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2025

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To cite this article: Ebikapaye Peretomode, Nadimul Faisal & Gbenga Oluyemi (05 Apr 2025): Experimental study on the effect of biocompetitive exclusion chemical on the unconfined compressive strength of sandstone reservoir rock under static saturation, Geomechanics and Geoengineering, DOI: [10.1080/17486025.2025.2484482](https://doi.org/10.1080/17486025.2025.2484482)

To link to this article: <https://doi.org/10.1080/17486025.2025.2484482>



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Published online: 05 Apr 2025.



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Experimental study on the effect of biocompetitive exclusion chemical on the unconfined compressive strength of sandstone reservoir rock under static saturation

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ABSTRACT

The potential impacts of oilfield chemical treatment on the petrophysical and geomechanical properties of reservoir rock are well known. In this paper, the effect of bio-competitive exclusion chemical (sodium nitrate) treatment on sandstone rock properties under static saturation has been examined. A combination of analytical and mechanical testing approaches was used. Analytical methods include scanning electron microscopy (SEM), energy dispersive X-ray spectroscopy (SEM/EDX), and X-ray powder diffraction (XRPD) while the mechanical testing method used was unconfined compressive strength (UCS) test. The test results suggest the dissolution and precipitation of new minerals, leading to mineralogical alterations and slightly enhanced porosity from $21.1 \pm 0.3\%$ to $21.6 \pm 0.1\%$, indicating an increase of about 2.9%. Results from the unconfined compressive strength (UCS) test show a 0.9% reduction for sandstone. The study suggests that biocompetitive exclusion chemical treatment has an insignificant impact on the geomechanical properties of the sandstone reservoir formation.

HIGHLIGHTS

- SEM, SEM/EDX, and XRPD tests were used to analyse potential changes in the reservoir rocks elemental and mineralogical change due to chemical-rock interaction.
- UCS test was used to check for changes in the strength of the reservoir rock before and after chemical treatment.
- Results from the test indicate mineral dissolution and precipitation and slightly increasing the porosity of the rock. However, this alteration did not have any significant effect on the strength of the rock.

ARTICLE HISTORY

Received 27 December 2023
Accepted 20 March 2025

KEYWORDS

Biocompetitive Exclusion;
core saturation;
geomechanical strength;
oilfield chemical; porosity
analysis; sandstone rock

1. Introduction

Fluid-rock interactions have an impact on reservoir formation rocks during oilfield chemical treatment, such as chemical flooding for enhanced oil recovery (EOR), reservoir stimulation via acidization, and geological CO₂ sequestration. Consequently, biocides or corrosion inhibitors that are utilised to modulate the production of H₂S as a result of reservoir souring brought on by sulphate reducing bacteria (SRB) may interact with the rock and change its petrophysical and geomechanical characteristics (Rijnaarts *et al.* 1993, Wuyep *et al.* 2020). It is still unknown how these oilfield chemicals affect the formation rocks. It is crucial to understand their effects on rock petrophysical and geomechanical properties under dynamic conditions, which are critical for reservoir integrity and productivity. In the evaluation of geological sequestration of CO₂,

an experimental study on the effect of a CO₂-NaCl solution on the compressive strength, chemical properties, and deformation of quartz-feldspar-detrital reservoir sandstone in a water-chemical environment demonstrates that CO₂ dissolved in the pore fluid reduced the compressive strength of sandstone to 7–15% of that without CO₂ (Zheng *et al.* 2015). This can be attributed to the mineral dissolution and precipitation reaction that occurs due to oilfield chemical-rock interactions which alters the elemental, mineralogical, particle size and porosity of the rock. This interaction results in the reduction of reservoir rock strength and may lead to sand production (Wuyep *et al.* 2020a, Peretomode *et al.* 2022a; Peretomode *et al.* 2022b). Chemical solutions like H₂SO₄ solution (pH 2.0), distilled water (pH 7.0), and NaOH solution (pH 12.0) have been used to study the effects of chemical

corrosion on the pore structure and mechanical characteristics of sandstone (Lin *et al.* 2019). Under static and dynamic conditions, the sandstone pore size becomes larger, the compressive strength and elastic modulus decrease, and the failure strain increases in the following order H_2SO_4 solution > NaOH solution > distilled water. This implies that concentration, type of chemical, corrosivity, and exposure time all affect how sandstone's pore structure and mechanical characteristics are altered by interactions with oilfield chemicals.

There has been a study on the flow-through investigation of the interactions between water and sandstone rock caused by CO_2 injection at temperatures and pressures similar to reservoir conditions (Huq *et al.* 2015). It was found from the fluid analysis that increased calcium and sulphate concentrations at early times under non-equilibrium geochemical conditions confirming the dissolution of cementing material anhydrite following fluid-rock interactions. The dissolution of rock cements following brine injection was primarily responsible for the sandstone's twofold increase in permeability. A study on how water-rock interactions affect the fracture and shear strength properties of sandstone in various hydrochemical conditions demonstrated that water-chemical solution corrosively rises as solution acidity or alkalinity increase (Huq *et al.* 2015). An investigation of how sulphuric acid-rock interactions with varying durations of treatment might cause chemical damage to sandstone and how this affects the mechanical behaviour has been published (Niu *et al.* 2023). According to the results, the acid rock reaction effectively dissolves the internal fillers such as calcite of rock pores, increasing pore volume. Additionally, the continuous dissolution damages the rock's pore structures, with the extent of the damage increasing over time, which results in the development of acid-induced fractures and subsequent decrease in the dynamic peak strength and dynamic elastic modulus. There are limited studies on the interactions of sodium nitrate with sandstone; most studies focus on the acidity/alkalinity of water solutions, brine, brine-carbon dioxide, and acid with sandstone. Thus, weakening of the rock grain matrices and reduction in unconfined compressive strength of the reservoir formation can cause sand failure. Consequently, chemical-rock interactions during oil production in the petroleum industry impact reservoir formation geomechanical characteristics resulting in formation damage, failure, and sanding.

On the other hand, the metabolic activities of sulphate-reducing bacteria (SRB) can be linked to reservoir souring commonly observed during the water flooding EOR approach. SRB-produced H_2S gas is toxic, causes

metal corrosion, precipitation of metal sulphides with the potential to clog reservoirs, contaminate natural gas and oil, and hence impair oil production (Reinsel *et al.* 1996, Davidova *et al.* 2001). Studies carried out by researchers such as Seto *et al.* (1997), Oluyemi (2014), and more recently, Wuyep *et al.* (2020)a, have reported the interactions of oilfield chemicals such as aluminium chloride (AlCl_3), polyethylene oxide (PEO), dodecyltrimethyl bromide (DTAB), scale inhibitors, and biocide used to control reservoir souring. However, biocides/inhibitors used to control H_2S production can cause a significant environmental hazard (Reinsel *et al.* 1996, Davidova *et al.* 2001). These chemicals are also constrained by duration and effectiveness. Thus, nitrate solution has been proposed as a potential oilfield chemical for controlling H_2S accumulation resulting from the activities of SRB in the reservoir (Davidova *et al.* 2001). Furthermore, the bio-competitive oilfield treatment with nitrate has proven environmentally friendly, cost-effective, versatile and extensive application in oil production (Anchliya 2006). Several authors have studied and published the controlling or treating of reservoir souring with nitrate (Reinsel *et al.* 1996, Telang *et al.* 1998, Sunde *et al.* 2004, Greene *et al.* 2006, Grigoryan *et al.* 2008, Hubert 2010, Voordouw *et al.* 2011, Tabari *et al.* 2011) and its use for oil recovery (Hitzman and Sperl 1994, Zhao *et al.* 2016). However, its impact on the formation rock's geochemical and geomechanical characteristics have never been explored. Thus, this work reports an investigation into the effects of nitrate-rock interactions on the petrophysical, geomechanical, and mineralogy characteristics of sandstone reservoir. The significance of evaluating the impact on petrophysical and geomechanical characteristics of reservoir rock resulting from the interaction between oilfield chemicals and the formation rock cannot be overemphasised. The microscopic investigation includes scanning electron microscope (SEM) examination of morphological changes resulting from the sodium nitrate interactions with the sandstone, while changes in mineralogical composition were studied using X-ray powder diffraction (XRPD). Whereas the unconfined compressive strength (UCS) was studied using the mechanical testing method following sodium nitrate treatment of sandstone.

2. Materials and methods

Sandstone core samples were obtained from Kocurek Limited in the US for this study. The length and diameters of the core are 51 mm and 38 mm respectively. Prior to the test, the cores were inspected to ensure there were no visual cracks on the surface of the samples that would impact on

Table 1. The list of salts used to prepare brine as used by Oluyemi (2014).

Salts	Active ions	Concentration (PPM)
NaCl	Na ⁺	10392
CaCl ₂ ·2H ₂ O	Ca ²⁺	426
MgCl ₂ ·6H ₂ O	Mg ²⁺	630
KCl	K ⁺	208
SrCl ₂ ·6H ₂ O	Sr ²⁺	10

the UCS of the samples. The biocompetitive exclusion chemical used for this study is sodium nitrate (NaNO₃) (Nitrate) obtained from Merck Life Science UK Limited. The composition of brine used is shown in Table 1.

2.1. Brine preparation

Table 1 shows the various salts used with deionised water to prepare the brine solution simulating the formation water, with concentrations obtained from Oluyemi (2014). The weight of the various salts as shown in Table 1 was measured and then diluted in 500 ml of deionised water at room temperature of 20°C to simulate formation brine. After the brine is prepared, it was kept in a 500 ml beaker and placed on a magnetic stirrer to stir the prepared formation brine at a speed of 300 m/s, just enough to prevent splashing of the brine and proper mixing for complete dissolution of the various salt components. The brine is then filtered with a 45 µm filter paper to remove any fine particles that may be present to avoid their impact on the test system during use by Oluyemi (2014).

2.2. Static chemical saturation

The core samples were put in separate beakers. Two of the beakers containing sandstone cores were filled with brine sufficient to cover the cores; these set-ups were the control tests. Similarly, 12.50 g of sodium nitrate was dissolved in a 500 ml of brine and poured into the other eight (8) beakers containing Sandstone cores well enough to cover them. The cores were then left for seven (7) days. This was to allow sufficient saturation of the brine and Sodium nitrate respectively (Oluyemi 2014, Wuyep *et al.* 2018). The cores were then removed from the brine and sodium nitrate filled beakers, aired, and oven-dried at 130°C as suggested by Lang *et al.* (2017) to prevent underestimation of specific surface area, before further analytical studies and strength test.



Figure 1. An image of rock sample under mechanical test using instron model 3382 machine.

2.3. Strength and analytical tests

Figure 1 shows the uniaxial compressive strength (UCS) test instrument which was done in displacement control at a rate of 0.5 mm/min with the use of a mechanical test

machine Instron (Model 3382) with a load capacity of 100 kN. Determination of the rock strength before and after chemical saturation was done with 0.93 ASTM correction factor for the length-to-diameter ratio. This was implemented in accordance to the ASTM standard (ASTM 1991) and described in Hill *et al.* (2019) and Wuyep *et al.* (2020)a.

Analytical tests to determine compositional elements and the impact of chemical saturation (i.e. brine and nitrate) on mineral alteration of untreated and chemically treated samples were carried out using a Scanning Electron Microscope (SEM) coupled with Energy Dispersive X-ray spectroscopy (SEM/EDX), and X-Ray Powder Diffraction (XRPD).

Examining clays and other cements connected to the sample pore systems is made easier by the SEM/EDX tests, which provide high magnification/resolution images of the smallest characteristics in the core samples. The samples were grounded to bits, degreased, and dried, and then placed on an SEM stub using a micro spatula for analysis. The SEM/EDX analytical studies require the use of a Zeiss EVO LS10 variable pressure SEM that produces high-resolution images of test samples.

Clay fraction and bulk mineralogy composition analysis were investigated with the use of X-Ray powder diffraction (XRPD) to identify the mineral phases present in the untreated and treated samples. The rock samples are grounded in ethanol and dried with an air brush. Using cobalt radiation, the radiation intensity peaks due to the sample's minerals plane lattice (Wuyep *et al.* 2018). Each intensity peak has Ka1 and Ka2 reflections at 2θ locations, which are measured at the peak's centre at 80% height. The results are tabulated as peak positions at 2θ and intensity (reported at peak heights). Quantitative analysis was made using a combination of Malvern Panalytical HighScore.

2.4. Particle size distribution (Malvern Laser Mastersizer 3000E)

A Malvern Laser Mastersizer 3000E was used to study the particle size distribution by examining the grain sizes in the static effluents from the core samples. Before the particle size test, deionised water is poured into the sampling compartment to rinse it. After rinsing, the contaminated deionised water is removed. This process is repeated four times until the sampling compartment is fully clean. Clean deionised water is then poured into the sampling compartment, and a magnetic stirrer is used to stir the deionised water while a 20 ml dropper is used to drop the effluent sample inside the continuously stirred deionised water. The measured value of effluents in volume percent (vol.%) is converted to weight percent.

2.5. Porosity measurement by liquid saturation and immersion

The petrophysical technique used in this study is carried out in accordance with the International Society for Rock Mechanics (ISRM) (Franklin *et al.* 1981) and the American Petroleum Institute API standards (Rp40 1998). Equation 1 was used to determine the density of brine using a graduated cylinder and then adding a predetermined volume of brine to estimate the pore volume of the core sample. The scale balance was properly calibrated, and all samples were repeatedly weighed to make sure a constant weight was obtained. Precision caliper measurements of the core dimensions were used to determine the bulk volume using Equation 2, and then Equation 3 was used to determine the porosity of the core samples. The difference between the two weights represents the mass of the brine (cylinder and brine). The mass of the fluid was then divided by its volume to get the brine density. The pore volume is determined by the weight differential between the dry and wet core samples (Anovitz and Cole 2015).

$$V_p = \frac{\text{weight of saturated core} - \text{weight of the dry core}}{\text{density of brine}} \quad (1)$$

$$V_b = \pi r^2 L \quad (2)$$

$$\emptyset = \frac{V_p}{V_b} \times 100\% \quad (3)$$

Where V_p is pore volume, V_b is bulk volume, L is the length of core (mm), and r is the radius of core (mm).

3. Results and discussion

3.1. Chemical effects on elemental and mineralogical composition

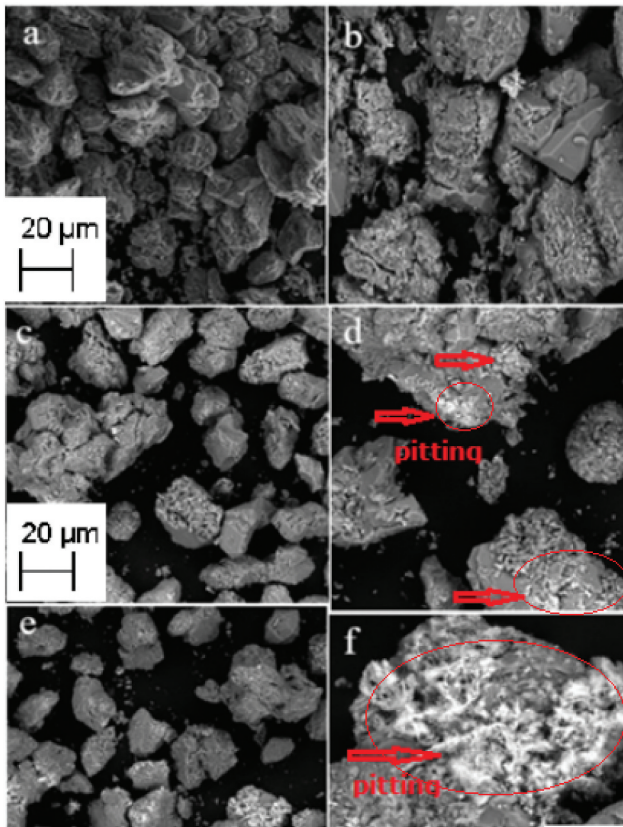
Sandstone consists of quartz, feldspars, clay minerals (illite and chlorite), and cements of carbonates and anhydrite (Huq *et al.* 2015). The variation in elemental composition of sodium nitrate-treated sandstone compared to the untreated and brine-treated sample is shown in Table 2. Similarly, Figure 2(a–f) shows the SEM photomicrographs for untreated sandstone, nitrate treated and brine-treated samples.

It can be observed that the textural appearance and morphologies of the chemically treated sandstone samples with either brine or sodium nitrate did not show significant changes when compared to the untreated sample (Figure 2(a,b)). However, unlike the brine-treated sandstone, the sodium nitrate-treated sandstone showed slight pitting (Figure 2 (e–

Table 2. The variation of treated and untreated sandstone elements.

Element	Untreated Sand (wt.%)	Brine-Sand (wt.%)	Nitrate-Sand (wt.%)
O	46.46	45.05	43.58
Na	0.86	1.35	0.85
Mg	0.34	0.49	0.39
Al	5.79	6.27	6.60
Si	36.94	33.89	30.85
K	1.93	0.41	1.68
Ti	0.59	0.54	0.55
Fe	5.73	10.10	14.71
S	0.19	0.07	ND
P	0.32	ND	ND
Ca	0.50	0.08	ND
Mn	0.35	1.09	0.51
Cl	ND	0.66	0.28

ND-Not Detected


Figure 2. Six EDX scan images showing the effect of chemical on mineral alterations in (a,b) untreated sand, (c, d) brine-treated sand, and (e,f) nitrate-treated sand.

f)), based on the EDX elemental composition presented in Table 2. Using samples shown in Figure 2, it is clear there is some variation in the composition of the untreated sample of the sandstone; elemental composition which includes Na (0.86 wt.%), Mg (0.34 wt.%), Al (5.79 wt.%), S (0.19 wt.%), K (1.93 wt.%), Ti (0.59 wt.%), Mn (0.35 wt.%) and Fe (5.73 wt.%), high traces of Si (36.94 wt.%) and O (46.46 wt.%), indicating the presence of feldspar, albite, and quartz.

In comparison with the treated samples, brine produced noticeable changes in the weight percentage of Na, Mg, K, Fe, S, Ca, and Mn, while the major changes for sodium nitrate-treated samples are Si, Fe, and Mn.

Furthermore, nitrate-treated sandstone shows a reduction in weight percentage of O (43.58 wt.%), Na (0.85 wt.%), Mg (0.39 wt.%), Si (30.85 wt.%), K (1.68 wt.%), Ti (0.55 wt.%), Fe (14.71 wt.%), an increase in Al (6.60 wt.%), Cl (0.28 wt.%), Mn (0.51 wt.%), and total dissolution of sulphur (S), phosphorus (P), and calcium (Ca) when compared with the untreated sample. The EDX analysis confirms the presence of quartz (Si, O), clay minerals (K, Al, Fe, Na), and also Ti and Mg. Consequently, the result confirms the large presence of Si (30.85 wt. %) and O (43.59 wt.%); the clay mineral and feldspar contents are indicated by the presence of Al (6.60 wt.%), Na (0.85 wt.%), K (1.68 wt.%), and Fe (14.71 wt.%). However, S and a major dolomite element Ca were found not to be present when compared to the untreated and brine-treated sandstone. This may be a result of feldspar and pyrite dissolution which may have led to the formation of increased pitting on the morphology of the nitrate-sand treated sample as can be seen in Figure 2(e,f). This observation is consistent with the dissolution of anhydrite, minor amounts of clay (chlorite), and calcites cement components of the sandstone observed in flow-through fluid analysis (Huq *et al.* 2015). The dissolution of feldspar is an important phenomenon that can affect rock quality (Parson *et al.* 2005, Yuan *et al.* 2015) and lead to a reduction in the reservoir rock strength (Han and Dusseault 2002). Also shown is a slight increase in Fe from 10.10 wt.% to 14.71 wt.%, and a decrease in Quartz content from 33.89 wt.% to 30.85 wt.%. The dissolution of quartz content is consistent with the effects of rock treatment with Betaine as shown in the previous work by Wuyep *et al.* (2018). Consequently, comparing the untreated sample with the

brine and nitrate treated sample, it can be observed that Fe increased from 5.73 wt.%, 10.10 wt.%, and then to 14.71 wt.% respectively. In this case, ferrite minerals embedded within the sample could have precipitated. On the other hand, as a result of brine treatment, P was not present and traces of Cl precipitated (0.41 wt.%), which was then reduced to 0.28 wt.% when nitrate was applied.

The XRPD patterns of the untreated sandstone, brine, and sodium nitrate-treated samples are shown in Figure 3(a–c). The test was analysed with a Malvern Panalytical HighScore suite. The sharpness of the peaks shows that the sandstone is a highly crystalline material. This is due to the high crystalline silica mineral content of sandstone. The peaks identified at 2θ equal 21° , 26.8° , 36.5° , 39.5° , 42.5° , 46° , 50.2° , 55° , 60° , 65° , and 68° represent the presence of quartz (i.e. silica) mineral, which is about 76%. Albite, which is a common feldspar mineral with composition sodium aluminosilicate ($\text{NaAlSi}_3\text{O}_8$) with about 13%, peaks at 2θ equals 22° , 28° , 31.4° , and 34° . Another identified mineral from the XRPD pattern is wollastonite, which is a calcium inosilicate mineral (CaSiO_3) and in some cases with Fe, Mg, and Mn peaks indicated at $2\theta = 28.7^\circ$, 33° , 39.5° , and 50.5° . Finally, kaolinite (i.e. an aluminium silicate mineral, $\text{Al}_2\text{Si}_2\text{O}_5(\text{OH})_4$) which is about 8% of the

sandstone is indicated to peak at 12.5° , 26° , 38.2° , 70° , and 73° , respectively. After treatment with brine, it can be observed that the amount of albite and quartz reduced significantly while the presence of another phase (Illite), which is a clay mineral was seen. This is due to the dissolution and precipitation of Aluminosilicate which in this case are kaolinite, albite, and quartz component of the sandstone due to brine-rock interactions. This affirms the result shown in Table 2 for sandstone-brine interaction during treatment. However, upon sodium nitrate treatment, an additional phase of sodalite can be identified with Illite. Although it is minimal, the formation demonstrates the impact of nitrate chemicals on sandstone. This is likely due to the dissolution and precipitation of albite minerals. Notably, treatment with sodium nitrate produced significant changes in quartz and albite, and new minerals such as Illite and sodalite compared to the treatment with brine.

3.2. Effect of chemical saturation on porosity

From the tests, the average weights of the untreated sandstone cores, brine, and nitrate saturated sandstone cores were 113.2 g, 124.9 g, and 125.6 g, respectively.

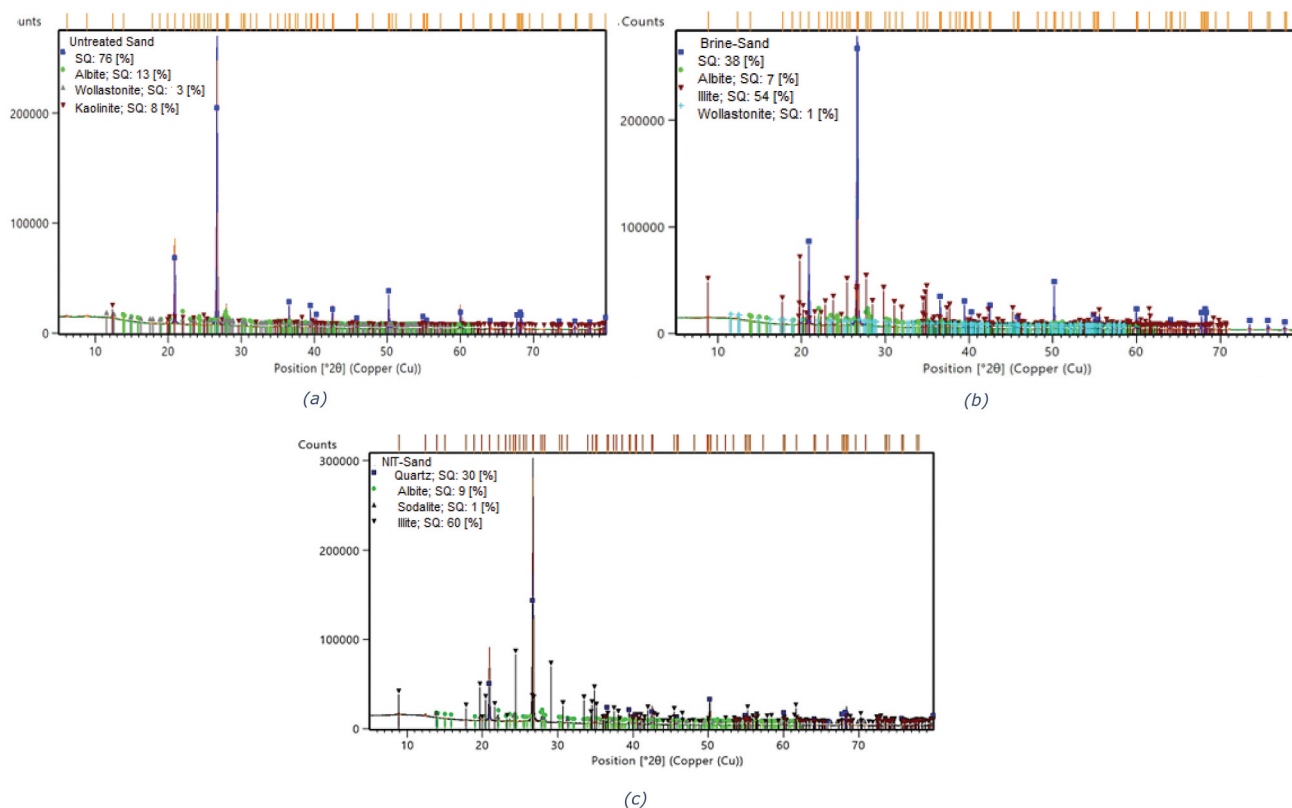


Figure 3. Three XRPD figures based on malvern panalytics HighScore for (a) untreated sandstone, (b) brine-treated sandstone, and (c) nitrate treated sandstone.

The porosity of untreated sandstone at 21% (declared porosity) is slightly enhanced from $21.1 \pm 0.3\%$ to $21.6 \pm 0.1\%$ upon brine and sodium nitrate treatment. This indicates an increase of about 2.9% for brine and sodium nitrate treatment, respectively. This finding that suggests the porosity of the sandstone increased after chemical treatment alludes to a widening of the pore space caused by the dissolution or disintegration of grain fibres. A similar observation has been reported for sandstone rock in the literature (Wuyep *et al.* 2020b, Ma *et al.* 2021, Lee *et al.* 2024). The increase was linked to the dissolution of the clay minerals in the sandstone rock matrix. The increase in porosity and correlatively permeability of the sandstone after nitrate treatment reported in the current study suggests widening of pore structure due to dissolution of grain fabrics, which collaborates with the literature (Lin *et al.* 2019, Gan *et al.* 2022, Li *et al.* 2023, Mahmud *et al.* 2023, Zhou *et al.* 2023). It is also worthy to note that the determined porosity of 21.10% for sandstone (Bandera Brown) is within range of the declared porosity (21–23%). It is also important to note that the amount of dissolved material is very small based on the observed increase in porosity. The hypothesis is therefore that when integrated with the UCS test, only a very small impact on rock strength will be observed.

3.3. Chemical effects on PSD

Figure 4 shows the particle size distribution profiles of original brine, brine-sand, and nitrate-sand effluents from sandstone. Table 3 summarises the PSD from original brine and effluents from both brine and nitrate treated sandstone rocks in terms of D_{10} , D_{50} and D_{90} .

Notably, in Table 3, there is no considerable difference in D_{10} and D_{50} values for both brine-sand (brine treated sandstone) and nitrate-sand (nitrate-treated sandstone)

effluents. However, the value of D_{90} for nitrate-sand effluent is 118 with reference to the original brine. The size characteristics of the PSD profiles of the brine effluents from both core samples indicate that the particles came from fines smaller than what the apertures can filter. As compared to the original brine, it is notable that the particle size for the corresponding D_{10} , D_{50} , and D_{90} values of the sand-nitrate saturation decreased from 20 μm to 11 μm (D_{10}), 75 μm to 52 μm (D_{50}), and 126 μm to 118 μm (D_{90}) (Table 3). This agrees with the changes in the sample porosity reported in Table 3. Hence, the bonding materials between the sand particles experienced minimal dissolution due to nitrate interaction with the sandstone core sample. However, it should be emphasised that even though the sand-nitrate treated effluents did not release particles, bond weakening was still likely (Wuyep *et al.* 2020b). However, integrating this result with the analytical and mechanical testing reveals that there was no failure of the nitrate-sand treated samples.

3.4. Chemical effect on compressive strength and Young's modulus

Figure 5(a,b) shows a failed sandstone rock and the test results of stress-strain profiles for untreated, brine and nitrate treated sandstone, respectively. From the results as shown in Table 4, the minimum strength of 28 MPa of sandstone as declared by Kocurek Industries (Kocurek 2023) is outside the determined strength range of 22 MPa. This may be due to water imbibition and a deterioration of the structural bonds (Durmekova *et al.* 2003, Liu *et al.*, 2020; Zhang *et al.* 2022).

The strength of the untreated sandstone core sample decreased slightly following chemical treatment with nitrate, as shown in Figure 4(b), from 22 ± 0.4 MPa to 21 ± 1.3 MPa and 20 ± 1 MPa when treated with brine

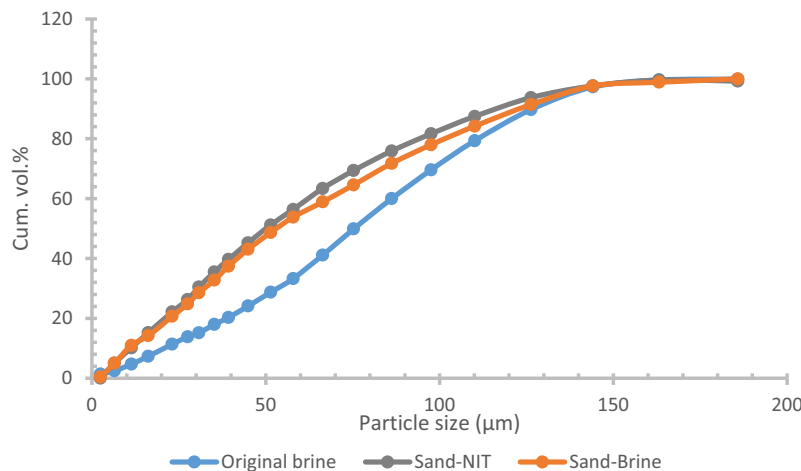


Figure 4. The particle size distribution of original brine, sand-brine, and sand-nitrate effluents.

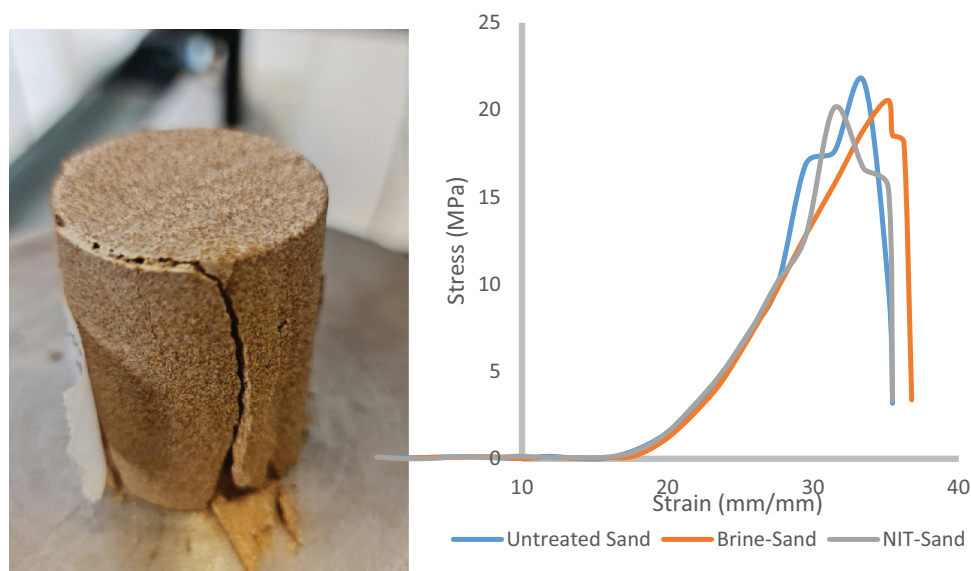
Table 3. The particle size distribution of original brine, sand-brine, and sand-nitrate effluents.

Sandstone (Bandera Brown)			
Original Brine	20	75	126
Sand-Brine	11	56	124
Sand-Nitrate	11	52	118

and nitrate, respectively. In real terms, with a 5% decrease in brine-treated sandstone and a 9% decrease in sandstone treated with nitrate, respectively, there was a negligible alteration in the nitrate-sandstone treated strength. This demonstrates that a 2.4% increase in sandstone porosity has an insignificant effect on compressive strength. On the other hand, the slight alteration in the compressive strength of sandstone core when treated with nitrate may be credited to the ability of sandstone to resist chemical alteration when quartz is the bonding material (Xi *et al.* 2015, Huddersfield 2022, Zeng *et al.* 2023), which may have led to only a slight change in its compressive strength.

The results for the Young's modulus for Bandera Brown Sandstone indicate a constant impact of about 1.3 MPa on stiffness, with no significant change noticed when treated with brine and nitrate, respectively. This is an indication that there was no nitrate chemical impact on the stiffness of sandstone upon brine or nitrate interaction. The outcome is in line with earlier studies by Wuyep *et al.* (2018).

However, the dissolution of cementitious feldspars, clay minerals such as illite and chlorite, and carbonates was evident in the XRPD reported in Figure 3. The pitting caused by the disintegration of these cement minerals due to nitrate-sandstone interactions can be observed on the SEM images (Figure 2). This dissolution of the sandstone cement materials has been reported to increase permeability and porosity (Huq *et al.* 2015, Zheng *et al.* 2015, Lin *et al.* 2019). It is evident that the impact of the dissolution could not significantly weaken binding material to the load-bearing framework resulting in negligible changes in UCS and Young's Modulus. The impact of dissolved CO₂-NaCl solution on sandstone's compressive strength (7–15% range decrease) correlated with this observation (Zheng *et al.* 2015). Unlike high acidic and alkaline solutions which have high impact on sandstone reservoir pore structure and mechanical properties (Lin *et al.* 2019), the reaction resulting from the interactions between nitrate and sandstone produced negligible effect on its geomechanical properties. Since no significant changes were observed in the geomechanical properties of sandstone reservoir formation, this suggests that nitrate can be utilised in conjunction with the water flooding EOR technique to regulate hydrogen sulphide accumulation caused by reservoir souring in the petroleum industry without resulting in formation damage and sand failure.

**Figure 5.** (a) Sample of a failed sandstone rock and (b) stress-strain UCS plot for untreated, brine and nitrate treated sandstone rock.**Table 4.** The geomechanical properties for sandstone.

Sandstone (Bandera Brown)			
Parameter	Untreated sandstone	Brine-sandstone	Nitrate-sandstone
L/D	1.3	1.3	1.3
UCS using ASTM 0.93 (MPa)	21	20	19
UCS (MPa)	22	21	20
Young's Modulus (MPa)	1.3	1.4	1.4

4. Conclusion

Oilfield-chemical rock interaction and consequent sand production in the oil and gas industry has major financial, environmental and health challenges on field operators. The interaction between BCX oilfield chemical (nitrate) and sandstone formation rock has been evaluated under static saturation. Analytical and mechanical tests were used to evaluate the core samples before and after chemical treatment. The analytical test results have shown that chemical interaction between BCX (sodium nitrate) chemical and the rocks minerals led to the dissolution/precipitation of new minerals. The mineral dissolution/precipitation led to the alteration in the grain-grain bond and a 2.9% increase in porosity. However, the alteration in Grain-grain bond and the slight increase in porosity were not sufficient to reduce the unconfined compressive strength of sandstone. Hence, from this study, nitrate oilfield chemicals may be recommended to oilfield operators for sandstone reservoir rock treatment due to their insignificant geomechanical effect on sandstone rock with respect to sand production. The results of this study prove that the geomechanical properties of the sandstone reservoir formation did not change significantly following nitrate treatment. It can be concluded that nitrate can be combined with water flooding EOR technique to control the build-up of hydrogen sulphide in the petroleum industry due to reservoir souring without causing sand failure or formation damage.

Acknowledgments

The authors acknowledge the Tertiary Education Trust Fund (TetFund) Nigeria, through the Delta State University, Abraka (where the primary and corresponding author is an academic staff), Nigeria, for the sponsorship of this research – The School of Engineering, Robert Gordon University, Aberdeen, UK, and the Faculty of Engineering, Oleh Campus, Delta State University, Abraka, Nigeria.

Disclosure statement

No potential conflict of interest was reported by the author(s).

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CRedit: **Nadimul Faisal:** Supervision.

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