interfacial tension and wettability conditions can improve CO_2 storage performance, particularly in reservoirs with varied geochemical characteristics. Further research is needed to develop methods for actively adjusting reservoir wettability, such as injecting surface agents or modifying the composition of the injected fluids.

Geochemical Properties of the Rock. The geochemical properties of the rock play a crucial role in the reservoir's ability to permanently trap CO_2. Once injected into the reservoir, CO_2 interacts with the minerals present in the reservoir rock, which can trigger a series of complex geochemical reactions. These reactions can lead to two primary outcomes: mineral dissolution and carbonate precipitation. Mineral dissolution can increase porosity and permeability, while carbonate precipitation (such as calcium carbonate, $CaCO_3$) can trap CO_2 in solid form, providing a permanent and safe storage solution.[75,76]

Mineral Dissolution and Reservoir Property Alterations. When dissolved CO_2 reacts with formation water, it forms carbonic acid (H_2CO_3), which can dissolve certain minerals in the reservoir rock, such as silicates and carbonates. This dissolution can alter the physical properties of the rock, notably by increasing porosity and permeability.[77] Although these changes can initially enhance the reservoir's CO_2 storage capacity, they may also pose risks. Recent studies by Liu et al. (2022),[78] and Al Ajmi et al. (2023),[79] have shown that excessive mineral dissolution in carbonate formations can weaken the reservoir structure and lead to stability issues.

Carbonate formations, such as limestones and dolomites, are particularly susceptible to dissolution under the effect of carbonic acid. These formations may undergo significant mass loss over time, potentially creating cavities or additional fractures, thereby increasing the risk of CO_2 leakage to the surface.[80,81] However, in some cases, this dissolution can be controlled and even beneficial, as it creates new pore spaces for additional CO_2 storage.

Mineralization and Carbonate Precipitation. One of the most stable and sought-after mechanisms for long-term CO_2 sequestration is mineralization, where CO_2 reacts with the minerals in the rock to form solid carbonates. These reactions are particularly common in formations rich in minerals such as calcium, magnesium, and iron. Once CO_2 is converted into carbonate minerals, it becomes permanently trapped in solid form, eliminating any risk of future leakage.[82]

Basaltic formations are particularly promising for mineralization, as they contain large amounts of reactive minerals such as olivine and pyroxene, which can rapidly react with CO_2.[83] The CarbFix project in Iceland, for example, demonstrated that more than 95% of the CO_2 injected into basaltic formations was converted into carbonates in less than two years.[84] This rate of mineralization is much faster than what is observed in other types of rock formations, making basalts an ideal candidate for long-term sequestration.

However, the mineralization process depends on several factors, including temperature, pressure, and the chemical composition of the rock. Fei Wang et al. (2022)[85] showed that higher temperatures (above 100 °C) and high metal concentrations (such as iron and magnesium) accelerate the mineralization process. Conversely, in colder or less reactive reservoirs, mineralization can take centuries or even millennia. Therefore, selecting reservoirs with favorable geochemistry is crucial to ensuring rapid and secure mineralization.

Adverse Effects of Geochemical Reactions. While mineralization provides a stable trapping mechanism, not all geochemical reactions are necessarily beneficial. Some reactions between CO_2 and reservoir minerals can lead to undesirable effects, such as increased permeability due to excessive dissolution or alterations in the reservoir's mechanical properties. Al-Khdheeawi et al. (2023)[86] showed that in certain clay-rich reservoirs, CO_2 reacts with clay minerals, causing clay swelling and a significant reduction in permeability, which complicates CO_2 injection and migration.

Although mineralization is one of the most secure long-term trapping mechanisms, its dependence on the reservoir's specific geochemical conditions requires careful evaluation of candidate formations for CO_2 sequestration. Reservoirs with high levels of reactive minerals, such as basalts, offer the best opportunities for rapid mineral trapping. However, in reservoirs lacking these characteristics, mineralization can be much slower, necessitating the implementation of long-term monitoring measures to ensure the stability of trapped CO_2.

Regarding mineral dissolution, while it can create additional storage space for CO_2, it must be controlled to prevent excessive alterations in the reservoir's geological structure. Advanced geochemical simulations are recommended to predict possible reactions between CO_2 and reservoir minerals and to assess the

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risks associated with these reactions. Finally, adverse reactions, particularly in clay-rich or fractured reservoirs, require careful monitoring. In such cases, techniques such as injecting sealing agents or adjusting injection pressure conditions may be necessary to mitigate the negative effects of geochemical reactions on reservoir permeability and stability.

CO_2 Sequestration Mechanisms. The effectiveness of long-term CO_2 sequestration relies on several trapping mechanisms that allow CO_2 to be securely confined within the geological formation. These mechanisms occur at different stages after injection, playing a key role in retaining CO_2 over geological time scales, and they can be classified into four main categories.[87,88] Each of these mechanisms, as shown in Table 2, presents specific advantages and challenges, with their effectiveness varying depending on the reservoir's characteristics.

The efficiency of structural and stratigraphic trapping depends on the integrity of the underlying formation, which must be free of faults, fractures, or vulnerable zones that could lead to CO_2 leakage. Research, illustrated by the work of Zappone et al. (2018),[97] highlights the importance of conducting seismic assessments before injection to detect any discontinuities in the caprock architecture. In some locations, tectonic changes or pre-existing faults may compromise structural trapping. Studies have indicated that even minor faults can, when subjected to increased pressure following CO_2 injection, become activated and lead to gradual leaks. Therefore, real-time seismic monitoring is essential to verify the stability of the caprock and identify any tectonic activity that could affect trapping efficiency.

Regarding residual trapping, it is considered effective when CO_2 is introduced into reservoirs characterized by sufficiently heterogeneous permeability and porosity, facilitating CO_2 retention in the reservoir's residual pores.[58,98] Once CO_2 passes through the porous matrix, part of it remains trapped in the pores due to capillary action, preventing its return to the surface. Research by Christopoulou et al. (2022),[99] Hesse et al. (2023) and Garing et al. (2019),[100] indicates that residual trapping is particularly effective in fine-grained sandstone reservoirs, where capillary forces can hinder the migratory behavior of CO_2. However, their study also highlighted a significant limitation: the effectiveness of this mechanism is heavily influenced by pore size distribution and water saturation levels in the reservoir. In highly homogeneous reservoirs or those with high water saturation, residual trapping may be less effective, as CO_2 may encounter reduced resistance during migration toward the surface.

As for dissolution trapping, it is regarded as a safer long-term solution since dissolved CO_2 is less likely to escape due to its increased density. Research indicates that the speed and effectiveness of dissolution trapping depend on the dynamics of the fluids present in the reservoir, as well as the temperature and pressure conditions.[101−103] Reservoirs at intermediate depths (ranging from 1,000 to 2,000 meters) offer optimal conditions for maximizing CO_2 dissolution in formation water. However, in reservoirs located at greater depths (greater than 3,000 meters), the limited fluid movement may restrict dissolution speed, making this mechanism less effective in the short term.

Finally, mineral trapping is particularly noteworthy in geological formations rich in basalt or other reactive lithologies.[104,105] However, basaltic formations are not ubiquitous, and other types of rock, such as sandstones or limestones,

Table 2. Types of CO_2 Trapping Mechanisms in DOGRs

Mechanisms	Description	Advantages	Limits	Ideal conditions
Structural-Stratigraphic Trapping	• Cap-Rock Anticline: CO_2 trapped under a layer of impermeable rock (clay or shale), preventing it from migrating to the surface[89] • Fault • Unconformity and sedimentary wedge • Mixed trap associated with a diapir (salt domes)	High storage capacity and long-term stability	Depends on cover quality and reservoir geometry.	Presence of impermeable geological cover and appropriate geological structure.
Residual trapping	• Capillary hysteresis: Once CO_2 migrates into the pores of the rock, it becomes difficult for it to return, trapped by capillary forces.[90,91] • Retention in the rock: This mechanism contributes to CO_2 retention even if escape routes are present.[87]	Effective even if escape routes exist, rapid stabilization.	Limited by residual rock saturation.	Reservoir rocks with good porosity and favorable capillary characteristics.
Solubilizing trapping	• Water solubility: CO_2 is partially soluble in water, forming H_2CO_3. This acid then reacts with the minerals present in the reservoir rock.[92]	CO_2 pressure reduction,	Limited by solubility of CO_2 in water,	Presence of groundwater with adequate dissolution capacity,
	• Dissolution reactions: This process reduces the pressure of CO_2 in the reservoir, making storage safer.[93]	The dispersion of CO_2 has the potential to function as a supplementary method of trapping, alongside structural trapping.	May require long-term monitoring	Reservoirs with good permeability
Mineralizing trapping	• Geochemical reactions: CO_2 reacts with the cations (calcium, magnesium, iron) present in the rock's minerals, leading to the precipitation of carbonates[94−96]	Permanent sequestration, creation of stable minerals.	Slow process, requires specific geochemical conditions.	Rocks rich in cations such as calcium, magnesium and iron, Favorable geochemical environment.

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react more slowly to CO_2. Thus, the effectiveness of mineral trapping can vary significantly from one formation to another, necessitating detailed geochemical evaluation before large-scale injection.

Figure 6 illustrates each of these mechanisms in detail. This visualization helps to better understand the physical and chemical processes that ensure the secure retention of CO_2 over different time scales.

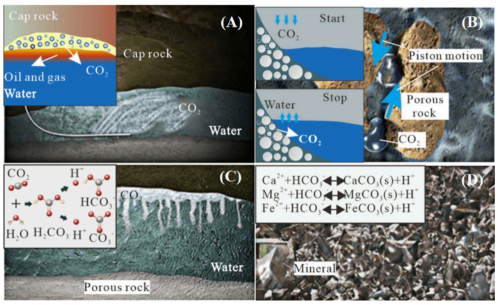

Figure 6. Types of CO_2 trapping mechanisms in DOGRs. The first panel (A) involves the entrapment of free CO_2 by impermeable rocks. Subsequently, CO_2 undergoes a process known as "piston motion" within the pores upon injection and cessation (panel (B)). Moreover, dissolved CO_2 interacts with water (panel (C)), while anions resulting from CO_2 dissolution engage with metal cations present in the formation water, leading to the formation of minerals (panel (D)). Reproduced with permission from ref 106. Copyright 2024 Elsevier.

In most reservoirs, these mechanisms interact to provide a multi-level storage solution.[58] However, challenges remain. For example, in fractured reservoirs, structural trapping may be compromised, leaving residual or dissolution trapping as the primary barriers. Additionally, the time required for some mechanisms, such as mineralization, can be a limiting factor. While dissolution and residual trapping are relatively rapid, the formation of solid carbonates can take decades or even centuries in some cases. Further research is needed to accelerate these processes by modifying the reservoir's geochemical conditions or using catalysts.

Geological Containment and Stability. Geological containment depends on the integrity of the caprock formation, the presence of faults and fractures, and the stability of the formation in the face of phenomena such as earthquakes or landslides.[107,108] Any discontinuity in the geological structure, such as fractures or active faults, can compromise CO_2 retention and lead to leakage. Recent studies, including those by Pevzner et al. (2020),[109] have highlighted the importance of seismic assessment of reservoirs before CO_2 injection. Their research showed that reservoirs subjected to excessive pressure following CO_2 injection can develop secondary fractures in the caprock, which could result in slow and uncontrolled leaks. Therefore, strict management of injection pressure is necessary to avoid exceeding critical rupture thresholds in the geological formation.

Fault integrity is also a major concern. Karolytė et al. (2020)[110] studied the influence of fluid properties on fault sealing capacity in hydrocarbon and CO_2 systems and demonstrated that even small faults can become conductive under pressure increases related to injection, leading to leaks or altering fluid migration pathways within the reservoir. However, in some cases, faults sealed by minerals such as clay can help seal the reservoir and contain the injected CO_2, requiring precise geological study for each site.

Finally, the seismic stability of the reservoir and its surroundings must be carefully considered, particularly in areas prone to earthquakes. The work of Bondarenko et al. (2021),[111] as well as a case study in the Delaware Basin in West Texas and Southeast New Mexico (United States) conducted by Dvory et al. (2021)[112] revealed that microseismic events can be triggered by CO_2 injection due to increased pore pressure. Although these microseismic events did not cause significant leaks, they underscore the importance of continuously monitoring induced seismicity to ensure the long-term stability of the reservoir.

Thus, a comprehensive geological assessment, combined with active seismic monitoring, is essential to ensure the long-term containment of CO_2 in depleted hydrocarbon reservoirs. Sequestration projects must incorporate predictive models to evaluate the potential impacts of injections on reservoir stability and implement proactive mitigation measures.

3.1.1.2. Estimation Methods. A variety of techniques are utilized to assess the storage capacity of CO_2 in DOGRs.[113−115] These include:

Geological Modeling and Numerical Simulation. The accurate estimation of storage capacity in DHRs is a critical factor for the success of CO_2 sequestration projects. Recent studies have highlighted significant advancements in storage capacity estimation techniques, focusing on improving geological models and complex numerical simulations. For example, the study by Pagáč et al. (2024)[116] demonstrated the importance of integrating multivariate flow simulations with high-resolution geological models. This approach has improved the prediction of storage capacities by accounting for the heterogeneous variability of geological formations. This method is particularly promising as it reduces uncertainties related to porosity and water saturation variations, which are often underestimated in classical volumetric calculations. However, Penedo et al. (2024)[117] acknowledge that this approach remains limited by the availability of high-quality regional geological data, which impacts the accuracy of storage capacity estimates and may hinder its widespread application in regions where seismic surveys are not well-detailed.

To overcome these limitations, integrating advanced geophysical imaging techniques, such as broadband seismic, could enhance the accuracy of geological models used in storage simulations. Recent work by Emerick et al. (2024)[118] has shown that the use of 4D seismic combined with machine learning algorithms can improve real-time storage capacity estimates by better tracking CO_2 flow evolution within the reservoir. However, while promising, these techniques require costly technological infrastructure, limiting their adoption in small to medium-sized projects.

Numerical techniques have also progressed, particularly with the improvement of hydrodynamic transport and geomechanical coupling models. In the context of the Aquistore project in Canada, advanced geochemical simulations were used to evaluate the long-term behavior of injected CO_2 in saline reservoirs.[36] The study by Mortazavi et al. (2024) highlights that the interaction between CO_2, reservoir rocks, and surrounding fluids is crucial for predicting long-term leakage scenarios. However, one of the persistent challenges remains the precise consideration of pore-level microdynamics, which can affect CO_2 retention over hundreds of years.

The use of coupled models, combining pore-scale geochemistry and hydrodynamics, as suggested by Mhaski et al. (2024),[119] could improve the accuracy of predictions. These

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Table 3. Overview of the Main Numerical Modeling Techniques

Techniques and Systems	Methods	Descriptions	Examples of completed projects
Long-term CO_2behavior models	Geochemical simulations[116,123,124]	Take into account the interactions between CO_2, rocks, fluids and micro-organisms in the reservoir to predict the long-term behavior of CO_2 and its potential impact on the underground environment.	Projet Aquistore (Canada)
Hydrodynamic transport models	Hydrodynamic transport models[125]	Simulate the movement of CO_2 and fluids in the reservoir, enabling optimization of injection well locations and sequestration strategies.	Projet Frio CCS (États-Unis)
Volumetric models	Volumetric Calculations	Based on volumetric equations (CSLF, USDOE) to estimate theoretical and effective capacity.	Standard methods in oil and gas reservoirs
Hydro-mechanical coupling models	Hydro-mechanical coupling models[126]	Simulate the impact of injected CO_2 on reservoir pressure and porosity, enabling assessment of storage site integrity and risk of leakage.	Projet Frio CCS (États-Unis)
3D reservoir modeling	3D Reservoir Modeling	Models based on seismic and geological data to visualize the distribution of reservoir properties.	Used in numerous CO_2 storage projects.
Model-based optimization algorithms	Model-based optimization algorithms[127,128]	Identify optimal injection well locations, injection volumes and CO_2 management strategies to maximize storage efficiency and minimize costs.	Projet Saline EOR (UK)
Reactive transport models	Reactive Transport Models	Integrate chemical reactions between CO_2 and reservoir rocks to estimate the long-term effect on porosity and permeability.	Used in several sequestration projects
Hypothetical scenario simulations	Simulation of "what if" scenarios[129,130]	Evaluate the impact of various factors, such as pressure variations, potential leaks and geological changes, on long-term storage performance.	Aquistore project (Canada)

models could be coupled with laboratory data on CO_2-rock interactions, incorporating results from small-scale experiments to better estimate mineral dissolution rates and precipitation effects on effective storage capacity.

Volumetric Calculations. The methodologies utilized in volumetric approaches stem from geological data[120] and techniques advocated by Carbon Sequestration Leadership Forum (CSLF) and United States Department of Energy (USDOE).[121] These calculations consider various technical, economic, and environmental factors to determine the theoretical, effective, practical, and matched storage capacity of CO_2.

Basic equation:

$$V_{CO_2} = A \times h \times \varnothing \times (1 - S_r) \tag{1}$$

In which V_{CO_2} is the volume of CO_2 that can be stored, A represents the surface area of the reservoir, h denotes the thickness of the formation, ϕ indicates the porosity, and S_r signifies the residual hydrocarbon saturation.

CSLF Methodology. Following the resource and reserve pyramid concept, theoretical and effective CO_2 storage capacities (M_{CO_2} *and* M_{CO_2e}) are calculated as follows:

For gas reservoirs:

$$M_{CO_2t} = \rho_{CO2r} \times R_f \times (1 - F_{IG}) \times OGIP \times \left[\frac{(P_s \times Z_r \times T_r)}{(P_r \times Z_s \times T_s)}\right] \tag{2}$$

For oil reservoirs:

$$M_{CO_2t} = \rho_{CO_2r} \times \left[\frac{R_f \times OOIP}{B_f} - V_{tw} + V_{pw}\right] \tag{3}$$

Reservoir geometry-based approach for calculating CO_2 storage capacity in oil and gas reservoirs:

$$M_{CO_2t} = \rho_{CO_2r} \times [R_f \times A \times h \times \varnothing \times (1 - S_w) - V_{tw} + V_{pw}] \tag{4}$$

- OGIP/OOIP: Initial gas/oil in place.
- R_f: Recovery factor.
- F_{IG}: Fraction of gas injected.
- P, T, Z: Gas pressure, temperature and compressibility factor respectively.
- B_f: Formation volume factor.
- V_{iw},V_{pw}: Injected and produced water volumes.

Adjustment Factors. The basic volumetric method can be refined by introducing adjustment factors to account for various processes and reservoir characteristics that can influence the actual CO_2 storage capacity. These factors include:

- Mobility (C_m): Represents the ability of CO_2 to move within the reservoir.
- Buoyancy (C_b): Takes into account the effect of the density difference between CO_2 and existing fluids in the reservoir.
- Heterogeneity (C_h): Considers the variability of reservoir properties within the formation.
- Water saturation (C_w): Adjusts storage capacity according to the amount of water present in the reservoir.
- Aquifer strength (C_a): Takes into account the influence of an underlying aquifer on CO_2 containment.

By combining the adjustment factors, we obtain an effective capacity coefficient (C_e) that reflects the cumulative impact of these factors on actual storage capacity:

$$M_{CO_2e} = C_m \times C_b \times C_h \times C_w \times C_a \times M_{CO_2t} \equiv C_e \times M_{CO_2t} \tag{5}$$

USDOE Methodology. The volumetric relationship is compatible with the estimation of CO_2 resources:

$$M_{CO_2t} = \rho_{CO_2r} \times A \times h \times \varnothing \times (1 - S_w) \times B \times E \tag{6}$$

with E as the storage efficiency factor, reflecting the fraction of total reservoir pore volume filled by CO_2, and B as initial formation volume factor for oil or gas.

Optimization of Adjustment Factors. While classical volumetric calculation techniques are effective, they require a more detailed consideration of adjustment factors (mobility, buoyancy, heterogeneity, water saturation, etc.). Recent studies, such as those by Leng et al. (2024),[122] have shown that the use of Bayesian methods to adjust these factors according to specific reservoir conditions can reduce the uncertainty of storage capacity calculations. In particular, integrating probabilistic

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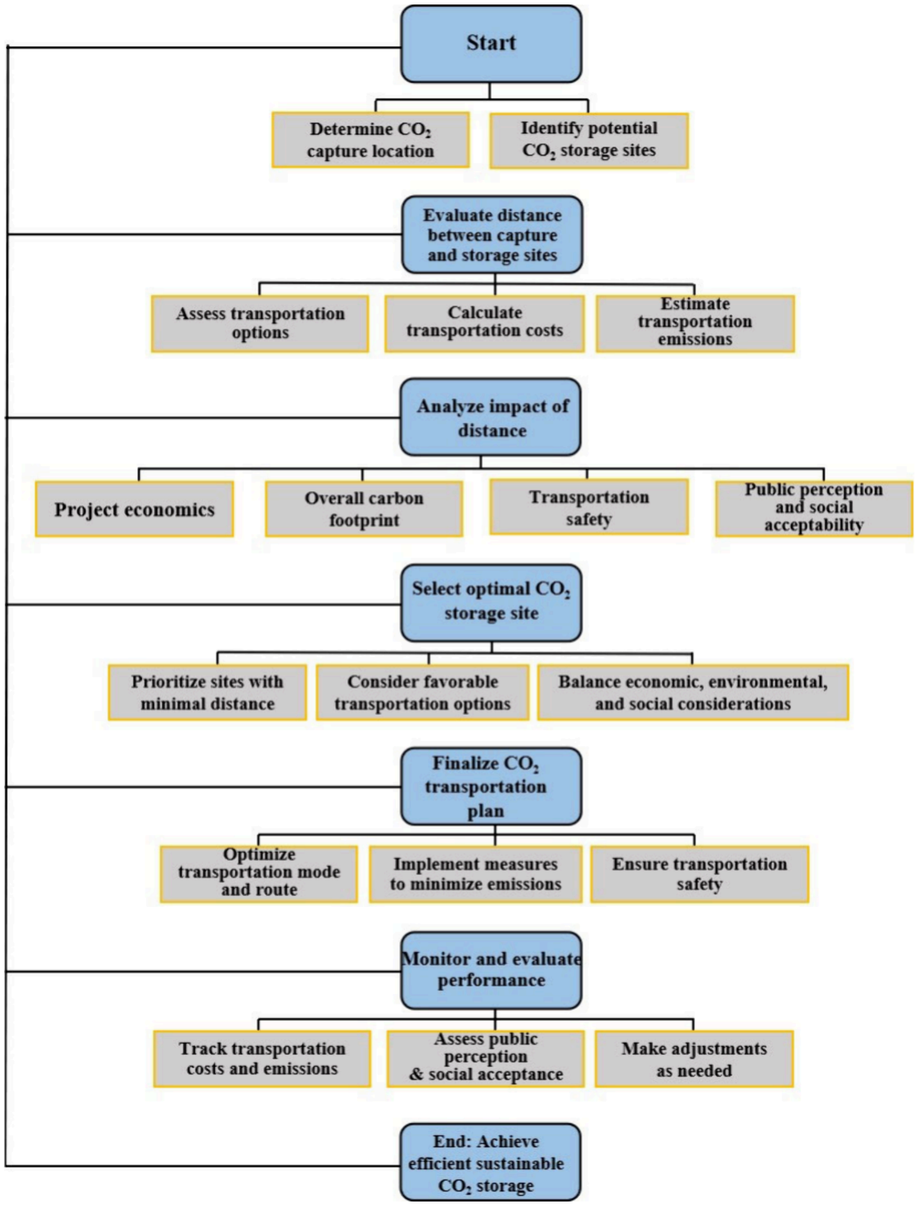

Figure 7. Flowchart: Factors Influencing CO_2 Storage Site Distance.

analysis has allowed for the identification of extreme scenarios where storage capacities are either overestimated or underestimated.

A promising improvement would be the application of stochastic modeling approaches to refine storage capacity predictions by incorporating probability distributions for each adjustment factor. This would help better understand the inherent uncertainties related to reservoir characteristics and fluid dynamics. Collaborations with research institutes specializing in probabilistic modeling could accelerate the development of these approaches.

To better understand the various numerical modeling techniques used to estimate storage capacity in depleted hydrocarbon reservoirs, it is essential to consider the diverse approaches employed in CO_2 sequestration projects. These methods include geochemical models, hydrodynamic simulations, and optimization algorithms for well placement. The Table 3 presents a summary of the main numerical modeling techniques, highlighting their characteristics and examples of projects that have integrated these approaches into their CO_2 storage strategies.

Use of Historical Data to Improve Estimates. The use of historical production data from reservoirs, combined with information from CO_2-enhanced oil recovery (CO_2-EOR) projects, has improved storage capacity estimation methods. Studies by Raza et al. (2020)[131] show that using production and reinjection data helps refine capacity estimates by considering the reservoir's depletion and saturation history. However, a major limitation of using historical data is the variability in data quality and availability. Some regions lack comprehensive historical data, which can skew storage capacity estimates.

3.1.2. Distance from CO_2 Sources. The distance between CO_2 capture and storage sites is a determining factor in evaluating the economic and environmental feasibility of CCS projects. The need to transport CO_2 over long distances can lead to significant costs, as well as additional GHGs emissions, which could undermine both the economic and environmental benefits of CCS projects.

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Economic and Environmental Impacts of Long-Distance Transport. Transporting CO_2 over long distances, whether by pipeline, ship, or rail, can represent up to 30% of the total costs of a CCS project.[130] According to a study by Gola et al. (2022),[132] projects located more than 300 km from CO_2 sources experience exponentially increasing transport costs, primarily due to the infrastructure needed to ensure gas compression and safety throughout the journey. Additionally, this infrastructure generates indirect emissions due to the energy consumption of compression stations and the construction of new pipelines, which can affect the project's overall environmental impact.

To mitigate these challenges, some authors propose prioritizing colocation solutions between capture and storage sites. Studies by Yang et al. (2023),[133] and Bandilla et al. (2020)[134] show that colocating these infrastructures, as seen in the Boundary Dam project in Canada, reduces transport-related costs by more than 40% while improving the project's environmental viability. This approach not only minimizes the additional emissions associated with transport but also reduces logistical complexity, making the project simpler to manage and more acceptable from a societal perspective.

Transport Safety and Associated Risks. The distance between capture and storage sites also has safety implications. Transporting CO_2 over long distances, particularly by pipeline, presents potential risks of leaks, accidents, or pipeline ruptures, especially in seismically active or geologically unstable regions. Arcangeletti et al. (2024)[135] examined the increased risk of pipeline ruptures in CO_2 transport projects in Southeast Asia, where seismic activity is frequent. They showed that longer distances increase vulnerability points along the pipeline, necessitating greater investments in safety and monitoring.

Conversely, in more stable regions such as the Permian Basin in the United States, projects like the CO_2 Pipeline Network have demonstrated that, under optimal conditions, large-scale pipeline transport can be safely conducted over distances exceeding 500 km by integrating advanced sensors and monitoring technologies.[136]

Social Acceptability and Public Perception. Another critical aspect of long-distance CO_2 transport is its impact on public perception and the social acceptability of CCS projects. The passage of pipelines or ships transporting CO_2 through urban or rural areas can raise concerns among local populations, particularly regarding safety and environmental impact. A qualitative case study in Greece by Stavrianakis et al. (2023),[137] highlighted participants' skepticism about new technologies, expressing concerns about leakage risks, disruption of the local environment, and the impact on land value, as well as a lack of information.

To address these concerns, CCS projects must include public communication and engagement strategies. For example, the Porthos project in The Netherlands incorporated a strong public consultation component from the early planning stages, improving social acceptability by reassuring communities about the safety measures in place.[138] These participatory approaches are essential for ensuring the long-term success of CCS projects, particularly when CO_2 transport involves infrastructure crossing densely populated areas. Figure 7 illustrates the parameters to be considered when analyzing the distance between the two sites.

In summary, a comprehensive evaluation of the distance between CO_2 sources and storage sites is essential to optimize the viability of CCS projects. Bielka et al. (2024)[139] suggest adopting an integrated approach that considers not only the economic and environmental aspects but also social and safety factors. Their study demonstrated that, in some cases, compromises may be necessary to maximize the overall benefits of the projects, particularly when deciding whether the construction of new transport infrastructure is justified by the storage benefits.

Thus, optimizing distance relies on a nuanced understanding of the trade-offs between costs, safety, environmental impacts, and social acceptability, depending on the geographic and geological characteristics of the regions concerned. In this regard, future strategies should focus on developing industrial clusters where capture and storage sites are colocated or located in close proximity, in order to minimize logistical challenges and maximize environmental benefits.

3.1.3. Proximity to Transport Infrastructure. The proximity of a CO_2 storage site to existing transport infrastructure, such as pipelines, ports, or railway stations, plays a crucial role in reducing costs and emissions related to transporting CO_2 to the storage site. Indeed, setting up new transport infrastructure is often expensive and can significantly increase the carbon footprint of the project. Therefore, proximity to such infrastructure represents a major competitive advantage, both economically and ecologically.[140,141]

Logistics Optimization and Cost Reduction. Direct access to existing transport infrastructure simplifies the logistical planning related to the capture, transport, and injection of CO_2 into depleted oil and gas reservoirs. In particular, pipelines—often considered the most efficient means of transporting CO_2 on a large scale—can transport the gas in supercritical form at lower costs and with minimal pressure losses. According to a recent study by Cho et al. (2024),[142] proximity to CO_2 transport pipelines reduces transport costs by more than 40%, compared to sites requiring the construction of new infrastructure. Additionally, seaports are essential interconnection points for offshore sequestration projects. For instance, in the Northern Lights project in Norway, ports play a key role in transporting CO_2 captured from heavy industries to storage reservoirs in the North Sea. Maritime transport offers alternatives to land pipelines by addressing geographical constraints in remote regions from storage sites.[143,144]

Synergies with Energy Infrastructure. Co-locating CO_2 storage facilities with existing energy infrastructure, such as power plants, refineries, or cement plants, offers significant opportunities for synergies. These facilities, often located near CO_2 capture centers, benefit from pre-existing logistical connections for fossil fuel supply or energy distribution. Consequently, this proximity allows the use of these infrastructures for transporting captured CO_2, reducing the need for costly new construction and minimizing environmental disturbances related to infrastructure works.

A study conducted by Wei et al. (2021)[145] showed that colocating CO_2 sequestration projects with refineries not only reduces logistical costs but also promotes the integration of value chains by combining capture, transport, and storage within a single industrial framework. For example, the Rotterdam Capture and Storage Demonstration Project (ROAD) used this approach to create a centralized logistical infrastructure around the ports and refineries of Rotterdam, facilitating the routing of CO_2 to offshore reservoirs.

3.1.4. Local Regulations. Local regulations are of paramount importance when it comes to identifying a feasible and sustainable CO2 storage site in DOGRs. These regulatory frameworks ensure that CO_2 storage projects comply with legal,

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environmental, and safety requirements. A comprehensive examination of this aspect, in conjunction with other technical and environmental parameters, is essential for the long-term success of CO_2 storage initiatives.[146]

Legal Frameworks and Permits. Regulatory frameworks for CO_2 storage are typically designed to address several key factors, including site selection, operational safety, environmental protection, and long-term monitoring. These frameworks define the legal prerequisites for storage, including the issuance of permits, licensing procedures, and adherence to safety standards.[147,148] One notable example is the Class VI Well permit in the United States, issued by the Environmental Protection Agency (EPA) under the Safe Drinking Water Act.[132] The Class VI wells are specifically designed for the long-term geological storage of CO_2. The EPA's Class VI regulations cover various aspects of CO_2 injection, such as

- Site characterization to assess the geology and ensure that the selected site is suitable for long-term storage.
- Well construction standards to prevent leaks and ensure the integrity of the storage site.
- Monitoring, reporting, and verification (MRV) requirements, which obligate operators to track CO_2 plume movement and ensure it remains within the designated geological formation.
- Postinjection site care and closure to ensure long-term safety after the cessation of injection operations, including a minimum 50-year postinjection monitoring period.

Similarly, in Europe, the European Union's Directive 2009/31/EC on the geological storage of carbon dioxide establishes the legal basis for the permitting and operation of CO_2 storage sites across member states.[149] The Directive imposes stringent requirements for risk assessment, site monitoring, and public involvement in the decision-making process. The directive mandates that operators conduct environmental impact assessments (EIA) and ensure ongoing monitoring of CO_2 migration through seismic surveys and pressure measurements. Moreover, operators must provide financial security to cover the costs of site closure and postclosure monitoring, ensuring that future liabilities are managed.

In Australia, the Offshore Petroleum and Greenhouse Gas Storage Act 2006 governs the injection of CO_2 in offshore depleted oil and gas reservoirs. It requires operators to obtain injection licenses and mandates community consultation during the permitting process.[150] The regulations also set out detailed provisions for well integrity, plume migration tracking, and emergency response plans to manage unforeseen CO_2 leakage.

Site Selection and Monitoring. Local regulations also establish specific criteria for site selection. For instance, regulations often dictate a minimum depth for CO_2 storage, typically between 800 m to 1,000 m, where the temperature and pressure conditions ensure that CO_2 remains in a supercritical state.[151] This state is critical for optimizing storage capacity and ensuring the CO_2 stays confined within the reservoir. Additionally, regulations frequently require that sites are located at a safe distance from populated areas or critical infrastructure to reduce the risk to public safety in the event of a leak or seismic event.[152] Moreover, legal frameworks generally impose routine monitoring and reporting obligations. In the U.S., under the Class VI rules, operators are required to submit regular reports to the EPA, documenting parameters such as CO_2 injection rates, reservoir pressure, and geophysical survey data. This real-time monitoring ensures the ongoing safety of the storage site, and deviations from expected behavior can trigger further investigation or remediation measures.

Community Involvement. Beyond the technical aspects, local regulations often emphasize the need for community consultation and stakeholder engagement in CO_2 storage projects. Public participation is critical to building trust and ensuring the project has broad social acceptance. For example, under the EU's CCS Directive, member states are required to engage in public consultations before granting storage permits, ensuring that local communities are informed and have an opportunity to express their concerns about the project. Similarly, Australia's regulatory framework mandates that companies seeking permits for offshore CO_2 storage must engage with Indigenous groups and coastal communities to address environmental and cultural concerns.

3.2. CO_2 Injection into DOGRs: Technical Aspect. The injection of CO_2 into AHRs or DHRs is a critical method both for geological sequestration in the context of reducing greenhouse gas emissions and for EOR.[28] Each of these applications relies on specific mechanisms related to the physical and chemical properties of CO_2, as well as crucial technological advances enabling efficient and safe injection.

Physical Properties of Injected CO_2. CO_2 exists in different phases (gaseous, liquid, supercritical) depending on temperature and pressure conditions. The supercritical state of CO_2 is particularly sought after for reservoir injection.[153] In its supercritical state, CO_2 exhibits both the properties of a liquid and a gas:[154] it diffuses like a gas through the reservoir pores while having a density similar to that of a liquid, optimizing its interaction with residual hydrocarbons and its ability to fill the reservoir's pore volume. These characteristics facilitate the extraction of remaining hydrocarbons while enabling efficient CO_2 storage, making its supercritical state crucial for both objectives mentioned above.

Infrastructure and Optimization of Injection Wells. Technological advances in infrastructure design for CO_2 injection have improved the safety and efficiency of operations. This infrastructure, as described in Figure 8, includes injection wells, compression stations to maintain CO_2 in supercritical form, and real-time monitoring systems to control pressure, temperature, and fluid chemistry in the reservoir. Optimizing the location of injection wells is a key advancement in reservoir management. This relies on a detailed analysis of the reservoir's porosity and permeability to maximize CO_2 distribution and avoid losses through preferential pathways where CO_2 might move without interacting with hydrocarbons.[155] Advanced

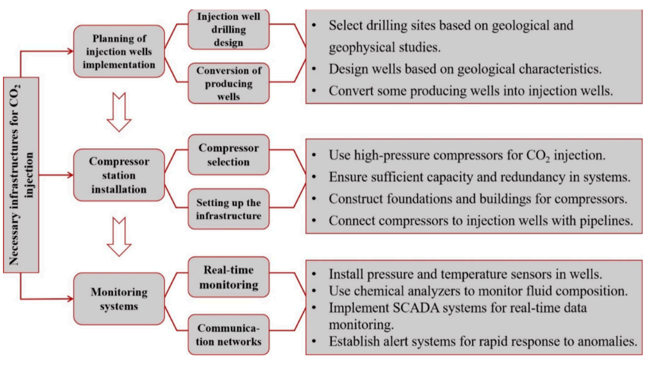

Figure 8. Infrastructure required for CO_2 injection into DOGRs.

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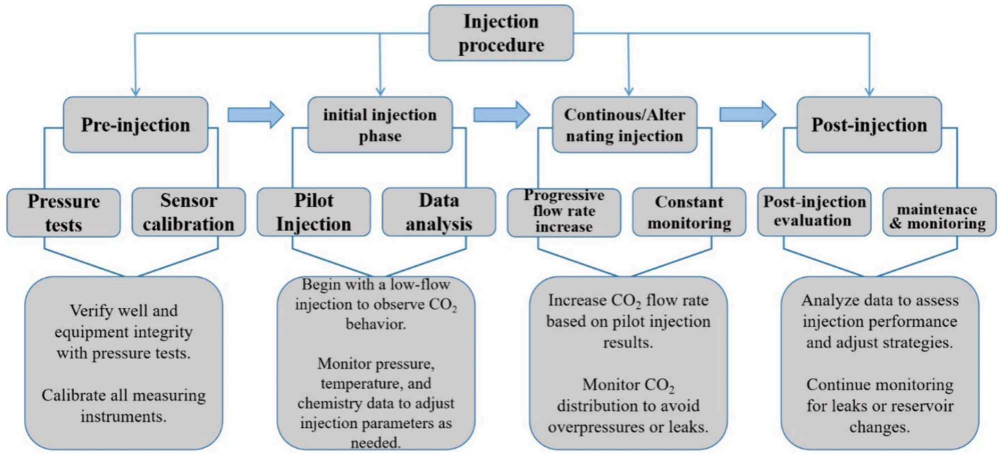

Figure 9. Complete procedure for the rigorous technical operation of CO_2 injection

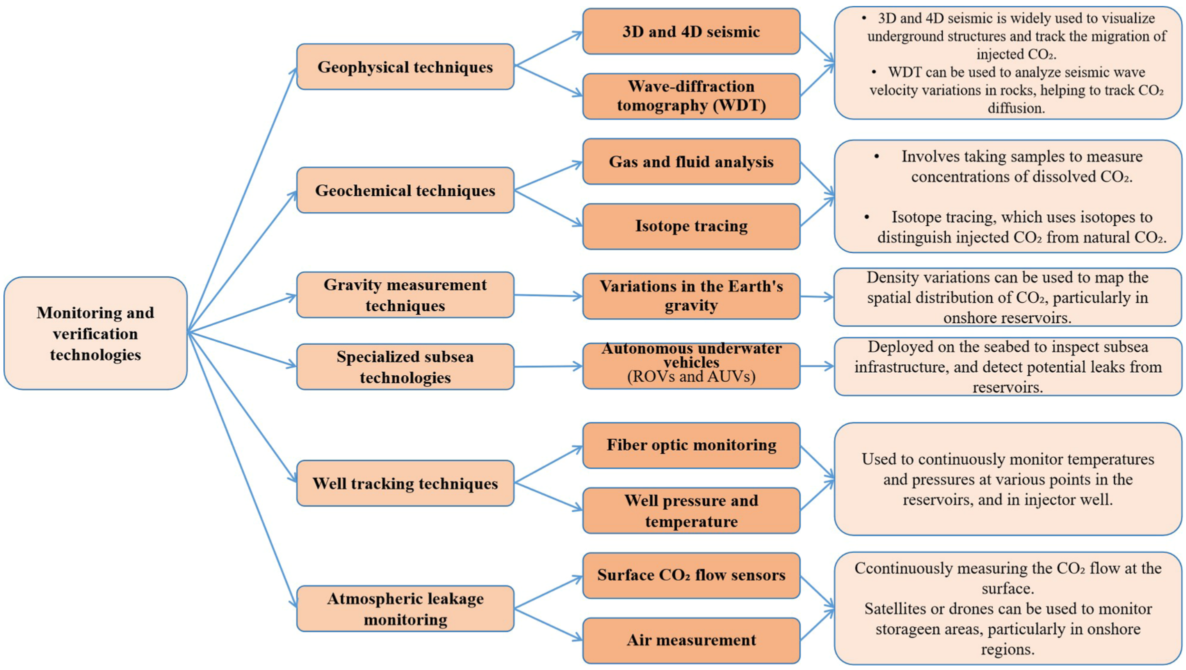

Figure 10. Organization chart of CO_2's Monitoring and Verification Technologies.

geophysical techniques, such as 3D mapping, now allow for precise selection of optimal zones for injection.

Injection Techniques. Once the infrastructure is successfully installed, this rather complex process involves a series of rigorous technical operations. The complete procedure includes several elements and steps, detailed in Figure 9. Several injection strategies have been developed based on the reservoir's characteristics and the objectives of each project.

(1) Continuous CO_2 Injection: Used primarily in the context of EOR, this technique involves continuously injecting CO_2 to maintain reservoir pressure.[156,157] This method allows for a comprehensive sweep of residual hydrocarbons toward production wells.

(2) Water-Alternating-Gas (WAG) Injection: This technique alternates CO_2 injection with water injection, allowing better control of CO_2 distribution within the reservoir and increased sweep efficiency.[158] WAG is particularly useful in reservoirs with heterogeneous zones where uniform CO_2 distribution is difficult. This technique has proven effective in minimizing preferential pathways and improving CO_2 contact with hydrocarbons.

CO_2/Hydrocarbon Interaction Mechanisms. CO_2 injection relies on a complex process where CO_2 is compressed and injected into reservoirs through injection wells. In the context of EOR, two major mechanisms can be observed depending on the reservoir pressure:

(1) Miscible Sweep: When reservoir pressure is sufficient to achieve miscibility between CO_2 and hydrocarbons (which typically occurs in deep reservoirs), CO_2 fully mixes with hydrocarbons, reducing their viscosity and facilitating their movement toward production wells.[159] This process maximizes hydrocarbon recovery efficiency while improving CO_2 distribution within the reservoir.

(2) Immiscible Sweep: In reservoirs where pressure is insufficient to achieve miscibility, CO_2 acts as a nonmiscible fluid, pushing hydrocarbons toward wells by simple pressure differential.[160] Although this mechanism is less effective than miscible sweep, it remains a

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viable method for shallow reservoirs where pressure cannot be increased.

Recent Advances in Injection Technologies. Recent advances in CO_2 injection techniques aim to improve its distribution within reservoirs and increase storage efficiency. One particularly effective approach involves mixing supercritical CO_2 with water or solvents to enhance its dissolution and dispersion within the reservoir.[161] This type of method was implemented in the Petra Nova project in Texas, where mixing supercritical CO_2 with saline water allowed for better CO_2 distribution in the underground saline formation. This maximized sequestration potential while reducing leakage risks.

In Australia, the Gorgon project, one of the largest CO_2 sequestration projects in the world, innovated by using foam injection of CO_2.[162,163] This approach is particularly effective in low-permeability geological formations, where foam enables better CO_2 dispersion throughout the reservoir.[164,165] Recent experimental studies, such as those by Koyanbayev et al. (2024),[166] and Aly et al. (2024)[167] show that foam injection improves both injection capacity in challenging formations and enhances CO_2 trapping efficiency by minimizing gas mobility in high-permeability zones, reducing the risk of CO_2 breakthroughs.

Other recent studies, such as those by Zoback et al. (2023),[168] and Subramanian et al. (2022)[169] have explored the use of hydrogen-enriched CO_2 to facilitate injection and distribution in reservoirs. This process, tested in the SACCAR project in Canada, demonstrated that adding hydrogen reduces CO_2 viscosity, allowing for better penetration into rock pores and improving enhanced oil recovery (EOR) while maximizing long-term storage potential.

3.3. Monitoring, Verification, and Assessment (MVA).

MVA are critical aspects of the CO_2 sequestration process, whether offshore or onshore. Rigorous management is necessary to ensure the safety, efficiency, and longevity of CO_2 storage, as well as to minimize the risk of leaks that could undermine the climate benefits of this technology. MVA primarily aims to monitor the behavior of injected CO_2 in the reservoir, verify its long-term containment, and assess its potential environmental impact.[170]

Monitoring technologies for CO_2 sequestration fall into several categories depending on their use before, during, and after injection. Figure 10 provides an overview of the main technologies, categorized into geophysical techniques, gravity measurements, well-based monitoring, geochemical methods, and atmospheric leak detection tools.

One of the major advancements in monitoring has been the integration of fiber optic sensor systems to monitor real-time reservoir deformation and pressure variations. This allows for highly precise tracking of CO_2 movements underground, ensuring its long-term containment.[61] As used in the Sleipner project in Norway, a pioneer in offshore CO_2 sequestration, Sun et al. (2021)[171] emphasize that distributed fiber optic sensing (DFOS) technologies can monitor multiple parameters, such as geomechanical deformation, temperature, acoustics, and pressure, in the deep subsurface for geological CO_2 sequestration. Fiber optic sensors offer increased sensitivity and the ability to monitor large areas with minimal infrastructure, making them a preferred technology for future sequestration projects.

Acoustic monitoring techniques are also advancing rapidly. These methods utilize acoustic sensors to detect CO_2 leaks and track seismic waves through the reservoir.[172] 4D seismic techniques, which involve conducting seismic surveys at regular intervals, have proven particularly effective in monitoring CO_2 dynamics within reservoirs. A recent study conducted as part of the Weyburn-Midale project in Canada demonstrated that acoustic and 4D seismic techniques can provide detailed information on the spatial distribution of CO_2 in the reservoir, helping to better control the risks of CO_2 migration.[173]

Another relevant example is the Ketzin project in Germany, where CO_2 was injected into a depleted natural gas field.[174] In this project, fiber optic monitoring and gas analysis from monitoring wells played a key role in detecting pressure variations and CO_2 concentrations, ensuring the confinement of the injected gas.

Postinjection CO_2 management requires advanced technologies to monitor and verify several parameters:

- **Tracking CO_2 migration**: The injected CO_2 must remain confined within the target reservoir without leaking to the surface or neighboring aquifers. MVA enables tracking the movement of CO_2 underground to ensure it remains in the intended storage area.
- **Leak prevention**: CO_2 leaks into the atmosphere or groundwater could negate the benefits of sequestration. Continuous monitoring helps quickly detect anomalies or signs of leakage.
- **Environmental impact**: It is essential to assess the impact of CO_2 injection on the local environment, including potential effects on marine ecosystems in the case of offshore reservoirs, or on groundwater in onshore reservoirs.

The Weyburn-Midale and Ketzin projects illustrate the importance of monitoring CO_2 migration and preventing leaks in aging or depleted reservoirs. For example, in this project, the use of surface CO_2 flux sensors helped detect any variations in surface emissions, ensuring that CO_2 remained confined within the reservoir.[175] Such continuous monitoring is crucial to prevent leakage into the atmosphere.

In the Ketzin project, data collected via fiber optics also proved useful in detecting subtle changes in temperature and pressure, indicating CO_2 movements and helping to prevent potential leakage risks.[176,177] This type of thorough monitoring is essential in depleted reservoirs where geological stability could be affected by fluid injections.

The examples from the Weyburn-Midale and Ketzin projects demonstrate the effectiveness of a combined MVA approach in depleted reservoirs. The use of advanced technologies such as 4D seismic and gravimetry, along with geochemical and well-based monitoring techniques, has proven effective in tracking CO_2 migration, preventing leaks, and managing environmental risks. In particular, lessons learned from these projects highlight the importance of tailoring monitoring strategies to the specific characteristics of each reservoir, taking into account its geological structure and production history. Finally, the integration of new technologies, such as autonomous underwater vehicles (AUV/ROV) for offshore reservoirs, enhances monitoring capabilities by detecting potential leaks at depths and in environments that are challenging to monitor using conventional methods.

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Table 4. Comparison of the Advantages and Disadvantages of Hydrocarbon Reservoirs versus Other CO_2 Sequestration Options

Criteria	Hydrocarbon reservoirs	Saline aquifers	Undeveloped coal formations
Storage capacity.	Proven capacity to contain fluids under pressure.	Large theoretical capacity but less proven.	Limited capacity.
Safety and containment.	Proven containment thanks to impermeable layers.	Uncertainties about long-term containment.	Increased risk of leakage.
Geological data.	Well-documented thanks to oil history.	Limited data, requires in-depth studies.	Less data available, poorly characterized.
Existing infrastructure.	Reusable, reducing costs.	Requires new infrastructure.	No infrastructure, high costs.
Set-up costs.	Reduced thanks to existing infrastructure.	High costs for new infrastructure.	Very high costs.
EOR synergy.	Synergy with EOR possible, offering double benefits.	No synergy with EOR.	No synergy with EOR.
Geological risks.	Low with well-known geological layers.	Increased risk of migration or leakage.	Unpredictable risks.
Implementation time.	Fast, thanks to existing infrastructures and studies.	Long to implement.	Very long.
Economic viability.	High thanks to EOR and carbon credits.	Limited viability, possible with carbon credits.	Low economic viability.
Environmental impact.	Reduced, infrastructure reused, favorable to energy transition.	Positive, but requires large quantities of water.	High environmental risks.

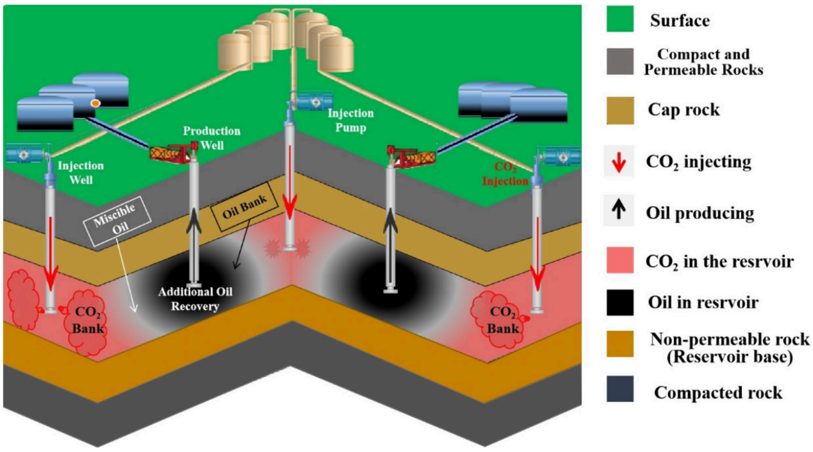

Figure 11. Flooding mechanism caused by the injection of miscible CO_2 as part of the EOR process. Modified with permission from ref 186. Copyright 2023 Elsevier.

4. HYDROCARBON RESERVOIRS FOR CO_2 STORAGE: MORE PROFITS

The utilization of former hydrocarbon reservoirs provides undeniable advantages over other geological formations that are being considered for CO_2 storage,[178] such as:

Proven Containment Capacity. The hydrocarbon reservoirs have proven their capacity to store pressurized fluids for millions of years, which considerably minimizes the risk of CO_2 leakage.[25] This essential feature is due to the presence of natural impermeable layers that effectively confine the injected CO_2, conferring increased confidence in the safety and effectiveness of long-term storage.

Simplified Evaluation of CO_2 Storage Capability. Hydrocarbon reservoirs are considered particularly suitable for CO_2 storage, as they have been extensively studied and well documented through historical oil and gas extraction. These sites are the best defined, which facilitates assessment of their storage capacity. The combined properties of all the categories of geological formations present on a specific site determine the CO_2 storage capacity of that field.

Reusing Existing Infrastructure. The oil and gas sector possesses a vast network of infrastructure, including wells, pipelines, and processing facilities, which can be reused for CO_2 storage.[49,179,180] This reuse considerably reduces development costs and speeds up the implementation of CCS projects.[181]

Double Benefit: EOR-CO_2 Storage. Injecting CO_2 into old hydrocarbon reservoirs can offer a dual benefit: EOR and simultaneous CO_2 storage. This synergy between EOR and CO_2 storage creates an additional economic incentive for oil companies, enabling them to extend the life of their oilfields while contributing to decarbonization.

New and Sustainable Business Opportunities. The utilization of CCS in old hydrocarbon reservoirs presents new business opportunities for oil companies.[182,183] These opportunities include the provision of CO_2 capture and storage services, as well as participation in carbon offset programs. Oil companies can generate additional revenue by selling carbon credits generated by storing CO_2 in their reservoirs.

Investing in Long-Term Competitiveness. By investing in CCS technologies, oil companies demonstrate their ability to adapt to market changes and meet the growing demand for more sustainable energy solutions. This proactive approach will enable them to maintain their long-term competitiveness in a world in transition to a low-carbon economy.

In summary, the use of hydrocarbon reservoirs for CO_2 storage offers clear advantages over other geological formations, such as saline aquifers or unmined coal seams. Their proven ability to contain pressurized fluids for millions of years, the reuse of existing infrastructure, and the possibility of combining EOR with CO_2 sequestration make them a particularly attractive solution. Additionally, these reservoirs benefit from decades of geological and geophysical data, simplifying the assessment of their storage capacity. This combination of safety, cost-effectiveness, and rapid implementation makes hydrocarbon

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Table 5. Synthesis of CO_2 Interactions in Gas Reservoirs

Processes	Effect and Mechanism	Advantages	Possible Disadvantages
Interaction with residual gases/condensates	• Partial miscibility	• Viscosity reduction	• Reduced purity of CO_2
	• Condensate revaporization	• Improved fluid displacement.	• Modification of geochemical properties
	• Hydrodynamic trapping	• Improved residual condensate recovery rate.	• Internal overpressure,
		• Compression of rocks	• Freeing up pore space for CO_2 storage.
		• Fault reactivations	
		• Uncontrolled gas migration	
		• Complex fluid management	
Interaction with brines	• Dissolution in formation water (dissolution trapping)	• Stability of dissolved CO_2	• Acidification of brines
	• Long-term mineralogical trapping	• Reduced risk of leakage	• Modification of geochemical properties
		• Storage durability	• Risk of corrosion
			• Alteration of permeability
			• Management complexity
Final CO_2 sequestration	Permanent containment of CO_2 in the geological structure through hydrodynamic and mineralogical trapping.		

reservoirs a preferred option for CO_2 sequestration projects, as shown in Table 4, which compares the advantages and disadvantages of hydrocarbon reservoirs to other candidate geological formations.

5. COMPARATIVE ANALYSIS OF RESERVOIR TYPES

AOGRs and DOGRs exhibit significant differences in terms of CO_2 storage potential, geomechanical behavior, and interactions with injected fluids. These differences, though subtle, necessitate specific injection and storage management strategies that directly influence their viability for geo-sequestration.

5.1. Oil Reservoirs. Oil reservoirs, often used in EOR operations, present a dual advantage. On the one hand, they enable additional oil recovery, and on the other, they can serve as CO_2 storage sites.[184,185] This synergistic phenomenon is driven by a combination of complementary physical and chemical mechanisms. CO_2, when injected into the reservoir, becomes miscible with the residual oil, facilitating its partial dissolution. This dissolution reduces the oil's viscosity and interfacial tension with water, enhancing fluidity and mobilization along the pore walls.[186] Additionally, dissolved CO_2 acts as a swelling agent, increasing the oil's volume and relative permeability within the reservoir rock. Moreover, when reservoir pressure exceeds the minimum miscibility pressure (MMP), the crude oil's viscosity significantly decreases, allowing for more efficient displacement of residual oil toward the production wells by the dissolved CO_2 (Figure 11). Consequently, CO_2 acts as an effective sweeping agent, dislodging residual oil from the rock pores, thus enhancing the recovery rate while the remaining CO_2 is sequestered within the geological structure.

However, recent studies highlight several critical points regarding the long-term efficacy of CO_2 trapping in these reservoirs. For instance, Adu-Gyamfi et al. (2022)[187] investigated CO_2 storage mechanisms in EOR contexts, demonstrating that CO_2 dissolution in hydrocarbons enables additional oil recovery while providing some storage capacity. Nevertheless, their simulations show that storage capacity varies considerably based on residual oil saturation and reservoir pressure.

Additionally, in a more innovative approach, Liu et al. (2022)[188] proposed the use of propanol to enhance CO_2 storage efficiency in oil reservoirs by increasing CO_2 solubility in residual oil. Despite promising results, this technique remains experimental and requires further validation for large-scale application. Moreover, oil reservoirs often exhibit geological heterogeneity, complicating predictions of long-term CO_2 behavior. Studies by Al-Khdheeawi et al. (2024)[189] and Singh et al. (2023)[190] emphasize that in reservoirs where fluids are trapped heterogeneously, CO_2 distribution becomes uneven, making its containment more challenging. Furthermore, residual hydrocarbon saturation limits the amount of CO_2 that can be stored, and current models still lack precision in estimating these saturations in diverse porous environments.

5.2. Gas Reservoirs. In the case of depleted gas reservoirs, the situation differs from oil reservoirs. Gas reservoirs are often preferred for long-term CO_2 storage due to their higher containment capacity. This is primarily due to their higher porosity and more homogeneous geological structure, in contrast to the complexity of oil reservoirs.[191] However, the absence of fluids, as seen in oil reservoirs, makes their geomechanical behavior more sensitive to high-pressure injections. Ramadhan et al. (2024)[192] and Pan et al. (2024)[193] explored this containment capacity by focusing on trapping mechanisms through adsorption and dissolution in gas reservoirs. Their results indicate that these reservoirs allow for relatively stable CO_2 containment, with reduced migration risks compared to oil reservoirs. Similarly, Rahman et al. (2024)[194] and Yakup et al. (2024)[195] studied the capacity of depleted gas reservoirs to store significant volumes of pressurized CO_2. They showed that this capacity depends on the production history and geomechanical properties of the reservoirs. Nonetheless, gas reservoirs remain the most robust candidates for large-scale storage projects.

Conversely, the lack of direct economic returns, such as gas recovery, explains why gas reservoirs are less studied than oil reservoirs. A study by Hu et al. (2023)[196] revealed that the absence of residual fluids leads to less efficient CO_2 distribution within the rock pores, necessitating the adoption of improved injection techniques to ensure effective containment. Furthermore, despite their homogeneous structure, gas reservoirs present geomechanical risks under high-pressure injection. Yoon et al. (2024)[197] showed in their simulations that previously dormant faults could reactivate under pressure, posing a significant risk to the safety of sequestration projects.

It is worth noting that while depleted gas reservoirs are generally devoid of oil, they are not always "dry" in the strict sense. Other fluids, such as formation water (brine), gas

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condensates, or residual gases, are often present. CO_2 injection into these reservoirs can lead to complex interactions between CO_2 and these fluids, involving various physical and chemical mechanisms. Table 5 summarizes the key processes, effects, and mechanisms associated with CO_2 injection into depleted gas reservoirs.

Comparison and Implications. Oil reservoirs, despite their complex geometry and fluid composition, allow for the recovery of residual hydrocarbons while storing CO_2. Wang, H. et al. (2020)[198] demonstrated that integrating EOR techniques in these reservoirs can extend their economic lifespan while maximizing their storage capacity. However, their long-term efficiency remains limited by the complex interactions between CO_2, oil, and rock formations. In parallel, gas reservoirs, with a more homogeneous structure and larger storage capacity, offer safer long-term containment, especially under high-pressure conditions. However, the geomechanical risks associated with high-pressure injections, along with the lack of immediate economic return, necessitate more innovative injection strategies. For instance, Zheng et al. (2023)[199] proposed stepwise injections to minimize fracture and fault risks while optimizing storage capacity.

In conclusion, the comparative analysis of oil and gas reservoirs shows that each type presents specific advantages and challenges for CO_2 storage. Oil reservoirs offer synergies with EOR but suffer from geological complexity and residual fluid saturation, limiting their long-term storage capacity. In contrast, gas reservoirs, while more stable, require technological innovations to ensure safe high-pressure injection. Therefore, future research should focus on developing injection strategies tailored to each reservoir type, while accounting for complex geochemical interactions and geomechanical risks.

6. CASE STUDIES AND EMPIRICAL DATA: APPROACH THROUGH RECENT PROJECTS

Recent CO_2 sequestration projects, particularly in Europe and globally, provide a new and pragmatic perspective on the large-scale implementation of this technology. Analyzing projects such as PYCASSO, GOCO2, and Northern Lights yields valuable insights into optimal practices, encountered technical challenges, and observed performance, offering a glimpse into the potential of geosequestration in various geological settings.

6.1. Recent Case Studies in France. *PYCASSO Project (France and Spain).* Launched in 2021, the PYCASSO project (Pyrenean CO_2 Abatement through Sustainable Sequestration Operation) focuses on the potential for storing CO_2 in depleted gas reservoirs in the Pyrenean foothills, between France and Spain.[200] By utilizing existing infrastructure, the project aims to capture and store between 1 to 3 million tons of CO_2 per year by 2030, with a target of increasing this capacity to 5 million tons per year by 2035.[201] PYCASSO represents an innovative example of infrastructure sharing to create a sustainable value chain for CO_2 capture, transport, and storage.[202] However, the early phases of the project revealed significant challenges related to retrofitting aging infrastructure and managing injection pressures to avoid reactivation of geological faults. Furthermore, the uneven distribution of CO_2 in heterogeneous reservoirs remains a major obstacle to achieving optimal performance.

GOCO2 Project (Pays de la Loire and Grand Ouest, France). The GOCO2 project, launched in 2023, is a flagship project in France for the capture and transport of CO_2 emitted by industries located in the Pays de la Loire and Grand Ouest regions. This project highlights interindustry collaboration, involving players such as TotalEnergies and Heidelberg Materials, with the goal of storing CO_2 in depleted geological reservoirs. GOCO2 serves as a concrete example of how interindustry cooperation can facilitate the decarbonization of hard-to-abate sectors, such as cement and steel industries. However, uncertainties persist regarding the long-term economic viability of sequestration projects in France, particularly in relation to financing mechanisms and economic incentives, which require ongoing evaluation.[203]

6.2. Recent International Case Studies. *Northern Lights Project (Norway).* Northern Lights, a key component of the Longship CCS Project in Norway, has been operational since 2022 and represents a pioneering model in Europe for CO_2 capture and storage. This cross-border project allows European countries to send-captured CO_2 to Norway for secure storage in subsea reservoirs.[204] The Northern Lights project marks a significant advancement in shared infrastructure for CO_2 sequestration while providing valuable data on the costs and logistics associated with long-distance transport.[205] However, the evolving regulatory framework between participating countries poses a potential challenge, limiting the pace of large-scale deployment.

Gorgon Project (Australia). The Gorgon project, launched in 2019, is one of the world's largest CO_2 storage projects. Located on Barrow Island, this project aims to inject approximately 4 million tons of captured CO_2 annually into a depleted gas reservoir.[206] Although adjustments were needed to stabilize reservoir pressure, Gorgon remains a key case study for large-scale projects. One of Gorgon's major contributions is the understanding of high-pressure injection dynamics in gas reservoirs. However, like other large-scale projects, it faces geomechanical challenges, particularly related to managing high injection pressures and the high costs of monitoring.[207] The complexity of active geological faults remains a significant barrier to realizing its full potential.

6.3. Long-Term Data Analysis. Empirical data from these projects provide crucial information for adjusting long-term storage models and refining operational practices. These studies reveal both commonalities and differences across reservoir types:

- Gas Reservoirs: The PYCASSO and Gorgon projects demonstrate that gas reservoirs have significant storage potential but require constant geological monitoring to prevent overpressure and fault reactivation. Early data from these projects offer a deeper understanding of high-pressure injection dynamics and long-term associated risks.

- Oil Reservoirs: The Weyburn project in Canada, among other initiatives combining EOR and CO_2 storage, shows that residual hydrocarbon recovery is possible while storing CO_2. However, managing complex geochemical interactions between CO_2 and rock formations, as well as challenges related to variable permeability, represent significant obstacles to overcome.[208]

In conclusion, recent case studies such as PYCASSO, GOCO2, Northern Lights, and Gorgon illustrate the significant progress made in the field of CO_2 sequestration. These projects emphasize the importance of continuous geological monitoring, precise operational adjustments, and enhanced interindustry collaboration to overcome technical and economic challenges. In the future, large-scale sequestration projects must build on

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the lessons learned from these initiatives to improve the efficiency and long-term viability of CO_2 storage solutions.

7. CHALLENGES AND PERSPECTIVES

Technical and economic challenges related to CO_2 sequestration in depleted oil and gas reservoirs remain significant, although progress has been made. Here is an overview of the main current challenges and future prospects.

7.1. Technical Aspect. *7.1.1. Integrity of Aging Reservoirs and Geological Stability.* Injecting CO_2 into AOGRs or DOGRs continues to provoke scientific debate due to the challenges related to preserving the integrity of aging infrastructures and the geological stability of pressurized formations.[209] Several large-scale projects, such as the In Salah CO_2 sequestration project in Algeria, have revealed the occurrence of induced seismicity and structural instabilities resulting from increased injection pressure.[210,211] While these projects have led to the development of risk mitigation strategies, more recent works, such as that conducted by T. Rathnaweera et al. (2020)[212] have highlighted persistent gaps in our understanding of structural failure mechanisms.

Recent studies on CO_2 injection into depleted reservoirs have highlighted promising solutions, but they also reveal shortcomings that require further research. For instance, research conducted by EV Egorova et al. (2021),[213] M Kremieniewski et al. (2020),[214] and DA Zimina et al. (2019)[215] demonstrated that the use of new reinforced cement materials in injection wells significantly reduces the risk of short-term mechanical failure. However, their studies emphasize that these cements have not been tested under extremely varied pressure and temperature conditions over extended periods, limiting our ability to guarantee their effectiveness over several decades. Future work should focus on prolonged testing of these materials in environments that closely resemble the real conditions of aging reservoirs. Long-term evaluation of the chemical interactions between injected CO_2 and the materials used remains a gray area in the literature, with contradictory results requiring more extensive studies.

Moreover, the research of Seth Busetti (2021)[216] and de Auregan Boyet et al. (2023)[217] on geomechanical modeling has shown that current models can predict the risks of induced seismicity with reasonable accuracy on a regional scale. However, their results revealed that these models still fail to capture in detail the microevolutions of mechanical stresses on local scales, where the first signs of structural failure may occur. It would be beneficial to combine these geomechanical models with real-time data from sensors installed in reservoirs to improve the accuracy of predictions. This synergy between modeling and real-time monitoring could enable earlier detection of risks.

Recent Contributions and Limitations of Advanced Solutions. Recent approaches to strengthening the integrity of aging wells and improving the geological stability of reservoirs include innovations in materials and monitoring technologies. The work of Lizhu Wang et al. (2023)[218] and Tang, J et al. (2024)[219] on self-healing materials represents a notable advance. Their development of new self-regenerating granular hydrogels capable of automatically sealing fractures and microcracks in geological formations, constitutes significant progress. Figure 12 illustrates how these materials work after injection into the reservoir.

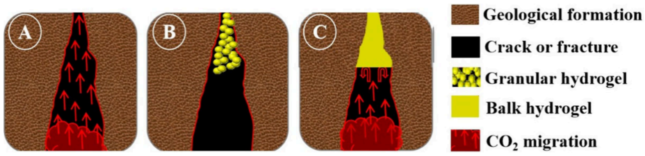

Figure 12. Schematic diagram of the application of self-healing materials as fracture sealing agents in geological formations. 12A: leakage of CO_2 through the crack in the reservoir; 12B: placement of granular hydrogels in the crack; 12C: swelling, agglomeration and clogging. Modified with data retrieved from ref 220. Copyright 2022 Elsevier.

However, despite promising laboratory results, these materials are still in the experimental phase, and their large-scale deployment under real reservoir conditions remains to be proven. The main challenge is ensuring long-term chemical and mechanical stability of these materials in complex geological environments, often subjected to significant thermal gradients and aggressive chemical interactions with reservoir fluids.

Additionally, the integration of nanomaterials, such as carbon nanotubes and graphene, into physical barriers represents another significant advance.[221] These materials improve the mechanical properties of cements used for well cementing and reduce the risk of CO_2 leakage. However, their high production costs and technical challenges associated with large-scale implementation are major obstacles to their adoption.[222] Special attention should be paid to studying their long-term behavior in high-pressure and high-temperature environments, as well as their potential impact on surrounding ecosystems.

Suggested Improvements for Future Work. To address these gaps, future studies should focus on several key areas:

(1) Long-term evaluation of self-healing materials: It is crucial to conduct long-term testing of self-healing materials, such as the hydrogels developed by Lizhu Wang et al. (2023)[218] and Tang, J et al. (2024)[219] to confirm their effectiveness under varied reservoir conditions and over extended periods.

(2) Improvement of geomechanical models: More precise geomechanical models need to be developed to simulate complex interactions at the local scale between injected CO_2 and reservoir structures, while integrating real-time monitoring data to refine predictions of induced seismicity risks.

(3) Durability studies of nanomaterials: While nanomaterials hold great potential for strengthening physical barriers, their durability in real-world conditions still needs to be studied. Further research should explore their behavior in extreme conditions and their long-term environmental impact.

7.1.2. Reservoir Characterization and Advanced Modeling Approaches. Accurate characterization of depleted reservoirs remains a fundamental challenge due to geological heterogeneity. This heterogeneity, marked by significant variations in porosity and permeability, considerably complicates the prediction of injected CO_2 behavior.[223] In particular, carbonate formations pose unique challenges, as they exhibit variable porosity and increased chemical reactivity compared to sandstones.

Research by Askarova et al. (2023)[40] has highlighted the need to integrate more detailed characterization of pore structures to prevent erratic CO_2 plume migration. Their study demonstrates that permeability variations within geological formations can significantly reduce the reservoir's storage capacity. However, while the study proposes solutions based on the integration of

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Table 6. Comparison of Numerical Models and Algorithms for Reservoir Modeling

Model Type	Data Requirements	Scale of Accuracy	Applications	Known Limits
Elastoplastic model.	Seismic data, core samples.	Complete reservoir.	Prediction of deformations under pressure.	Simplification of complex structures.
Digital Rock Physics (DRP).	High-resolution CT scans, pore structure.	Microscopic (pore level).	Pore-scale fluid flow prediction.	Time-consuming and computationally expensive
Multiscale modeling.	Seismic, pressure, fluid data.	Full reservoir with pore-scale detail.	Integrated fluid migration modeling.	Large data sets required.
Geomechanical model.	Geological and pressure data.	Complete reservoir.	Prediction of reservoir deformation and fracturing.	Limited by data availability.

high-resolution data, it acknowledges a significant limitation: collecting such data is still too expensive and complex on a large scale, limiting its application to pilot projects. Future research should therefore focus on developing less costly and faster methods to capture these microscopic variations.

Other research, such as that conducted by Zeeshan Tariq et al. (2023),[224] Gege Wen et al. (2021),[225] and H. Kumar et al. (2020),[226] has highlighted the limitations of traditional models in simulating CO_2 migration in carbonate formations. Their work showed that elastoplastic models often oversimplify the complex geology of reservoirs, particularly regarding natural fractures and microfissures. This can lead to inaccurate predictions of CO_2 behavior, especially when it comes to detecting potential leakage pathways. These models need improvement to better capture the nuances of rock microstructures, particularly through the integration of new imaging and simulation techniques.

Recent Contributions and Limitations of Advanced Modeling Approaches. Recent approaches, such as Digital Rock Physics (DRP), have enabled significant advancements in fluid flow modeling at the pore scale.[227] For example, DRP uses high-resolution CT scans to analyze pore structures and predict CO_2 migration.[228] However, as noted by Balcewicz et al. (2021),[229] and LL Schepp et al. (2020),[230] this approach is extremely time-consuming and resource-intensive, limiting its use to specific and experimental cases. While DRP provides detailed information, its large-scale applicability in long-term CO_2 sequestration projects is limited by challenges related to scaling, computational requirements, long-term predictions, and integration with field data. One improvement could be automating the rock scanning and analysis process, which could reduce costs and accelerate reservoir characterization.

Additionally, geomechanical models, while useful for predicting pressure-induced deformations, lack precision in complex reservoirs where multiscale interactions are at play.[231] According to a study by Guo et al. (2022),[232] current geomechanical models do not adequately incorporate the interactions between injected fluids and existing fractures. Guo and his team propose integrating in situ sensors to improve model accuracy and anticipate deformations at various time and spatial scales, but acknowledge that installing such systems is still technically and economically prohibitive for most projects.

To better understand the challenges and progress in reservoir modeling for CO_2 sequestration, it is essential to examine the various numerical approaches used to simulate the behavior of injected CO_2 and its interactions with the complex geology of depleted reservoirs. Elastoplastic models, Digital Rock Physics (DRP), as well as multiscale and geomechanical approaches, each with their strengths and limitations, contribute to a better understanding of fluid migration and pressure-induced deformations. Table 6 presents a comparison of different models in terms of required data, precision scale, main applications, and known limitations, highlighting the importance of selecting methods suited to the specifics of each CO_2 sequestration project.

Suggested Improvements. To improve reservoir modeling and the prediction of CO_2 migrations, several research areas can be explored:

Improvement of characterization methods: Future work should focus on automating high-resolution data collection. The development of more affordable and less intrusive sensors capable of capturing microscopic variations in porosity and permeability would enable more accurate reservoir characterization without significantly increasing costs.

Hybrid approaches: Combining seismic data with tomography and high-resolution scans (such as DRP) could provide a more complete view of geological heterogeneities. Hybrid approaches, such as integrating these techniques with multiscale modeling, could capture both microscopic and macroscopic details of reservoirs.

(1) Use of artificial intelligence and machine learning: Artificial intelligence (AI) and machine learning represent powerful tools for predicting CO_2 migration. Recent works by Xiaobin Li et al. (2023),[233] Hui Dou1 et al. (2023),[234] Liu et al. (2023) have shown that AI can enhance models' ability to integrate large amounts of historical and real-time data, offering more reliable predictions of injected fluid behavior. However, a significant limitation is the quality of available data.[235] For these models to be effective, it is crucial to improve geological data collection and validation.

(2) Advanced geomechanical modeling: The development of more sophisticated geomechanical models that incorporate fluid-rock interactions and real-time constraints is essential for improving prediction accuracy. Multiphysics approaches that integrate the chemical and mechanical properties of rocks need further exploration. This would improve risk management related to fracturing and potential leakage.

7.1.3. Long-Term Monitoring and Verification (MVA). The long-term management of DOGRs used for CO_2 storage requires continuous monitoring and rigorous verification to ensure that the CO_2 remains securely confined within the geological formations.[31,236,237] Current technologies, such as 4D seismic, gravimetry, and geochemical analyses, have shown substantial improvements in monitoring capabilities,[238] but these technologies still have significant limitations, particularly in geologically complex and offshore environments.

4D seismic remains one of the most widely used methods to track CO_2 migration in reservoirs,[239,240] but it has limitations in detecting small leaks or mapping movement in heterogeneous geological formations, and in accurately monitoring CO_2 during injection or quantifying the volumes injected.[241,242] These limitations are especially evident in projects such as Gorgon in

Australia, where the region's complex geology made it difficult to detect leaks despite the use of advanced technologies.[207,243] The Sleipner project in Norway also highlighted these limitations, where uncertainty over how much CO_2 reached Layer 9 and the interdependence of matching parameters drove up monitoring costs due to the need for continuous surveillance to maintain sufficient accuracy.[244−246] These studies underscore the need to improve detection and monitoring methods, particularly in complex environments where current technologies struggle to provide reliable results.

In offshore environments, the challenges are exacerbated by limited access to monitoring infrastructure, making anomaly detection and leak identification even more difficult. Recent work by Zhang L. (2022),[247] Jones et al. (2022), Zhiming Xiong et al. (2020, 2021),[248,249] M. Valitov et al. (2020),[250] A. Sokolov et al. (2019)[251] has highlighted the imprecision and low resolution of gravimetric methods in marine environments, due to disruptions caused by water movements and underwater pressure changes, and dynamic errors from inertial accelerations, environmental and instrumental noise, sensor and navigation system limitations, data synthesis defects, and systematic errors. While progress has been made with the use of autonomous underwater sensor networks (ROVs and AUVs) to address some of these gaps,[252,253] interference from the marine environment remains a major obstacle to early leak detection.[254]

To overcome these limitations, a promising approach lies in the integration of new technologies based on artificial intelligence (AI) and machine learning. Recent studies have shown that the use of machine learning algorithms can help identify subtle signals in the massive data sets collected from seismic, gravimetric, and geochemical sensors. For example, WA Khan et al. (2024),[255] Z Fan et al. (2024),[256] AN Rehman et al. (2023),[257] Hassan Khaled Hassan Baabbad et al. (2022),[258] Nianyin Li et al. (2023)[259] demonstrated that AI algorithms can improve anomaly detection by combining multiple data sources to produce more accurate predictions in geologically complex environments. These systems also help reduce false positives, a recurring issue in CO_2 monitoring, and better anticipate high-risk areas.

Another area of potential progress is the use of centralized platforms that aggregate data from different monitoring technologies.[260] For exemple, X. Ju et al. (2024),[261] Mingliang Liu et al. (2023),[262] Z Jiang et al. (2023),[263] M Li et al. (2021),[264] have explored the application of multisensor systems coupled with neural networks to monitor CO_2 migration in reservoirs in real-time. This approach allows for dynamic adjustments to injection parameters based on changing subsurface conditions, reducing the risk of leaks or overpressure in reservoirs.

In addition, improvements in the use of satellite and LiDAR (Light Detection and Ranging) technologies have been suggested to complement the data collected in situ. The work of Lyu et al. (2024),[265] de Fibbi et al. (2022),[266] de Asadzadeh et al. (2022),[267] de Zhang et al. (2021)[268] on integrating satellite data into CO_2 reservoir monitoring has shown promising results in providing large-scale coverage and improved resolution in hard-to-reach environments.

The future of long-term monitoring and verification of CO_2 in depleted oil and gas reservoirs lies in improving the integration of existing technologies with new developments in AI and machine learning. Pilot projects, such as those described by Thompson et al. (2023), show significant potential for automating monitoring processes and reducing long-term operational costs. However, these systems still need to be widely adopted and tested in varied environments to fully assess their robustness and reliability.

In summary, although significant progress has been made in CO_2 reservoir monitoring, notably through advanced technologies and recent innovations, challenges remain, particularly in geologically complex and offshore environments. Recent studies emphasize the need to continue developing more precise and effective solutions while exploring possible synergies between traditional technologies and emerging AI-based approaches. In summary, although significant progress has been made in CO_2 reservoir monitoring, notably through advanced technologies and recent innovations, challenges remain, particularly in geologically complex and offshore environments. Recent studies emphasize the need to continue developing more precise and effective solutions while exploring possible synergies between traditional technologies and emerging AI-based approaches.

7.1.4. Challenges Related to Geochemical Reactivity and Long-Term Impact. Injecting CO_2 into geological reservoirs triggers a series of complex geochemical reactions that affect both the stability of CO_2 and the properties of reservoir rocks.[61,189] The process of mineralization, where CO_2 reacts with present minerals to form solid carbonates, is crucial for ensuring long-term storage.[189] However, the slow pace of mineralization reactions and their dependence on specific reservoir conditions (temperature, pressure, mineral composition) limit the effectiveness of this process.[82,269,270]

Recent research, such as the study by Wang Fei et al. (2022),[270] has shown that the addition of nanoparticles to injected fluids can accelerate the mineralization reaction. These nanoparticles, by interacting with reservoir minerals, increase the reaction surface area, promoting carbonate precipitation. However, the study also highlighted a limitation: although short-term efficacy is demonstrated, the long-term effects on reservoir porosity and permeability remain uncertain. Long-term studies are necessary to evaluate the impact of this method on storage capacity and the geochemical stability of reservoirs.

Additionally, the works of Al-Khdheeawi et al. (2024), Fawad, M. et al. (2021),[237] Sun et al. (2021) and M Seyyedi et al. (2020)[271] have studied salt precipitation, a phenomenon frequently observed in reservoirs containing saltwater. Their research revealed that the precipitation of gypsum and halite in the presence of dissolved CO_2 can lead to a significant reduction in permeability, thus limiting the injection and storage capacity of CO_2. However, the models used in this study still struggle to capture the small-scale interactions between CO_2, brine, and reservoir minerals, particularly under variable temperature and pressure conditions. This underscores the need to develop more robust models capable of accurately simulating the long-term effects of these precipitations.

Future Perspectives and Areas for Improvement.

(1) Advanced Reactants and Catalysts: A promising approach to overcoming these challenges involves using reactants or catalysts, such as those studied by Wang, Z. et al. (2023),[272] Benjamin Kash et al. (2023),[273] Barkov, A. Y. et al. (2021),[274] J. Hartmann et al. (2022).[275] Their studies on using alkaline additives to accelerate carbonate formation while inhibiting salt precipitation have shown promising laboratory results. However, the challenge lies in scaling this up to real reservoir conditions, where complex factors can limit the efficacy of the additives.

https://doi.org/10.1021/acs.energyfuels.4c03512
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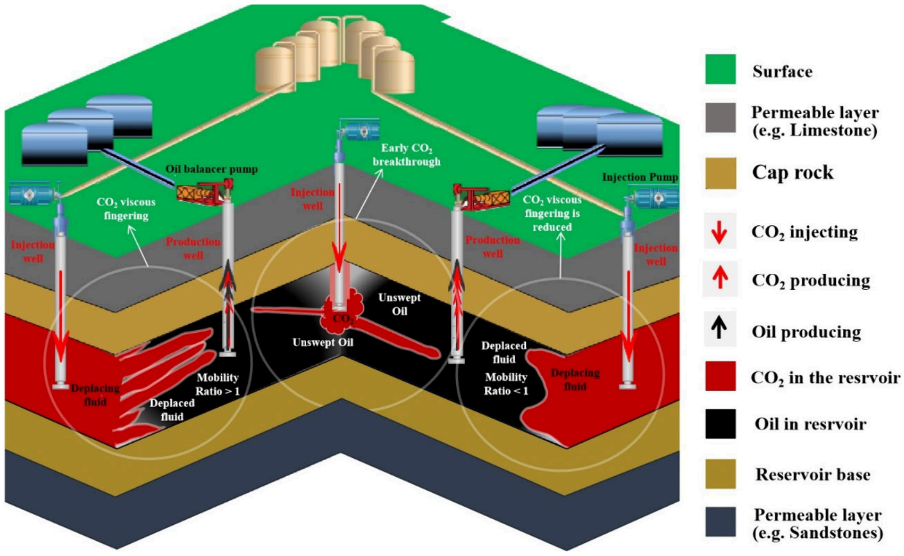

Figure 13. Schematic representation of CO_2 viscous fingering, the phenomenon of early CO_2 breakthrough, and the concept of controlled CO_2 mobility.

Further research is needed to evaluate their long-term durability and effectiveness.

(2) Advanced Monitoring Technologies: Positron Emission Tomography (PET) and Nuclear Magnetic Resonance (NMR) techniques, as explored by Zhuo Li et al. (2023),[276] Catherine Noiriel et al. (2022),[277] and Manzar Fawad et al. (2021),[237] offer real-time visualization of geochemical processes in reservoirs. These technologies allow for monitoring changes in mineral composition as CO_2 reacts with reservoir minerals. While these techniques have shown significant potential, their high cost and complexity in large-scale implementation present major obstacles to their adoption in industrial projects. A possible improvement would be developing more affordable and integrable sensors for large-scale operations.

(3) Advanced Kinetic Modeling: Current geochemical models, such as those studied by Khan et al. (2024),[36] EA Al-Khdheeawi (2024),[189] Elham Tohidi et al. (2021),[278] struggle to integrate the multiple time and spatial scales necessary to predict the complex interactions between fluids and minerals over the long-term. In response to this, integrating multiphysical approaches, including thermodynamic and mechanical simulations, is a promising path to improving the accuracy of these models. Additionally, using high-resolution experimental data to feed these models could significantly improve the reliability of predictions.

(4) Long-Term Experimental Studies: Prolonged experiments in simulated environments, such as those conducted by Chen et al. (2024),[279] et Wang Fei et al. (2022),[270] are essential to understanding geochemical dynamics over long periods. Their study revealed that under variable pressure and temperature conditions, mineralization can be unexpectedly slowed or accelerated, highlighting the need for a better understanding of these interactions in real reservoir environments. This suggests that long-term experiments, combined with improved predictive models, are crucial for the success of large-scale CO_2 sequestration projects.

7.1.5. Challenges Related to CO_2 Viscosity during EOR-CO_2. In light of the challenges discussed above, it is imperative to take into account the viscosity of CO2 when used for EOR purposes. The liquid CO2 viscosity under reservoir conditions typically usually varies from 0.03 to 0.10 cP, whereas for crude oil, it falls within the range of 0.1 to 50 cP.[280] This comparison reveals that the CO_2 viscosity is approximately one hundred times lower than that of crude oil. Due to the similarity in relative permeability between CO_2 and crude oil, an unfavorable viscosity ratio (where mobility is greater than 1) occurs between the displacing fluid (CO_2) and the displaced fluid (crude oil). This leads to undesirable effects,[281,282] as illustrated in Figure 13, which include:

- Viscous fingering of CO_2: CO_2 flows preferentially into the most permeable channels of the reservoir, leaving behind unrecovered crude oil.
- Early CO_2 breakthrough: CO_2 reaches production wells before crude oil, reducing the efficiency of the EOR process.

The research conducted by Sun et al. (2023),[283] and Al-Khdheeawi et al. (2024)[189] demonstrates that the addition of thickening agents, such as polymers and nanoparticles, enhances the viscosity of CO_2, thereby mitigating the phenomenon of viscous fingering. They emphasize, however, that maintaining stability under variable reservoir conditions poses challenges and necessitates rigorous control measures to ensure long-term effectiveness, which can lead to increased operational costs.

Additionally, a study by Wu et al. (2023)[284] et Zhuo Li et al. (2023),[276] investigated the effects of nanoparticulate additives on CO_2 viscosity and revealed a significant improvement in oil recovery efficiency by minimizing early breakthroughs. Nonetheless, a major limitation of this approach is the high cost associated with nanoparticles and their uneven distribution within porous reservoirs.

A key challenge remains managing the costs associated with increasing CO_2 viscosity, especially for large-scale operations. While thickening polymers offer a viable solution, Zeynalli et al. (2023), and Pan, Y. (2023)[285] highlighted that the efficiency of these polymers decreases under extreme temperature and pressure conditions. Further research is needed to develop

https://doi.org/10.1021/acs.energyfuels.4c03512
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Table 7. Cost-Benefit Analysis of CO_2 Sequestration in Hydrocarbon Reservoirs

Project type	Initial costs	Operating Costs	Potential Revenues	Available Subsidies	Return on Investment	Economic Risks
Onshore Reservoir	Well infrastructure, local transport	Low to moderate	Carbon credit sales, EOR	Government subsidies for CO_2 capture	Moderate	Fluctuating carbon prices
Offshore Reservoir	Offshore platforms, subsea pipelines	Very high	Carbon credit sales, EOR, long-term security	Offshore-specific subsidies	Low to moderate	High offshore operating costs
Combined project	Combining onshore and offshore costs	Varies by location	Diversification of revenue sources (EOR, carbon credits)	Mixed subsidies	Moderate	Offshore and onshore management risks

more robust polymers that are adapted to the specific conditions of depleted oil and gas reservoirs. Additionally, Khan et al. (2024)[36] and Zhuo Li et al. (2023)[276] have proposed using advanced geochemical modeling techniques to simulate the effect of additives on CO_2 viscosity in various reservoir configurations. These models help better understand the interactions between CO_2, additives, and reservoir rock, thus paving the way for more effective injection strategies.

Future Perspectives. The future of CO_2-EOR also depends on optimizing thickening agents and reducing the costs associated with their use. The development of innovative nanomaterials capable of modifying CO_2 viscosity while maintaining uniform distribution in the reservoir represents a promising avenue. Additionally, the integration of advanced predictive models, combining experimental data and numerical simulations, will improve the management of CO_2 injections, reduce early breakthroughs, and maximize oil recovery.

7.1.6. Challenges Specific to Offshore Environments. CO_2 sequestration in offshore environments represents a crucial option for emission reduction, but it involves considerable technical challenges related to underwater infrastructure, geographic isolation, and high costs.[61,286] Projects like Sleipner in the North Sea have highlighted these constraints, where a significant portion of the costs is dedicated to continuous monitoring of underwater infrastructure.[287,288]

Recent studies by Zhang et al. (2023),[289] and Smith et al. (2023),[290] have proposed integrating autonomous sensors for real-time monitoring of CO_2 leaks in deep marine environments. These sensors, capable of operating at extreme depths, provide data on dissolved CO_2 concentration, pressure, temperature, and other critical parameters. However, despite these advancements, the systems are still limited by the long-term durability of sensors in harsh marine environments and their high cost.

Other studies conducted by Fanelli et al. (2022),[291] Scherer et al. (2022),[292] and Isah et al. (2022)[293] explored the potential impact of CO_2 leaks on marine ecosystems, particularly on local water acidification. Their modeling showed that even minor leaks could alter sensitive ecosystems, such as coral reefs, at depths greater than 1000 m. However, the studies highlight that current models lack precision in predicting the long-term impacts on ecosystems. Improvements are needed to better understand long-term acidification and its effects on calcifying marine species.

Emerging Technologies and the Use of Artificial Intelligence. Zhang et al. (2022),[294] and Liu et al. (2023)[262] demonstrated that integrating artificial intelligence (AI) into offshore monitoring systems can significantly improve early anomaly detection. Relying on machine learning algorithms, these systems can predict potential CO_2 leaks or changes in environmental conditions, allowing for real-time dynamic adjustments to injection parameters. While this technology is promising, one of the main challenges lies in collecting high-quality data to feed these models, as well as optimizing the costs associated with deploying AI-based infrastructure.

Future Perspectives. To overcome these challenges, developing durable autonomous sensors capable of operating over long periods is essential for ensuring continuous monitoring without compromising operational costs. In parallel, optimizing predictive models by integrating local environmental data is crucial to improving the understanding of the long-term impacts of CO_2 leaks on marine ecosystems. International collaborations are also necessary to share data and knowledge, which could accelerate the development of cost-effective and efficient solutions.

Advances in underwater robotics, combined with AI-based monitoring technologies, pave the way for automatic interventions in the event of leak or anomaly detection. These innovations promise to transform the management of offshore reservoirs, ensuring better operational safety and reducing long-term environmental risks.

7.2. Economic Aspect. Injecting and sequestering CO_2 in depleted oil and gas reservoirs poses significant economic challenges, particularly concerning infrastructure costs, long-term management, and regulatory uncertainties.[26,295] These challenges are amplified by the aging state of reservoirs, which requires costly interventions to ensure their structural integrity and environmental safety. Table 7 presents a cost-benefit analysis of sequestration projects in different types of reservoirs (onshore, offshore, and mixed).

Although efforts have been made to reduce costs through public and private incentives, several obstacles remain, hindering the large-scale economic viability of these projects. Addressing these challenges is essential to promoting the adoption of this technology.

7.2.1. Economic Viability without EOR. Historical CO_2 sequestration projects in depleted reservoirs have largely depended on EOR to ensure their economic viability.[296,297] However, this strategy is increasingly criticized as it does not fully meet carbon neutrality goals. Indeed, a study conducted by McGlade, C. (2019),[298] highlights that EOR projects still contribute to indirect CO_2 emissions by extending fossil fuel extraction, limiting their net impact on global greenhouse gas emissions reduction. A transition to alternative economic models is therefore crucial to strengthen the legitimacy of CO_2 sequestration projects without EOR.

Furthermore, the example of the Petra Nova project illustrates the vulnerability of these projects to energy market fluctuations. The shutdown of the project in 2020, despite its technological advancements,[299] shows that EOR does not offer a sustainable long-term model. As observed by Khaled Enab et al. (2024),[295] integrating sequestration goals with larger CO_2 utilization projects (such as the production of synthetic fuels or construction materials) represents a promising path to ensure economic viability while contributing to decarbonization.

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By examining recent projects like the Northern Lights project, we see that the support of government subsidies, combined with public-private partnerships, is a key element for the economic viability of these initiatives. This Norwegian project, although still under development, demonstrates how diversifying CO_2 capture sources (e.g., the cement and steel industries) and creating intersectoral synergies can establish a strong value chain around sequestration.[300] However, an analysis by Khaled Enab et al. (2024)[295] indicates that even in such projects, uncertainties remain regarding the long-term stability of revenue streams from the CO_2 circular economy. As a result, additional incentives, such as carbon credits or residual emissions taxes, may be necessary to encourage new forms of investment.

The future of CO_2 sequestration could also benefit from recent advances in synthetic fuels. For example, Erik Ringle et al. (2023),[301] and Saleh et al. (2023),[302] have shown that emerging technologies for converting CO_2 into renewable fuels could eventually constitute an alternative revenue source, thus reducing dependence on EOR and aligning sequestration projects with carbon neutrality goals.

7.2.2. High Costs of Injection and Monitoring. The costs associated with CO_2 injection and monitoring in depleted oil and gas reservoirs pose a major challenge to the profitability of sequestration projects.[295] The Weyburn-Midale sequestration project, despite being one of the most extensively studied, has demonstrated that the deployment of large-scale geophysical technologies (such as 4D seismic and fiber optic sensors) requires substantial investments.[303] A study by Korre et al. (2021) revealed that monitoring costs accounted for up to 20% of the total operational expenses of such projects. However, the same study notes that optimizing monitoring techniques, particularly by integrating more sensitive sensors and real-time tracking methods, could reduce these costs by 10% to 15% in the long term.

Analyses by Michael Dent e(2021),[299] and Dahowski et al. (2022) underscore that aging infrastructure in depleted reservoirs requires costly upgrades to ensure reservoir integrity, thereby increasing the initial costs of sequestration projects. The absence of standardized technology for reservoir monitoring and management exacerbates this issue. Nevertheless, significant progress has been made in sensor miniaturization and automation, which could potentially offer more affordable and precise continuous monitoring.

A study by Daramola et al. (2024)[304] demonstrated that monitoring technologies based on artificial intelligence (AI) and machine learning are revolutionizing reservoir tracking by enabling early leak detection at reduced costs. Specifically, machine learning algorithms can process large data sets of seismic and gravimetric data in real-time, reducing reliance on costly manual inspections. However, these technologies still require broader validation before being widely adopted on a large scale.

To improve the economic outlook for sequestration, further research into more efficient injection methods is essential. As highlighted by Parisio et al. (2020),[45] Khudaida et al. (2020),[305] the development of supercritical CO_2 formulations could allow for better pressure management in reservoirs while minimizing the amount of CO_2 injected. Such optimization could also significantly impact cost reduction.

7.2.3. Uncertainties Related to Long-Term Liability. The uncertainties surrounding long-term liability for CO_2 leaks continue to pose a major challenge to the economic viability of sequestration projects.[306] Once injected into depleted reservoirs, CO_2 must be monitored for decades, if not centuries, to ensure that it does not escape into the atmosphere. This requirement for long-term monitoring incurs ongoing costs, and the question of who bears financial responsibility in the event of a leak remains unclear.[43] Companies are often hesitant to engage in projects that could impose long-term financial obligations. Recent work by Arlota et al. (2024)[307] on the regulation of CO_2 sequestration risks highlights a persistent lack of clear legal frameworks concerning liability for leaks, particularly for cross-border projects. Their study suggests that existing liability regimes in several jurisdictions are insufficient to cover long-term monitoring scenarios, deterring private investors.

The In Salah project in Algeria, as mentioned, illustrates the challenges faced in the absence of clear rules regarding leak liability. However, the analysis by Cheng et al. (2023)[308] pointed out that injecting CO_2 into deep reservoirs could induce seismic activity, thereby increasing the potential risks of leaks. This emphasizes the need for regulatory frameworks that incorporate the geophysical risks specific to each project. Additionally, the challenges of this project revealed the importance of continuous postinjection monitoring, highlighting that the transition of responsibility between private operators and governments must be clearly defined.

Perspective for Improvement. Establishing insurance funds or specific guarantees for managing long-term leak risks could encourage greater private sector participation. Recent research, such as that by Kali et al. (2022),[43] has proposed pooled insurance systems among several EU countries to cover the costs associated with sequestration risks. Such models could be expanded to other regions and integrated into future projects. Additionally, it would be useful to study the effectiveness of long-term liability frameworks implemented in the Gorgon Project in Australia, where the government plays an active role in managing these risks after well closure.

Improvements in liability frameworks could also include cost-sharing mechanisms between private companies and governments for long-term monitoring. These efforts would be supported by legislative incentives, such as extending tax credit schemes for CO_2 sequestration over longer periods to make investments in monitoring more attractive.

7.2.4. Access to Long-Term Financing. Access to financing for CO_2 sequestration projects, particularly for long-term monitoring, remains a significant hurdle. According to the Global CCS Institute (2023),[309,310] although investments in CO_2 capture and storage projects have increased in recent years, the lack of long-term financing mechanisms is slowing the growth of large-scale projects. The volatility of carbon markets and uncertainty about future climate regulations deter investors.

The Gorgon Project in Australia, with its high costs, received substantial funding through the participation of energy companies and the government. However, as noted in a recent study by Marshall et al. (2022),[163] even with strong initial financial support, securing long-term financing remains a concern, particularly for postinjection monitoring. This study highlighted that the absence of financial mechanisms for the postinjection phase is one of the major gaps in existing projects.

Perspective for Improvement. To ensure stable access to long-term financing, innovations in financial instruments are necessary. Green bonds and carbon credits have demonstrated potential for sustainable financing, but their broader adoption could be facilitated by strengthened public policies and enhanced partnerships between governments and international financial institutions. For instance, the World Bank's "Sustain-

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able Energy Fund" initiative, which supports energy transition projects, could be expanded to specifically include long-term financing for CO_2 sequestration projects.

Additionally, further fiscal incentives, such as those provided under the U.S. 45Q tax credit, which offers tax credits for CO_2 capture and storage, could be extended to other countries and beyond the injection phase to cover long-term monitoring costs. Another option would be to bolster public-private partnerships, where governments could partially guarantee the necessary investments for postinjection monitoring, especially for projects conducted in aging and technically complex reservoirs.

8. CONCLUSION

This exhaustive review on CO_2 sequestration in DHRs provides an overarching and critical analysis of recent advances, persistent challenges, and future prospects. By critically analyzing literature from 2020 to 2024, it is evident that DHRs represent a highly promising avenue for geological carbon storage, backed by their proven containment capacity and existing infrastructure. Technological advancements, such as EOR using CO_2, the application of nanoscale molecular simulations, and the optimization of AI-driven monitoring systems, highlight the growing potential of these reservoirs for safe and effective CO_2 storage.

However, significant gaps remain. Field trials, particularly in unconventional reservoirs such as shales, are still insufficient to validate the scalability of these techniques. Moreover, long-term monitoring solutions, especially in offshore or geologically complex environments, require more robust and cost-effective sensor technologies. The geochemical and ecological impacts of prolonged CO_2 injections, as well as the optimization of viscosity-modifying agents, also need further investigation to ensure the long-term safety and performance of these operations.

This review emphasizes the need for continued interdisciplinary research efforts, field experimentation, and technological development to overcome these challenges. Collaboration between academia, industry, and regulatory bodies is crucial to enable large-scale deployment of these solutions, which are essential for meeting global climate goals. By integrating the latest advancements and identifying areas that require further investigation, this study provides a strategic roadmap aimed at promoting more sustainable and resilient carbon storage solutions.

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https://doi.org/10.1021/acs.energyfuels.4c03512
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■ ACKNOWLEDGMENTS

The authors would like to express their gratitude to the Chinese Scholarship Council, and the China University of Geosciences, Wuhan, as well as to all those who contributed supervision, knowledge, advice and operational resources to the development of this paper.

■ ACRONYMS

CCS	carbon capture and storage
CCUS	carbon capture, use and storage
GHGs	greenhouse gases
DHRs	depleted hydrocarbon reservoirs
AHRs	aging hydrocarbon reservoirs
DOGRs	depleted oil and gas reservoirs
AOGRs	aging oil and gas reservoirs
DSAs	deep saline aquifers
EOR	enhanced oil recovery
CO_2	carbon dioxide
MMP	minimum miscibility pressure
WAG	water-CO_2 alternating injection
USDOE	United States department of energy
CSLF	carbon sequestration leadership forum
MRV	monitoring, reporting, and verification
MVA	Monitoring, Verification, and Assessment
IGCC	integrated gasification combined cycle
ARP	assisted recovery projects
EIA	environmental impact assessments
DFOS	distributed fiber optic sensing

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