

The Effect of Stearic Acid and an Alumina Nanofluid on the Calcite Substrates' CO₂ Wettability: CO₂ Geological Storage Implications for Carbonate Reservoirs

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Abstract

Topographical data is an essential of structural designing foundation projects. Notwithstanding, the displaying, portrayal, update, and trade of geographical data are testing since they are overseen by heterogeneous information models upheld by the two-layered (2D) portrayal that needs volumetric data, 3D perception, and coordination. This study presents an original land information model utilizing BIM and GIS to work with three-layered (3D) displaying and the board of geographical data. The IFC and CityGML ADE are extended to accommodate the significant geometric, semantic, and spatial information contained in the proposed geological data model. IFC and CityGML were used to map the BIM and GIS data. Besides, the proposed geographical information model purposes a limit and voxel mathematical portrayal for the topographical information. Calculations are created to make an effective 3D geographical limit and voxel model in light of the created land information model. Moreover, the voxel size, number, and traits can be refreshed effectively, empowering the portrayal of geographical data at various scales. In this manner, the proposed BIM-GIS system is exhibited for a situation concentrate on utilizing geotechnical examination information from a city. In order to confirm the proposed method's practical applications, a survey using a questionnaire was carried out. As a result, it was discovered that the proposed method improves the efficiency of geological data management as well as the process of exchanging geological information.

This paper primarily provided a synopsis of a special issue titled "Application of Novel High-Tech Methods to Geological Hazard Research." This issue covers a variety of aspects of geological hazard prevention and mitigation, including characteristics and mechanisms, numerical simulations, susceptibility and hazard assessment, monitoring and early warning, prevention and control measures, and geotechnical research of geological hazards. The application of cutting-edge and novel approaches to the prevention and mitigation of geological disasters was further pushed forward by these studies.

Keywords: 3D land information model; Digital twin of the geology; Modeling using voxels; Geological data administration

Introduction

Geographical carbon stockpiling has been surveyed as a possible strategy to relieve an Earth-wide temperature boost and environmental change issues. Profound saline springs, exhausted hydrocarbon supplies, basaltic rocks, natural rich shales, and salt caves can store CO₂ [1]. In addition, an injection well injects CO₂ into oil-depleted reservoirs to move remaining oil toward the production well and enhance oil recovery. Trapping mechanisms like residual trapping, mineral trapping, solubility trapping, adsorption trapping, and structural trapping typically play a role in the geological CO₂ storage mechanism. CO₂ trapping capacity, geological storage (geo-storage), and contamination security all benefit from water-wet rocks.

Additionally, the value of CO₂ saturation at the conclusion of drainage (increased CO₂ saturation results in a smaller height below the seal for the same volume of injected CO₂) may indirectly contribute to the volume of structurally stored CO₂ below the seal [2]. Residual hydrocarbon saturation can always be found in reservoir rocks. Hence, hints of hydrocarbon (e.g., broke up natural material) can change the CO₂-wettability of rock. As a result, the brine droplet contact angle on the rock surface can be altered by a minute concentration of organic matter and its coating. Accordingly, it is fundamental to assess and forestall the impact of natural material on repository rocks, which essentially influences CO₂ geo-capacity activities.

Numerous oil and gas applications use a variety of nanofluids, such as drilling fluids, enhanced oil recovery, and wettability modifications.

The wettability of land rocks or their intermediary minerals changes from oil-wet to water-wet surface qualities. As a result, the capability to transform oil-to-water-wet surfaces determines the effect of nanofluid as a wettability modifier [3]. The land rock comprises of an intricate pore-network framework, mineralogy, organics, and bottle states of being, influencing wettability. For quantitative reservoir rock wettability behavior as a rock/gas/liquid system, contact angle evaluation is widely used. Based on contact angles, wettability is frequently divided into strongly water-wet, intermediate-wet, and strongly oil-wet systems in the literature on petroleum engineering. Such orders can be utilized for CO₂-brackish water mineral with the term oil-wet changed to CO₂-wet. The definitions from physical chemistry are compared to these classifications. For instance, the terms "completely water-wet," "partially wetting," and "completely nonwetting" are all synonyms for " $\theta = 0^\circ$."

Over extended depositions, water and organic acids form in deep

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Received: 02-May-2023, Manuscript No. jpmm-23-100920; **Editor assigned:** 04-May-2023, PreQC No. jpmm-23-100920 (PQ); **Reviewed:** 18-May-2023, QC No. jpmm-23-100920, **Revised:** 23-May-2023, Manuscript No. jpmm-23-100920 (R); **Published:** 30-May-2023, DOI: 10.4172/2168-9806.1000357

Citation: Seo WJ (2023) The Effect of Stearic Acid and an Alumina Nanofluid on the Calcite Substrates' CO₂ Wettability: CO₂ Geological Storage Implications for Carbonate Reservoirs. J Powder Metall Min 12: 357.

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geo-storage rocks [4]. The carbon atoms that make up these organic acids range from C₂ to C₂₆. The wettability of the reservoir could be altered by multiple alkyl chains on the rock surface. The diagenesis of organic matter and hydrocarbon biodegradation that transform the rock's hydrophilic (water-wet) behavior into a hydrophobic one are the sources of these organic molecules found in underground formations. discovered that during CO₂ storage, the risk of containment security in geological formations may be increased by organic acids. Additionally, discovered that the storage capacity of carbonate reservoirs is influenced by organic acids, including carboxylic compounds. These acids essentially influence the water-wetness and change the water-wetness on the stone surface. The threshold wettability values—defined as a water contact angle of more than 90 degrees for structural trapping and more than 50 degrees for capillary trapping—were found to be extremely low concentrations of organic acid—between 103 and 107 M for structural trapping and between 107 M and 1010 M for capillary trapping, respectively [5]. Exceptionally low groupings of natural acids could bring down the capacity limits and increment the control risk at reasonable repository conditions (i.e., saltiness, temperature, tension, and natural corrosive fixation).

However, in order to increase the CO₂ geo-storage capacity at in situ reservoir conditions, there is a pressing need for data that provide comprehensive insight into the effect of hydrophilic nanoparticles on reservoir rock. Carbonate or calcite rock has been treated with silica nanoparticles in a number of studies for CO₂ geo-storage. Geoscientists have focused a lot on using nanofluids, like magnesium oxide, titanium oxide, carbon nanotubes, and nano silica, on the oil-wet carbonate rock surface. They found that these nanofluids changed the rock's oil-wet surface to water-wet. In a similar vein, researchers have observed that alumina nanofluid has significant potential as a wettability modifier for enhanced oil recovery applications after using it to treat sandstone and shale rocks to increase their wettability. For improved CO₂ geo-storage potential, we therefore treated calcite substrates, which are examples of carbonate reservoirs, with alumina nanofluid.

As a wettability enhancer for calcite/CO₂/brine systems, we made use of hydrophilic alumina nanoparticles at various concentrations (0.05, 0.1, 0.25, and 0.75 weight percent). The outer layer of the calcite substrate is normally water-wet at encompassing circumstances and may become feeble to moderate wet at higher CO₂ tensions and temperatures. Subsequently, tuning the calcite wettability to water-wet at supply conditions is profoundly alluring. Hence, we assessed the impact of natural acids (stearic corrosive) and their treatment with alumina nanofluid on the outer layer of calcite through the progressing and subsiding contact points of salt water (10 wt%, NaCl) within the sight of CO₂ gas at in situ repository conditions: ranging from 0 to 20 MPa and temperatures of 23 to 50 °C. For stearic acid-aged calcite substrates, we also investigated the effect of alumina nanofluid as a wettability modifier [6]. The irreversible adsorption of alumina nanofluid at various concentrations (0.05, 0.1, 0.25, and 0.75 weight percent) is the method by which the alumina nanofluid treatment of the calcite surface is carried out. To summarize, accurately predicting CO₂ geo-storage capacities necessitates measuring these effects.

Materials and Method

The nanofluids were made with hydrophilic alumina nanoparticles that Sigma Aldrich provided. presents the properties of nanoparticles utilized in this work. Deionized water and NaCl (99.999 mol% immaculateness) were bought from David Dark and Rowe Logical. The purity of the brine solution, which is 99.99 mol%, is 10 wt% NaCl. The majority of carbonate rocks contain pure calcite mineral, which

was purchased from Iceland Spar, Ward's Natural Science. Sigma Aldrich supplied the stearic acid (98.5 mol%) and n-decane (99 mol%) that were needed to age the mineral's surface. Based on the operating temperatures and pressures, CO₂ was also purchased from Core Gas and utilized as a supercritical fluid [7]. BOC provided ultra-pure nitrogen, with a purity of more than 99.9 mol%, for use as a drying gas.

Calcite/CO₂/brine equilibrium and cleaning

In a mixing reactor made by the Parr Company, the fluid the calcite substrates, and CO₂ were equilibrated at the test pressure and temperature until no more dissolution occurred, resulting in the formation of bicarbonate ions. The mineral surface is cleaned before contact point estimations, as tainting buildup can cause methodical blunders. Calcite minerals were cleaned with DI water, trailed by super unadulterated nitrogen air to eliminate free soil and calcite particles. Afterward, toluene was utilized to wash the stone to eliminate any natural or inorganic contaminations. So, the rock samples were treated with air plasma for 15 minutes to get rid of organic pollutants. After that, they were dried for 60 minutes in an oven at 80 °C before being tested for wettability.

Making of an alumina nanofluid

Alumina nanofluids were ready at centralizations of 0.05, 0.1, 0.25, and 0.75 wt%. Sonication was used to create the alumina nanofluid's homogeneous suspensions [8]. Using an ultrasonic homogenizer, the nanofluids were sonicated for 15 minutes at 20 kHz to achieve the desired concentrations. Afterward, the nanofluid was passed on in the open climate to cool to surrounding conditions. These focuses were tried to switch the wettability of the natural corrosive matured calcite substrate. This mechanism makes use of a 9.5 mm-diameter titanium microtip with 9500 J of energy and a 40% sonication amplitude.

Calcite in organic acid and alumina nanofluids: Characterization and aging

Energy dispersive spectroscopy (EDS) and field-emission scanning electron microscopy (FESEM) were used to examine the elemental composition and surface morphology of the pristine and organic acid-aged alumina nanofluid calcite substrates. more on this is provided in Section 3.1). Organic solutions formulated by mixing stearic acid with n-decane at various concentrations of 102 to 109 mol/L were used to age the calcite substrates for seven days in airtight acrylic containers. Ratio of liquid to rock was used to age calcite using alumina nanofluid (1 g of calcite substrate to 5 g of nanofluid). Numerous studies have utilized this constant ratio to provide comparable coverage for each calcite surface.

The measurement of the contact angle

The Van Der Waals force happens among particles and molecules. As a result, Derjaguin, Landau, Verwey, and Overbeek's (DLVO) theory takes into account one of the two forces of intermolecular interaction [9]. These powers are electrodynamic and can be appealing and horrendous. As a result, the wettability of interactions between polar molecules (water) and non-polar molecules (organic acids) on the surface of a solid (rock) can be determined using the DLVO theory. However, CO₂ geological storage is highly dependent on depth because of its critical phase behavior, which can influence interactions between capillaries and DLVO. As a result, we used the contact angle (advancing and receding) tilted plate method to measure the calcite/CO₂/brine system's wettability. Under reservoir conditions, such as varying pressures and temperatures, the contact angle chamber functions. Fig.

The experimental setup for measuring CO₂/brine contact angles on the substrates of steric acid-aged and alumina nanofluid-aged calcite is shown in Figure 1. A stone example was placed on the shifted plate in the tension cell. The system temperature was set to 323 K prior to beginning each experiment, and an ISCO syringe pump was used to raise cell pressure to the desired experimental conditions. A high-precision needle was used to drop a drop of degassed DI water (6–10 μ L) onto the substrate surface after the cell's temperature and pressure had stabilized. ImageJ software was used to measure the brine's advancing and receding contact angle values on the calcite surface. Previous studies provided a more in-depth explanation of the experimental setup.

Results

Surface morphology of pristine calcite substrates and those that have been nanofluid-aged

High-magnification FESEM was utilized to look at the surface morphology of immaculate and nanofluid-matured calcite substrates representing the unblemished calcite surface without the natural corrosive and nanofluid medicines presentations the monolayer of alumina nanoparticles at a higher magnification of 200 nm [10]. Compared to other nanofluid concentrations (0.05, 0.1, and 0.25 wt%), the alumina nanofluid has a higher average particle size aggregation of 0.75 wt percent. Particle aggregation caused by static charges or van der Waals forces between the particles accounts for this mechanism, which results in alumina nanoparticle aggregation on the calcite substrate. As a result, the calcite rock's surface cannot be appropriately altered by the large particle aggregate size, which can result in a low surface area-to-volume ratio.

To ascertain the elements' composition and distribution on the surface of the calcite, quantitative EDS elemental analysis and x-ray mapping were carried out. demonstrates the presence of C, O, Mg, and Ca in the original calcite substrate. These elements show that the calcite rock is a carbonate formation in its entirety. Al and Cl, which are inaccessible in pure calcite, were discovered when organic acid-aged calcite substrates were treated with alumina nanofluid. When compared to the untreated calcite substrate, the reduction in C in the nanofluid-treated calcite also indicates a decrease in organic molecules, which alter the wettability to become more CO₂-wet.

Stearic acid's effect on calcite's CO₂-wettability

Anoxic and reductive conditions in which organics play a significant role characterize natural geological formations. In order to comprehend the potential for CO₂ geo-storage, it is essential to accurately assess the wetting characteristics of carbonate geological formations in the presence of organic acids [11]. The quantitative evaluation is critical for inspecting the CO₂ geo-capacity, infusion potential, and toxin security across the repository. As a result, under in situ reservoir conditions, we examined the CO₂-wettability of calcite substrates in the presence of stearic acid, which serves as a model for organic acids in carbonate formation. The moment centralizations of stearic corrosive (recreates of natural corrosive in the profound saline spring rocks) were presented to the calcite substrate.

demonstrates that even at a concentration of 102 mol/L, stearic acid significantly reduces the water-wetness of the calcite surface—much higher concentrations are found in natural geological formations. As a result, the calcite substrate became more CO₂-wet (the structural trapping capacities are severely impacted when r is greater than 90 degrees) [12]. For instance, at a 10–2 mol/L stearic corrosive fixation,

25 MPa, and 50 °C, the progressing and subsiding contact points were 141.2° and 131.8°, individually. However, the CO₂-wettability of calcite substrates also decreases when the concentration of stearic acid is decreased. For instance, at a 10–9 mol/L stearic corrosive fixation, 10 MPa, and 50 °C, the progressing and retreating contact points were 52° and 45.6°, separately (when $\theta_a > 50^\circ$, remaining catching limits are impacted). Indeed, even the least stearic corrosive focus significantly affects CO₂-wettability and, in this manner, the control security of CO₂. The irreversible adsorption of organics that alter wettability is caused by the covalent bonding of the hydroxyl group of organics to the hydroxyl group of the rock substrate (calcite in this instance). For long-term CO₂ geo-storage, adequate knowledge of organic acids in the carbonate reservoir is therefore required.

Implications

The discoveries affirm that the presence of natural corrosive on calcite substrate can set off wettability adjustment and change wettability to CO₂-wet, diminishing the lingering and underlying CO₂ catching limit values. To increase the CO₂ trapping potential, the optimal concentration of alumina nanofluid (0.25 wt%) should be used to change the wettability from hydrophobic to hydrophilic. Generally speaking, hydrophilicity on the calcite surface can be accomplished through the accompanying two systems:

(a) To begin, a homogeneous 0.25 percent alumina nanofluid suspension is injected into the carbonate reservoirs to shift the calcite surface's wettability from CO₂-wet to intermediate-wet conditions, indicating an increase in the carbon dioxide trapping potential of the reservoirs.

(b) After wettability adjustment with alumina nanofluid flooding, CO₂ is infused over the supercritical state pressure, dislodging the wetting stage (development salt water), bringing about the vertical relocation of free CO₂, catching itself basically beneath the caprock [13–18]. When the CO₂ infusion stops, the wetting stage applies the tension back to the nonwetting stage, where transitional wettability because of alumina nanofluid makes groups of CO₂, catching it excessively in the carbonate arrangement.

As a result, alumina nanofluid has a lot of potential and could significantly improve CO₂ geo-storage.

Conclusion

Wettability is a basic boundary that checks the liquid elements, stockpiling catching limit, and control security of CO₂ in underground developments. The potential for CO₂ geo-storage was lessened by less water-wet rock characteristics. Additionally, underground storage formations have high concentrations of diluted organic molecules and are either anoxic or redox. Thusly, insignificant convergences of these particles are adequate to change the wettability from water-wet to CO₂-wet, expanding the gamble of pollutant security. Accordingly, the component of nanofluid preparing can change rock wettability, as these particles oversee strong synthetic connections between the Gracious gatherings of nanofluid arrangement and mineral substrate. The irreversible adsorption of the nanomaterial on the mineral substrate's surface leads to the chemical interaction. The substrate's hydrophobic behavior is transformed into a hydrophilic one as a result of this irreversible adsorption of nanomaterials onto the organic acid-aged minerals' surfaces, decreasing the likelihood of contamination issues and increasing CO₂ geo-storage capacity.

This study compares CO₂ geo-storage at four concentrations,

ranging from 0.05 to 0.75 weight percent, before and after alumina nanofluid treatment under realistic reservoir conditions. At realistic reservoir conditions, including in situ organic traces, pressures, and temperatures, the calcite substrate's behavior for CO₂ geo-storage has rarely been documented. In order to replicate the actual potential for the storage of carbonate reservoir rock, we examined the CO₂ wettability of organic acid-aged calcite. At a low concentration of 102 mol/L, the effect of stearic acid switched from the water-wet calcite substrate to the CO₂-wet substrate (much higher concentrations are found in geological formations). However, when an organic acid-aged calcite substrate was subjected to treatment with an optimal concentration of 0.25 weight percent of alumina nanofluid, the calcite's wettability changed from CO₂-wet to weakly water-wet, enhancing its residual and structural trapping capacity.

As a result, we conclude that carbonate reservoir rock's geo-storage capacity and security for CO₂ containment are lower than anticipated. Investigating how the surface of the calcite substrate, also known as the carbonate rock-forming unit, behaves and reaches the limits of the CO₂ geo-storage potential is essential. Additionally, it is essential to evaluate the impact that various organic acids have on the surface of the calcite. Additionally, selecting and making use of hydrophilic nanoparticles to increase wettability is crucial to achieving CO₂ geo-storage operations that are secure, sustainable, and safe.

Acknowledgement

None

Conflict of Interest

None

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