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Review

Selecting Geological Formations for CO_2 Storage: A Comparative Rating System

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Abstract: Underground storage of carbon dioxide (CO_2) in geological formations plays a vital role in carbon capture and storage (CCS) technology. It involves capturing CO_2 emissions from industrial processes and power generation and storing them underground, thereby reducing greenhouse gas emissions and curbing the impact of climate change. This review paper features a comparative analysis of CO_2 storage in deep saline aquifers, depleted reservoirs, coal seams, basaltic formations and clastic formations. The comparison has been drawn based upon seven factors carefully selected from the literature, i.e., safety, storage capacity, injection rates, efficiency, residual trapping, containment and integrity and potential to improve, and all of these factors have been rated from low (1) to high (5) based upon their individual traits. Based upon these factors, an overall M.H. rating system has been developed to categorize geological formations for CO_2 storage and it is observed that deep water aquifers and basaltic formations are the most effective options for CO_2 storage. Lastly, a detailed way forward has been suggested, which can help researchers and policymakers to find more viable ways to enhance the efficiency of CO_2 storage in various geological formations.

Keywords: CO_2 storage; geological formation; M.H. rating scale; mineralization

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1. Introduction

Carbon dioxide (CO_2) is a well-known greenhouse gas that contributes significantly to global warming and climate change [1]. As a means of mitigating these harmful effects, one strategy is to reduce the amount of CO_2 released into the atmosphere [2]. CO_2 capture and storage (CCS) is a promising and innovative technology that aims to capture CO_2 emissions from various industrial processes and store them safely in underground geological formations [3]. This process of storing CO_2 in geological formations beneath the Earth's surface is known as geologic CO_2 storage or carbon capture and storage (CCS) [4,5]. The potential benefits of CCS are significant, as it provides an opportunity to reduce carbon emissions while simultaneously allowing for the continued use of fossil fuels. In addition, CCS can help to address the challenge of reducing CO_2 emissions from industrial sectors that are difficult to decarbonize, such as steel and cement production [6].

For several decades, carbon capture technologies have been under development, and numerous pilot and demonstration projects have been conducted globally [7]. However, the primary challenge for the widespread deployment of CCS is the cost and effectiveness of storing CO_2 in geological formations [8]. As a result, extensive research and development efforts are being directed toward comprehending the geology of different formations, assessing their suitability for CO_2 storage and enhancing CO_2 storage processes to improve their efficiency [9,10]. The study of CO_2 storage in geological formations has gained significant attention as a promising approach to mitigating climate change [11]. However, the variations in the geological characteristics and suitability of different formations for CO_2 storage highlight the need for a comparative study. Each geological formation has unique properties that can affect the efficiency and cost-effectiveness of CO_2 storage, making it essential to identify the most suitable option for storage [12].

A comparative study can help understand the selection of CO_2 storage processes for each geological formation based on different parameters. Furthermore, a comparative study can also address the lack of data on CO_2 storage in certain geological formations, such as basaltic formations, which are an emerging storage option due to their ability to react with CO_2 and mineralize it over time. The choice of a geological formation for CO_2 storage depends on several factors, such as proximity to CO_2 sources, storage capacity, geological characteristics, storage costs, etc. As a result, it is crucial to conduct extensive site characterization studies to evaluate the suitability of geological formations for CO_2 storage and optimize CO_2 storage processes to enhance storage efficiency and reduce costs.

In this study, an M.H. rating system has been developed that can help in understanding the selection of geological formations for CO_2 storage if more than one option is available and proximity is not a deciding factor. The rating system will be based on seven evident factors, which are usually considered separately or sometimes two or more altogether. The seven factors are, i.e., safety risks and mitigations, storage capacity, injection rates, efficiency, residual trapping, containment and integrity and potential to improve, and all of these factors have been rated on a scale from low (1) to high (5) based upon their individual traits.

M.H. Rating System and Evalutaion Factors

The M.H. rating system is a method for selecting geological formations that are suitable for the storage of CO_2. The rating system is based on the combination of seven parameters, including storage capacity, storage efficiency, containment and integrity, injection rate, safety risk and mitigation, residual trapping and potential to improve. By combining these seven parameters, the M.H. rating system provides a comprehensive approach for evaluating the suitability of different geological formations for CO_2 storage. The system can be used to identify the most promising storage formations and to prioritize investment and research efforts in CO_2 storage technologies.

a. Safety risk and Mitigations: This factor will help us in making a comparison between various safety risks and efforts to mitigate risks associated with CO_2 storage in geological formations [12–20]. A scale of one–five will be used where one stands for high safety risk and high mitigation efforts while five stands for low safety risks and low mitigation efforts.

b. Storage capacity: pertains to the maximum quantity of CO_2 that a geological formation can accommodate. Typically, it is measured in metric tons of CO_2 per unit volume of the formation, such as tons of CO_2 per cubic meter of rock. The storage capacity is contingent on factors, such as the formation's thickness, permeability, and porosity, as well as the density and solubility of CO_2 [21–25]. In the M.H. rating system, one stands for low storage capacity, while five stands for high storage capacity.

c. Injection rate: describes the velocity at which CO_2 can be inserted into a formation without triggering excessive pressure buildup or fracturing. Usually, it is expressed in units, such as cubic meters per day (m^3/day) or metric tons per day (t/day). The injection rate depends on factors, such as the depth, porosity, permeability, injection pressure, and temperature of the formation [26–31]. In the M.H. rating system, one stands for low injection rates, while five stands for high injection rates.

d. Storage efficiency: denotes the percentage of injected CO_2 that remains stored in the formation over a specific time frame. Generally, it is calculated as the proportion of stored CO_2 to injected CO_2. The storage efficiency is influenced by factors, such as the formation's porosity, permeability, pressure, and the physical and chemical properties of the CO_2 and the formation fluid [32–37]. In the M.H. rating system, one stands for low storage efficiency, while five stands for high storage efficiency.

e. Residual trapping: This trapping mechanism occurs when the CO_2 plume goes through the porous rocks, as small amounts of CO_2 get disconnected and get trapped in the pore spaces and traps by surface tension [37–42]. The residual trapping capacity depends on factors, such as the formation's mineralogy, pH, and temperature. In the M.H. rating system, one stands for low residual trapping, while five stands for high residual trapping.

f. Potential to improve: Though a great deal of work has been conducted on CO_2 storage in various geological formations, the formations and processes involved still have a lot of potential to be improved in order to favor effective CO_2 storage based on their innate traits [43–45]. In the M.H. rating system, one stands for low potential to improve further, while five stands for high potential to be improved.

g. Containment and integrity: Containment and integrity are critical factors in the successful implementation of CO_2 storage in geological formations. CO_2 must be stored safely and securely to prevent its release into the atmosphere, which could cause environmental and health hazards [46]. Containment refers to the ability of the storage site to retain CO_2 for an extended period, while integrity refers to the ability of the storage site to prevent leakage of CO_2, which are predominantly somewhat related to the sealing capacity, geometry and integrity of the formation.

2. Development of M.H Rating System—Formation by Formation Analysis

To develop a successful M.H. rating system all seven parameters of the rating system have been reviewed individually first for each geological formation which is later analyzed to develop the M.H. Rating system.

2.1. Deep Saline Aquifers

Deep saline aquifers are large underground rock formations that contain briny water and are found deep beneath the Earth's surface. These aquifers are typically several thousand feet deep and can stretch for hundreds of miles. Due to their geological characteristics, they have been identified as one of the most promising and economically viable options for the long-term storage of carbon dioxide (CO_2) produced by industrial processes [47,48].

2.1.1. CO_2 Storage Mechanism for Deep Saline Aquifers

The CO_2-storage mechanism directly relates to the storage sites. In this section, the CO_2-storage mechanism in deep saline aquifers is briefly summarized on the basis of the IPCC report. Deep saline formations are porous rock formations that are typically several kilometers below the surface and contain enormous quantities of unusable water with high salt and/or mineral content. This saltwater brine is around 10 times saltier than the oceans and has been trapped by impermeable rock, called a "caprock," for millions of years. The brine (saltwater) is called formation fluid [49,50].

Once CO_2 is injected into a deep saline aquifer, as CO_2 is less dense than the formation fluid, the supercritical CO_2 rises buoyantly as a separated phase through the porous rocks until it reaches the top of the formation, where it meets and is trapped by an impermeable layer of caprock. This is called structural/stratigraphic trapping. Meanwhile, the injected supercritical CO_2 displaces fluid as it moves through the porous rock, as shown in Figure 1. As the CO_2 continues to move, the brine replaces it again, but some of the CO_2 will be left behind as disconnected (residual) droplets in the pore spaces are immobile. This is called residual trapping. When CO_2 encounters the brine present in the porous rock, CO_2 will dissolve into the brine. As the brine containing dissolved CO_2 is denser than the surrounding fluids (i.e., brine without dissolved CO_2), it will sink to the bottom of the rock formation over time. This process is defined as solubility trapping, and it will trap the CO_2 even more securely with less risk of leakage. When CO_2 dissolves in water, it forms a weak carbonic acid [51,52].

Over a long period, this weak acid can react with the minerals in the surrounding rock to form solid carbonate minerals. This process is called mineral trapping. Depending on the mineralogy of the rock and water in a specific storage site, the mineral trapping process can be rapid or very slow, but it effectively binds CO_2 to the rock. These trapping processes take place at different rates ranging from days to years to thousands of years.

In general, geologically stored CO_2 becomes more securely trapped with time due to the higher density of fluid that contains dissolved CO_2, as well as the fixation of CO_2 through its reaction with minerals. CO_2 dissolution occurs over hundreds to thousands of years, whereas the conversion of the injected CO_2 to solid carbonate minerals takes over millions of years [25,53].

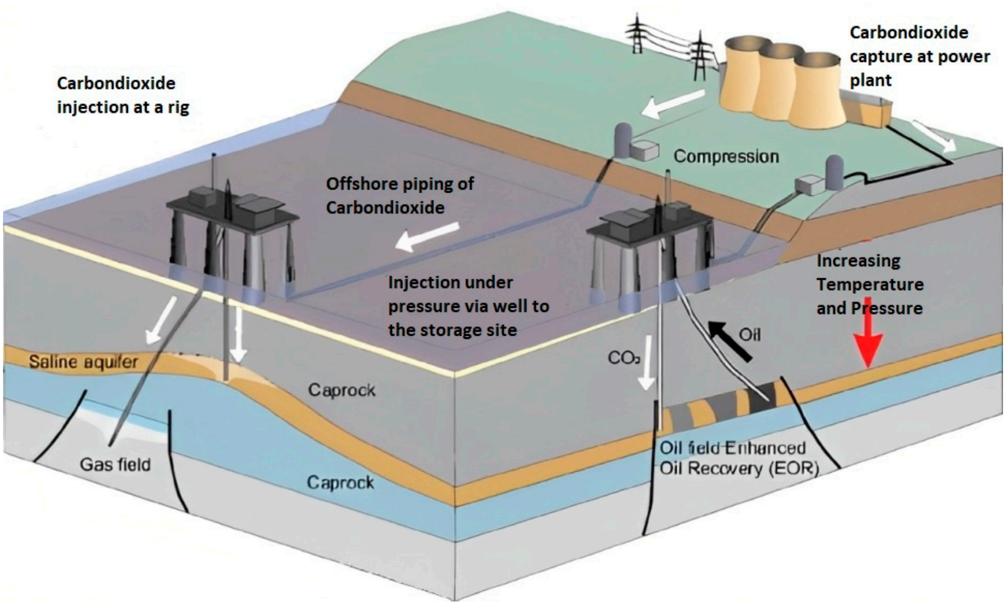

Figure 1. Mechanism for CO_2 storage in deep saline aquifers [54].

2.1.2. M.H. Rating System Factors for Deep Saline Aquifers

a. Safety risks and mitigations:

Preventing the escape of buoyant CO_2 to the surface is crucial for safe and long-term storage because it can result in the failure to retain CO_2 permanently in the storage aquifer and contaminate shallow potable aquifers. The key to safe storage in deep saline formations is immobilizing or preventing the upward movement of CO_2. These formations have closed structures that can immobilize buoyancy-driven flow, such as supercritical CO_2 in oil and gas reservoirs. The subsurface has retained oil, natural gas, and naturally occurring CO_2 for millions of years, indicating a low leakage risk. Over time, the risk of leakage is expected to decrease due to CO_2 dissolving into saltwater and sinking to the bottom of the geologic formation, as well as the further reaction of dissolved CO_2 with surrounding rock minerals to form solid carbonate minerals [55,56].

Despite ongoing and proposed pilot and commercial projects for CCS, the numbers fall short of those needed to significantly reduce atmospheric CO_2 emissions, and the feasibility of CCS is dependent on various factors, such as cost, storage capacity, safety, risk and environmental impact. These factors are linked to the properties of CO_2 and deep saline formations, the physical–chemical processes involved and impurities in the CO_2 [15,47,57–59].

b. Storage Capacity of aquifers:

Deep saline aquifers offer a promising solution for CO_2 storage due to their significant storage capacity. The estimated storage capacity of deep saline aquifers in the United States alone is between 8000 and 12,000 gigatons of CO_2. This is significantly higher than the amount of CO_2 emissions from human activities in the past decade. Therefore, deep saline aquifers have the potential to store a substantial amount of CO_2 emissions, which can contribute to mitigating climate change [60,61]. One of the contributing factors to the high storage capacity of deep saline aquifers is their large spatial extent. These aquifers can be found at depths ranging from a few hundred meters to several kilometers below the surface, and they are present in many regions worldwide. In the United States, the total area of deep saline aquifers is around one million km^2. This large spatial extent allows for a distributed and decentralized approach to CO_2 storage, which can help to reduce transportation costs and infrastructure requirements [62,63].

The storage capacity of deep saline aquifers is significantly impacted by the thickness and depth of the formation. The greater the thickness and depth of the formation, the greater the storage capacity. The United States Department of Energy reports that deep saline formations with a thickness of 200 m or more and a depth of 800 to 3000 m have the potential to store billions of metric tons of CO_2. Furthermore, a single formation in the US, the Mount Simon Sandstone formation, could store up to 150 billion metric tons of CO_2, equivalent to approximately 50 years of the country's current CO_2 emissions from fossil fuels [64].

The density of CO_2 also plays a crucial role in the storage capacity of deep saline aquifers. CO_2 exists in various phases depending on the temperature and pressure conditions. Supercritical CO_2 is the most commonly used phase for storage in deep saline aquifers as it has a higher density than gaseous CO_2 and is more mobile than liquid CO_2. At a temperature of 25 °C and a pressure of 8.4 megapascals, the density of supercritical CO_2 is approximately 0.75 g per cubic centimeter, similar to that of water. However, the density of CO_2 can fluctuate depending on the temperature and pressure conditions of the storage formation, which can impact the buoyancy and movement of CO_2 in the formation [65]. Apart from thickness, depth and CO_2 density, the porosity and permeability of the formation also impact its storage capacity. The porosity of the formation refers to the amount of pore space available for CO_2 storage, while permeability refers to how easily CO_2 can move through the formation. Higher porosity and permeability indicate a higher storage capacity. According to the US Geological Survey, deep saline formations with a porosity of 15% and a permeability of one millidarcy can store up to 400 metric tons of CO_2 per square kilometer [58,66].

Finally, it is worth noting that the actual storage capacity of deep saline aquifers can vary depending on site-specific characteristics, such as depth, porosity, permeability, and geological features, such as faults and fractures. However, various studies have estimated the potential storage capacity of deep saline aquifers worldwide. For example, a recent study estimated that the storage capacity of deep saline aquifers in Europe is around 30,000 megatons of CO_2, equivalent to over 100 years of CO_2 emissions from the European Union [67–69].

c. Injection Rates:

Deep saline aquifers are a promising option for long-term CO_2 storage, but the safe injection rate must be carefully considered. The injection rate is influenced by several factors, including the porosity and permeability of the aquifer, the thickness of the storage formation and the pressure of the formation. Studies have shown that the injection rate for CO_2 storage in deep saline aquifers can range from 0.1 to 10 million metric tons of CO_2 per year per well. However, the injection rate can vary based on the specific geological characteristics of the aquifer, with higher porosity and permeability generally supporting higher injection rates [70–72].

Operational considerations, such as the size and number of wells used for injection, injection pressure and distance between wells, can also impact the injection rate. The injection rate must be carefully managed to avoid overpressurization of the aquifer, which can result in fracturing and potential CO_2 leakage. To determine the safe injection rate for a specific aquifer, modeling and monitoring are essential. Injection modeling simulates the behavior of the injected CO_2 in the aquifer over time, accounting for geological and operational factors that influence the injection rate. Monitoring of the injection process ensures that the injection rate remains within safe limits and that there is no CO_2 leakage from the storage formation [73,74].

In summary, the injection rate for CO_2 storage in deep saline aquifers can vary depending on the geological and operational characteristics of the aquifer. However, careful modeling and monitoring can help ensure safe and effective CO_2 storage in these formations.

d. Storage Efficiency:

Deep saline aquifers are widely recognized as one of the most effective options for long-term CO_2 storage. The efficiency of CO_2 storage in these formations is determined by a number of factors, including injection rates. Storage efficiency is used to measure the effectiveness of CO_2 storage, which is the ratio of the amount of CO_2 that can be stored in the aquifer to the amount of CO_2 injected. Research has shown that the storage efficiency of CO_2 in deep saline aquifers ranges from 5% to 40%, with an average of 15–20%. This implies that for every 100 metric tons of CO_2 injected, 5 to 40 metric tons can be stored in the aquifer. The efficiency of CO_2 storage is determined by various factors, including the thickness, porosity and permeability of the aquifer, as well as the pressure of the formation [72].

The injection rate is also an essential factor in CO_2 storage efficiency. High injection rates generally lead to higher storage efficiency since more CO_2 can be injected and stored in the aquifer over time. However, it is important to manage injection rates cautiously to avoid overpressurization of the aquifer, which can cause fractures and CO_2 leakage [63,75,76]. The use of enhanced oil recovery (EOR) methods is one approach to improve the efficiency of CO_2 storage in deep saline aquifers. EOR entails injecting fluids, such as water, steam or gases into oil reservoirs to improve oil recovery. When CO_2 is used as the injection fluid for EOR, the CO_2 can also be stored in the reservoir, which enhances storage efficiency. The application of EOR techniques can increase CO_2 storage efficiency in deep saline aquifers by up to 50% [77,78].

In summary, injection rates have a significant impact on the efficiency of CO_2 storage in deep saline aquifers. Higher injection rates result in higher storage efficiency, but they must be managed carefully to avoid overpressurization of the aquifer. The application of EOR techniques can also enhance the storage efficiency in these formations.

e. Residual Trapping:

Residual trapping is a crucial process for the long-term storage of CO_2 in deep saline aquifers. This mechanism involves the immobilization of CO_2 in small pores and rock crevices after the initial injection phase, which reduces the potential for CO_2 leakage. Research indicates that residual trapping can account for up to 30% of the total CO_2 storage capacity in deep saline aquifers. The efficiency of residual trapping is affected by several factors, including the porosity and permeability of the aquifer, the pressure and temperature of the formation and the properties of the injected CO_2. High porosity and permeability are crucial for effective residual trapping, as they provide more pore spaces and crevices for the CO_2 to be trapped. The pressure and temperature of the formation also play a significant role, with higher pressures and lower temperatures leading to more effective residual trapping [79–81].

Moreover, the properties of the injected CO_2 also affect the effectiveness of residual trapping. More dense and viscous CO_2 is more likely to be trapped in the small pores and crevices of the rock formation, leading to more efficient residual trapping. Overall, residual trapping is an essential mechanism for the safe and efficient storage of CO_2 in deep saline aquifers. The effectiveness of residual trapping is influenced by several factors, including porosity, permeability, pressure, temperature and CO_2 properties, and it can significantly enhance the storage capacity of these formations [37,82–84].

f. Containment and integrity:

Deep saline aquifers are a promising storage option for carbon dioxide (CO_2) due to their large storage capacity. However, it is essential to maintain the containment of the CO_2 within the aquifer and ensure the storage site's structural integrity to prevent any hazards or leakage. Various factors, such as pressure, temperature, porosity, permeability and natural barriers, influence the containment of CO_2 within deep saline aquifers. Design and operation of the injection system are also crucial to maintain containment [62,85,86].

Regular monitoring of geological stability and detection of any structural damage or leakage is essential to ensure the storage site's integrity. Injection well quality and design also affect the integrity and should be appropriately managed to prevent any failure or damage. In conclusion, successful CO_2 storage in deep saline aquifers requires prioritizing containment and integrity, considering various parameters and implementing robust monitoring and risk management practices. This approach can help mitigate greenhouse gas emissions and address climate change [16,87–89].

g. Potential to improve:

Deep saline aquifers have emerged as a promising option for the safe and long-term storage of carbon dioxide due to their large storage capacity and secure containment. Nonetheless, there is potential for further enhancement of their storage capacity. One approach to increasing storage capacity involves optimizing injection strategies, which includes methods, such as controlling the injection rate and pressure and selecting the injection well location. By fine-tuning these strategies, it may be possible to safely store more CO_2 in the aquifer [90,91].

Another approach is to improve the physical properties of the aquifer, such as its porosity and permeability. By increasing the amount of space between rock particles and the flow rate of fluids through the rock, more CO_2 could be stored while minimizing any leakage risks. Advancements in drilling and well completion technologies could also enhance the storage capacity of deep saline aquifers. Horizontal drilling techniques, for instance, can facilitate the construction of multiple injection wells from a single surface location, making the injection process more efficient and potentially increasing the amount of CO_2 that can be stored [92,93].

Furthermore, monitoring and verification technologies could improve the safety and integrity of deep saline aquifer storage sites. Continuous monitoring can promptly detect any leaks, changes in pressure, temperature or other variables that could indicate a problem, thereby helping to maintain safe storage [71,78]. In summary, deep saline aquifers offer a large storage capacity for CO_2, but there are various methods to improve and enhance their storage capacity, such as optimizing injection strategies, improving the physical properties of the aquifer, advancing drilling technologies and implementing monitoring and verification technologies. These strategies can help to ensure the long-term effectiveness and safety of deep saline aquifer storage for carbon dioxide.

2.2. Depleted Reservoirs

Depleted reservoirs are oil and gas fields that have been exploited and have reached the end of their production life. These reservoirs can potentially serve as a viable option for CO_2 storage due to their established geological characteristics and infrastructure. Injecting CO_2 into depleted reservoirs can help enhance oil recovery through enhanced oil recovery (EOR) techniques, such as miscible and immiscible flooding [94]. Additionally, the presence of depleted reservoirs in close proximity to major sources of CO_2 emissions can provide a cost-effective solution for carbon capture and storage (CCS). However, depleted reservoirs can also pose risks in terms of wellbore integrity and potential for CO_2 leakage. Therefore, careful site characterization and monitoring are essential to ensure the long-term containment and integrity of CO_2 storage in depleted reservoirs [95].

2.2.1. CO_2 Storage Mechanism in Depleted Reservoirs

The technique of CO_2 storage in depleted reservoirs entails injecting carbon dioxide into underground rock formations that were previously utilized to extract natural gas or oil, as shown in Figure 2. These formations are usually made up of porous and permeable rock types, such as limestone or sandstone, that can confine the CO_2 underground. When the CO_2 is injected into the reservoir, it starts to dissolve into the fluids of the formation or react with the rock minerals, which aids in confining it in place. As time goes on, the

CO_2 becomes progressively more firmly attached to the rock, gradually forming a stable mineral that can no longer move back to the surface [96–98].

The storage method comprises several steps, including site selection, characterization and monitoring. The suitability, capacity and integrity of the geological site must be evaluated, and any possible hazards linked with the storage procedure must be recognized and resolved. Monitoring is a crucial aspect of the storage process, as it helps to guarantee that the CO_2 remains entrapped in the reservoir and does not escape back to the surface. This involves a variety of techniques, such as geochemical analysis, seismic surveys and monitoring of changes in temperature and pressure within the reservoir [99].

CO_2 storage in depleted reservoirs has the potential to play an important part in reducing greenhouse gas emissions and mitigating climate change. By trapping and storing CO_2 underground, this approach can help minimize the amount of CO_2 released into the atmosphere, consequently reducing the rate of global warming [100].

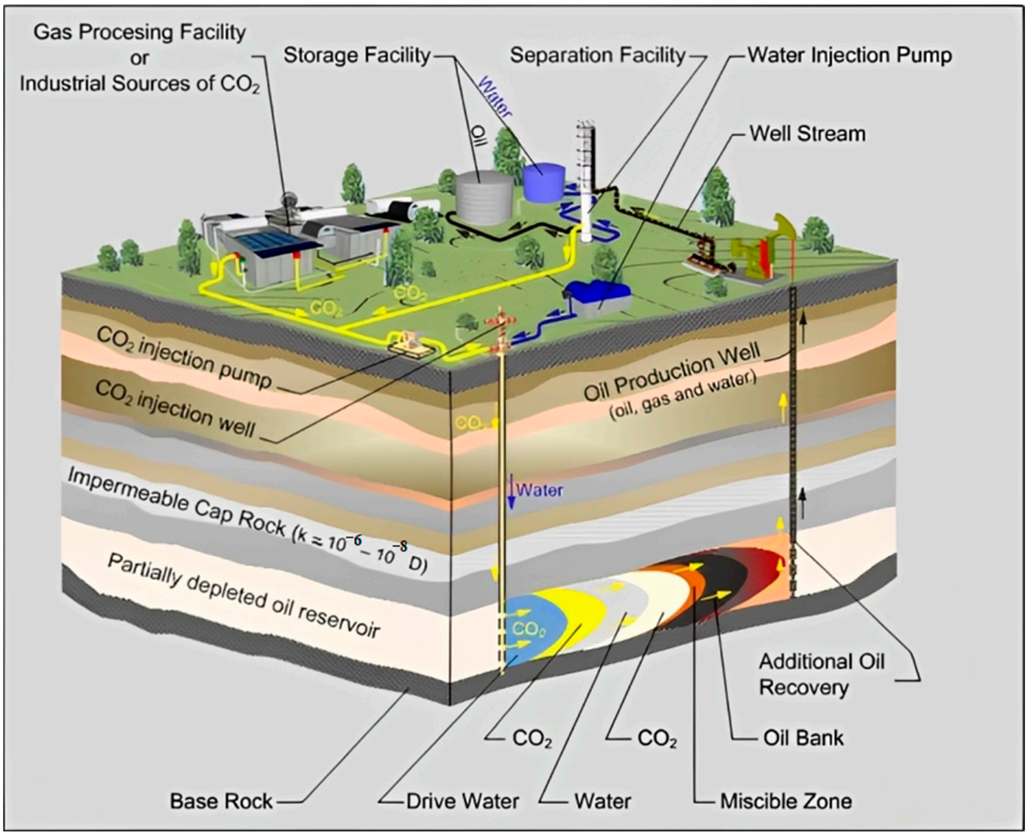

Figure 2. Mechanism for CO_2 storage in depleted reservoirs [101].

2.2.2. M.H. Rating System Factors for Depleted Reservoirs

a. Storage capacity of depleted reservoirs:

Depleted oil and gas reservoirs offer a promising option for CO_2 storage due to their vast storage capacity. According to estimates, the total storage capacity of depleted oil and gas reservoirs in the US ranges between 1000 and 3000 gigatons of CO_2. This is a significant amount, given that the annual global CO_2 emissions from human activities are around 40 gigatons per year. Depleted reservoirs, therefore, have the potential to store a significant proportion of CO_2 emissions and help mitigate climate change. One of the factors that contribute to the high storage capacity of depleted reservoirs are their existing infrastructure [94,102,103]. These reservoirs have pre-existing wells and pipelines, which can be repurposed for CO_2 injection and storage. This can significantly reduce the cost and time required to establish a new storage site. The storage capacity of depleted reservoirs is also affected by their porosity and permeability, as well as the presence of sealing formations that can prevent CO_2 from escaping. Depleted reservoirs typically have high porosity and permeability due to the previous extraction of oil and gas. For instance, their porosity ranges from 10% to 35%, while permeability can range from one millidarcy to several darcies. As a result, a single depleted reservoir can potentially store billions of tons of CO_2 [99,104,105].

It is worth noting that the actual storage capacity of depleted reservoirs may vary depending on the specific site characteristics, such as the porosity and permeability of the formation, as well as the presence of sealing formations. Nevertheless, various studies have estimated the potential storage capacity of depleted reservoirs in different regions around the world. These estimates generally indicate that the storage capacity is enough to accommodate a significant proportion of the world's CO_2 emissions [106,107].

b. Injection rates:

Depleted reservoirs, which are oil and gas reservoirs that have been emptied of their hydrocarbon reserves, offer a potential solution for the long-term storage of CO_2. Injection rates play a crucial role in the efficiency of CO_2 storage in depleted reservoirs. Studies have revealed that the injection rates for CO_2 storage in depleted reservoirs can vary significantly, ranging from less than 100 metric tons per day (mtpd) to over 5000 mtpd. The injection rate largely depends on the reservoir characteristics and the design of the injection well. Higher injection rates are generally more efficient for CO_2 storage in depleted reservoirs as they enable more CO_2 to be injected and stored in a shorter period of time [108–110].

However, higher injection rates can also pose challenges in managing the pressure and ensuring the stability of the reservoir. Overpressurization of the reservoir can cause fracturing, leading to CO_2 leakage and compromising the safety and effectiveness of CO_2 storage. To tackle these challenges, several injection strategies have been developed for CO_2 storage in depleted reservoirs, such as using multiple injection wells to distribute the CO_2 evenly, implementing intermittent injection to allow for pressure dissipation and using pressure management techniques, such as gas cycling. The efficiency of CO_2 storage in depleted reservoirs can also be impacted by the formation properties, such as the permeability and porosity of the reservoir. Reservoirs with higher permeability and porosity are generally more efficient for CO_2 storage since they offer more space for CO_2 to be stored and a more efficient pathway for the CO_2 to displace any remaining hydrocarbons in the reservoir [111–113].

In summary, injection rates are a crucial factor in the efficiency of CO_2 storage in depleted reservoirs. While higher injection rates are generally more efficient, proper management of pressure and reservoir stability is crucial. Different injection strategies and formation properties can affect the effectiveness of CO_2 storage in depleted reservoirs, and careful consideration of these factors is vital for the successful implementation of CO_2 storage projects in these formations.

c. Efficiency:

Efficiency is a crucial factor in the successful storage of CO_2 in depleted reservoirs, and it is primarily determined by two factors storage capacity and injectivity rates. The storage efficiency of a reservoir is defined as the fraction of its pore volume that can be filled with CO_2, and this value is influenced by the porosity and permeability of the formation. For depleted reservoirs, the storage efficiency can range from 5–30%, with an average value of around 15%. This implies that only a small fraction of the pore space in the reservoir can be utilized for CO_2 storage. In addition to storage capacity, injectivity rates also impact the efficiency of CO_2 storage in depleted reservoirs. Injectivity is a measure of how quickly CO_2 can be injected into the reservoir and stored. High injectivity rates can increase the efficiency of CO_2 storage, as more CO_2 can be injected and stored in a shorter period. However, it can also lead to challenges in managing the pressure and stability of the reservoir. Overpressurization can cause fracturing and leakage of CO_2, compromising the safety and effectiveness of CO_2 storage [114–116].

To enhance the efficiency of CO_2 storage, researchers are exploring various techniques, such as hydraulic fracturing, to improve reservoir properties and CO_2-enhanced oil recovery (CO_2-EOR) methods to increase injectivity and storage capacity. These techniques can improve the efficiency of CO_2 storage in depleted reservoirs, but proper management of pressure and reservoir stability is critical to ensuring safety and efficacy [117,118].

In conclusion, the efficiency of CO_2 storage in depleted reservoirs is influenced by storage capacity and injectivity rates. The low storage efficiency of depleted reservoirs underscores the need for large volumes of CO_2 to be stored in these formations to achieve significant reductions in greenhouse gas emissions. The injectivity rate can impact the efficiency of CO_2 storage, but it should be managed appropriately to prevent the fracturing and leakage of CO_2. Ongoing research is investigating various techniques to improve the efficiency of CO_2 storage in depleted reservoirs, with an emphasis on safety and efficacy.

d. Residual trapping:

Residual trapping is a vital process for the effective storage of CO_2 in depleted reservoirs. It involves the capture of CO_2 in small pores and crevices that are inaccessible to the injection well and can contribute up to 30% of the total CO_2 storage capacity in depleted reservoirs. The efficiency of residual trapping is affected by several factors, including capillary pressure, wettability and injection rate. Capillary pressure is a measure of how strongly fluids are attracted to the rock surface, and higher capillary pressure can result in more efficient residual trapping. The wettability of the reservoir rock also plays a crucial role in residual trapping, with favorable wettability resulting in more evenly distributed CO_2 and increased efficiency [119,120].

Injection rate is another factor that can impact the efficiency of residual trapping. Higher injection rates can lead to better mixing of the CO_2 with the reservoir fluids, resulting in increased residual trapping efficiency. However, excessively high injection rates can also cause pressure buildup and fracturing of the reservoir, leading to reduced efficiency of residual trapping [121].

In conclusion, residual trapping is a significant mechanism for CO_2 storage in depleted reservoirs, and its efficiency is influenced by capillary pressure, wettability and injection rate. Managing these factors carefully is crucial for the effective storage of CO_2 in depleted reservoirs.

e. Safety risks and mitigations:

Aside from the primary safety risks and mitigation measures discussed earlier, there are other prominent risks that come with CO_2 storage in depleted reservoirs. Here are some of the additional risks and corresponding mitigation measures: Well Integrity Failure: Well integrity failure can happen due to a variety of factors, such as corrosion, mechanical damage and casing failure. A well failure can lead to CO_2 leakage, which can cause environmental harm. To prevent this, wells must be designed and constructed to withstand the high pressure and corrosive nature of CO_2. Regular inspections and maintenance of wells are also necessary to prevent potential issues [25,122].

Fault Reactivation: CO_2 injection can trigger fault reactivation, which can cause induced seismicity and CO_2 leakage. To mitigate this risk, injection wells should be placed away from active faults, and seismic monitoring should be used to detect any potential fault reactivation [123].

Geological Migration: CO_2 injected into a depleted reservoir can migrate to other geological formations through natural pathways such as faults or fractures. This can lead to the release of CO_2 into the atmosphere or groundwater contamination. To mitigate this risk, detailed geological characterization of the storage formation and surrounding areas is necessary to identify potential migration pathways, and monitoring and verification measures should be in place to detect any CO_2 migration [124].

Operational Accidents: Accidents can occur during CO_2 transportation, injection or storage, which can pose serious safety hazards. To mitigate this risk, strict regulations and safety procedures must be in place, including personnel training and emergency response plans [125].

Public Perception: Public perception and acceptance of CO_2 storage can be a significant risk factor for the long-term viability of this technology. Concerns about safety and potential environmental impacts can lead to opposition to CO_2 storage projects. To mitigate this risk, stakeholders and communities must be engaged early in the project development process, and transparent information about the safety measures in place must be provided [95].

In conclusion, CO_2 storage in depleted reservoirs can be a safe and effective technology for reducing greenhouse gas emissions. However, the safety risks associated with this technology must be carefully considered and mitigated. This can be achieved through careful site selection, monitoring, regulation of injection pressure and rate, well design and maintenance, emergency response planning and stakeholder engagement.

f. Containment and Integrity:

Carbon capture and storage (CCS) has become a crucial strategy for reducing greenhouse gas emissions and mitigating climate change. One of the widely used methods of CCS involves injecting carbon dioxide (CO_2) into depleted oil and gas reservoirs. However, there are some containment and integrity issues that need to be addressed when storing CO_2 in depleted reservoirs. One of the primary concerns is the possibility of leakage, as CO_2 can migrate through porous rock formations and create a pathway to the surface. This can potentially pose environmental, health and safety hazards. Hence, ensuring the safe and long-term containment of CO_2 in the reservoir is essential. Additionally, the injection of CO_2 can affect the physical and chemical properties of the reservoir, such as permeability, porosity and mineralogy, which may compromise its structural integrity. This can cause subsurface instability and induced seismicity, leading to environmental and social concerns [126–128].

To address these issues, various measures are being implemented, including careful site selection, comprehensive site characterization studies, optimized injection strategies, continuous monitoring and verification and post-closure monitoring. These measures are essential to ensure the safe and effective containment and integrity of CO_2 storage in depleted reservoirs. In conclusion, CO_2 storage in depleted reservoirs is an effective CCS method, but it requires careful management of containment and integrity issues. Implementing proper measures, such as site selection, site characterization, optimized injection strategies, monitoring and closure and post-closure monitoring, can ensure the long-term safety and effectiveness of CO_2 storage in depleted reservoirs [129,130].

g. Potential to improve:

Depleted reservoirs have a great potential for increasing their ability to store CO_2, which could increase their effectiveness in combatting climate change by storing greenhouse gases permanently. Depleted reservoirs have the possibility for improvement because to a number of reasons, including their vast storage capacity and secure containment, their current infrastructure and the potential for better oil recovery (EOR) [131,132].

With their enormous storage capacity, depleted reservoirs can hold a sizable amount of CO_2. However, by fine-tuning the injection rate and pressure and choosing the ideal injection well site, optimizing injection tactics can further boost the storage capacity. This may make it possible to store more CO_2 in the reservoirs safely while lowering the chance of leaks. Depleted reservoirs also have existing infrastructure that can be used for CO_2 injection and transportation, such as wells and pipelines, hence lowering the requirement for additional infrastructure and associated costs. The use of monitoring and verification technologies, which enhance the security and reliability of the storage locations, can be made easier as a result [133,134].

There are also opportunities to improve the storage potential of depleted reservoirs. One approach is to enhance the understanding of the geological properties of the reservoir, such as its porosity and permeability, to better predict and manage CO_2 storage capacity. Additionally, advances in drilling and well completion technologies can increase the efficiency of CO_2 injection and improve the distribution of CO_2 within the reservoir. In summary, depleted reservoirs offer significant potential for CO_2 storage, and their existing infrastructure and geological properties make them an attractive option for CCS projects. With continued research and technological advancements, there is an opportunity to further improve the storage potential of depleted reservoirs for long-term carbon sequestration [135].

2.3. Coal Seams

Coal seams are underground layers of sedimentary rock that contain coal. They are an important source of energy and have been extensively mined for centuries. Coal seams can also be used for carbon capture and storage (CCS) by injecting CO_2 into the coal seams, where it is adsorbed and stored within the coal matrix [136]. The injected CO_2 can displace the methane present in the coal seams, which can then be extracted and used as a source of energy. Coal seam storage is considered one of the promising options for CCS as it provides a relatively large storage capacity and can potentially enhance coal bed methane recovery. However, research is still needed to understand the feasibility, efficiency and long-term stability of CO_2 storage in coal seams [137].

2.3.1. CO_2 Storage Mechanism of Coal Seams

Injecting CO_2 into underground coal seams is a technique that enhances the recovery of methane gas while simultaneously storing the CO_2 in the coal. This process involves injecting CO_2 into the coal seam under high pressure to displace methane gas, which can be extracted and sold. CO_2 is adsorbed by the coal, trapping it underground, as shown in Figure 3 [137,138]. The process requires site selection, characterization and monitoring to ensure the suitability, capacity and integrity of the site and identify potential risks. Monitoring techniques, such as geochemical analysis and seismic surveys, are employed to ensure the CO_2 remains trapped in the coal seam. This technique has the potential to reduce greenhouse gas emissions and mitigate climate change by capturing and storing CO_2 in coal seams, slowing global warming. Additionally, it can increase the recovery of valuable methane gas [139].

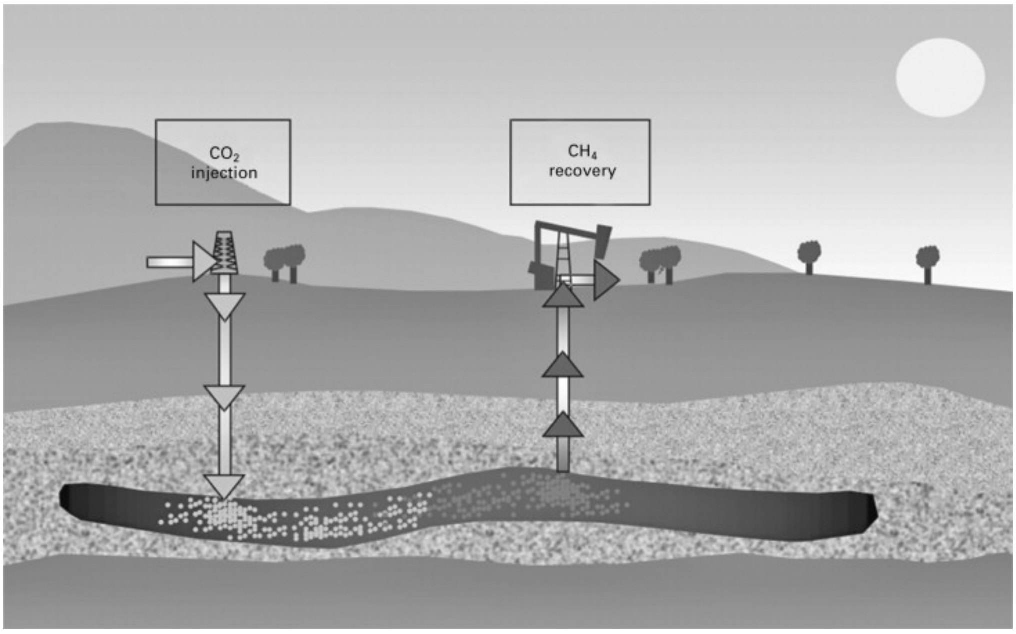

Figure 3. Mechanism for CO_2 storage in coal seams [140].

2.3.2. M.H. Rating System Parameters for Coal Seams

a. CO_2 storage capacity:

Coal seams are a promising option for CO_2 storage, as they have the potential to store substantial amounts of CO_2. The storage capacity of coal seams depends on factors, such as the depth and thickness of the seams, as well as the coal rank and quality. Deeper and thicker seams with higher coal rank and quality generally have greater storage capacity. The US Department of Energy estimates that the total CO_2 storage capacity of coal seams in the United States ranges from 2500 to 20,000 gigatons of CO_2. To put this into perspective, human activities have emitted around 2200 gigatons of CO_2 since the industrial revolution. This means that coal seams have the potential to store several times the total amount of CO_2 emitted by humans to date [141–143].

The depth and thickness of coal seams are critical factors in determining their CO_2 storage capacity. According to the US Department of Energy, coal seams at depths greater than 1500 m have the potential to store up to 10 times more CO_2 than shallower coal seams. Similarly, thicker coal seams can provide a larger storage volume and increase the overall storage capacity. A study conducted by the University of New South Wales found that coal seams with a thickness greater than 2 m can store up to 4 times more CO_2 than thinner seams [144].

The coal rank and quality also impact CO_2 storage capacity. Higher rank coals generally have greater CO_2 adsorption capacity due to their higher organic content. Bituminous coals, which are the most commonly mined coal in the United States, have a CO_2 adsorption capacity of around 3–6 milligrams per gram of coal. Porosity and permeability are critical parameters in determining the CO_2 storage capacity of coal seams. The higher the porosity and permeability, the greater the CO_2 storage capacity. Coal seams generally have higher porosity and permeability compared to other rock formations, making them attractive candidates for CO_2 storage. According to a study by the US Geological Survey, coal seams in the Powder River Basin have an average porosity of 6.5% and a permeability of 8 millidarcies, which contributes to their high CO_2 storage capacity [145].

However, coal seams can have limitations as CO_2 storage sites. The presence of fractures or faults in the coal seam can reduce the storage capacity by allowing CO_2 to escape. Similarly, coal seams may contain methane gas, which can be released during CO_2 injection and storage, creating safety concerns and reducing the overall effectiveness of CO_2 storage efforts. Therefore, careful site selection and characterization are necessary to ensure the success of CO_2 storage in coal seams [146,147].

It is important to note that the CO_2 storage capacity of coal seams can vary significantly depending on site characteristics, such as the presence of water and pressure and temperature conditions. For example, the storage capacity of coal seams in the Powder River Basin in the United States is estimated to be around 2.2 metric tons of CO_2 per acrefoot, while the storage capacity of coal seams in the San Juan Basin is estimated to be around 0.5 metric tons of CO_2 per acrefoot. Despite these variations, coal seams have the potential to significantly contribute to CO_2 storage efforts [148,149].

b. Injection rates:

CO_2 injection into coal seams is a promising carbon storage option, with coal acting as a natural reservoir for CO_2. The injection rate plays a crucial role in determining the effectiveness of CO_2 storage in these seams. Studies have shown that the optimal injection rate for CO_2 storage in coal seams falls between 0.1 and 1.0 metric tons per day per well. Injection rates above this range may result in poor storage efficiency, as the pressure buildup and fluid saturation within the coal seams can lead to fracturing and CO_2 leakage. Similarly, low injection rates can lead to poor CO_2 distribution within the coal seams, limiting the storage capacity. Scientists are exploring various techniques to improve injection rates for CO_2 storage in coal seams. Hydraulic fracturing is one such method, which can increase the permeability and porosity of the coal seams, allowing for greater CO_2 storage capacity.

Additionally, the use of surfactants can reduce surface tension and improve CO_2 flow into the coal matrix, increasing storage efficiency [150–153].

In summary, the injection rate is a critical factor in determining the effectiveness of CO_2 storage in coal seams. The optimal range of injection rates is between 0.1 and 1.0 metric tons per day per well. Researchers are exploring various techniques to improve injection rates, including hydraulic fracturing and surfactants, to increase storage capacity while ensuring safety and effectiveness.

c. Efficiency:

The efficiency of CO_2 storage in coal seams is a crucial parameter to consider when evaluating the effectiveness of this carbon storage technique. It is defined as the ratio of the amount of CO_2 stored in the coal seam to the amount of CO_2 injected. Efficiency can be influenced by several factors, including the permeability and porosity of the coal seam, injection rate and the storage method used. Studies have shown that the efficiency of CO_2 storage in coal seams can range from 10% to 70%, with coal seams with higher permeability and porosity generally having higher efficiency for CO_2 storage. The injection rate also plays a crucial role in determining the efficiency, with an optimal rate required to balance storage efficiency and operational safety [154–156].

The CO_2 storage method used can also impact the efficiency of CO_2 storage in coal seams. The dissolution method generally has a higher efficiency than the adsorption method, which stores CO_2 by adhering to the surface of the coal particles. Ongoing efforts are being made to improve the efficiency of CO_2 storage in coal seams, including the use of surfactants to increase the CO_2 solubility in the coal seam fluids and hydraulic fracturing to increase permeability and porosity. Monitoring technologies are also advancing to ensure that the injected CO_2 remains safely and effectively stored within the coal seams. In conclusion, careful management and monitoring are crucial to ensure safe and effective CO_2 storage in coal seams, and efforts to improve the efficiency of this storage method are ongoing [157,158].

When CO_2 is injected into the coal seam, it can displace methane from the coal matrix, making it available for extraction. However, not all of the injected CO_2 is consumed in this process. Some of the CO_2 remains in the coal seam and can adsorb onto the coal matrix, effectively storing carbon in the formation. The adsorption of CO_2 onto coal surfaces can occur through several mechanisms, including physisorption and chemisorption. Physisorption occurs when CO_2 molecules are attracted to the coal surface through weak intermolecular forces, such as Van der Waals forces. Chemisorption occurs when CO_2 molecules react with functional groups on the coal surface to form more stable chemical bonds. The amount of CO_2 that can be stored in the coal seam through adsorption depends on several factors, including the coal seam characteristics (such as porosity and permeability), the injection rate and pressure of the CO_2, and the composition of the coal itself.

d. Residual trap:

Residual trapping is a crucial process for storing CO_2 in coal seams over the long term. It involves the trapping of CO_2 in the coal matrix due to capillary forces, surface adsorption and dissolution in the coal seam fluids. The residual trapping capacity of a coal seam is influenced by several factors, such as injection rate, coal seam properties, and the CO_2 storage method used. Studies have demonstrated that residual trapping can account for up to 60% of the total CO_2 storage in coal seams. The amount of CO_2 that can be stored through residual trapping is affected by the permeability and porosity of the coal seam, which determines the ability of CO_2 to flow through the coal matrix and be stored within it. Coal seams with higher permeability and porosity tend to have a higher residual trapping capacity [159–161].

Injection rate is another factor that can affect the residual trapping capacity of a coal seam. A slow injection rate can improve the amount of CO_2 stored through residual trapping by giving more time for CO_2 to be absorbed by the coal matrix. However, a slow injection rate can also limit the overall amount of CO_2 that can be stored. The residual trapping capacity of a coal seam is also impacted by the CO_2 storage method used. The adsorption method, where CO_2 is stored by adhering to the surface of the coal particles, tends to have a higher residual trapping capacity than the dissolution method, where CO_2 is stored by dissolving into the coal seam fluids. Researchers are exploring several techniques to optimize residual trapping as a CO_2 storage mechanism in coal seams. These techniques include hydraulic fracturing to increase the permeability and porosity of the coal seam and using surfactants to enhance CO_2 solubility in the coal seam fluids. Advanced monitoring technologies can also help ensure that CO_2 remains safely and effectively stored within the coal seams [156].

In conclusion, residual trapping is a crucial process for the long-term storage of CO_2 in coal seams. The residual trapping capacity is influenced by several factors, such as injection rate, coal seam properties and CO_2 storage method. Ongoing research and development efforts are focused on optimizing residual trapping as a CO_2 storage mechanism in coal seams to ensure the safe and effective storage of this greenhouse gas [162].

e. Safety risks and mitigations:

One significant safety risk is groundwater contamination. Injecting CO_2 into a coal seam can displace natural gas and release saline-produced water that may contain contaminants, thus threatening groundwater quality. To mitigate this risk, measures, such as site selection, water quality monitoring and injection pressure regulation, are employed. Another risk is induced seismicity caused by CO_2 injection that can lead to coal seam fractures. To minimize this risk, injection pressure and rate are closely monitored, and injection wells are placed away from active faults [163,164].

CO_2 leakage is also a concern. Leakage can occur due to natural fractures or drilling activities, posing health and environmental risks. To address this, monitoring and verification measures, including continuous pressure and temperature monitoring and CO_2 concentration measurement, are usually implemented. Subsidence caused by CO_2 storage in coal seams is also a potential risk. Careful injection rate control and well placement away from vital infrastructure can help mitigate this risk [165,166].

In conclusion, CO_2 storage in coal seams is a promising technology for mitigating greenhouse gas emissions, but safety risks need to be addressed. Careful site selection, monitoring and regulation of injection pressure and rate can effectively mitigate these risks.

f. Containment and Integrity:

Carbon capture and storage (CCS) in coal seams is a promising method for reducing greenhouse gas emissions and mitigating climate change. However, there are potential containment and integrity issues associated with CO_2 storage in coal seams that need to be carefully addressed. One of the main concerns with CO_2 storage in coal seams is the potential for leakage. CO_2 can migrate through the cleats and fractures in the coal seams and find pathways to the surface, potentially leading to environmental, health and safety hazards. Therefore, it is crucial to ensure that the CO_2 remains safely contained in the coal seam for the long term.

Another concern is the potential impact of CO_2 on the integrity of the coal seam. CO_2 injection can change the physical and chemical properties of the coal seam, such as its permeability and porosity, which can affect the structural integrity of the coal seam over time. This can lead to potential subsurface instability and induced seismicity, which could cause environmental and social concerns [167].

To address these concerns, various measures are being implemented to ensure the containment and integrity of CO_2 storage in coal seams. These include:

Site Selection: Careful site selection is essential to identify suitable coal seams that can safely and effectively contain CO_2 for the long term. Coal seams that have good sealing properties, low permeability and a thick overburden are preferred [168].

Site Characterization: Comprehensive site characterization studies are performed to assess the geological and hydrological characteristics of the coal seam, including its permeability, porosity, cleat network and subsurface conditions, to ensure that the site is suitable for CO_2 storage [169].

Injection Strategies: Injection strategies are optimized to ensure that the CO_2 is safely and efficiently injected into the coal seam. This includes selecting the appropriate injection rate, pressure and location to maximize CO_2 storage and minimize the risk of leakage [170].

Monitoring and Verification: Continuous monitoring and verification of the coal seam are critical to detect any potential leakage or changes in subsurface conditions that could indicate a problem. This includes monitoring the pressure, temperature and composition of the coal seam and surrounding areas to ensure that the CO_2 remains safely contained [169].

Closure and Post-Closure Monitoring: After the CO_2 injection is complete, the site is closed, and post-closure monitoring is performed to ensure that the coal seam remains stable and that there are no leaks or other integrity issues.

In summary, CO_2 storage in coal seams can be a safe and effective method for CCS, but it requires careful consideration and management of containment and integrity issues. Proper site selection, site characterization, injection strategies, monitoring and verification, and closure and post-closure monitoring are essential to ensure the long-term safety and effectiveness of CO_2 storage in coal seams.

g. Potential to Improve:

Carbon dioxide (CO_2) storage in coal seams is a promising approach for carbon capture and storage (CCS) due to the high storage potential of coal seams. Improving the capacity and effectiveness of CO_2 storage in coal seams is essential to mitigate climate change and decrease greenhouse gas emissions. Here are several methods for enhancing CO_2 storage in coal seams. Various novel techniques can be applied to enhance the CO_2 storage potential of coal seams [150].

2.4. Basaltic Formation

Basalt formations are geological formations composed of volcanic rocks that can be found on land as well as in the oceanic crust. They are formed when magma from volcanic eruptions cools and solidifies, resulting in a dense, fine-grained rock that is highly permeable. Basalt formations have gained interest in recent years as a potential option for CO_2 storage due to their high reactivity with CO_2, which can lead to mineralization and permanent storage of CO_2 [171,172].

2.4.1. Mechanism of CO_2 Storage in Basaltic Formations

The sequestration of carbon dioxide (CO_2) in basaltic formations involves mineral carbonation, a complex chemical process where CO_2 reacts with minerals in the basalt to form stable carbonates. The reactions that take place can be represented by the following equations [46,173]:

CO_2 (g) + H_2O (l) ↔ H_2CO_3 (aq)—Initial dissolution of CO_2 in water.

H_2CO_3 (aq) ↔ H+ (aq) + HCO_3^- (aq)—Carbonic acid dissociation.

HCO_3^- (aq) ↔ CO_3^{2-} (aq) + H^+ (aq)—Formation of bicarbonate.

CO_3^{2-} (aq) + Ca^{2+} (aq) + Mg^{2+} (aq) + $2SiO_2$ (s) → $CaMg(SiO_3)_2$ (s) + $2CO_3^-$ (aq)—Reaction with calcium and magnesium silicates in basalt.

Upon injection into the basaltic formation, CO_2 reacts with water to form carbonic acid, which breaks down into bicarbonate ions. These bicarbonate ions react with calcium and magnesium silicates in the basalt to form solid carbonates, such as calcium magnesium silicate ($CaMg(SiO_3)_2$), effectively trapping the CO_2 underground. Physical trapping of CO_2 also occurs in the porous and permeable spaces within the basaltic rock [174].

Continued research is being conducted to optimize the CO_2 storage process by accelerating mineral carbonation reactions and enhancing physical trapping. Nonetheless, this technique has immense potential to reduce greenhouse gas emissions and mitigating climate change.

2.4.2. M.H. Rating System Parameters for Basalt

a. CO_2 storage capacity:

Basalt formations have emerged as a viable option for storing CO_2 due to their high storage capacity and ability to permanently mineralize CO_2. The CO_2 storage capacity of basalt formations is influenced by various factors, including the porosity, permeability, depth and thickness of the rock. Studies by the U.S. Department of Energy's National Energy Technology Laboratory estimate that the total CO_2 storage capacity of the Columbia River Basalt Group in the United States ranges from 100 to 600 gigatons of CO_2. For perspective, the annual global CO_2 emissions from human activities in 2019 were around 36 gigatons. Thus, the Columbia River Basalt Group alone can store several times the yearly amount of CO_2 emissions from human activities [175,176].

The porosity and permeability of basalt formations are critical to their storage capacity. Basalt formations undergo mineral carbonation, a unique process in which they react with CO_2 to create solid carbonate minerals. The porosity and permeability of the basalt allow CO_2 to penetrate the rock, react with minerals and become permanently stored. Moreover, solid carbonate minerals take up additional space within the rock, increasing storage capacity. The depth and thickness of basalt formations also impact their storage capacity. In general, deeper formations have higher storage capacity due to greater pressure and higher CO_2 adsorption capacity at depth. Moreover, thicker formations provide a larger storage volume, which enhances overall storage capacity [177,178].

However, it is important to note that not all basalt formations are suitable for CO_2 storage, as porosity and permeability can vary widely depending on site-specific characteristics. Nonetheless, basalt formations have the potential to play a critical role in CO_2 storage efforts, particularly in areas where conventional storage options may not be feasible.

b. Injection Rates:

The injection rate plays a crucial role in CO_2 storage in basalt formations. The injection rate measures the rate of CO_2 injection into the formation in tons per day, and its optimization is crucial for maximizing storage capacity while ensuring safe and effective storage. The injection rate can vary widely depending on the formation characteristics and project requirements, ranging from less than 1 ton per day to over 1000 tons per day. Several factors influence the injection rate, including the thickness of the basalt layers, the permeability of the formation and the pressure capacity of the formation. Higher injection rates can lead to more CO_2 being stored in a shorter time, but excessive injection rates can pose risks, such as formation fracturing or CO_2 leakage. Therefore, it is essential to determine the optimal injection rate for each storage project to balance efficiency and safety [176,179]. To determine the optimal injection rate, computer simulations are commonly used to model CO_2 behavior within the basalt formation. These simulations consider factors, such as the flow properties of the formation and the chemical reactions between CO_2 and minerals within the basalt. The results of these simulations can provide insights into the ideal injection rate for a particular storage project [180].

In conclusion, optimizing the injection rate is critical to successful and safe CO_2 storage in basalt formations. Ongoing research and development efforts are aimed at optimizing injection rates for CO_2 storage in basalt formations to ensure that greenhouse gases are stored safely and effectively.

c. Efficiency:

Efficiency plays a crucial role in the successful storage of CO_2 in basalt formations. The efficiency of CO_2 storage refers to the amount of CO_2 that can be stored in the formation compared to the amount of CO_2 injected. Higher efficiency means that more CO_2 is stored in the formation, leading to better greenhouse gas mitigation outcomes. Studies have shown that the efficiency of CO_2 storage in basalt formations can range from 10% to 90%, depending on the specific storage project and the characteristics of the formation. The permeability of the formation, the thickness of the basalt layers and the pressure capacity of the formation are factors that can influence efficiency [181].

Several methods can be employed to improve the efficiency of CO_2 storage in basalt formations. For instance, optimizing the injection rate and pressure can help enhance efficiency. Another method is using supercritical CO_2, which has a higher density and can penetrate the porous basalt formation better. Additionally, adding trace metals to the CO_2 stream can improve CO_2 reactivity, which increases the amount of CO_2 that reacts with the minerals in the basalt, thereby improving efficiency. Computer simulations are also used to optimize the efficiency of CO_2 storage in basalt formations. These simulations take into account several factors, such as the flow properties of the formation, the chemical reactions that occur between the CO_2 and the minerals within the basalt and the effect of temperature and pressure. The simulations aid in determining the optimal injection rate, pressure and CO_2-rock interactions for a specific storage project.

In summary, the efficiency of CO_2 storage in basalt formations is a critical factor in greenhouse gas mitigation efforts. The efficiency can be improved by optimizing the injection rate, pressure and CO_2-rock interactions. Ongoing research and development efforts are focused on optimizing the efficiency of CO_2 storage in basalt formations to ensure the safe and effective storage of this greenhouse gas.

d. Residual trap:

The trapping of CO_2 residually in basalt formations is a method that still needs some exploring. Unlike solubility and mineral trapping, which involve chemical reactions between CO_2 and minerals in the formation, residual trapping refers to the CO_2 that is physically trapped in the pore spaces of the basalt and cannot move or escape. Research has shown that residual trapping can account for up to 30% of the total CO_2 stored in basalt formations, making it a significant factor in storage efficiency. The amount of CO_2 trapped residually is dependent on factors, such as the permeability, thickness and pressure capacity of the formation. To predict the amount of CO_2 trapped residually, computer simulations are frequently employed. These simulations consider flow properties, chemical reactions and the impact of temperature and pressure to model CO_2 behavior within the basalt formation accurately. Additionally, other trapping mechanisms, such as solubility and mineral trapping, can also contribute to the total amount of CO_2 stored [182,183].

Overall, residual trapping plays a vital role in storing CO_2 efficiently in basalt formations. Computer simulations are an essential tool for optimizing injection rates and pressure and predicting the amount of CO_2 trapped residually. Ongoing research and development efforts aim to enhance our understanding of residual trapping and other trapping mechanisms to ensure safe and effective CO_2 storage in basalt formations.

e. Safety risks and mitigations:

Storing CO_2 in basaltic formations shows promise as a solution to reduce greenhouse gas emissions, but it also poses safety concerns that require careful consideration and mitigation. Leakage of CO_2 is a primary risk that can occur naturally or from human activities, such as drilling or earthquakes, and it can endanger human health and the environment. To prevent leakage, monitoring techniques, such as pressure, temperature and CO_2 concentration checks, are implemented, and modeling tools are used to detect potential leakage pathways [184].

Another hazard associated with CO_2 storage in basaltic formations is induced seismicity, which can cause harm to human life and infrastructure and compromise the integrity of the storage area. To prevent this, injection rates and pressures are monitored and controlled, and injection wells are placed away from areas with a high seismic hazard. Additionally, modeling and simulation tools are employed to predict and detect seismic events and optimize injection operations [180].

Overall, enhancing CO_2 storage in basaltic formations requires a combination of careful site selection, optimized injection and monitoring techniques, pre-treatment of the basaltic formation, co-injection of other gases, EOR and appropriate site management practices. These efforts can help maximize the potential of CO_2 storage in clastic formations for effective carbon capture and storage.

f. Containment and Integrity:

CO_2 storage in basaltic formations is an emerging method for CCS due to the high storage potential and mineralization potential of basalt. However, there are potential containment and integrity issues associated with CO_2 storage in basaltic formations that must be carefully addressed [185,186].

One concern is the potential for CO_2 leakage due to the natural fractures and permeability of basalt. Basaltic formations can have complex fracture networks that can create pathways for CO_2 to migrate out of the storage formation. Additionally, the chemical composition of basalt can make it more susceptible to mineral dissolution, which can further increase the potential for leakage. Therefore, it is crucial to ensure that the CO_2 remains safely contained in the basaltic formation for the long term. Another potential issue is the risk of induced seismicity or earthquakes caused by human activities, such as CO_2 injection. The injection of large volumes of CO_2 into basaltic formations can cause changes in pore pressure and potentially trigger earthquakes. Careful management of injection pressure and monitoring of seismic activity can help mitigate this risk [187].

Furthermore, CO_2 injection can potentially impact the quality of the surrounding groundwater. In basaltic formations, groundwater is typically found within the fractures and pores of the rocks. The injection of CO_2 can potentially impact the pH and mineral content of the surrounding groundwater. It is important to carefully monitor and manage any potential impacts on groundwater quality. Lastly, the long-term integrity of the storage site must be considered. Over time, the storage formation may experience changes in pressure and temperature, which can affect the structural integrity of the formation. Appropriate site management practices, such as regular monitoring and maintenance, can help ensure the long-term integrity of the storage site.

Overall, the containment and integrity issues associated with CO_2 storage in basaltic formations require careful consideration and management to ensure safe and effective carbon capture and storage. The development of appropriate regulations and best practices can help mitigate these risks and promote the widespread adoption of CCS technologies in basaltic formations.

g. Potential to improve:

Carbon capture and storage (CCS) is a promising technology for reducing greenhouse gas emissions and mitigating climate change. Basaltic formations are considered a potential storage option for CO_2 due to their high capacity for mineralization. Mineralization is the process by which CO_2 reacts with minerals in the rock formation, forming stable carbonates and thereby reducing the risk of CO_2 leakage over the long term. Here are some ways that CO_2 storage in basaltic formations can be enhanced [185,188–190]:

Site selection: Choosing the appropriate site for CO_2 storage is crucial for successful storage. Basaltic formations with high permeability and reactive minerals are ideal for CO_2 mineralization. Additionally, the site should be located in close proximity to CO_2 sources to reduce transportation costs.

CO_2 injection and monitoring: The injection of CO_2 into the basaltic formation can be optimized by adjusting the injection rate, pressure and location. Additionally, monitoring of the CO_2 injection and mineralization process can help identify potential leakage and optimize the storage process.

Stimulating mineralization: Basaltic formations can be stimulated to increase the rate of mineralization through various methods, such as adding reactive minerals or nutrients to the CO_2 stream, injecting brines to enhance mineral dissolution, or using microorganisms to promote mineralization. These methods can help accelerate the formation of stable carbonates and increase the long-term storage capacity of the basaltic formation.

Hydraulic fracturing: Hydraulic fracturing, or "fracking," can be used to create artificial fractures in the basaltic formation, which can increase its permeability and surface area for mineralization. This method can help enhance CO_2 storage capacity in low-permeability formations and improve mineralization rates.

Co-injection of other gases: Co-injection of other gases, such as oxygen and hydrogen sulfide, with CO_2 can help enhance CO_2 mineralization rates by increasing the pressure and creating a more reactive environment within the basaltic formation.

Post-injection site management: Once CO_2 injection is complete, it is crucial to monitor the site for potential leakage and ensure the CO_2 remains safely stored in the basaltic formation for the long term. Appropriate site management practices, such as regular monitoring and maintenance, can help ensure the long-term integrity of the storage site.

Overall, enhancing CO_2 storage in basaltic formations requires a combination of careful site selection, optimized injection and monitoring techniques, stimulating mineralization, hydraulic fracturing, co-injection of other gases and appropriate site management practices. These efforts can help maximize the potential of CO_2 storage in basaltic formations for effective carbon capture and storage.

2.5. Clastic Formation

Sandstone (clastic rock) formations are sedimentary rocks consisting of sand-sized mineral particles, which are typically composed of quartz, feldspar, mica and other minerals. They are one of the most common reservoir rocks in the subsurface and are often targeted for oil and gas exploration and production. Sandstone formations can also be suitable for carbon dioxide (CO_2) storage due to their porosity and permeability, which can allow for the injection and storage of CO_2 [191,192].

2.5.1. Mechanism for CO_2 Storage in Clastic Formation

CO_2 storage in clastic formations involves a distinct process called geochemical trapping. Clastic formations, which include sandstones, contain a complex structure of various minerals, such as quartz, feldspar, and clay minerals. Once CO_2 is injected into these formations, it interacts with the minerals and undergoes various chemical reactions, which result in immobilization and long-term storage of the CO_2, as shown in Figure 4. The primary mechanism for CO_2 storage in clastic formations is mineral dissolution and precipitation. The CO_2 injected reacts with the water present in the formation to form carbonic acid, which then dissolves the minerals. The dissolved minerals react with bicarbonate ions produced during the carbonic acid dissociation to form solid carbonates, thereby trapping CO_2 in a mineral form.

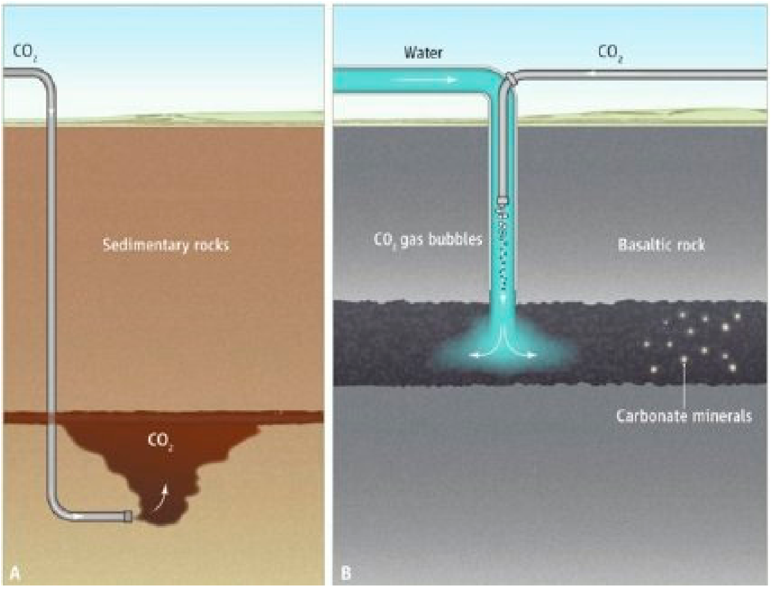

Figure 4. Mechanism for CO_2 storage in (**A**) Clastic Formation (Sedimentary Rock) and (**B**) Basaltic Formations [193].

The mineral dissolution and precipitation reactions can be represented by the following equations [194]:

CO_2 (g) + H_2O (l) $\leftrightarrow$ H_2CO_3 (aq)

H_2CO_3 (aq) $\leftrightarrow$ H^+ (aq) + HCO_3^- (aq)

$XSiO_2$ (s) + $2H^+$ (aq) + H_2O (l) $\leftrightarrow$ H_4SiO_4 (aq) + X^{2-} (aq)

X^{2-} (aq) + CO_2 (g) + H_2O (l) $\rightarrow$ XCO_3 (s) + $2H^+$ (aq)

Here, X represents any mineral in the formation, such as feldspar or quartz. The overall process involves mineral dissolution and precipitation, resulting in permanent CO_2 immobilization in a mineral form.

In addition to mineral dissolution and precipitation, physical trapping of CO_2 occurs in the pore spaces of clastic formations. The porous and permeable nature of these formations allows for CO_2 to be physically trapped within the rock's pore spaces, contributing to the overall storage capacity of the formation.

Research into CO_2 storage in clastic formations is ongoing, and scientists are developing techniques to optimize the process, including improving mineral dissolution and precipitation reactions and enhancing the physical trapping of CO_2. Despite ongoing research, this technique has the potential to significantly contribute to reducing greenhouse gas emissions and mitigating climate change.

2.5.2. M.H. Rating System Parameters for Clastic Formation (Sandstone)

a. CO_2 storage capacity for clastic formations:

Sandstones and conglomerates, known as clastic formations, have significant potential as CO_2 storage options due to their widespread occurrence and high storage capacity. The storage capacity of clastic formations is affected by several factors, including the thickness and depth of the formation, as well as the porosity and permeability of the rock. In the United States alone, clastic formations are estimated to have a total CO_2 storage capacity of between 2600 and 20,000 gigatons of CO_2, according to the United States Geological Survey. To put this in perspective, global CO_2 emissions from human activities in 2019 were approximately 36 gigatons, indicating that clastic formations in the United States alone have the potential to store several times the amount of CO_2 emissions from human activities to date [195].

The storage capacity of clastic formations is influenced by their porosity and permeability. In general, formations with higher porosity and permeability have higher storage capacity, as CO_2 has more space to be stored and can move more easily through the rock. Additionally, the mineral composition of the formation plays a role in CO_2 storage capacity, as certain minerals can react with CO_2 and store it permanently. The thickness of clastic formations is also a crucial factor in their storage capacity. Thicker formations provide more storage volume, which increases their overall storage capacity. However, thicker formations may be more complex and heterogeneous, which can make CO_2 storage more challenging. When assessing the CO_2 storage potential of clastic formations, it is essential to consider site-specific characteristics, such as local geology, the presence of faults or fractures and proximity to potential sources of CO_2 emissions. While clastic formations have the potential for high storage capacity, their suitability for CO_2 storage depends on several factors specific to each site.

b. Injection rates:

Injection rates can affect CO_2 storage efficiency, and the optimal injection rate depends on the characteristics of the formation. Computer simulations can determine the optimal injection rate by considering the flow properties of the formation and the chemical reactions that occur between CO_2 and minerals in the formation. Studies have revealed that injection rates can vary widely based on the type of clastic formation and the storage project. For example, injection rates for CO_2 storage in clastic formations can range from 1 to 1000 metric tons per day. However, lower injection rates are generally preferred to improve storage efficiency and reduce the risk of leaks and fractures [196–198].

Adjusting the pressure and flow rates of the injection well and improving the permeability and porosity of the formation can optimize injection rates. Hydraulic fracturing can increase the permeability of the formation and improve the efficiency of CO_2 storage, but it also carries risks and may not be suitable for all storage projects [199].

In conclusion, injection rates must be optimized for each storage project in clastic formations to ensure CO_2 storage efficiency and minimize the risk of leaks and fractures. The optimal injection rate depends on the characteristics of the formation and the specific storage goals, and computer simulations and other optimization techniques can help determine the optimal injection rate.

c. Efficiency:

The storage efficiency of CO_2 in clastic formations is a crucial factor in carbon capture and storage (CCS) projects, indicating the percentage of injected CO_2 that is retained within the formation over time. Storage efficiency depends on various factors, such as injection rates, reservoir properties and storage mechanisms. Studies have revealed that efficiency can range from 10% to 90%, depending on the specific storage project and the characteristics of the formation. Higher storage efficiency is preferred as it indicates more CO_2 is being retained within the formation and less is being released into the atmosphere. Efficiency can be influenced by several factors, including the permeability and porosity of the formation, reservoir pressure and temperature, and the type of storage mechanism employed. Storage mechanisms, such as residual trapping and solubility trapping can enhance storage efficiency by physically or chemically trapping the CO_2 within the formation. Conversely, buoyancy trapping and capillary trapping can decrease storage efficiency by enabling CO_2 to migrate towards the surface or become stuck in small pores [200,201].

Optimizing injection rates, pressure and flow rates, as well as improving the permeability and porosity of the formation, can improve efficiency. Hydraulic fracturing is an example of a technique that can improve permeability and enhance storage efficiency. Research and development efforts continue to focus on improving our understanding of storage mechanisms and developing new technologies to boost storage efficiency [202].

In conclusion, storage efficiency plays a critical role in the success of CCS projects. Efficiency can vary depending on several factors, but optimizing injection rates and pressure, improving formation permeability and porosity and using appropriate storage mechanisms can improve efficiency. Ongoing research and development efforts will be necessary to advance our understanding of storage mechanisms and develop new technologies to enhance efficiency.

d. Residual trap:

Residual trapping is a physical mechanism that is used for storing CO_2 in clastic formations. It involves the physical trapping of CO_2 within the pore spaces of sedimentary rock formations, such as sandstone or shale, preventing it from migrating and potentially leaking back into the atmosphere. Residual trapping can be a very effective method for storing CO_2 in clastic formations, particularly when combined with other trapping mechanisms, such as solubility and mineral trapping [23,203]. Studies have demonstrated that residual trapping can account for a significant portion of the total CO_2 storage in clastic formations. Researchers estimated that residual trapping accounted for approximately 35% of the total CO_2 storage in a sandstone formation over a period of 10 years. The efficiency of residual trapping can be affected by several factors, including the permeability and porosity of the formation, the size and shape of the pores and the pressure and temperature of the reservoir. Generally, higher permeability and porosity can improve the efficiency of residual trapping by providing more pore space for the CO_2 to occupy. Thus, optimizing these factors can help enhance the efficiency of CO_2 storage in clastic formations through residual trapping [204].

e. Safety risks and mitigations:

One of the significant concerns associated with CO_2 storage in clastic formations is the risk of stored CO_2 leakage back into the atmosphere, which can be harmful to human health and the environment. Leakage can occur naturally through fractures or faults in the formation or due to human activities such as drilling or earthquakes. To mitigate this risk, several monitoring and verification measures are typically implemented. Continuous monitoring of the pressure and temperature of the reservoir and periodic measurement of the CO_2 concentration in the storage formation and surrounding areas are employed. Additionally, modeling and simulation tools are used to detect potential leakage pathways and optimize storage operations [124,205].

Another safety risk associated with CO_2 storage in clastic formations is the potential for induced seismicity. Induced seismicity refers to earthquakes triggered by human activities, such as drilling or injection of fluids into the formation. Induced seismicity can pose a risk to human safety and infrastructure and compromise the integrity of the storage formation, leading to CO_2 leakage. To mitigate this risk, injection rates and pressures are closely monitored and controlled. Injection wells are typically placed away from active faults or other high seismic hazard areas, and modeling and simulation tools are used to predict and detect potential seismic events and optimize injection operations.

In conclusion, CO_2 storage in clastic formations has significant potential for reducing greenhouse gas emissions. However, the safety risks associated with CO_2 storage must be considered and appropriately mitigated. Monitoring and verification measures, control of injection rates and pressures, proper equipment design and maintenance and training and procedures for handling and transporting CO_2 are crucial in ensuring safe and effective CO_2 storage in clastic formations.

f. Containment and Integrity:

Carbon capture and storage (CCS) is a crucial solution for reducing greenhouse gas emissions and mitigating climate change. Clastic formations, including sandstone and shale, offer high storage potential for CO_2 storage, but there are containment and integrity concerns that require careful attention. One concern is the potential for CO_2 leakage due to natural fractures and the permeability of clastic formations. This can occur through poorly sealed wellbores, faults and fractures, resulting in atmospheric CO_2 leakage. It is essential to ensure that CO_2 remains safely contained in the clastic formation to avoid this risk [206].

Another issue is the possibility of induced seismicity, which can lead to earthquakes due to human activities, including CO_2 injection. Injection can cause increased pore pressure and lead to rock fracturing, triggering earthquakes. Management of injection pressure and seismic activity monitoring can help reduce this risk. Moreover, the injection of CO_2 can impact the quality of groundwater in clastic formations. Since groundwater is present within the pore spaces of rocks in clastic formations, CO_2 injection may affect the pH and mineral content of the groundwater. Close monitoring and management of potential impacts on groundwater quality are crucial. Lastly, long-term site integrity is critical. Over time, pressure and temperature changes in the storage formation can affect its structural integrity. Appropriate site management practices, including regular monitoring and maintenance, can help ensure the long-term integrity of the storage site [207].

In conclusion, the containment and integrity issues associated with CO_2 storage in clastic formations require careful management and consideration to guarantee effective and safe carbon capture and storage. The establishment of suitable regulations and best practices can help minimize these risks and promote the widespread use of CCS technologies.

g. Potential to improve:

Carbon capture and storage (CCS) in clastic formations, such as sandstone and shale, is a promising method for mitigating climate change and reducing greenhouse gas emissions. Enhancing the capacity and efficiency of CO_2 storage in clastic formations can help maximize the potential of CCS. Here are some ways that CO_2 storage in clastic formations can be enhanced [208,209]:

Site selection: Choosing the appropriate site for CO_2 storage is crucial for successful storage. The clastic formation should have high porosity and permeability, allowing for efficient CO_2 injection and storage. Additionally, the site should be located in close proximity to CO_2 sources to reduce transportation costs.

CO_2 injection and monitoring: The injection of CO_2 into the clastic formation can be optimized by adjusting the injection rate, pressure and location. Additionally, monitoring the CO_2 injection and storage process can help identify potential leakage and optimize the storage process.

Pre-treatment of the clastic formation: Pre-treatment of the clastic formation can increase the CO_2 storage capacity by increasing the surface area of the rock particles. Techniques, such as acidification, fracturing or stimulation of the formation can increase its surface area, allowing for more efficient adsorption of CO_2 molecules.

Co-injection of other gases: Co-injection of other gases, such as nitrogen and methane, with CO_2 can help enhance CO_2 storage by reducing the adsorption of CO_2 molecules onto the rock surface, allowing for more CO_2 storage capacity.

This is because the injection of other gases can help to increase the overall volume of the subsurface reservoir and create additional pore space for CO_2 storage. Additionally, some gases can act as displacement agents, pushing the CO_2 into areas of the reservoir where it can be more effectively trapped and stored.

Enhanced Oil Recovery (EOR): The injection of CO_2 into clastic formations can also enhance the recovery of oil by displacing the oil and reducing its viscosity. This can result in a dual benefit of increasing CO_2 storage capacity while also increasing oil production.

Post-injection site management: Once CO_2 injection is complete, it is crucial to monitor the site for potential leakage and ensure the CO_2 remains safely stored in the clastic formation for the long term. Appropriate site management practices, such as regular monitoring and maintenance, can help ensure the long-term integrity of the storage site.

3. Analysis of M.H. Rating System Parameters

The individual analysis of all parameters of the M.H. rating system has been carried out in this section which will be the foundation of the development of the full-fledged M.H. rating scale for categorizing geological formation for CO_2 storage.

a. CO_2 storage capacity (Storage scale)

The CO_2 storage capacity of all geological formations has been compared on a scale of one–five, where one stands for low storage capacity, while five corresponds to the highest storage capacity. From Table 1, it can be seen that deep saline aquifers and basalt formations have a high storage capacity as compared to coal seams which ranked lowest in the storage scale.

b. Injection rates (Injectivity scale)

Injection rates favored by all geological formations have been compared on a scale of one–five, where one stands for low injection rates while five corresponds to the high injection rate. From Table 2, it is seen that deep saline aquifers and basalt formations can favor high injection rates as compared to coal seams and sandstones which ranked lowest in the injectivity scale

c. Efficiency (Efficiency scale)

CO_2 storage efficiency of all geological formations has been compared on a scale of one–five, where one stands for low efficiency, while five corresponds to the highest efficiency. From Table 3, it is seen that deep saline aquifers and basalt formations have high CO_2 storage efficiency as compared to coal seams which ranked lowest in the injectivity scale.

d. Residual trapping (trapping scale)

Residual trapping of all geological formations has been compared on a scale of one–five, where one stands for low residual trapping, while five corresponds to the highest residual trapping. From Table 4, it is seen that deep saline aquifers have high residual trapping as compared to basaltic formations, which have the lowest residual trapping.

Table 1. Comparison of CO_2 storage capacity rating for geological formations.

Formation Type	CO_2 Storage Capacity Rating	Justification
Deep Saline Aquifers	5	Deep saline aquifers have the highest CO_2 storage capacity due to their large pore spaces and extensive underground storage volume. They can store CO_2 in both dissolved and supercritical forms.
Depleted Reservoirs	3	Depleted reservoirs have moderate CO_2 storage capacity due to their reduced pore spaces and lower storage volume compared to saline aquifers. However, their previous use for oil or gas storage may have left them with infrastructure for CO_2 injection.
Coal Seams	2	Coal seams have limited CO_2 storage capacity due to their low permeability, which makes it difficult for CO_2 to migrate into the coal. Additionally, coal seams may also have limited storage volume compared to other formations.
Basaltic Formations	4	Basaltic formations have high CO_2 storage capacity due to their extensive storage volume and ability to trap CO_2 through mineralization. Basalt can react with CO_2 to form carbonate minerals, which can permanently store the CO_2.
Clastic Formations	3	Clastic formations have moderate CO_2 storage capacity due to their moderate pore spaces and storage volume. However, their permeability may vary, which can affect CO_2 migration and storage. Clastic formations may also be associated with oil or gas reservoirs, which can affect CO_2 storage.

Table 2. Comparison of CO_2 storage injectivity rating for geological formations.

Formation Type	Injection Rate Rating	Justification
Deep Saline Aquifers	5	Deep saline aquifers have the highest injection rates due to their large storage volume and high permeability, which allows for rapid CO_2 injection. Additionally, the saline water in these aquifers can help to dissolve the CO_2, allowing for faster injection and storage.
Depleted Reservoirs	4	Depleted reservoirs have a high injection rate potential due to their existing infrastructure for fluid injection. However, their reduced permeability compared to saline aquifers may limit the injection rate. The previous use for oil or gas storage may have left them with infrastructure for CO_2 injection.
Coal Seams	3	Coal seams have lower injection rates compared to saline aquifers and depleted reservoirs due to their low permeability. However, injection rates may be increased through hydraulic fracturing or other stimulation techniques.
Basaltic Formations	4	Basaltic formations have a high potential for CO_2 injection. However, the mineralization process may also limit the injection rate, as the CO_2 needs to react with the basalt to form carbonate minerals.
Clastic Formations	3	Clastic formations have moderate injection rates due to their moderate permeability, which can limit the rate of CO_2 injection. Additionally, their association with oil or gas reservoirs may also limit the injection rate due to potential for reservoir damage. However, some clastic formations may have higher permeability and injection rates.

Table 3. Comparison of CO_2 storage efficiency rating for geological formations.

Formation Type	CO_2 Storage Efficiency Rating	Justification
Deep Saline Aquifers	4	Deep saline aquifers have a high CO_2 storage efficiency due to their large storage volume and ability to store CO_2 for long periods of time. However, there is some potential for CO_2 leakage due to their permeability, and some of the stored CO_2 may eventually dissolve into the saline water, reducing efficiency.
Depleted Reservoirs	3	Depleted reservoirs have moderate CO_2 storage efficiency due to their existing infrastructure for fluid injection and potential for long-term storage. However, their reduced permeability compared to saline aquifers may limit the storage efficiency, and the previous use for oil or gas storage may have left them with infrastructure that is not optimized for CO_2 storage, reducing efficiency.
Coal Seams	2	Coal seams have lower CO_2 storage efficiency compared to saline aquifers and depleted reservoirs due to their lower porosity and limited storage volume. Additionally, some CO_2 stored in coal seams may eventually be released due to the high pressure that is necessary for CO_2 injection, reducing efficiency.

Table 3. *Cont.*

Formation Type	CO_2 Storage Efficiency Rating	Justification
Basaltic Formations	4	Basaltic formations have a high potential for CO_2 storage efficiency due to their ability to mineralize CO_2, which can reduce the risk of CO_2 leakage over time. However, the mineralization process can be slow or rapid depending upon the conditions of T and P, which may limit the storage efficiency.
Clastic Formations	3	Clastic formations have moderate CO_2 storage efficiency due to their moderate porosity and permeability. However, their association with oil or gas reservoirs may limit the storage efficiency, and their storage efficiency may also be limited by potential reservoir damage.

Table 4. Comparison of CO_2 storage trapping rating for geological formations.

Formation Type	CO_2 Storage Residual Trap Rating	Justification
Deep Saline Aquifers	5	Deep saline aquifers have a high potential for residual trapping, with estimates indicating that up to 95% of injected CO_2 can be permanently stored in these formations. The cap rock acts as a physical barrier, trapping CO_2 beneath it, and the CO_2 can also dissolve into the water, reducing the risk of leakage.
Depleted Reservoirs	3	Depleted reservoirs have a moderate potential for residual trapping, with estimates indicating that around 50% of injected CO_2 can be trapped in these formations. Residual trapping occurs as CO_2 is immobilized by capillary forces and chemical reactions with the rock. However, there is still some risk of leakage over the long term.
Coal Seams	4	Coal seams have a high potential for residual trapping, with estimates indicating that up to 80% of injected CO_2 can be trapped in these formations. Residual trapping occurs as CO_2 is trapped in micropores. This type of trapping is relatively stable over the long term, reducing the risk of leakage.
Basaltic Formations	2	Basaltic formations have a lower potential for residual trapping compared to other formations, with estimates indicating that around 30% of injected CO_2 can be trapped in these formations. However, this type of trapping in basalt is not well understood and there is still some risk of leakage over the long term.
Clastic Formations	3	Clastic formations have a moderate potential for residual trapping, with estimates indicating that around 50% of injected CO_2 can be trapped in these formations. Residual trapping occurs as CO_2 is immobilized by capillary forces and chemical reactions with the rock. However, there is still some risk of leakage over the long term, particularly if the rock is fractured.

e. Safety risks and mitigations (Safety scale)

The safety rating scale ranges from one (high risk and high efforts of mitigations) to five (low risk and low values of mitigations), based on the likelihood of CO_2 leakage or potential risks associated with storage methods. It can be seen from Table 5 that deep saline aquifers have the most safety risks, and efforts required to mitigate the risks are also extensive.

Table 5. Comparison of safety rating for geological formations.

Storage Method	Security Risk	Mitigation Efforts	Overall Result	Justification
Deep Saline Aquifers	3	2	2.5	The risk of CO_2 leakage is high due to the uncertain behavior of subsurface fluids. However, monitoring and verification techniques are moderately effective in mitigating risks.
Depleted Reservoirs	3	3	3	The risk of CO_2 leakage is moderate, but the mitigation efforts can be moderately effective, using techniques, such as injection well management and subsurface monitoring.
Coal Seams	2	4	3	The risk of CO_2 leakage is relatively low, but the cost and time efforts required for mitigation can be high. However, the mitigation techniques, such as pressure management and water production, can be very effective.

Table 5. *Cont.*

Storage Method	Security Risk	Mitigation Efforts	Overall Result	Justification
Basalt formations	5	5	5	The risk of CO_2 leakage is very low, and the storage is considered permanent. The mitigation efforts required are minimal as the natural properties of basalt formations offer secure storage.
Clastic formations	3	4	3.5	The risk of CO_2 leakage is moderate, but the mitigation efforts can be very effective, such as enhancing mineral dissolution and physical trapping.

f. Contamination and integrity (Containment scale)

The containment rating scale ranges from one (low containment and integrity) to five (high containment and integrity), based on the likelihood of CO_2 leakage or potential risks associated with storage methods. It can be seen from Table 6 that deep saline aquifers and basalts are the safest options in the context of containment and integrity.

Table 6. Comparison of containment rating for geological formation.

Storage Formation	Contamination and Integrity Issues	Rating (1–5)	Justification
Deep Saline Aquifers	Low	5	Saline aquifers are naturally isolated from the freshwater resources, and their geology typically has low permeability, which reduces the risk of CO_2 leakage.
Depleted Reservoirs	Moderate	3	The risk of CO_2 leakage in depleted reservoirs is higher than deep saline aquifers due to their previous history of hydrocarbon production, which may have caused faults and fractures.
Coal Seams	Moderate	3	The potential for CO_2 leakage from coal seams is higher than deep saline aquifers due to their high permeability and potential for natural fractures. Appropriate site management is crucial.
Basaltic Formations	Low	5	CO_2 injected into these formations reacts with the minerals present, reducing the risk of CO_2 leakage.
Clastic Formations	Moderate to High	2.5	Clastic formations, such as sandstone and shale, have natural fractures and permeability, which increase the risk of CO_2 leakage. Appropriate site management practices are crucial to reduce risk

g. Potential to improve (Potential scale)

The potential rating scale ranges from one (low potential to be improved) to five (high potential to be improved) based on the likelihood of difference storage enhancement methods. It can be seen from Table 7 that deep saline aquifers and basalts have the most potential to be improved.

Table 7. Comparison of potential rating for geological formation.

Formation	Potential for CO_2 Storage Improvement	Justification
Deep saline aquifers	4	There is potential for improvement in storage efficiency through the use of advanced monitoring techniques and modeling tools to better understand the subsurface dynamics and optimize injection strategies. Additionally, the development of new technologies, such as subsurface imaging and flow control devices can help increase storage capacity and enhance long-term storage reliability.
Depleted reservoirs	3	Although depleted reservoirs have already been used for CO_2 storage, there is potential for improvement in storage efficiency by developing new technologies such as optimized well placement and advanced monitoring systems to better characterize the reservoir and improve injection strategies. Additionally, the use of integrated models to predict and optimize reservoir behavior can also help improve storage efficiency.

Table 7. *Cont.*

Formation	Potential for CO_2 Storage Improvement	Justification
Coal seams	2	There is potential for improvement in storage efficiency through the use of enhanced coal bed methane recovery techniques that can help increase storage capacity and reduce leakage. Additionally, the development of new technologies, such as CO_2-ECBM (Enhanced Coal Bed Methane) can potentially increase the overall storage efficiency.
Basaltic formation	4	There is potential for improvement in storage efficiency by developing advanced technologies, such as CO_2-solubility trapping mechanisms to increase storage capacity and long-term storage reliability. Furthermore, improving the understanding of subsurface geology and using advanced monitoring techniques to optimize injection strategies can also increase storage efficiency.
Clastic formation	3	There is potential for improvement in storage efficiency by developing new technologies, such as CO_2-foam injection that can help overcome the challenges of heterogeneity and increase storage capacity. Additionally, improving the understanding of subsurface geology and using advanced monitoring techniques can help optimize injection strategies and improve storage efficiency.

4. M.H. Rating System for Categorizing Geological Formations for CO_2 Storage

Based upon Tables 1–7, i.e., seven rating scales to categorize the CO_2 storage potential of various geological formations, a unified M.H. rating scale has been formulated. This scale ranges from one–five and ranges from least effective to very effective storage options, i.e., 1–1.9; least effective, 2–2.9; slightly effective, 3–3.9; moderately effective, 4–5; very effective as shown in Table 8.

Table 8. M.H. rating scale for selecting geological formations for CO_2 storage.

	Safety Risks and Mitigations	CO_2 Storage	Parametric evaluation		Residual Trapping	Potential to Improve	Containment and Integrity	Overall Rating
			Injection Rate	Efficiency				
Deep Saline Aquifers	2.5	5	5	4	5	4	5	4.3
Depleted Reservoirs	3	3	4	3	3	3	3	3.1
Coal Seams	3	2	3	2	4	2	3	2.6
Basaltic Formations	5	4	4	4	2	5	5	4.1
Clastic Formations	3.5	3	3	3	3	3	2.5	3

Based on the individual rating of safety risks and mitigations, potential to improve CO_2 storage, containment and integrity, injection rate, efficiency, residual trapping and overall rating, the formations can be ranked from least effective to highly effective for selection for CO_2 storage as follows:

Coal seams (**slightly effective**)**:** Coal seams have a relatively low potential to improve CO_2 storage capacity and efficiency. They also have the lowest ratings for containment and integrity, injection rate, efficiency and residual trapping. The safety risks and mitigations associated with CO_2 storage in coal seams are moderate. Therefore, the overall rating for coal seams is the lowest among the formations evaluated.

Clastic formations (**moderately effective**)**:** Clastic formations have a moderate potential to improve CO_2 storage capacity and efficiency. However, they have the second-lowest rating for containment and integrity, injection rate and efficiency. The safety risks and mitigations associated with CO_2 storage in clastic formations are moderate. Therefore, the overall rating for clastic formations is moderate.

Depleted reservoirs (**moderately effective**)**:** Depleted reservoirs have a moderate potential to improve CO_2 storage capacity and efficiency. They have a moderate rating for containment and integrity, injection rate and residual trapping. However, they have a lower rating for efficiency. The safety risks and mitigations associated with CO_2 storage in depleted reservoirs are moderate. Therefore, the overall rating for depleted reservoirs is moderate.

Basaltic formations (**very effective**)**:** Basaltic formations have a high potential to improve CO_2 storage capacity and efficiency. They have the highest rating for containment and integrity and the second-highest rating for injection rate and residual trapping. However, they have a lower rating for CO_2 storage and efficiency. The safety risks and mitigations associated with CO_2 storage in basaltic formations are relatively low. Therefore, the overall rating for basaltic formations is moderately effective.

Deep saline aquifers (very effective): Deep saline aquifers have a high potential to improve CO_2 storage capacity and efficiency. They have the highest rating for CO_2 storage and efficiency and the second-highest rating for containment and integrity, injection rate and residual trapping. The safety risks and mitigations associated with CO_2 storage in deep saline aquifers are relatively low. Therefore, the overall rating for deep saline aquifers is highly effective.

5. Way forward

Extensive research has been conducted and is ongoing regarding the storage of CO_2 in various geological formations. However, as the saying goes, there is always room for improvement. Therefore, new research endeavors can be explored to enhance the efficiency of the storage process and system. This section, based on a thorough literature review, identified gaps in knowledge and proposed potential research opportunities for each geological formation.

5.1. Deep Saline Aquifers

a. Investigating the impact of CO_2 injection on the microbial ecology of deep saline aquifers: This research could explore the potential changes in the microbial community within deep saline aquifers as a result of CO_2 injection and assess whether these changes could impact the safety and effectiveness of CO_2 storage.

b. Developing new monitoring technologies for CO_2 storage in deep saline aquifers: This research could focus on developing innovative monitoring techniques, such as advanced sensors or novel imaging technologies, improving our ability to accurately track CO_2 storage over time.

c. Assessing the potential for induced seismicity during CO_2 injection: This research could examine the potential for CO_2 injection to trigger seismic activity in deep saline aquifers and explore mitigation strategies to minimize this risk.

d. Investigating the potential for CO_2 leakage pathways in deep saline aquifers: This research could focus on identifying and characterizing potential pathways for CO_2 leakage from deep saline aquifers and assessing the effectiveness of different containment strategies.

5.2. Depleted Reservoirs

a. Characterization of reservoir heterogeneity and its effect on CO_2 storage capacity: Depleted reservoirs often have complex geologic structures and heterogeneity. A detailed characterization of these features and their impact on CO_2 storage capacity can help optimize injection strategies and ensure long-term storage security.

b. Developing low-cost and effective monitoring techniques for CO_2 leakage detection: Continuous monitoring of CO_2 storage reservoirs is crucial for ensuring the containment and integrity of the stored CO_2. Developing low-cost and effective monitoring techniques can significantly reduce operational costs while enhancing the reliability and accuracy of CO_2 leak detection.

c. Enhancing CO_2 storage capacity through geomechanical manipulation: Depleted reservoirs can have poor porosity and permeability, limiting their CO_2 storage capacity. Geomechanical manipulation techniques, such as hydraulic fracturing or chemical treatments can improve the reservoir's properties and increase its storage capacity.

d. Investigating the impact of CO_2 injection on subsurface microbial communities: CO_2 injection can create significant changes in the subsurface microbial communities, potentially impacting reservoir properties and CO_2 storage security. Studying the microbial response to CO_2 injection can help identify potential environmental risks and develop mitigation strategies.

5.3. Coal Seams

a. Investigating the impact of coal seam properties on CO_2 **storage efficiency:** There is still much to be learned about the physical and chemical characteristics of coal seams and how these affect the behavior of CO_2 stored within them. A research project that delves into these topics could lead to more effective storage strategies.

b. Developing novel methods for monitoring CO_2 **storage in coal seams:** Monitoring the behavior of CO_2 stored in coal seams can be a difficult task due to the complex nature of the subsurface environment. Developing new monitoring techniques, such as advanced geophysical imaging or chemical analysis, could improve our understanding of CO_2 behavior in coal seams.

c. Evaluating the potential for CO_2**-induced coalbed methane production:** Injecting CO_2 into coal seams can lead to an increase in methane production, a process known as enhanced coalbed methane (ECBM). However, the relationship between CO_2 injection and methane production is not well understood. A research project that explores this topic could provide valuable insights into the feasibility of using ECBM as a means of storing CO_2.

d. Assessing the long-term stability of CO_2 **stored in coal seams:** While coal seams have been identified as a potentially effective storage medium for CO_2, it is important to understand the long-term stability of stored CO_2. A research project that evaluates the long-term stability of CO_2 storage in coal seams could provide valuable insights into the safety and efficacy of this storage method.

5.4. Clastic Formations

a. Investigation of CO_2**-induced changes in mineralogical, petrophysical, and geomechanical properties of clastic formations:** This research can focus on studying the impacts of CO_2 injection on clastic formations' properties, including mineralogical composition, porosity, permeability and geomechanical strength. The findings can help understand the behavior of clastic formations during CO_2 injection and storage operations.

b. Developing cost-effective and environmentally friendly chemicals for enhancing CO_2 **storage capacity in clastic formations:** This research can focus on the development of new chemical agents that can increase the CO_2 storage capacity of clastic formations. These chemicals should be environmentally friendly, low-cost and easy to apply in the field.

c. Evaluating the feasibility of CO_2 **storage in unconventional clastic formations:** This research can explore the feasibility of CO_2 storage in unconventional clastic formations, such as shale formations. The study can focus on analyzing the unique properties and characteristics of unconventional clastic formations and assessing their potential for CO_2 storage.

d. Investigation of the impact of CO_2 **injection on microbial communities in clastic formations:** This research can explore the impact of CO_2 injection on microbial communities in clastic formations, including their composition and diversity. The study can provide insights into the potential environmental impacts of CO_2 injection and storage operations.

5.5. Basaltic Formations

a. Evaluation of the long-term stability of CO_2 **storage in basaltic formations:** A critical aspect of CO_2 storage in basaltic formations is the long-term stability of the stored CO_2. Research can be conducted to evaluate the potential long-term risks associated with CO_2 storage, including the potential for leakage, migration or reactivity of the CO_2 with the host rock.

b. Assessment of the impact of mineral reactions on CO_2 **storage in basaltic formations:** Mineral reactions can occur between the CO_2 and the host rock, potentially altering the physical and chemical properties of the rock and affecting the storage capacity of the basaltic formation. Research can investigate the extent and impact of these reactions on the storage capacity, integrity and containment of CO_2.

c. Development of new monitoring techniques for CO_2 **storage in basaltic formations:** Monitoring the movement and behavior of CO_2 in basaltic formations is crucial for ensuring the integrity and containment of the stored CO_2. Research can be conducted to develop new and innovative monitoring techniques that can detect changes in the physical and chemical properties of the host rock and CO_2.

d. Investigation of the potential for enhanced CO_2 **storage in basaltic formations using geothermal energy:** Basaltic formations can have high geothermal gradients, making them suitable for geothermal energy production. Research can be conducted to investigate the potential for using geothermal energy to enhance CO_2 storage in basaltic formations, such as through the use of downhole heating or circulating hot water through the formation to enhance CO_2 solubility.

6. Conclusions

The selection of the most economically feasible CCS technology based on the M.H. rating system can be achieved through a careful evaluation of the geological formations and the costs associated with each technology. The MH rating system provides a framework for assessing the suitability of geological formations based on parameters, such as storage capacity, efficiency, containment, injection rate, safety and potential to improve. The costs of each CCS technology, including equipment, construction, operation and maintenance, should also be considered. Finally, decisionmakers should evaluate the economic feasibility of each technology by comparing the costs and benefits, including potential revenue streams. The selection of the technology that provides the highest economic benefit while minimizing environmental impact is crucial for the success of the project.

Usually, the primary factor in the choice of the storage location is the proximity to the capture side; if the proximity is not an issue, then the M.H. rating scale provides a reliable idea to make a decision to choose the storage location. As per this study, basaltic formations and deep saline aquifers have the highest effectiveness for CO_2 storage, while coal seams ranked the lowest on this scale. Moreover, as a part of this study, various research gaps and ideas have been introduced for each discussed formation that will be helpful for policymakers and researchers to further enhance the already existing knowledge in CO_2 storage in geological formations.

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