

Nanosilica-Based Sealing of Wellbore Cement Leaks in Geological CO₂ Storage: A Geotechnical and Geochemical Approach

Olayiwola Olatunji

Olayiwolaolatunji@yahoo.com

University of Louisiana at Lafayette

Nabaladiomon Coulibaly

University of Louisiana at Lafayette

Kumarasan Muthian

SafesourceDirect

Ning Liu

University of Louisiana at Lafayette

Boyun Guo

University of Louisiana at Lafayette

Research Article

Keywords: CO₂, NANOSILICA, GEL, LEAKAGE, GEOLOGY, SEALING PRESSURE

Posted Date: September 28th, 2026

DOI: <https://doi.org/10.21203/rs.3.rs-11156557/v1>

License:  This work is licensed under a Creative Commons Attribution 4.0 International License.

[Read Full License](#)

Additional Declarations: No competing interests reported.

Nanosilica-Based Sealing of Wellbore Cement Leaks in Geological CO₂ Storage: A Geotechnical and Geochemical Approach

Olayiwola Olatunji^{1,2,3}, Nabaladiomon Coulibaly², Kumarasan Muthian³, Ning Liu², Boyun Guo²

²University of Louisiana at Lafayette, USA

³SafesourceDirect, Broussard, LA, USA

¹Corresponding Author

Olayiwolaolatunji@yahoo.com

ABSTRACT

Leakage through micro-annuli and fractures in the wellbore cement is a major concern for the long-term integrity of geological CO₂ storage. Effective remediation necessitates a low-viscosity sealant that can penetrate narrow leakage pathways and create a durable barrier under subsurface conditions. This study explores the use of a nanosilica-based sealant to mitigate CO₂ leakage through fractured wellbore cement. Introduction of sodium ions into the nanosilica dispersion induced gelation to give a homogeneous silica gel with excellent thermal and mechanical stability under high-pressure and high-temperature conditions representative of geological carbon storage. Core-flooding experiments showed that the in-situ formed gel effectively sealed cement fractures and withstood substantial differential CO₂ pressures. The effects of nanosilica concentration and fracture width on sealing performance were also investigated. The holdback pressure increased from 300 psi to 900 psi when the concentration of nanosilica increased from 15% to 25%. In contrast, as fracture width increased from 0.05 inch to 0.15 inch, the holdback pressure decreased from 400 psi to 250 psi. These results indicate that nanosilica gel can be a useful sealant to prevent the leakage of CO₂ through the wellbore

Keywords: *CO₂, NANOSILICA, GEL, LEAKAGE, GEOLOGY, SEALING PRESSURE*

1. INTRODUCTION

Global climate change and increasing temperatures are direct parameters which contribute to anthropogenic greenhouse gas emissions. As a result, carbon capture and storage (CCS) has become a technically feasible method of reducing these emissions. Under the CCS framework, CO₂ is separated from industrial exhaust streams, transported, and stored for an extended period in subterranean geological formations or other constructed repositories. CCS is widely recognized as a crucial element of current decarbonization plans to achieve emission reduction trajectories that are consistent with keeping global warming below 1.5 °C. [1,2]

CO₂ leakage through defective wellbores presents complex environmental, geochemical, and operational challenges. Owing to its colorless and odorless nature, CO₂ migration is often difficult to detect before significant subsurface transport has occurred [3]. Escaping CO₂ may migrate through interconnected fracture networks, cement microannuli, debonded interfaces, or degraded cement matrices before entering overlying formations. Upon contact with groundwater, dissolved CO₂ forms carbonic acid, lowering pore water pH and initiating a series of geochemical reactions capable of dissolving carbonate minerals, mobilizing trace metals, and altering groundwater chemistry.[4]. Such reactions may adversely affect groundwater quality, disrupt indigenous microbial communities, and modify mineral equilibria within storage formations.

Furthermore, persistent leakage may compromise reservoir pressure management, reduce storage efficiency, increase operational costs, and ultimately diminish confidence in CCS as a reliable climate mitigation technology. These concerns have motivated extensive research aimed at understanding leakage mechanisms and developing durable remediation technologies capable of restoring wellbore integrity under realistic subsurface conditions. The ability of CO₂ storage to capture emissions at the source and lower atmospheric loading is its main advantage. Thermal rise, sea level fluctuation, and the intensification of extreme weather patterns are just a few of the climate-related effects that this intervention helps to mitigate. Despite these benefits, long-term CO₂ confinement presents several technological difficulties, with leakage risk being a major concern. [5-7] The intrinsic characteristics of CO₂, which lack color and odor, make detection even more difficult, requiring indirect monitoring techniques.

CO₂ may find its way into nearby subsurface formations, especially groundwater-bearing zones, if migration takes place. In this regard, CO₂ dissolution can lower pH, change geochemical equilibria, and perhaps cause acidification. These alterations may have a negative impact on aquatic life and lower the quality of the water. Furthermore, in some circumstances, leakage may contribute to surface water system pollution and interfere with microbiological and geochemical activities in the sedimentary layers above. [8-10]

As a result, a significant amount of study has been focused on developing efficient sealing techniques as well as characterizing leakage processes.^[11–15] Numerous remediation strategies have been put forth, such as mechanical isolation using packers, biologically mediated sealing methods, squeezing cementing procedures, targeted chemical treatments close to the wellbore, and intervention through tube replacement or repair.^[16,17] Among them, squeeze cementing is still a common procedure used in the oil and gas industry to control integrity. Cementitious slurry is injected into fractured networks at high pressure, where it is hard to create a barrier that prevents fluid movement.

Numerous wellbore remediation techniques have been proposed to mitigate CO₂ leakage, each possessing distinct advantages and limitations. Conventional approaches include mechanical isolation using bridge plugs and packers, squeeze cementing, casing repair or replacement, resin injection, polymer-based sealant^[18], biologically induced mineral precipitation, and various chemical grouting techniques. Among these methods, squeeze cementing remains the most widely practiced intervention due to its operational familiarity and relatively low implementation cost. In this process, cement slurry is injected under pressure into damaged regions where it subsequently hydrates and forms a low-permeability barrier intended to restore hydraulic isolation.

Although squeeze cementing has demonstrated considerable success in conventional oil and gas operations, its effectiveness in fractured wellbore systems associated with geological CO₂ storage remains inconsistent. Furthermore, penetration into fine-scale cracks is restricted by the rheological properties of typical cement systems, especially their comparatively high viscosity. Because solid particles may be trapped before they reach deeper portions of the fracture network, filtration effects may make this restriction even worse^[19]. Because of this, residual flow channels may continue, and imperfect sealing is not unusual. These results may result in more frequent interventions, longer operating times, and higher expenses.

Cement slurries typically possess relatively high viscosity and contain solid particles that are substantially larger than the apertures of many naturally occurring microfractures. As a result, particle bridging and filtration frequently occur near fracture entrances, restricting slurry penetration into deeper sections of the damaged zone^[19]. In addition, gravitational settling, inadequate dispersion stability, poor rheological control, fluid loss, premature hydration, contamination by formation fluids, and complex fracture geometries often produce highly non-uniform slurry placement. Reservoir heterogeneity further exacerbates these challenges by promoting preferential flow through larger fractures while leaving finer leakage pathways untreated. Consequently, residual conductive channels frequently remain after remediation, allowing continued fluid migration despite repeated cementing operations. These shortcomings have stimulated increasing interest in alternative sealing materials capable of overcoming the transport limitations associated with conventional cement systems.

Alternative materials have been studied to overcome these constraints, with an emphasis on polymeric and gel-based systems because of their adjustable characteristics and enhanced resistance to gas migration^[20–23] For example, Ito et al. investigated the use of sodium silicate solutions using glass-bead flooding at 10 MPa and 40 °C in lab-scale studies intended to mimic leakage control.^[24] In a comparable work, Hatzignatiou et al. assessed the volumetric stability, mechanical integrity, and gelation behavior of silica gel systems under controlled circumstances.^[25] Wiese et al. documented a pilot-scale application of potassium silicate gel for near-wellbore sealing in a CO₂ storage reservoir at the field level, proving its usefulness.^[26]

Nanotechnology offers an attractive pathway toward addressing these challenges. Owing to their exceptionally small particle size, large specific surface area, and high surface reactivity, nanosilica particles exhibit transport characteristics fundamentally different from those of conventional cement particles^[27]. Properly dispersed nanosilica suspensions can penetrate microfractures and narrow pore throats that remain inaccessible to traditional cement slurries. Once transported into damaged regions, nanosilica can participate in physical pore filling, particle aggregation, and pozzolanic interactions with hydrated cement phases, leading to progressive refinement of the pore structure and reduction of permeability. Furthermore, nanosilica has been shown to enhance cement microstructure by accelerating hydration reactions, promoting calcium silicate hydrate (C–S–H) formation, reducing porosity, and improving mechanical properties. These characteristics make nanosilica an attractive candidate for repairing leakage pathways within deteriorated wellbore cement.

In recent years, silica-based gels, polymeric sealants, and nanomaterial-enabled remediation systems have emerged as promising alternatives for enhancing wellbore sealing performance^[28]. Silicate gels possess the ability to penetrate fine pore spaces before undergoing controlled gelation, thereby improving fracture coverage compared with conventional cement. Polymer gels offer excellent flexibility and chemical resistance, while their tunable rheological properties permit adaptation to varying reservoir conditions. Nevertheless, many gel systems suffer from limitations including uncontrolled gelation kinetics, reduced thermal stability, susceptibility to syneresis, and performance degradation in high-salinity environments. Consequently, there remains an ongoing need for sealing materials that simultaneously exhibit excellent injectivity, long-term stability, chemical durability, and compatibility with cementitious substrates.

The effectiveness of nanosilica-based sealing systems, however, depends strongly on colloidal stability during transport through fractured porous media^[29]. Unmodified nanoparticles are prone to agglomeration because of strong van der Waals attractions and elevated ionic strength commonly encountered in subsurface environments. Particle aggregation not only reduces mobility but also limits penetration depth and compromises sealing efficiency. Surface modification provides a practical approach for improving nanoparticle dispersion by introducing electrostatic or steric stabilization mechanisms that suppress aggregation and maintain suspension stability. Enhanced colloidal stability facilitates deeper migration into interconnected fracture networks, enabling more uniform placement throughout damaged cement matrices. Despite these recognized advantages, the

application of surface-modified nanosilica for repairing CO₂ leakage pathways in wellbore cement remains insufficiently explored, particularly under conditions representative of geological carbon storage operations.

More recently, Li et al. showed that electro-migration may be used to introduce nanosilica particles into cement matrices, allowing for penetration into micro-scale flaws.^[30] The potential of nanosilica as a sealing agent for damaged cement structures is highlighted by this discovery. Its use in wellbore rehabilitation is yet relatively unexplored, though. Because it improves dispersion stability and makes transport across porous media easier, surface modification of nanosilica is particularly interesting because it increases placement efficiency within specific zones.

Although previous investigations have demonstrated the potential of silica gels, silicate solutions, and nanosilica for permeability reduction, most studies have focused on homogeneous porous media, bulk cement modification, or simplified laboratory systems. Comparatively little attention has been devoted to understanding how fracture width, fracture interface, and nanosilica concentration collectively influence sealing efficiency in fractured wellbore cement exposed to CO₂ storage environments. Furthermore, the mechanisms governing nanoparticle transport, fracture penetration, permeability reduction, and resistance to coupled CO₂-brine flow remain inadequately understood. These knowledge gaps limit the practical deployment of nanosilica-based remediation technologies for field-scale CCS applications.

The present study addresses these challenges by systematically evaluating the feasibility of using surface-modified nanosilica suspensions to seal fractures within wellbore cement relevant to geological carbon storage. Artificially fractured cement specimens were prepared to simulate representative leakage pathways, while key parameters including nanosilica concentration, fracture width, and fracture interface were varied to investigate their influence on sealing performance. The effectiveness of the proposed sealing system was assessed through permeability reduction and resistance to CO₂ and brine flow, providing quantitative insight into the transport behavior and sealing mechanisms of nanosilica within fractured cement matrices. By establishing the relationships between nanoparticle characteristics, fracture morphology, and hydraulic sealing performance, this work contributes to the development of more reliable remediation technologies for enhancing long-term wellbore integrity and improving the overall security of geological carbon storage systems.

2. Materials and Experimental Procedure

The Nanosilica

The nanosilica dispersion used in this study was supplied by Nouryon Pulp and Performance Chemicals Inc. The dispersion contained approximately 50 wt% solids, with an average particle diameter of approximately 50 nm as shown in Table 1. The silica nanoparticles exhibited a discrete, smooth, and approximately spherical morphology. The nanosilica was supplied as a stable aqueous colloidal dispersion with an opaque white appearance and low-to-moderate viscosity, slightly higher than that of deionized water. No appreciable particle

settling was observed during handling, indicating good colloidal stability and uniform nanoparticle dispersion. Sodium chloride (NaCl) obtained from Fisher Scientific and deionized (DI) water were also used in the experiments. A brine solution was incorporated into the nanosilica system as a gelation accelerator to promote gel formation and facilitate the development of the desired sealing structure.

Table 1 Properties of the Nanosilica Solution

Property	Value / Description
Solids content	≈ 50 wt%
Average particle diameter	≈ 50 nm
Particle morphology	Discrete, smooth, approximately spherical
Form	Stable aqueous colloidal dispersion
Appearance	Opaque white
Viscosity	Low-to-moderate (slightly higher than deionized water)
Colloidal stability	Good; no appreciable particle settling observed
Dispersion uniformity	Uniform nanoparticle dispersion

Preparation of Cement Core Samples

Class H oil-well cement was used to prepare the cement core specimens in accordance with API Recommended Practice 10B. A predetermined quantity of Class H cement powder was mixed with fresh water using a laboratory blender. The cement slurry was initially blended at 4000 rpm for 5s, followed by mixing at 1200 rpm for 35s. The resulting slurry was subsequently transferred into a slurry cup and conditioned at 190 °F (87.8 °C) and 150 rpm for 30min. Following conditioning, the cement slurry was allowed to cure for 24h to develop the required mechanical strength. After curing, the plastic Mold was carefully removed to obtain the consolidated cement core. The resulting core specimens were approximately 10 in. (25.4 cm) in length and 2 in. (5.08 cm) in diameter. This property is summarily discussed in Table 2.

Table 2 Properties of Class H oil-well cement specimens

Parameter	Value / Description
Cement type	Class H oil-well cement
Preparation standard	API Recommended Practice 10B
Mixing procedure	Laboratory blender: 4000 rpm for 5 s, followed by 1200 rpm for 35 s
Conditioning	190 °F (87.8 °C) at 150 rpm for 30 min
Curing time	24 h
Specimen length	≈ 10 in. (25.4 cm)
Specimen diameter	≈ 2 in. (5.08 cm)

Table 3 summarizes the cement core mix design and specimen preparation conditions used for the experimental testing. Portland cement was prepared at a water–cement ratio of 0.40–0.45, providing a relatively dense cement matrix suitable for evaluating fracture sealing and fluid-flow behavior. Cylindrical cement cores with a diameter of 2 in. were used as standardized test specimens. The cores were artificially fractured to simulate a representative crack or leakage pathway within a cementitious wellbore system. Following curing under controlled laboratory conditions, the specimens were placed in a 2-in. core holder and subjected to a confining pressure of 2,000 psi. Water was used as the test fluid to evaluate fluid penetration and the sealing performance of the treated/fractured cement under controlled pressure conditions. Overall, these parameters establish a consistent and reproducible experimental baseline for assessing fracture sealing, permeability reduction, and pressure-holding capability of the cement specimens.

Table 3 Cement Core Mix Design and Specimen Preparation

Parameter	Value
Cement	Portland cement
Water–cement ratio	0.40–0.45
Core diameter	2 in.
Core condition	Artificially fractured
Curing	Controlled laboratory conditions
Confining pressure	2,000 psi
Test fluid	Water, CO ₂
Core holder	2-in. core holder

Preparation of Cement-Related Fractures

Cylindrical cement cores with a diameter of 2 in. were prepared using a professional diamond-blade tile saw as shown in Figure 1. Each core was positioned horizontally on the saw table and aligned with the desired cutting plane. The specimen was securely held using a core-handling fixture to minimize movement, rolling, or rotation during cutting. The diamond blade was allowed to reach its operating speed before the core was gradually advanced toward the blade under controlled pressure. Cutting continued until the blade completely traversed the specimen, producing a clean, flat, and uniform cross-sectional surface suitable for subsequent fracture creation and sealing experiments.



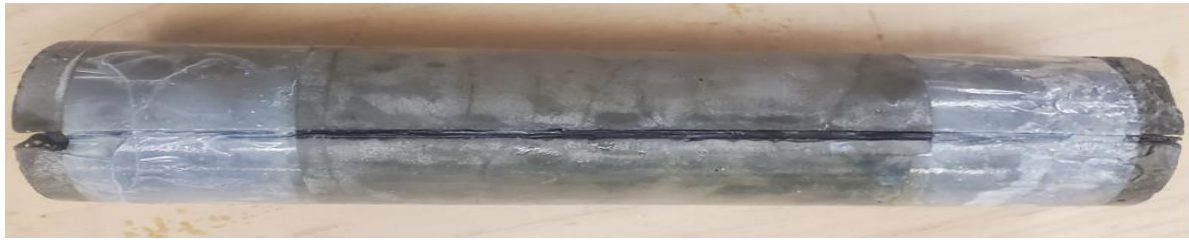
Figure 1 Representative of Cement-Related Fractures

Three representative fracture configurations were prepared to simulate different wellbore leakage pathways: (i) cement–cement, (ii) cement–sandstone, and (iii) cement–casing interfaces. A controlled fracture aperture was introduced into each configuration using a thin lead sheet of predetermined thickness as a spacer.

For the *cement–cement configuration*, the cured cement core was secured on the flat bed of a tile saw and longitudinally cut into two approximately equal sections as shown in Figure 2a. Thin lead sheets were positioned at the interface between the two cement sections to establish the desired fracture aperture. The two sections were then aligned and wrapped with cellophane tape to maintain the configuration during handling. The assembled fractured core was subsequently placed inside a rubber core sleeve and installed in the core holder. A confining pressure of 2000 psi was applied to ensure adequate sealing and mechanical confinement during the experimental test.

For the *cement–sandstone configuration*, a sandstone core section having the same nominal length and diameter as the cement core was positioned against a fractured cement-core section. A controlled interfacial aperture was established by placing a thin lead sheet of predetermined thickness between the cement and sandstone surfaces as shown in Figure 2b. The assembled cement–sandstone specimen was wrapped securely to maintain the prescribed fracture geometry and subsequently placed inside a rubber core sleeve for installation in the core holder.

The *cement–casing configuration* was designed to simulate the interface between wellbore cement and steel casing. A smooth cement surface was positioned against a cement core section whose external surface was covered with a stainless-steel sheet to represent the casing interface. A controlled interfacial aperture was established using a thin lead-sheet spacer of predetermined thickness. The two components were carefully aligned and secured to preserve the desired cement–casing geometry before placement in the rubber core sleeve as shown in Figure. 2c.



(a) Cement-Cement Section



(b) Cement-Sandstone Section



(c) Cement-Casing Section

Figure 2 Images of Core/Fracture arrangements

Experimental Setup

The experimental setup used to investigate nanosilica gel propagation through fractured cement specimens is illustrated in Figure 3a. The flow system comprised two high-precision syringe pumps, two piston-driven accumulators, and a high-pressure core holder configured to simulate fluid transport through fractured wellbore cement under controlled laboratory conditions. This configuration enabled precise regulation of injection rate, pressure, and fluid displacement throughout the experiments. Artificial fractures with predetermined apertures were created by inserting lead shims of known thickness between two matching halves of each cement core prior to assembly. The lead shims served as spacers to establish reproducible fracture widths representative of leakage pathways that may develop in degraded wellbore cement. Once assembled, the fractured cement specimen was installed within the core holder, and an external confining pressure was applied to reproduce the in-situ stress conditions encountered in subsurface geological formations. The confining pressure also ensured intimate contact between the core and the sealing sleeve, thereby preventing external fluid bypass and ensuring that all injected fluids migrated exclusively through the engineered fracture.

Pressure variations across the fractured cement sample were continuously monitored using a Honeywell Model 3000 differential pressure transducer, providing real-time measurements of hydraulic resistance during fluid injection. Prior to permeability measurements, the mounted cement specimen was fully saturated with deionized (DI) water to establish a

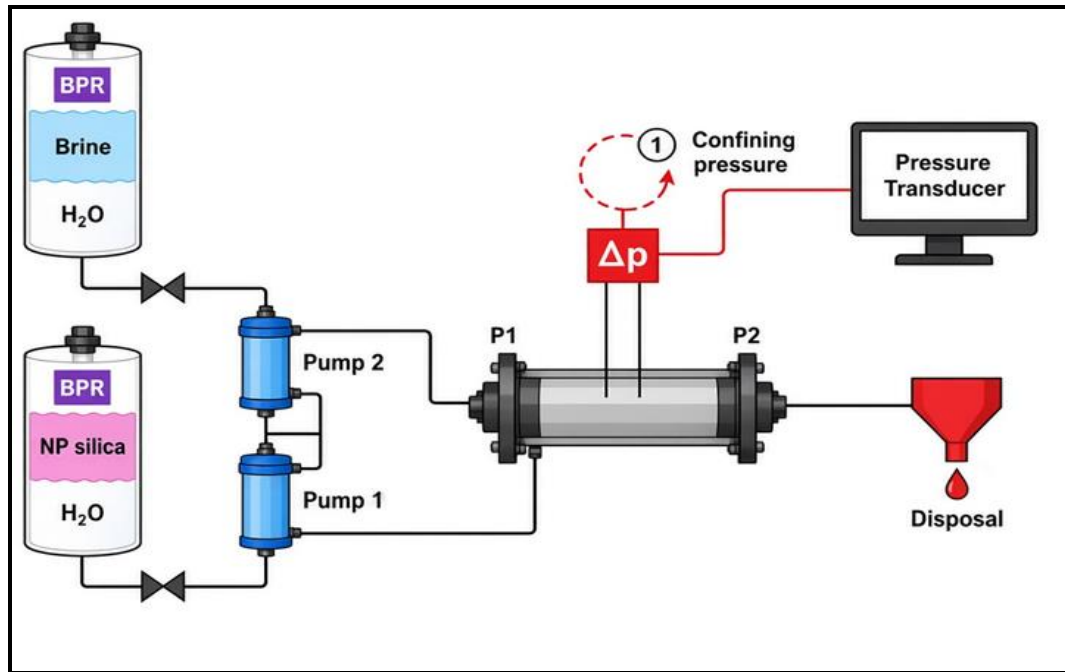
uniform initial saturation condition and eliminate the influence of trapped air on flow behaviour. Baseline hydraulic characteristics of the fractured specimen were subsequently determined by injecting DI water at multiple constant flow rates while recording the corresponding pressure differential across the core. The resulting flow-pressure relationship was used to calculate the initial fracture permeability and hydraulic conductivity, thereby providing a reference condition for evaluating the sealing performance of the nanosilica gel following treatment.

After the core sample is placed in the core holder, the nanosilica dispersion and the brine are co-injected into the core and shut-in for different periods of time. Then brine is injected into the core to assess the durability of the gel formed in the fracture. To avoid the disruption of the reactive gel structure in the fracture and to simulate an instantaneous constant pressure exerted on the inserted gel, pressure drop is progressively increased during the test by pumping the holdback test fluid at a very slow rate. The holdback pressure gradient (psi/ft) was computed based on the length of the core and the maximum pressure drop that occurred prior to liquid breach, which is recorded as the maximum holdback pressure. Thus, it is anticipated that the nanosilica gel in place will resist any steady pressure that is lower than the maximum holdback pressure.

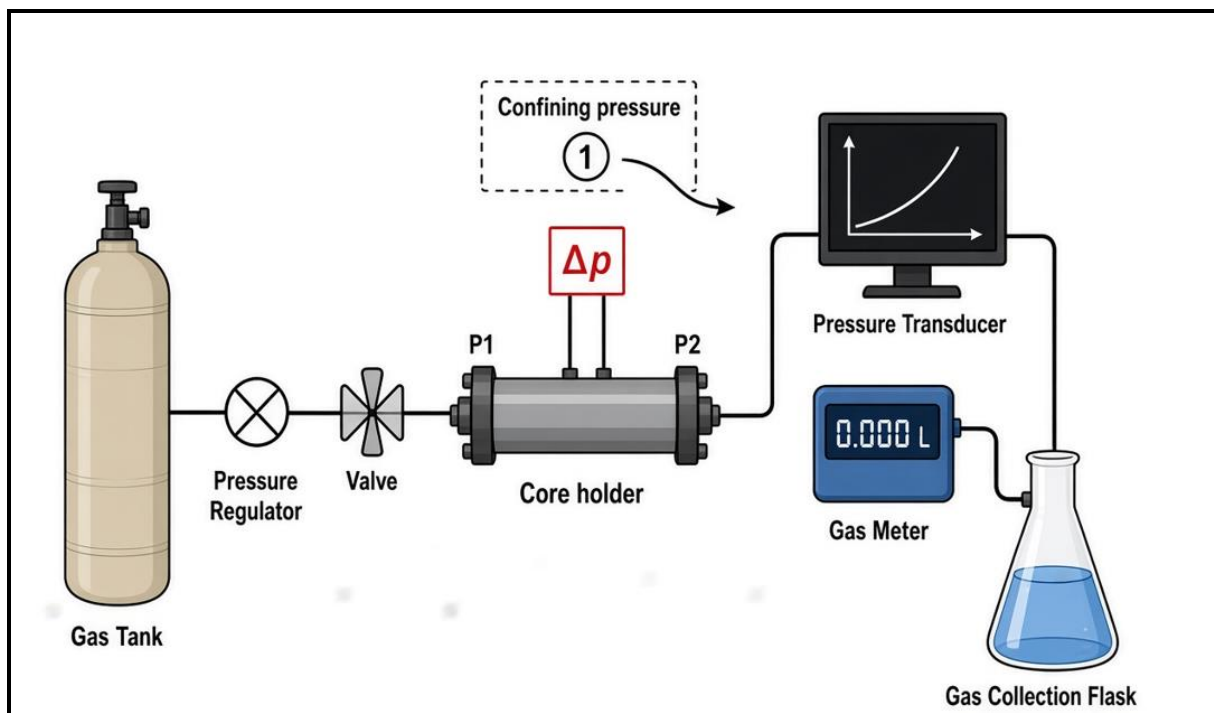
The sealing performance of the nanosilica sealant for gas leakage remediation is tested by injecting CO₂ into the core and measurement of the gel holdback pressure. As depicted in Figure 3b, a CO₂ tank with a regulator is connected to the core holder to provide fluid injection. A gas meter is used to measure the leakage gas flow rate from the core. During the test, CO₂ is injected into the core by stepwise increase of the injection pressure. The CO₂ flow out from the core is monitored by the gas meter for every stepwise increment in the applied injection pressure. The test continues until CO₂ breakthrough is observed. The sealing pressure is regarded as the maximum holdback pressure before CO₂ breakthrough the gel. To estimate the fracture conductivity during the injection test, Eqn.1 is used^[31].

$$C_f = 8.036 \frac{q\mu dL}{D\Delta P} \quad (1)$$

Where q (flowrate) in cc/min, μ (viscosity) in cp, dL is the core length in inch, D is the core diameter in inch and C_f is the fracture conductivity in mD-ft.



(a)



(b)

Figure 3. Experiment setup for nanosilica placement (a) and gel sealing performance measurement (b).

3. RESULTS AND DISCUSSION

3.1 Effect of nanosilica concentration on the sealing performance for brine

The sealing performance of nanosilica gel under brine injection is a critical parameter for evaluating its ability to restrict fluid migration through fractured cement. Figure 4 presents the pressure response as a function of time during brine injection through an artificially fractured cement core containing nanosilica gel. Following injection, the nanosilica interacted with the aqueous phase and developed a silica-gel network within the fracture, progressively restricting the available flow pathways. Consequently, the injection pressure increased substantially while little or no visible fluid leakage was observed, indicating progressive fracture sealing.

As shown in Figure 4, the pressure response of the 25 wt% nanosilica gel-treated core increased rapidly during the initial stage of the experiment and subsequently continued to build as the gel developed within the fracture. The pressure reached approximately 800–820 psi, with 805 psi identified as the hold-back pressure at which gel migration from the fracture was first observed. The corresponding hold-back pressure gradient, calculated based on the length of the cement core, was 966 psi/ft. The substantial pressure developed before gel migration demonstrates the ability of the nanosilica system to withstand a high hydraulic pressure differential and effectively restrict brine transport through the fractured cement.

For comparison, *Tavassoli et al.* reported the use of a polymer gel based on *poly(acrylic acid) polymers* for wellbore leakage remediation [11]. Their study reported an average hold-back pressure gradient of approximately 70 psi/ft. The substantially higher-pressure gradient obtained with the nanosilica gel (966 psi/ft) indicates considerably greater resistance to fluid migration under the tested conditions. This result suggests that the nanosilica gel forms a mechanically robust sealing structure capable of sustaining significantly higher-pressure differentials than the polymer-gel system reported by *Tavassoli et al.* [11].

The water-only control test further demonstrates the effectiveness of the nanosilica treatment. As shown in Figure 4, the control exhibited only a small pressure increase, stabilizing at approximately 50–60 psi, whereas the nanosilica-treated specimen developed pressures exceeding 800 psi. This large difference confirms that the high-pressure resistance observed in the treated specimen was primarily associated with the formation and consolidation of the nanosilica sealing network rather than the hydraulic resistance of the fractured cement alone.

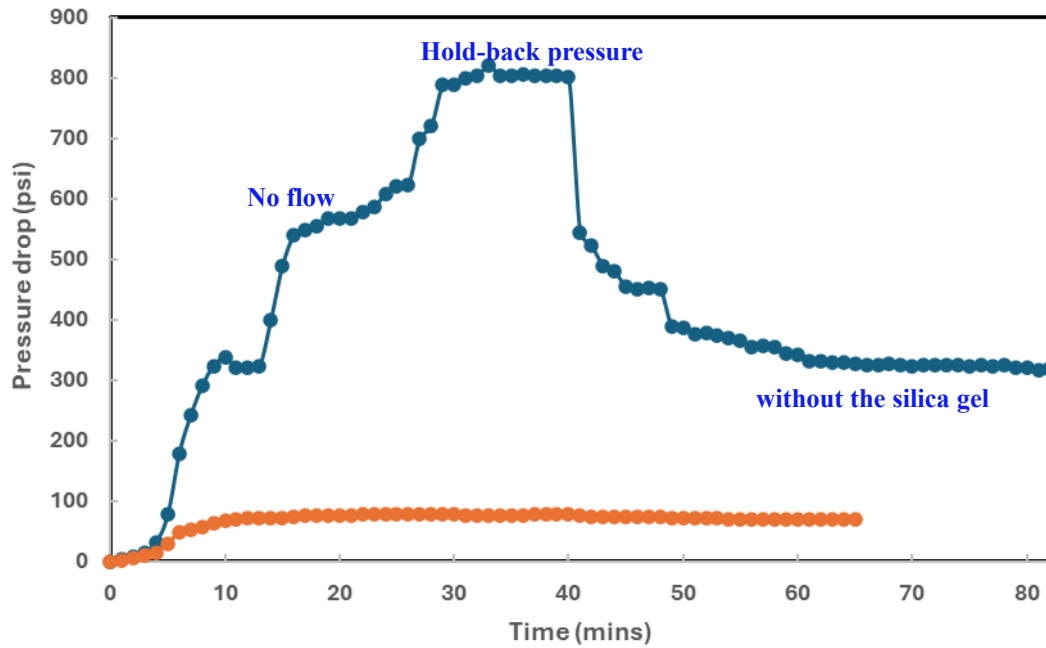


Figure 4 Effect of Nanosilica Concentration on the sealing pressure of nanosilica gel

Table 4 summarizes the measured hold-back pressure responses at varying nanosilica concentrations. At a concentration of 15 wt%, the gel system exhibited a hold-back pressure of 520 psi, whereas increasing the concentration to 25 wt% resulted in a substantially higher value of 1400 psi. This marked improvement clearly demonstrates a strong positive correlation between nanosilica concentration and sealing performance. The observed trend confirms that higher nanosilica loading enhances gel strength, thereby improving the system's ability to sustain higher differential pressures and effectively seal fracture pathways.^[31]

Table. 4 Experimental results for the sealing and leakage tests.

Conc. (%)	W (in)	DP (psi)	C _f (md-ft)
25	0.0625	1400	0.96
20	0.0625	1044	0.96
18	0.0625	805	0.96
15	0.0625	635	0.96
13	0.0625	520	0.96

This result indicates that Nano silica gel strength plays a critical role in governing sealing performance in fractured geological media because it determines the ability of the sealing material to withstand an imposed pressure differential without excessive deformation or displacement. The nanosilica particles used in this study are inherently hydrophilic, with surfaces dominated by abundant silanol ($-\text{Si}-\text{OH}$) functional groups. These hydroxyl groups promote hydrogen bonding and interparticle interactions, facilitating the development of an interconnected three-dimensional particulate network. The resulting filler network enhances

structural integrity and increases resistance to deformation under hydraulic loading, thereby improving fracture-sealing efficiency [32]. Furthermore, nanosilica concentration is an important parameter controlling gelation behaviour and the resulting microstructural density of the sealing matrix. Increasing nanosilica concentration increases the frequency of particle–particle interactions, promoting the formation of a denser and more interconnected gel network. The resulting reduction in pore connectivity and increase in structural rigidity enhance resistance to fluid penetration and improve the overall sealing capability [33].

3.2 Effect of fracture width on the sealing performance

The effect of fracture width on the sealing performance of the nanosilica gel was evaluated at a constant nanosilica concentration of 20 wt% and the results are presented in Figure 7. The 20% nanosilica concentration was selected based on both sealing performance and rheological behavior. Previous experimental investigations by Olayiwola et al. [31] demonstrated that nanosilica concentrations in the range of 15–25 wt% exhibited relatively lower gel strength over a suitable gelation period, whereas concentrations of 30–40 wt% produced higher gel strength but exhibited shorter gelation times [31]. This behavior is important for core-scale injections because excessively rapid gelation can result in premature solidification and blockage at the core-holder inlet before the sealing material has adequately penetrated the target crack. Therefore, 20 wt% nanosilica was selected as an intermediate concentration providing a practical balance between injection time, gelation behavior, and developing gel strength, for this sensitivity observation.

As shown in Table 5 and Figure 5, the sealing pressure decreased systematically with increasing fracture width. For fracture widths of 0.050, 0.0625, and 0.100 in., the corresponding sealing pressures were 1044, 802, and 335 psi, respectively. This pronounced reduction demonstrates that fracture aperture is an important parameter governing the pressure resistance of the nanosilica seal. At the smallest fracture width of 0.050 in., the nanosilica gel exhibited the highest sealing pressure of 1044 psi. Increasing the fracture width to 0.0625 in. resulted in a reduction in sealing pressure to 802 psi, corresponding to an approximately 23.2% decrease. A further increase in fracture width to 0.100 in. reduced the sealing pressure to 335 psi, representing a 58.2% decrease relative to the 0.0625-in. fracture and an overall reduction of approximately 67.9% relative to the 0.050-in. fracture. The results therefore indicate a strong inverse relationship between fracture width and sealing pressure within the range investigated.

The observed behavior can be attributed primarily to the increased flow capacity and available void volume associated with wider fractures. For a given pressure gradient, a wider fracture provides a larger flow across a cross-sectional area and a less restrictive pathway for fluid transport. Consequently, a greater volume of nanosilica dispersion may be required to effectively occupy and bridge the fracture before a high-resistance sealing structure can be established. In addition, the larger fracture aperture may facilitate preferential migration or bypass of the nanosilica dispersion, thereby reducing the extent of particle accumulation and gel bridging across the fracture. These effects can collectively

result in a lower pressure resistance of the resulting seal. The results also suggest that the efficiency of fracture sealing is governed not only by the intrinsic gel strength but also by the geometric characteristics of the leakage pathway. In a narrow fracture, the confined geometry promotes contact between the nanosilica dispersion and the fracture surfaces and facilitates the development of a continuous sealing structure over a relatively small flow aperture.

As the fracture width increases, greater gel penetration and placement may be required to establish an equivalent degree of hydraulic isolation. Therefore, the lower sealing pressure observed for the wider fractures does not necessarily indicate a loss of nanosilica gel functionality; rather, it reflects the greater hydraulic and volumetric demands associated with sealing a larger flow pathway ^[31].

Table 5. Effect of fracture width on the sealing pressure of 20 wt% nanosilica gel

Nanosilica Conc. (%)	Fracture Width. (in)	Sealing Pressure ΔP (psi)	Fracture Conductivity C_f , (md-ft)
20	0.05	1044	0.63
20	0.0625	802	0.96
20	0.1	335	40.18

Another possible contributing factor is the residence and reaction time of the nanosilica dispersion within the fracture. Nanosilica can interact with the cementitious matrix through surface reactions and pozzolanic processes, potentially contributing to the development of a more stable sealing structure. However, the extent to which these reactions contribute to the measured sealing pressure depends on the available reaction time, water chemistry, fracture surface area, and transport conditions. For the wider fractures, increased dispersion mobility and a larger flow volume may reduce the residence time of the nanosilica within localized regions of the fracture, potentially limiting the development of a uniformly consolidated seal.

The results further demonstrate that increasing fracture width from 0.0625 to 0.100 in. produces a disproportionately large reduction in sealing pressure compared with the increase from 0.050 to 0.0625 in. Specifically, an increase in fracture width of only 0.0125 in. between the first two conditions resulted in a 23.2% reduction in sealing pressure, whereas an increase of 0.0375 in. between 0.0625 and 0.100 in. resulted in an additional 58.2% reduction. This nonlinear response indicates that the sealing efficiency may become increasingly sensitive to fracture aperture as the fracture becomes wider. Thus, extrapolation of the observed trend beyond the investigated fracture-width range should be avoided without additional experimental data.

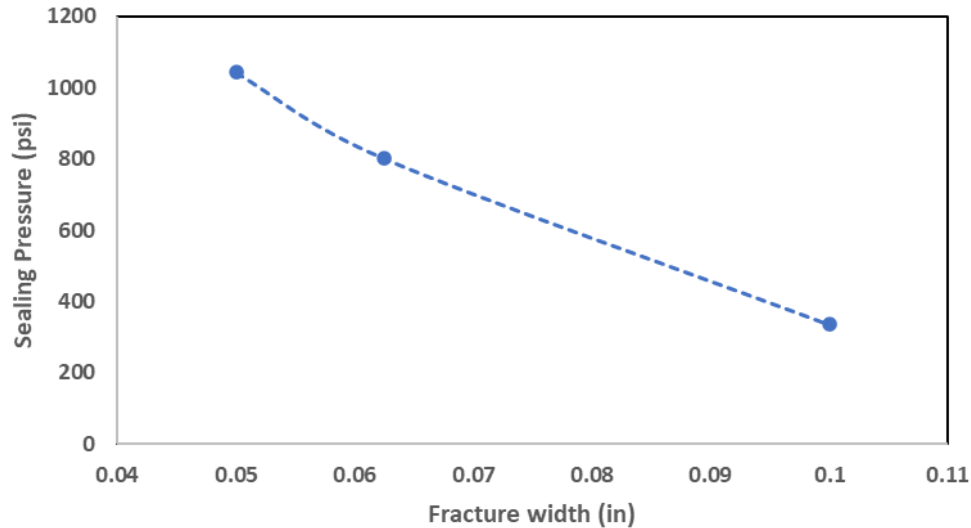


Figure 5 Effect of fracture width on the sealing pressure of nanosilica gel

The results in Figure 5 have important implications for the application of nanosilica-based sealing materials in wellbore integrity and subsurface leakage-control applications. The ability to sustain a sealing pressure of 1044 psi in a 0.050-in. fracture demonstrates strong performance under relatively narrow fracture conditions. However, the reduction to 335 psi in the 0.100-in. fracture indicates that fracture width must be considered when designing nanosilica-based remediation treatments. Wider leakage pathways may require optimization of nanosilica concentration, injected volume, placement strategy, or gelation characteristics to achieve sufficient fracture filling and pressure resistance. Previous findings have similarly indicated that increasing nanosilica concentration can enhance gel strength and sealing performance, particularly where larger fracture apertures require a stronger and more stable sealing structure ^[31]. Overall, the results establish that fracture width has a substantial influence on the sealing pressure of 20 wt% nanosilica gel. The approximately 68% reduction in sealing pressure as the fracture width increased from 0.050 to 0.100 in. highlights the importance of matching the rheological and mechanical properties of the sealing material to the geometry of the target leakage pathway. These findings further emphasize that nanosilica concentration and fracture width should be considered jointly when optimizing the sealing formulation for fractured cement systems.

3.3 Effect of fracture Interface on the gel sealing properties

Wellbore cement fractures are most likely to occur between the cement-casing interface, cement-formation rock interface, or within the cement itself ^[34]. The performance of nanosilica gel to seal the fractures with different types of interfaces was evaluated in this study. Cracks may develop in cement-cement (cmt-cmt), cement-sandstone (cmt-sst), and cement-casing (cmt-csg) portions depending on the downhole conditions. On the other hand, calcium in the cement section can promote the gelation of the nanosilica gel system on the cement surface, but the porosity of sandstone formation can enable nanosilica solution to flow through its surface rather than building a sealing gel on it. To replicate the various

geological wellbore cement fractures previously addressed, three types of fractures were prepared: *cement-cement*, *cement-sandstone*, and *cement-casing*. The sealing pressure of the nano silica gel under different contact conditions is shown in Figure 6. The findings in Figure 6 show how different fracture arrangements react to the nanosilica gel's propensity to seal. The cement-cement and cement-casing interfaces produced sealing pressures of 802 psi and 820 psi, respectively, whereas the cement-sandstone interface produced a sealing pressure of 565 psi. This may have been caused by the porosity impact of the cement-sandstone section, which impeded the formation of the nanosilica gel and had a more severe filtering effect, particularly in the sandstone region^[35].

The results further indicate that the sealing performance of nanosilica gel is controlled by both fracture width and interface characteristics. As demonstrated previously, increasing fracture width reduces sealing pressure because a larger flow pathway requires greater resistance to achieve hydraulic isolation. The present results extend this observation by showing that, even at comparable fracture conditions, the nature of the material forming the fracture interface can substantially influence the resulting sealing pressure. Thus, effective application of nanosilica-based sealing systems in wellbore integrity remediation requires consideration not only of fracture aperture but also of whether the leakage pathway is located within cement, along the casing interface, or at the cement–formation interface.

From an application perspective, the relatively high sealing pressures measured for the cmt–cmt (802 psi) and cmt–csg (820 psi) configurations demonstrate that the nanosilica gel can develop considerable pressure resistance at cement-associated and casing-associated interfaces. The lower value obtained for the cmt–sst interface (565 psi) highlights a potential limitation when sealing leakage pathways associated with porous formation materials. In such cases, optimization of the nanosilica concentration, gelation characteristics, injection volume, or placement pressure may be necessary to compensate for dispersion loss into the formation and achieve an adequate sealing barrier.

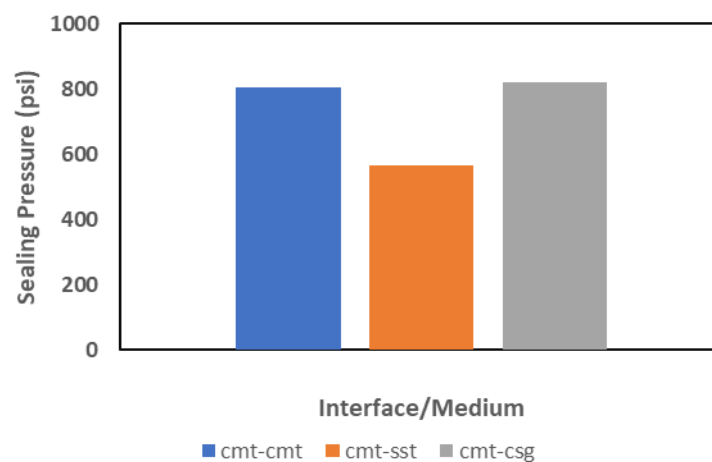


Figure 6 Effect of fracture-interface type on the sealing pressure of nanosilica gel

3.4 Effect of Ca^{2+} leaching from cement on the gel sealing properties

The role of Ca^{2+} is particularly important because divalent ions can be considerably more effective in destabilizing colloidal silica than monovalent ions at comparable ionic concentrations. The interaction of Ca^{2+} with negatively charged silica surfaces can reduce the electrostatic barrier to particle association and facilitate the transition from a relatively mobile nanosilica dispersion to a more rigid gel structure. In the present system, the cement therefore functions not only as the substrate containing the fracture but also as a potential in situ source of gelation-promoting ions. This represents an important advantage over formulations requiring the prior addition of chemical gelation accelerators.

When the nanosilica dispersion encounters the cement wall, the high concentration of Ca^{2+} ions in the hydrated cement may seep out of the cement and start the nanosilica gelation process. This procedure involves injecting only nanosilica dispersion with no other additives into the fractures. By doing this, the extra expense of preparing and injecting chemicals and brine as gelation accelerators in the field application will be eliminated. A cement-cement fracture was created and cleaned using DI water to evaluate the effectiveness of this procedure. Subsequently, a nanosilica dispersion was introduced into the fracture and left there for various durations. Figure 7 displays the pressure change with time as brine was injected to test the hold-back pressure.

Two different soaking times were observed. The blue line displays the gel sealing performance after 1-week soaking time with the maximum hold-back pressure of 53 psi. The orange line displays the hold-back pressure after 5-week soaking time. The maximum hold-back pressure increases to 105 psi. The results indicate that a stronger gel is developed after a longer soaking time is allowed. In addition, the developed gel after 1-week soaking time can hold pressure of 53 psi and produce pressure gradient of 63.6 psi/ft, which is even greater than the pressure gradients in CO_2 storage^[36]. Hence, our laboratory results revealed that the injection of nano silica dispersion without any chemical additive into cement fractures, where the dispersion reacts with Ca^{2+} leached from the cement, generates silica gel, and effectively seal the fracture leakage.

The soaking-time dependence also provides evidence that the sealing process is not instantaneous. After 1 week, the resulting gel was already capable of sustaining approximately 53 psi, demonstrating that sufficient gel development occurred solely through interaction with the cement environment. Continued exposure to the cement for an additional four weeks resulted in a hold-back pressure of 105 psi. The increase in pressure resistance suggests that the nanosilica network continued to evolve with time, potentially through further particle aggregation, network consolidation, and interfacial bonding.

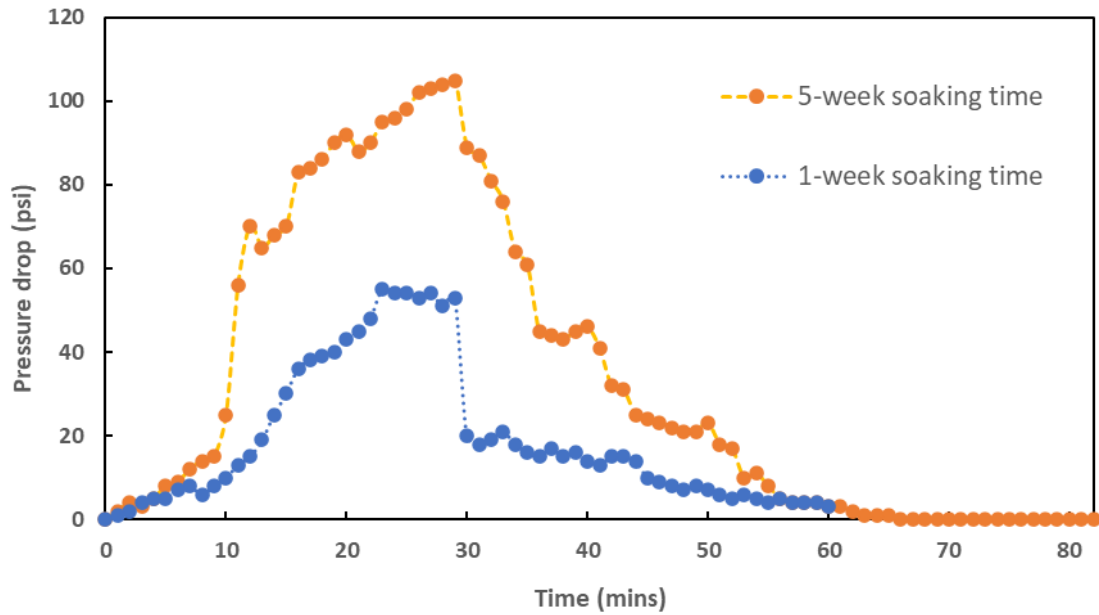


Figure 7 Effect of Cement–Nanosilica soaking time on the hold-back pressure of the nanosilica gel in an artificially fractured cement core.

The enhancement in sealing performance observed with electrolyte addition can be attributed to changes in the colloidal interactions of the nanosilica particles. In aqueous suspension, nanosilica particles are stabilized by negatively charged surface silanol groups, which create an electrical double layer that prevents particle aggregation through electrostatic repulsion^[19].

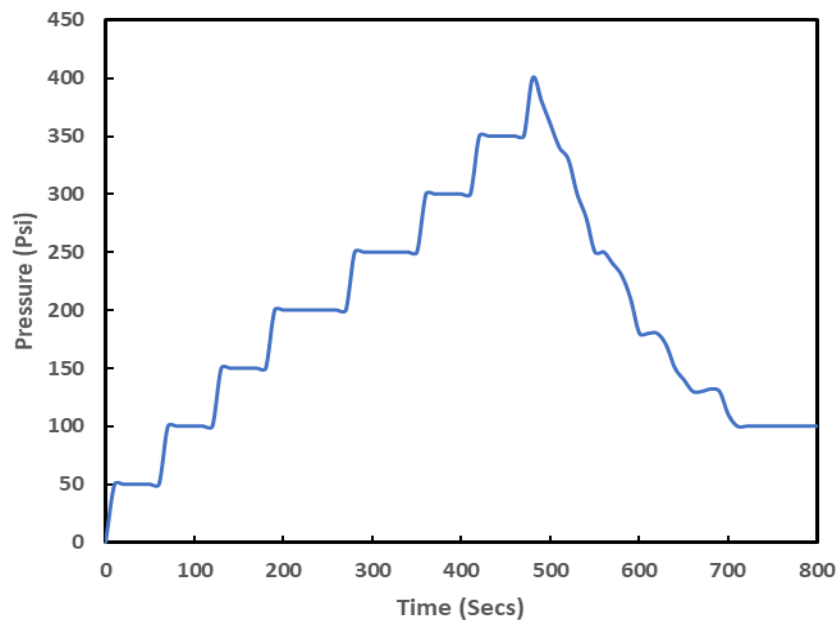
Overall, Figure 7 demonstrates a clear time-dependent enhancement of nanosilica sealing performance in a cement–cement fracture. The increase in hold-back pressure from 53 psi after 1 week to 105 psi after 5 weeks indicates progressive development and strengthening of the nanosilica seal during prolonged contact with the cement matrix. The results support the hypothesis that ions released from hydrated cement, particularly Ca^{2+} , can promote nanosilica destabilization and gel formation by reducing electrostatic repulsion between silica particles. The resulting increase in particle association and network connectivity provides greater resistance to hydraulic flow through the fracture. Importantly, the ability of the nanosilica dispersion to develop sealing strength without an externally added gelation accelerator demonstrates the potential for cement-activated nanosilica gelation as a simplified and potentially cost-effective approach for sealing leakage pathways in wellbore cement.

3.5 The sealing performance of nanosilica sealant for CO₂ leakage

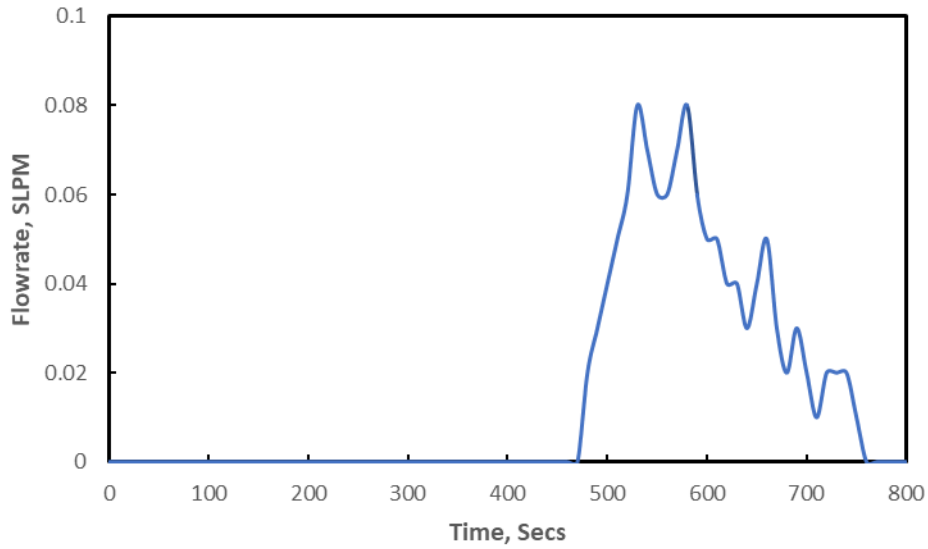
Figure 8 presents the variation in CO₂ injection pressure following the placement of 18 wt.% nanosilica dispersion within the artificially generated fracture. No measurable CO₂ flow was observed through the cement core during the initial stage of injection. As the injection

pressure increased to approximately 400 psi, CO₂ breakthrough occurred through the fractured pathway, accompanied by a subsequent decline in injection pressure. This pressure reduction provides further evidence of breakthrough and indicates the onset of CO₂ migration through the silica-gel-sealed fracture. Compared with the brine breakthrough pressure presented in Figure 4, CO₂ breakthrough occurred at a lower injection pressure. This difference can be attributed primarily to the substantially lower viscosity of CO₂ relative to brine, which facilitates its transport through the gel-filled fracture under an equivalent pressure gradient. The results therefore demonstrate that the sealing resistance of the nanosilica gel is dependent not only on the properties of the gel and fracture but also on the physicochemical properties of the migrating fluid

Based on the measured maximum holdback pressure and the length of the cement core, the corresponding holdback pressure gradient was calculated to be approximately 480 psi/ft. This value is substantially greater than the pressure gradients generally associated with CO₂ leakage from geological storage formations. Ho et al. reported that CO₂ leakage driven by buoyancy and pressure differences can correspond to a pressure gradient of approximately 0.2–0.4 psi/ft, depending on whether the stored CO₂ exists predominantly in the supercritical or gaseous state ^[36]. Furthermore, they estimated a pressure gradient of approximately 5 psi/ft for a scenario in which CO₂ injection increases the pressure of the brine phase by 500 psi above its initial pressure and leakage occurs through an overlying sealing formation with a thickness of 100 ft ^[36]. The experimentally determined holdback pressure gradient of 480 psi/ft is therefore substantially higher than these representative formation-scale pressure gradients. This large pressure-gradient margin indicates that the nanosilica-derived gel has a strong capacity to resist CO₂ migration through the fracture.



(a)



(b)

Figure 8 Nanosilica gel resistance to pressure buildup in CO₂-breakthrough test (a) and gas flow rate measured vs. injection time (b).

However, Figure 9 illustrates the effect of nanosilica concentration on the maximum hold-back pressure. Increasing the nanosilica concentration from 15 wt% to 25 wt% increased the maximum hold-back pressure from 300 psi to 900 psi, corresponding to a pressure gradient increase from 360 psi/ft to 1080 psi/ft. This significant improvement indicates that higher nanosilica concentrations produce stronger gel networks capable of withstanding greater pressure differentials. The observed trend is consistent with polymer gel systems, where increasing the concentration enhances gel strength and sealing performance. Our previous study further supports this finding, showing that increasing the nanosilica concentration from 15 wt% to 25 wt% increased the gel strength from 504 to 3006 lb/100 ft² and the yield point from 27.9 to 536.9 lb/100 ft² [31]. Although higher nanosilica concentrations can further improve sealing performance, they also accelerate gelation, reducing the available placement time. Therefore, an optimum nanosilica concentration is required to balance gel strength and injectivity for effective fracture sealing under CO₂ geological storage application.

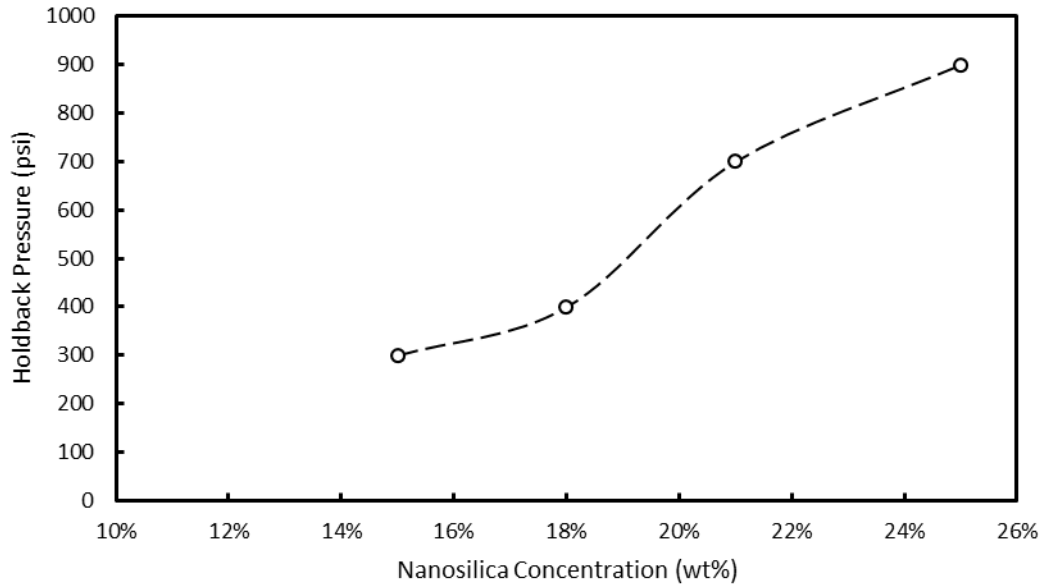


Figure 9. The maximum holdback pressure changes with nanosilica concentration.

4. CONCLUSION

This study's findings could lead to the following conclusions:

1. Increasing nanosilica concentration enhanced sealing performance. Increasing the nanosilica concentration from 15 wt% to 25 wt.% increased the brine sealing pressure from 520 psi to 1400 psi. At a constant concentration of 20 wt%, reducing the fracture width from 0.10 to 0.05 in. increased the sealing pressure from 335 psi to 1044 psi. This improvement is attributed to the formation of a denser, more interconnected silica gel network, while narrower fractures facilitate particle bridging and reduce fluid flow pathways.
2. Cement-based interfaces exhibited superior sealing efficiency. The cement–cement and cement–casing interfaces achieved an average brine sealing pressure of approximately 800 psi, compared with 565 psi for the cement–sandstone interface at a constant fracture width of 0.0625 in. This behavior is likely due to enhanced chemical interactions and improved gel adhesion at cement-rich interfaces, resulting in stronger and more stable seals.
3. Calcium ion leaching promoted nanosilica gelation. Calcium ions (Ca^{2+}) released from the cement matrix accelerated nanosilica gelation, with longer soaking periods (from one to five weeks) producing stronger gels and higher sealing capacity. The increased availability of Ca^{2+} promotes silica particle aggregation and network formation, thereby improving the mechanical strength of the gel.
4. Nanosilica gel-maintained stability under CO_2 storage conditions. The nanosilica-derived silica gel remained stable under high-pressure and high-temperature CO_2 conditions and effectively sealed cement fractures. The chemically stable silica network resists degradation in CO_2 -rich environments, making it a promising sealing

material for maintaining long-term wellbore integrity in geological carbon storage applications.

Credit Authorship Contribution Statement

Olayiwola Olatunji: Writing – Original draft, Writing, Writing -Review & Editing, Conceptualization and Experimental Testing.

Nabaladiomon Coulibaly: Writing - Review & Editing

Kumarasan Muthian: Writing -Review & Editing.

Ning Liu: Supervision, Conceptualization and Experimental Testing.

Boyun Guo: Supervision, Conceptualization and Experimental Testing.

Funding Declaration

This research did not receive any specific grant from funding agencies in the public, commercial, or not for profit sectors.

Data Availability.

All data generated or analyzed during this study are included in this published article.

Declaration

Ethical Approval

Not Applicable

Consent to Participate

Not Applicable

Consent to Publish

Not Applicable

Competing Interest

All Authors declare that there are no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

References

1. Shukla, J.B., Arora, M.S., Verma, M., Misra, A.K., Takeuchi, Y. The Impact of Sea Level Rise Due to Global Warming on the Coastal Population Dynamics: A Modeling Study. *Earth Systems and Environment* 5, 909–926 (2021).
2. Ehlig-Economides, C., Economides, M.J., Sequestering carbon dioxide in a closed underground volume. *Journal of Petroleum Science and Engineering* 70 123-130 (2010).
3. Schäfer, D., Hagrey, S. A., Auken, E., Bahr, A., Beyer, M., Dahmke, A., ... & Wöhr, C. (2012). Environmental and process monitoring. In *CLEAN: CO₂ Large-Scale Enhanced Gas Recovery in the Altmark Natural Gas Field–GEOTECHNOLOGIEN Science Report No. 19* (pp. 131-167). Berlin, Heidelberg: Springer Berlin Heidelberg.
4. Citalingam, K., Zeinijahromi, A., Salmachi, A., & Xie, Q. (2026). Wellbore interface and cement defects in CO₂ geological storage: A review. *Greenhouse Gases: Science and Technology*, 16(2), 332-352.
5. Cao, P., Karpyn, Z.T., Li, L. Self-healing of cement fractures under dynamic flow of CO₂-rich brine. *Water Resources Research* 51 4684–4701 (2015).
6. Song, Z., Hou, J., Liu, X., Wei, Q., Hao, H., Zhang, L., Conformance control for CO₂-EOR in naturally fractured low permeability oil reservoirs. *Journal of Petroleum Science and Engineering* 166 225-234 (2018).
7. Ma, X., Zhang, X., Tian, D., Farmland degradation caused by radial diffusion of CO₂ leakage from carbon capture and storage. *Journal of Cleaner Production* 255, 120059 (2020).
8. Peter, A., Hornbruch, G., Dahmke, A., CO₂ Leakage test in a shallow aquifer for investigating the geochemical impact of CO₂ on groundwater and for developing monitoring methods and concepts. *Energy Procedia* 4, 4148–4153 (2011).
9. Rastelli, E., Corinaldesi, C., Dell’Anno, A., Amaro, T., Greco, S., Martire, M.L., Carugati, L., Queirós, A.M., Widdicombe, S., Danovaro, R., CO₂ Leakage from carbon dioxide capture and storage (CCS) systems affects organic matter cycling in surface marine sediments. *Marine Environmental Research* 122, 158–168 (2016).
10. Ko, D., Yoo, G., Yun, S.-T., Chung, H., Impacts of CO₂ leakage on plants and microorganisms: A review of results from CO₂ release experiments and storage sites. *Greenhouse Gases: Science and Technology* 6, 319–338 (2016).
11. Onishi, T., Nguyen, M.C., Carey, J.M., Will, B., Zaluski, W., Bowen, D.W., Devault, B.C., Duguid, A., Zhou, Q., Fairweather, S.H., Spangler, L.H., Stauffer, P.H. “Potential CO₂ and brine leakage through wellbore pathways for geologic CO₂ sequestration using the National Risk Assessment Partnership tools: Application to the Big Sky Regional Partnership” *International Journal of Greenhouse Gas Control* 81, 44-65 (2019).
12. Su, X., Liu, S., Zhang, L., Liu, G., Wang, Y., Gan, M., Li, X. “Wellbore leakage risk management in CO₂ geological utilization and storage: A review” *Energy Reviews* 2, 100049 (2023).
13. Tavassoli, S., Ho, J.F., Shafiei, M., Huh, C., Bommer, P., Bryant, S., Balhoff, M.T. “An experimental and numerical study of wellbore leakage mitigation using pH-triggered polymer gelant” *Fuel* 217, 444-457 (2018).
14. Phillips, A. J., Lauchnor, E., Eldring, J., Esposito, R., Mitchell, A.C., Gerlach, R., Cunningham, A.B., Spangler, L.H. Potential CO₂ leakage reduction through biofilm-induced calcium carbonate precipitation, *Environmental Science & Technology* 47, 142-149 (2013).
15. Castañeda-Herrera, C. A., Black, J. R., Llanos, E. M., Stevens, G. W., Haese, R. R. Formation of an amorphous silica gel barrier under CO₂ Storage Conditions. *International Journal of Greenhouse Gas Control* 78 27-36 (2018).
16. Noshi, C. I., & Schubert, J. J. (2018, September). Self-healing biocement and its potential applications in cementing and sand-consolidation jobs: a review targeted at the oil and gas industry. In *SPE Liquids-Rich Basins Conference-North America* (p. D022S010R001). SPE.
17. Dliwayo, C. (2022). *Cementing slurry suitable for oil and gas wellbore drill for application in South Africa* (Master's thesis, University of the Witwatersrand, Johannesburg (South Africa)).

18. Castaneda-Herrera, C. A., Stevens, G. W., & Haese, R. R. (2018). Review of CO₂ leakage mitigation and remediation technologies. *Geological Carbon Storage: Subsurface Seals and Caprock Integrity*, 327-337.
19. Altin, B. (2019). *Synthesis and characterization of poly ((2-dimethylamino) ethyl methacrylate)(PDMAEMA) modified silica nanoparticles* (Doctoral dissertation, Dissertation, Berlin, Technische Universität Berlin, 2019).
20. Li, D., Zhang, L., Ren, S., Rui, H., Leakage mitigation during CO₂ geological storage process using CO₂ triggered gelation. *Industrial & Engineering Chemistry Research* 58, 3395–3406 (2019).
21. Todorovic, J., Raphaig, M., Lindeberg, E., Vrålstad, T., Buddensiek, M.-L. Remediation of leakage through annular cement using a polymer resin: A laboratory study, *Energy Procedia* 86, 442-449 (2016).
22. 17, Ito, T., Xu, T., Tanaka, H., Taniuchi, Y., Okamoto, A., Possibility to remedy CO₂ leakage from geological reservoir using CO₂ reactive grout. *International Journal of Greenhouse Gas Control* 20, 310–323 (2014).
23. Salami, B. A., Oyehan, T. A., Gambo, Y., Badmus, S. O., Tanimu, G., Adamu, S., ... & Saleh, T. A. (2022). Technological trends in nanosilica synthesis and utilization in advanced treatment of water and wastewater. *Environmental Science and Pollution Research*, 29(28), 42560-42600.
24. 18, Hatzignatiou, D.G., Giske, N.H., Strand, D., Water-soluble silicate gelants: Comparison and screening for conformance control in carbonate naturally fractured reservoirs. *Journal of Non-Crystalline Solids* 479, 72–81 (2018).
25. 19, Wiese, B.U., Fleury, M., Basic, I., Abdollahi, J., Patrnogic, A., Hofstee, C., Carlsen, I.M., Wollenweber, J., Schmidt-Hattenberger, C., Drysdale, R., et al., 2019. Near wellbore sealing in the Bečej CO₂ reservoir: Field tests of a silicate-based sealant. *International Journal of Greenhouse Gas Control* 83, 156–165 (2019).
26. Li, L., Zhang, Y., Hubler, M.H., Xi, Y., “Experimental study on nanoparticle injection by using a lab-scale wellbore system” *Cement and Concrete Composites* 127, 104409 (2022).
27. Shaibu, R., Guo, B., Wortman, P. B., Lee, J. Stress-sensitivity of fracture conductivity of Tuscaloosa Marine Shale cores. *Journal of Petroleum Science and Engineering*, 210, 110042 (2022).
28. Jia, H., Niu, C. C., & Yang, X. Y. (2020). Improved understanding nanocomposite gel working mechanisms: From laboratory investigation to wellbore plugging application. *Journal of Petroleum Science and Engineering*, 191, 107214.
29. Almohsin, A., Hung, J., Alabdrabalnabi, M., & Sherief, M. (2021, December). A nano method for a big challenge: Nanosilica-based sealing system for water shutoff. In *SPE Middle East Oil and Gas Show and Conference* (p. D031S028R002). SPE.
30. Zarcie, C., Bahramian, A. R., Sefti, M. V., Salehi, M. B. Network-gel strength relationship and performance improvement of polyacrylamide hydrogel using nano-silica; with regards to application in oil wells conditions. *Journal of Molecular Liquids*, 278, 512-520 (2019)
31. Olayiwola, O., Nguyen, V., Yousuf, N., Baudoin, N., Liu, N., Guo, B. Experimental Investigation of Nanosilica Gel Properties for Well Integrity Remediation. *Energy & Fuels*, 36(23), 14094-14100 (2022)
32. Davies, R. J., Almond, S., Ward, R. S., Jackson, R. B., Adams, C., Worrall, F., Herringshaw, L.G., Gluyas, J.G., Whitehead, M. A. Oil and gas wells and their integrity: Implications for shale and unconventional resource exploitation. *Marine and Petroleum Geology*, 56, 239-254 (2014).
33. Hodgkinson, E. S., Hughes, C.R. (1999). *The mineralogy and geochemistry of cement/rock interactions: high-resolution studies of experimental and analogue materials*, Geological Society, London, Special Publications.
34. Ho, J.F., Tavassoli, S., Patterson, J.W., Shafiei, M., Huh, C., Bommer, P.M., Bryant, S.L., Balhoff, M.T. “The use of a pH-triggered polymer gelant to seal cement fractures in wells”, *SPE Drilling & Completion* 31 225-235 (2016).
35. Hunt, J.D., Ezzedine, S.M., Bourcier, W., Roberts, S. “Kinetics of the gelation of colloidal silica at geothermal conditions, and implications for reservoir modification and

management”, paper SGP-TR-198 presented at the Thirty-Eighth Workshop on Geothermal Reservoir Engineering held at Stanford University, Stanford, California, February 11-13, **2013**.

36. Tu Y., Chen N., Li C., Liu H., Zhu R., Chen S., Xiao Q., Liu J., Ramakrishna S., He L. Advances in injectable self-healing biomedical hydrogels. *Acta Biomater.* 90, 1-20 (**2019**).