# Geomechanical impact of bio-competitive exclusion chemical on reservoir rocks.

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# **GEOMECHANICAL IMPACT OF BIO-COMPETITIVE EXCLUSION CHEMICAL ON**

**RESERVOIR ROCKS** 

Ebikapaye Peretomode

# GEOMECHANICAL IMPACT OF BIO-COMPETITIVE EXCLUSION CHEMICAL ON RESERVOIR ROCKS

Ebikapaye Peretomode

A thesis submitted in partial fulfilment of the requirements of the Robert Gordon University for the degree of Doctor of Philosophy (School of Engineering)

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# **GEOMECHANICAL IMPACT OF BIO-COMPETITIVE EXCLUSION CHEMICAL ON**

## **RESERVOIR ROCKS**

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# **Dedication**

In this work, I give thanks to the All-Powerful God for his never-ending kindness and tenderness.

This work also acknowledges the love, support, and understanding I have had from my lovely wife, Mrs. Obiajulu V. Peretomode, and my incredible children, Miss. Oyinlayefa, Master Ebikapaye (Marvel), and Miss. Tamarakarena. This work is also dedicated to my parents, Prof., and Dr. (Mrs.) Victor Peretomode, for

their shining light and, constant advise, and ensuring I get this level of education.

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#### <u>ABSTRACT</u>

This study describes a novel approach known as "bio-competitive exclusion" that uses chemical nitrates as an oilfield chemical to treat reservoir souring and control the activities of sulfate-reducing bacteria. Because of its flexibility and extensive use in oil production, this oilfield treatment method has been regarded as a more cost-effective and environmentally friendly alternative. Oilfield chemical-rock interaction occurs when reservoir rocks are treated with oilfield chemicals for increased oil recovery (EOR) and reservoir souring. This interaction reduces the strength of the formation rock, may cause the production of sand, and has a detrimental effect on oil production and its facilities. A lot of research has focused on the use of Nitrate for reservoir souring control, treatment, and oil recovery. However, the deleterious effects of Nitrate on the geochemical and geomechanical properties of the rock have not been considered under static and flooding conditions.

This work uses a combination of UCS, analytical, and PSD tests to experimentally investigate the geochemical and potential geomechanical effects of treating sandstone and carbonate reservoir rocks with a biocompetitive exclusion (BCX) chemical (sodium Nitrate) under static and flooding conditions. The flooding approach was adopted to study the effects of varying chemical concentrations on sandstone rock's geochemical and geomechanical properties. For the static saturation test, the results showed there was mineral dissolution and precipitation response, which caused the separation of grain particles, and as a result, decreased the strength of the rock. The core flooding investigation was performed at increasing concentrations of 637.5 ppm, 850 ppm, 1062.4 ppm, and 1275 ppm. The results demonstrate that when nitrate concentration increases, mineral precipitation, and dissolution alter elemental and mineralogical

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phases, PSD, porosity, and permeability, decreasing the unconfined compressive strength (UCS) of the rock.

This study has demonstrated that the rate of mineral dissolution or precipitation is a direct function of the rate of porosity change; increasing chemical concentration reduces the rock's UCS. In addition, the experimental study from both static and flooding tests suggests that applying nitrate for sandstone reservoirs should be encouraged but discouraged in its application to carbonate formations due to its potential for sand failure and production.

**Keywords**: Biocompetitive Exclusion, Sand production, Nitrate, Sandstone rock, Dissolution, Precipitation, Carbonate rocks, Chemical concentration, Porosity, Permeability, Static test, Mineral phase.

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# **Nomenclature**

A	Column cross-sectional area (cm <sup>2</sup> )
A	Concentration of reactant
A, B, C, D	A, B Chemical reactants, C and D Reaction products
a, b, c, d	Stoichiometric coefficients of the reactants and products
A <sub>0</sub>	Initial surface area of solid
A <sub>0</sub>	Surface area (m <sup>2</sup> )
BCX	Bio-Competitive Exclusion
С	Concentration (ppm)
CCS	Confined Compressive Strength
ck	Total concentration of component
Ста	Total concentration of primary species
D	Diffusivity (m²/s)
D	Dispersion/diffusion coefficient
DEM	Discrete Element Method
dh/dl	Hydraulic gradient
Dk	Diffusion coefficient
E	Youngs Modulus (Pa, N/m <sup>2</sup> )
EDXA	Energy Dispersive X-Ray Spectrometry
f	Efficiency factor
F	Minor compressible force effects
g	Gravitational acceleration (g, m/s <sup>2</sup> )
IAP	Ionic Activity Product
ICP-OES	Inductively Coupled Plasma Optical Emission Spectroscopy

К	Hydraulic conductivity
к	Solubility product
k <sub>rl</sub>	Relative permeability (F/m)
L	Length of core (cm)
Μ	Molecular mass (kg)
m <sub>0</sub>	Initial moles of solid at a specific time
η	Dynamic viscosity
Np	Number of primary species
NRB	Nitrate Reducing Bacteria
р	Pressure (Atm)
PSD	Particle Size Distribution
Q	Rate of fluid flow (cm <sup>3</sup> /s)
r	Radius of core (mm)
r R <sub>i</sub>	Radius of core (mm) Rate of reaction (M/s)
r R <sub>i</sub> <i>rk</i>	Radius of core (mm) Rate of reaction (M/s) Rate contribution of mineral precipitation-dissolution
r Ri <i>rk</i> SEM	Radius of core (mm) Rate of reaction (M/s) Rate contribution of mineral precipitation-dissolution Scanning Electron Microscope
r Ri <i>rk</i> SEM SRB	<ul> <li>Radius of core (mm)</li> <li>Rate of reaction (M/s)</li> <li>Rate contribution of mineral precipitation-dissolution</li> <li>Scanning Electron Microscope</li> <li>Sulfate-Reducing Bacteria</li> </ul>
r Ri <i>rk</i> SEM SRB SSA	<ul> <li>Radius of core (mm)</li> <li>Rate of reaction (M/s)</li> <li>Rate contribution of mineral precipitation-dissolution</li> <li>Scanning Electron Microscope</li> <li>Sulfate-Reducing Bacteria</li> <li>Specific surface area</li> </ul>
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r Ri <i>rk</i> SEM SRB SSA Sv u U UCS	Radius of core (mm)Rate of reaction (M/s)Rate contribution of mineral precipitation-dissolutionScanning Electron MicroscopeSulfate-Reducing BacteriaSpecific surface areaSample volumeFluid velocity (m/s)Velocity vectorUnconfined Compressive StrengthKinematic viscosity

# XRPD X-Ray Powder Diffraction

θ	Porosity change
к	Permeability (D or m <sup>2</sup> )
ρ	Density of the fluid (kg/m <sup>3</sup> )
Ea	Activation energy (J)
RT	Gas constant (K)
Greek symbols	

μ	Fluid viscosity (cp)
τ	Tortuosity
$\phi$	Porosity (dimensionless)
λ	Sanding coefficient
C <sub>i</sub>	Concentration of species
$Q_b$	Flow rate (cm <sup>3</sup> /s)
$V_T$	Total volume (cm <sup>3</sup> )
κ <sub>o</sub>	Initial permeability (D or m <sup>2</sup> )
$\nabla$	Vector pointing to largest pressure direction.
abla p	Pressure gradient

#### List of Publications from this study

#### Journal Articles

Peretomode, E., Oluyemi, G. & Faisal, N. H., 2022. Oilfield chemical-formation interaction and the effects on petrophysical properties: a review. *Arab. J. Geoscience,* Volume 15, p. 1223.

Peretomode, E., Oluyemi, G. & Faisal, N. H., 2022. Sand production due to chemicalrock interaction. *Engineering Failure Analysis,* Volume 142, p. 106745.

Peretomode, E., Oluyemi, G. & Faisal, N. H., (2023). Biocompetitive Exclusion Chemical Effect on The Geomechanical Properties Of Carbonate And Sandstone Rock Under Static Condition. *International Journal of Rock Mechanics and Mining Sciences*. (Under review).

#### **Under Preparation**

Peretomode, E., Oluyemi, G. & Faisal, N. H. The influence of biocompetitive exclusion chemical on the microstructure and uniaxial compressive strength of sandstone and carbonate reservoir rocks (Currently under preparation).

Peretomode, E., Oluyemi, G. & Faisal, N. H. Biocompetitive Exclusion Chemical Effect On The Geochemical and Geomechanical Properties Of Sandstone Rock Under Flooding Conditions (Currently under preparation).

#### **CHAPTER ONE**

#### **1 INTRODUCTION**

#### 1.1 Background

The production of sand has been a major problem in weak or unconsolidated formations. In other words, sand control may be necessary depending on fluid pressure, history production, or compressive strength of the rock. In addition, based on the formation's compressive strength, the porosity of the formation may be used as a guide to determine whether sand management is required. This is because porosity is thought to significantly affect a rock's compressive strength (Chen, et al., 2013). Whenever the porosity of a formation exceeds 30%, the likelihood of sand production is high, due to the absence of cementation. Therefore, it is crucial to understand if a well would generate sand due to the impact of chemical-rock interaction, which may change the properties of rock formations such as permeability, porosity, and compressive strength.

An estimate of sand production during the stimulation of an oil or gas reservoir is necessary to establish the necessity for sand control. Pipeline erosion brought on by sanding can result in a loss of integrity and hydrocarbon leakage (Subbiah, et al., 2021). Sand may be carried to the surface or deposited in the well because of several variables. The negative effects on oil and gas production include formation damage and losses in hydrocarbon production rates due to formation sand and fines plugging perforations and separators or flow lines (Abass, et al., 2002; Willson, et al., 2002). Additionally, this issue is probably going to result in higher operating expenses (Rahmati, et al., 2012; Wang, et al., 2016), and erode pipelines and other surface facilities, causing damage to expensive equipment and increasing the overall cost of production operations (Tronvoll & Fjaer, 1994; Rahmati, et al., 2012 ). Wellbore failure increases with deteriorating equipment and well integrity, downtime, and disposal expenses (Penberthy & Jr Shaughnessy, 1992; Eshiet, 2012 ). Although advanced computing systems and new technologies have improved sand production modeling and prediction, there are still many difficulties associated with this process due to its complexity, notably because of interactions between chemicals and rocks. As a result, the production of sand has negative effects on the environment. For example, the highly erosive nature of sand-laden fluids causes downhole and surface equipment to deteriorate over time, which can cause production facilities to completely fail and present a serious risk to people's safety, health, and the environment (Penberthy & Jr Shaughnessy, 1992). Reduced pore pressure and compaction of the reservoir rock may cause the reservoir formation to collapse, causing damage to the formation and, in certain situations, the creation of sand. Sand can be formed because of the pore collapse failure mechanism, according to studies (Penberthy & Jr Shaughnessy, 1992).

On the other hand, during production, rock failure can result from reservoir pressures and stress conditions, which may likely cause sand to be produced. It is worth noting that rock failure only occurs when the formation stress exceeds the strength of the rock (Carlson et al., 2002). Therefore, before sand can be produced, the rock must fail. Understanding the failure mechanism is critical for this process. The mechanisms for failure can either be mechanical or chemical (Zhou & Sun, 2016). Several factors can determine whether a rock will fail mechanically, including its strength (UCS), the mean-effective stress acting on it, the stress distribution near the wellbore, and the drawdown caused by drilling and production (Subbiah, et al., 2021). Tensile, shear, cohesive, and pore collapse mechanisms can all cause sand

to fail. Abass et al. (2002) reported that the chemical effects on rock strength are derived from the contact forces between grains (friction) and the physical bond between adjoining grains (cohesion). However, rock failure can also result from the interaction between chemicals and rock during the drilling process, enhanced oil recovery, formation treatments, etc. Chemicals are frequently utilized as biocides, surfactants, water floods, drilling fluids, scavengers, demulsifiers, and defoamers in various operations in the oil and gas sector. The porosity, permeability, and changes in rock strength because of dissolution-precipitation reactions are among the mechanisms of rock failure caused by chemical-rock interactions. Additionally, cementation elements (such as carbonate, clay, etc.) may degrade due to chemical interaction with rock formation, weakening the grain fabric, lowering UCS, and ultimately leading to sand failure. Therefore, one way to control sanding is to choose chemicals that do not degrade the cementing components in rock formations. In a nutshell, the geochemical and geomechanical characteristics of the formation might alter because of fluid-rock interactions. A weakening of the grain cementitious material holding the rock together may also result in chemical reactions, depending on the cementing materials. In general, chemical-rock interactions can cause reactions in cementing materials such as clay, releasing disintegrated sand grains into the fluid stream, causing more porosity in rock and a lower UCS, resulting in sand failure. Consequently, reservoir parameters such as permeability and porosity of the formation may change, which are also very critical parameters that can be adversely affected by geomechanical phenomena.

Researchers (Rijnaarts, et al., 1993; Jordan, et al., 1994; Wuyep, et al., 2020) have noted that the interaction between formation rock and oilfield chemicals is by adsorption through Electrostatic and Van der Waals forces and that the level of chemicals adsorbed by the formation can be quantified by factors such as chemical concentration, pH, temperature, and mineral substrate. In contrast, Li et al. (2003) found that oilfield chemicals and rock interaction lead to the precipitation and dissolution of rock minerals, altering the porosity and permeability of the reservoir rock. This alteration, as noted, can either increase or decrease the rock's properties (Lamy-Chappuis, et al., 2014). The alteration that causes the rock to fail potentially leads to sand production (Wuyep, et al., 2020; Peretomode, et al., 2022; Peretomode, et al., 2022). Figure 1.1 shows a typical reservoir rock failure mechanism. In the event of rock failure, reservoir fluid and sand are likely to be produced (Salama, 2000). Al-Awad (2001) observed that sand failure is of no economic benefit and costs production companies lots of money.





Researchers such as Seto et al. (1997), Oluyemi (2014), and more recently, Wuyep et al. (2020) have used chemicals such as aluminum chloride (AlCl<sub>3</sub>), polyethylene oxide (PEO), dodecyltrymetyl bromide (DTAB), scale inhibitors, biocide, etc. to treat and examine the interaction between chemicals and rocks effects on rock strength under static and dynamic conditions.

Different chemicals have different properties, which will display varying effects on the geomechanical strength of reservoir rocks when applied. The extent of the impact on the rock properties depends on the chemical nature, concentration, and flow rate. Wuyep et al. (2018) studied the Chemical and physical effects of interaction between oilfield chemicals and formation rocks using biocide, which is used for the control and treatment of microorganisms such as sulfate-reducing bacteria (SRB). The result showed that dissolution-precipitation reduced permeability and porosity, leading to formation damage. Biocides are used in oil wells for the treatment of harmful microorganisms such as Sulphur-reducing bacteria (SRB) (Gieg, et al., 2011). However, these chemicals could be hazardous to both oilfield personnel and the environment. Research has shown us that biocides are quite expensive economically. Furthermore, they are not always trustworthy since resilient bacteria might survive and evolve into resistant forms (Dennis & Hitzman, 2007). However, another strategy that can be used to control the activities of the SRB is the use of Nitrates, which can exhibit a variety of effects on the reservoir rock (Davidova, et al., 2001). The technology of using nitrates as an oilfield chemical is known as "Biocompetitive Exclusion" (BCX). This process requires injecting nitrate into the reservoir to stimulate the growth of nitrate-reducing bacteria (NRB), which prevents the growth of SRB by producing a sulfate inhibitor (i.e., Nitrite) (Sturman and Goeres 1999). This is beneficial as nitrate production inhibits SRB (Hubert, 2010). Furthermore, this Nitrate inhibitor outcompetes SRB for oil organics and nutrients,

thereby reducing and eliminating the activities of SRB (Voordouw, et al., 2011). As a result, the interaction between Nitrates (NRB) and Sulphide (SRB) can affect the production, accumulation, and elimination of sulfides in oilfields (Davidova, et al., 2001). Reinsel et al. (1996) experimentally reported the control of microbial souring by nitrate, nitrite, and glutaraldehyde injection in a sandstone column. In the study, the microbial souring of a sandstone rock was incubated at 60°C and then inhibited by adding nitrate (NO<sub>3</sub>). According to the results of the experiments, nitrite is a more effective souring inhibitor than glutaraldehyde.

In another study by Sunde et al. (2004), they treated injection water with nitrate to reduce H<sub>2</sub>S production. It was found that there was a 1000-fold reduction in  $H_2S$  production in the injection water. The authors noted that the use of nitrates is a more economical, common, and environmentally friendly alternative to the use of biocides as oilfield chemicals. It is also worth noting that a lot of research on the use of nitrate has focused on reservoir souring control and treatment (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 oil recovery (Hitzman & Sperl, 1994); (Sandbeck & Hitzman, 1995); (Giangiacomo & Dennis, 1997); (Zhao, et al., 2016). Even though an extensive and nearly exhaustive review has been conducted on biocompetitive exclusion for the treatment of reservoirs, a comprehensive understanding of the potential effects on the reservoir's geochemical and geomechanical properties has not been evaluated. The impacts of oilfield chemical-rock interactions on reservoir geochemical and mechanical properties have been the subject of several researches; nevertheless, because these chemicals react in different ways, it is impossible to generalize about the effects they produce. As such, the objective of this research is to model, while

assessing experimentally, the application of sodium nitrate for reservoir treatment without introducing nutrients, which are usually responsible for the development of microorganisms, to evaluate how chemical nitrate influences the geochemical and geomechanical characteristics of reservoir rocks. Specifically, an extensive integrated approach was used to develop a geochemical model of reservoir geochemistry and geomechanical properties as well as assess the effect of biocompetitive exclusion chemicals on rock properties. This was achieved by coupling the effects of bioexclusion chemical treatment on the rock with existing geomechanical models for predicting sand production. This method is aimed at reducing financial and equipment losses that can arise from fine migration and sand production during the injection of production solution chemicals into reservoirs.

#### **1.2 Research Gaps**

After a thorough assessment of the literature pertinent to this work, it became evident that a lot of research on the use of nitrate has focused on reservoir souring control, treatment, and oil recovery. However, there is no understanding or technical information regarding the failure impact of the BCX chemical and rock interactions on the geochemical and geomechanical parameters of the reservoir rock. There is a lot of research on the use of BCX to treat reservoir interaction between BCX and the rock; however, none of these studies take into account the impact of the chemical on reservoir rock geochemical and geomechanical properties.

### 1.3 Aim and Study Objectives

This study aims to experimentally investigate the geomechanical effects of biocompetitive exclusion chemical treatment on sandstone and Clastic/carbonate

reservoir rocks. A geochemical model that accounts for these effects on sandstone rock and can be integrated into an existing geomechanical model for predicting sand production is also developed. The objectives of the research are:

- 1. To evaluate how the chemical treatment with BCX affects the geochemical and geomechanical characteristics of sandstone and carbonate because of static saturation.
- To investigate the effects of BCX chemical concentration on the geochemical and geomechanical properties of sandstone rock due to dynamic/flooding conditions.
- To develop a comprehensive geochemical model based on the effect of BCX chemical injection on sandstone reservoir.

#### **1.4 Description of Methodology**

This chapter presents the materials used and the experimental methods used in evaluating the effects of BCX chemical-rock interaction on the petrophysical and geomechanical properties of carbonate and sandstone reservoir rocks. Mechanical, analytical (SEM/EDX and XRPD), liquid saturation and immersion and ICP-OES, and PSD tests were required for UCS and Youngs Modulus, elemental and mineralogical, porosity, and particle size distribution analysis respectively for static and dynamic flooding conditions. These tests and analyses were carried out before and after chemical treatment for all samples.

By combining fluid flow, chemical reaction, and mineral transport, a numerical modeling tool (COMSOL Multiphysics) was utilized to develop a model to evaluate the impact of biocompetitive exclusion chemicals on rock characteristics. The COMSOL Multiphysics module used for this simulation is the Chemical Reaction Engineering Module with the interphase "Reacting Flow in Porous Media". The interphase incorporates equations that enable fluid flow, chemical reactions, and mineral transport in a porous medium.

#### **1.5 Original Contributions**

By examining BCX chemical-rock interactions, this research project aims to advance our understanding of reservoir rock's geochemical and geomechanical properties. The results of this study, which are shown here, specifically add to the body of knowledge in the following areas.

- i. BCX chemical (nitrate) has been utilized in earlier research to treat the reservoir for SRB through the employment of cultures, but none of them have taken into consideration the chemical or mechanical effect of BCX chemical on the qualities of the reservoir rock without the growth of microbial organisms. This work fills a knowledge gap about BCX's static saturation effect on the chemical and mechanical characteristics of reservoir rock.
- ii. Although multiple BCX chemical concentrations have been utilized to treat SRB in the reservoir, no study has taken into account how the various BCX chemical concentrations alter the chemical and mechanical characteristics of the reservoir rocks. However, this work fills in the information gap about the dynamic impacts of various BCX chemical concentrations on the chemical and mechanical properties of the reservoir rocks.
- iii. The dissolution of minerals due to the interaction of detached particles increases porosity and results in the weakening of the formation's strength.

#### **1.6 Thesis Organization**

This thesis is divided into seven chapters.

- Chapter 1 Introduction: In this chapter, the research problem, aims and objectives of the study, methodology, research gaps, and unique contributions to knowledge are explored.
- Chapter 2 Review of the literature: To identify the knowledge gaps in the field, this chapter provides a thorough analysis of the background literature on the interactions between oilfield chemicals and rocks. The various techniques for measuring permeability, porosity, PSD, UCS, and elemental and mineralogical compositions in the lab are also discussed.
- Chapter 3 Experimental technique: This chapter provides a thorough explanation of the methods (static saturation, flooding, PSD, analytical, and mechanical) used in this study to accomplish the thesis's goals.
- Chapter 4 Static Saturation Test: The findings of an experimental examination into the interactions between formation rocks (sandstone and carbonate) and BCX chemicals (nitrate) are presented in this chapter. The impacts of nitrate interaction on the mineralogical, petrophysical, and geomechanical characteristics of rocks under static saturation are also covered.
- Chapter 5 Test for flooding: The findings of an experimental examination into how different nitrate concentrations interact with formation rock (sandstone) are presented in this chapter. The impact of nitrate concentrations on the mineralogical, petrophysical, and geomechanical characteristics of rocks under flooding situations are also covered.
- Chapter 6 Using experimental data, this chapter describes the COMSOL Multiphysics modelling of the nitrate-rock interaction component of the

endeavour. The linkage of fluid movement, chemical processes, and mineral transport is considered in the model.

• Chapter 7 - This chapter discusses the study's findings and suggestions for additional research.
#### **CHAPTER TWO**

## **2 LITERATURE REVIEW**

## **2.1 Introduction**

The flow of fluid in porous media is covered in geophysics, hydraulics, reservoir engineering, soil mechanics, biomechanics, chemical, and aeronautical. and petroleum engineering. In petroleum exploration and production, the injection of fluids into the reservoir's porous rock formation serves the purpose of increasing the recovery of oil or gas. However, oilfield chemicals used as corrosion inhibitors, scale inhibitors, scavengers, etc. generally have adverse effects on the geomechanical and geochemical properties of the reservoir rock (Binh Bui & Azra Tutuncu, 2014). They display some geomechanical effects on reservoir rocks, such as sand failure, resulting in sand production. It is therefore of immense importance to understand the reaction, dispersion, and dissolution due to the interaction of a chemical or biological tracer and the transport of fluid through porous reservoir formation rock. During the transport process, the evaluation of the geomechanical properties of the reservoir rock becomes a vital requirement in the optimization and prediction of sand production (Oluyemi, 2014). As a result, the rock properties are greatly altered and impacted. These alterations in the properties of the rock based on the interaction between the rock and the reactive fluid transport have been a subject of study both in the industry and academia. The induced effects of chemical damage due to rockfluid interactions are yet to be fully characterized.

The primary objectives of adding chemicals to an oil and gas field operation are to increase oil and gas output, clear blocked formations, repair formation damage, ensure that oil flows freely, and avoid scale and corrosion. It is significant to remember that these substances are absorbed by and interact with the

characteristics of the formation after being put there. Conversely, the fluid flow and geochemical transport in fractured reservoir rock formations have received considerable attention for studies such as carbon dioxide sequestration, acid mine drainage remediation, fluid-rock interactions in hydrothermal systems, waste disposal, groundwater quality, etc. (Xu and Pruess, 2001; Liping et al., 2019). This process has been investigated by applying analytical and numerical approaches. However, the complexity of fluid-rock interactions and fracture heterogeneity pose some challenges in the prediction of changes in flow and transport properties (Berkowitz, 2002). For instance, during chemical flow in fractured rock, the minerals on the surfaces readily dissolve, and the components and concentrations of solutes change in the process. It is worth noting that fractures and their networks are channels for the transport of chemical fluids and water in oil and gas reservoirs as well as in groundwater systems.

It is well known that reservoir formation rocks are composed of diverse minerals such as carbonate, clays, feldspar, and quartz. Therefore, these minerals could be mobilized, dissolved, and mixed with the fluid flow. In light of this, Walsh et al. (1984) developed a model that computes the equilibrium between the fluid flow and rock minerals, considering the dissolution of minerals and their precipitation as a result of chemical-rock interaction. Oluyemi (2014) investigated the geomechanical significance of the interaction between chemical inhibitor species and formation rock. The results demonstrate sand failure and its release into the flow, signifying detrimental effects on reservoir formation and sand production. This occurrence happens due to mechanical and/or chemical reactions that cause grain particles to separate from the rock matrix. To put it another way, failure and production occur when formation stress surpasses formation strength (Wuyep, et al., 2020). In a recent study by Wuyep et al. (2020), the effects of scale inhibitors, biocide, and

corrosive inhibitors on the geomechanical strength of carbonate and sandstone reservoir rocks were reported. It was discovered that the reservoir grain fabrics were weakened, and unconfined compressive strength was reduced due to chemical adsorption, precipitation, dissolution, and ionic substitute reactions because of the interaction between the fluid and the formation rock, causing sand failure. Furthermore, it has been found that the changes in surface morphologies and the minerals on fracture surfaces induced by the flow-rock interaction exhibited nonuniform features because of heterogeneity in the soluble minerals as well as their nonuniform distribution on the rock surfaces (Liping, et al., 2019). On the other hand, the fluid-rock interaction could cause alteration in the rock's porosity and permeability due to the dissolution and precipitation of embedded minerals (Lamy-Chappuis, et al., 2014). Depending on the rock fabric, the modification of the rock structure can either improve or impair the permeability. There are several reports on the investigation of the effect of rock-fluid interaction on the properties of Sedimentary basins worldwide. For example, Yang et al. (2017) studied the transformation of reservoir rock properties based on core samples taken from sandstone, and they discovered alteration in the rock properties due to the dissolution of feldspar, calcite, and other cement bonding minerals present within the mineral content of the sandstone and as a result, its interaction with brine and ethanoic acid.

Traditionally, reservoir formations have been treated with biocides to inhibit sulfate-reducing bacteria (SRB) and reduce microbial-induced corrosion (Thorstenson, et al., 2002). Besides adding biocides to wells, another approach that seems promising is modifying the reservoir ecology through the addition of nitrates. This strategy can be used to control the activities of SRB, which have exhibited a variety of effects on the reservoir rock (Davidova, et al., 2001). In the study by Hubert (2010), he noted the benefit of nitrate in production, especially the inhibition

of SRB. Additionally, sulfide production declines and this drop in concentration encourages the growth of a native microbial community to take the place of the SRB population. This method relies on adding small amounts of a water-soluble nutrient solution that particularly promotes the growth of a local microbial population, such as nitrate-producing bacteria while suppressing the unfavorable SRB population that releases H<sub>2</sub>S. This deliberate and controlled modification of the microflora and reservoir ecology is termed biocompetitive Exclusion. The effect of treating the reservoir formation with nitrate could potentially alter the rock's mechanical properties. Therefore, this study seeks to elucidate the impact of the exclusion process on rock properties as well as the evolution of the rock formation's permeability and porosity. Furthermore, a model that describes the fluid flow and rock formation interaction, including the dissolution of minerals, their precipitation, and reactions as a result of the interaction, will be developed and used to characterize the system. The effects of these chemicals on the geomechanical and geophysical properties of the rock, as investigated and reported by Oluyemi et al. (2010), suggest the likelihood of leading to sand production, impacting the cost and oil and gas production.

Fluid-rock interaction processes have been studied with simulation, at laboratory scale, and in field trials. Egermann et al. (2010) studied the fluid-rock interactions during carbon dioxide injection for geological storage. The results showed that the extent of fluid-rock interaction is dependent on thermodynamic conditions, the nature of the fluid itself, the composition of the rock, and the flow regime. It was also found that the evolution of permeability is a function of dissolution rate and porosity. Several experimental studies (Egermann, et al., 2010; Madland, et al., 2011; Marty N., 2015; Wuyep, et al., 2018) have been published on the interaction between chemicals and the formation of rock and how this interaction affects the

petrophysical and geomechanical properties of the rock. It is, however, imperative to evaluate the geomechanical effects of these oilfield chemicals on the properties of the reservoir rock to be able to develop a precise failure prediction model (Oluyemi et al. 2010). This literature review is aimed at extensively highlighting the extent of prior work carried out and identifying areas needing further investigation based on existing knowledge. The impact of chemical injection and its resultant effects on rock formations will be covered. The evolution of the rock formation morphology, porosity, and permeability because of the oilfield chemicals and rock interaction, which induce mineral dissolution and precipitation, was studied. The causes and mechanisms of sand failure, the mechanical and petrophysical characteristics of the rock, and the effects of oilfield chemicals and rock dissolution are all examined as well.

The chapter is organized as follows: petrophysical properties of rock such as porosity, permeability, and particle size in Section 2, the geomechanical properties such as rock strength, confined and unconfined compressive strengths, and Young's modulus and Poisson's ratio are covered in Sections 2.3 – 2.5; reported in Section 3 are interactions between chemical and rock, numerical modeling of the interaction between fluid and rock in Section 4, sand failure and management in Section 5, and finally, failure prediction.

# 2.2 Petrophysical Properties

This section of the study covers the effect of fluid-rock interaction on the petrophysical properties of the rock. In the study reported by Hill et al. (2018), they combined information on rock geomechanics with information on rock petrophysical properties such as porosity and permeability, PSD, pore volume, and rock mineralogy, to elucidate the impact of chemical fluid-rock interaction, reservoir stability, and the possibility of sand failure and its production.

#### 2.2.1 Effects of Oilfield Chemicals on Petrophysical Properties

It is well known that injected fluids interact with rock minerals and/or formation fluids and generate fine particles in addition to dissolution and precipitation, which can cause damage to the formation, either from fluids in the reservoir or generated in situ because of fluid-rock interactions. These processes induce changes in the rock's permeability, porosity, and strength, which are very important factors for reservoir rock petrophysical properties (Ahmad, et al., 2018), indicating that they can be adversely affected by geochemical and geomechanical phenomena (Oluyemi, 2010). Crawford et al. (2011) developed a model that relates petrophysical and petrographic properties to rock strength. This suggests it is plausible to predict and estimate mechanical properties from the geophysical properties of the rocks due to fluid-rock interactions. Consequently, formation damage and the onset of sanding can also be predicted. Using rock properties to calculate the onset collapse of a pore can be a helpful approximation to predicting the onset collapse of the pore and changes in compressibility of the reservoir formation with the reduction in pressure of the fluid at uniaxial strain boundary settings. A review of selected approaches and models that have been developed for sanding prediction has been published (Rahmati, et al., 2013). Most of these models are built on a continuum assumption, but a few have recently been developed based on discrete element models. Analytical models are commonly used for the estimation of the onset of sanding, while numerical models are suitable for predicting the sanding rate. Overall, a realistic sanding model should include all failure mechanisms (shear, tensile, and compression) as well as fluid flow effects. The discrete element method (DEM) is another valuable tool to simulate sand production, especially to understand the mechanism of sanding, but it cannot be used for large-scale problems because of the large computational time required and difficulty in the calibration of the model (Rahmati, et al., 2013). In the investigation,

as described by Hill et al. (2018), data on the formation's geomechanical and petrophysical properties, like the rock mineralogy and grain size distribution, were combined to explain the impact of fluid-rock interaction, the formation stability, and the prospect of sand failure and its production. The pressure gradient developed in the pore channels due to fluid flow also facilitates the detachment of sand grains. Additionally, the flow of fluid leads to the transport and production of detached sand aggregates as well as disaggregated sand grains. Therefore, sand management and modeling are always cost-effective if they are implemented early before a well is drilled. This complex phenomenon depends on various factors, such as the stress distribution, and the properties of the rock and fluid-rock interactions in the reservoir (Rahmati, et al., 2013). The fluid flow is mostly modeled using the Navier-Stokes equations solved by the finite volume method. However, it can be challenging to account for all these factors and mechanisms in the numerical models, resulting in limitations on their applicability.

## 2.2.2 Pore volume, porosity, and permeability

Petroleum reservoirs, which are made of sedimentary rocks, usually have porosity ranges of 10-40 % in sandstone formations and between 5-25 % in carbonate formations. Sand production is a common occurrence in weakly consolidated sandstone reservoirs, which host a substantial portion of the world's oil and gas reserves (Rahmati, et al., 2013). The strength-weakening effect of fluid-rock interactions may gradually lead to sandstone reservoir formation degradation. Additionally, rock porosity and permeability evolution influence chemical distribution and mobility in the reservoir. Porosity, as shown in Figure 2.1, determines the rock's storage capacity, which is described as the ratio of its void spaces, generally termed pore volume, to bulk volume and is described either as a percentage or a fraction (Coneybeare, 1967; Keelan, 1982).



Figure 2. 1: A graphic view of a porous medium (Liou, 2005).

The study of fluid-rock interaction requires an understanding of transport and geochemical kinetics. Presently, reactive transport is faced with the most challenging problem of how to treat cases where the petrophysical properties of the porous reservoir formation change due to geochemical reactions (Steefel & Mäher, 2009). The most frequently identified evolutions in petrophysical properties are porosity and permeability, which are induced by chemical reactions such as dissolution or precipitation. The modeling approach involves coupled flows and chemical reactions. In reactive transport simulations, porosity is typically the first-order parameter predicted, as it is directly related to the total volume of minerals precipitated or dissolved (Steefel & Mäher, 2009). Since detailed pore geometry is required, it is more difficult to predict transport parameters, in particular permeability and diffusivity. It is possible to circumvent this problem by combining modeling and microscopic characterization of the porous reservoir formation as mineral dissolution or precipitation occurs. The governing advection-dispersion-reaction model is shown in Equation 2.1.

$$\frac{\partial(\emptyset C_i)}{\partial t} = \nabla . \left( \emptyset D_i \nabla C_i \right) - \nabla . \left( \emptyset u C_i \right) - \sum_{r=1}^{N_r} v_{ir} R_r - \sum_{m=1}^{N_m} v_{im} R_m$$
(2.1)

The aqueous (homogeneous) reactions,  $R_r$ , and the rates of the  $N_m$  solid phase (mineral) reactions,  $R_m$ , u is the fluid velocity, D is diffusivity, and stoichiometry is given in the coefficients  $v_{ir}$  and  $v_{im}$ .

Currently, reactive transport in porous media is described by three types of models: 1) continuum models, 2) pore-scale models, and 3) multiple continuum or hybrid models involving a combination of scales (Steefel & Mäher, 2009). Among the transport processes relevant to the study of chemical-rock interaction are advection, which occurs most commonly due to fluid flow through porous media; molecular diffusion, which is modified by electrochemical migration in the presence of charged species; and hydrodynamic dispersion.

The phenomena of oilfield chemical-rock interaction can cause alterations to the formation's porosity and permeability rock (Xu, et al., 2011; Lamy-Champpius, et al., 2014). Therefore, this modifies the rock's permeability and porosity characteristics. Also, a scientific model that describes the evolution mechanism of porosity and permeability triggered by several chemical and physical interactions among reservoir rocks and fluids has been investigated by Chang and Civian (1991). There is, however, no one-fit-all relationship between permeability and porosity applied to all porous mediums (Bernabe, et al., 2003). This can be credited to the added complications introduced by precipitation and the release of fine grains, which are likely to plug pore throats, swelling of clay, and improved compaction (Chang and Civan, 1991; Yu, et al., 2012). Thus, the link between permeability, porosity, and rock strength has been the focus of wide study and is soon to be completely understood. Conversely, sedimentary rocks such as carbonate reservoirs are known from studies for their huge commercial hydrocarbon accumulation around the world with altered petrophysical properties, mainly due to precipitation and dissolution of minerals leading to increased porosity. The dissolution or precipitation of chemical species that leads to changes in porosity depends on parameters like mineral composition, the shape of the grain, grain size distribution, and pore size (Lamy-Chappuis, et al. 2013, Wuyep, et al. 2018). Additionally, Egermann et al. (2010) studied the petrophysical properties as a result of fluid (CO<sub>2</sub> injection) and rock interfaces on the capacity to hold and store carbon dioxide. The rock-CO<sub>2</sub> interaction was observed to alter the petrophysical properties, such as the permeability of the carbonate rock. This occurred because of the pore network framework imbalance and the degree of mineral dissolution in the rock. Considering this, many permeability and porosity experimental equations have been reported in the literature. Porosity is primarily associated with tortuosity and many small pores, so the dissolution of small sand particles or distinct calcite may have only a small impact on the connectivity of pores, as well as a decrease in tortuosity and/or dissolution at pore throats. As a result, the maximum strength of siltstones, sandstones, and a few limestones will reduce with increased porosity (Friedman, 1976; Dyke & Dobereiner, 1991; Chang, et al., 2006; vasarhelyi & Van, 2006; Atapour & Mortazavi, 2018; Zhao, et al., 2018; Amiri & Moomivand, 2019).

To study rock's petrophysical properties, the Kozeny-Carman (K-C) equation is usually fitted with experimental data to define the relation between porosity ( $\varphi$ ) and permeability ( $\kappa$ ) in a fluid-rock interface system (Walsh and Brace, 1994; Lamy-Chappuis, et al., 2014). This advocates power-law relationships amongst the appropriate pore geometry, such as tortuosity and surface area, hydraulic radius, porosity, and permeability (Bernabe et al., 2003). But Lamy-Chappuis and coworkers (2014) validated their experimental data with the use of equation (2.1),

whereas equation 2.3 as established by Chang and Civan (1991), can be used to evaluate permeability alteration due to formation damage. Hence, equation 2.4 is the general form of equations (2.1) and (2.3).

In the equations,  $\phi$  denotes porosity, k permeability ( $\phi_o$  and  $\kappa_o$  represent initial porosity and permeability, respectively), *n* ranges between 3 and 7, the efficiency factor *f* stated as the unplugged pore throat area fraction (determined stochastically), and the experimental matching parameters are represented as a, b, and c.

Furthermore, Yang et al. (2017) investigated the sandstone rock and brine interface examined rock properties during diagenesis, and the results revealed that minerals such as calcite dissolution led to porosity increases. Using empirical, numerical simulations, petrographic observations, and the ability to restructure the diagenetic process, the authors concluded that reservoir formation petrophysical properties can be predicted. Additionally, Liu et al. (2019) examined the effect of the shale and water interface on the sensitivity of stress on shale rock rich in organic materials. Shale reservoirs were found to have natural fractures and low permeability based on the study results. However, when the fluid used is water, the chemistry between water and rock is rather different from that between oilfield chemicals and the rock interface, which is the focus of this study. On the other hand, the interaction

between iron carbonate and corrosion inhibitors showed that imidazoline can bind to, adsorb to, and develop a film on non-conductive materials such as iron carbonate (FeCO<sub>3</sub>), resulting in a reduction in porosity and delaying the transportation of reactants to the corrosion surfaces, as reported in the literature (Ramachandran, et al., 1999). This suggests that porosity is a function of the strength of the material. In addition, Wuyep et al. (2019) found that a decrease in permeability and porosity suggests a decrease in pore space due to new mineral formation in the carbonate rock when treated with Betaine and Aminotrimethylphosphonic acid (ATMP). It is therefore obvious that there is a strong connection between uniaxial strength and the porosity of formation materials, which is a function of the composition and internal structures (Li & Aubertin (2003). In other words, porosity is an important parameter when dealing with uniaxial strength. In a study by Bertaux & Lemanczyk (1987), the behavior of sandstone reservoir rock treated with potassium hydroxide and Sodium hydroxide (KOH and NaOH) was examined. It was discovered that the interaction between the sandstone rock and alkali fluid at 90 °C and 150 °C, produced a new mineral, crystalline zeolite, and precipitated amorphous at 200 °C. The amount of precipitated and dissolved minerals was found to be responsible for changes in permeability and clay reactivity with alkali chemicals.

A typical example where the impact of oilfield chemical-rock interaction is experienced is in chemical flooding techniques such as alkali-surfactant-polymer (ASP) flooding for EOR (Pal, et al., 2018). A study on the incremental oil recovery factor and degree of permeability damage in heterogeneous sandstone reservoirs subjected to strong-base and weak-base ASP flooding processes was also evaluated and compared (Zhong, et al., 2020). It was found that the permeability-damage ratio can be reduced by approximately 15% with weak-base ASP flooding compared to strong-base flooding, and the reservoir flow assurance issues related to chemical loss

can be addressed. This shows the formulation of oilfield chemicals and their concentration. As reservoir rock minerals dissolve, the grains are carried away by fluid flow, which settles on the surface of the pore walls. The induced porosity change during fluid flow and the rock-fluid interface is a result of the precipitation of insoluble salts, formation swelling, clay particle deposition, mineral dissolution, and surface solid entrainment (Chang and Civan, 1991). Shebl & Surdam (1995) empirically studied the possibility of oil-water-rock reactions. The authors utilized oxidized sandstone rock, which originally contains anhydrite and intergranular clay cement with 6-15 % range porosity and about 10-25 % carbonate. After the experiment, it was found that there was a major possibility for a redox reaction to occur between an oxidized mineral and crude, and this reaction impacted the permeability and porosity (increasing them from a range of 12-20 %) of an elastic reservoir formation. Based on the results from the literature, it can be concluded that chemical and rock interfaces cause mineral precipitation and dissolution, changing the porosity and permeability of the formation. But changes in the permeability and porosity of the rock depend on the rock's mineralogy, particle size distribution, the shape of the grain, and pore size (Lamy-Chappuis, et al., 2014; Wuyep, et al., 2019).

## 2.2.3 Effect of Chemical-Rock Interaction on Particle Size Distribution

When a reactive fluid flows through a geologic porous medium, such as a reservoir rock, it is possible for minerals embedded in the reservoir formation to dissolve, releasing fine particles. While the dissolved mineral species could be in ionic form, the precipitated counterparts and the sand grains comprise a range of particle size distributions. Also, the minerals (ions) may precipitate from other ions dissolved in the fluid, or they may also be conveyed with the dissolved minerals to form precipitates when the concentration of the ions is greater than the solubility of the precipitates (Chang and Civan, 1991). The solid particle size distribution in the

solution (see Figure 2.2) may influence the ionic exchange between ions in the solution and the rock surface and the possibility of precipitation. This is because several materials make up the reservoir rock, which differ in their porosity, microvoids, and boundary structure and are thus characterized by a fragile structure (Jongpradist, et al., 2011). Therefore, the redistribution of grains and their arrangement in the reservoir formation are closely related to the characteristics of the rock (Kwan & Surip, 2020). It can increase the deformation of rocks, affect their porosity and permeability, and lead to structural uncertainty (Alonso EE, 2010).



Figure 2. 2: Grain size distribution of brine and brine effluents from rock samples (Oluyemi, 2014).

The reactions that occur when oilfield chemicals are introduced into a geological formation are classified as 1) mineral dissolution and precipitation of the rock; 2) precipitation and dissolution of metallic ions and ionic compounds in the chemical; 3) ion exchange between the rock surface and the chemical; and 4) crystal growth and nucleation of the precipitate (Chang and Civan, 1991). Dvorkin and Gutrierrez (2002)

proposed that particle size distribution (PSD) is an important feature of rocks, as it directly affects the rock's geomechanical properties and geochemical characteristics. It is therefore possible for chemical-reservoir rock interaction to cause distortions in mineral configuration, causing mineral dissolution and precipitation and, in turn, decreasing or increasing rocks' petrophysical properties depending on particle size distributions (Lamy-Chappuis, et al. 2014). But when interparticle pores dominate fluid flow channels, such as in sandstone, they are moderately consistent in their spread. Therefore, all pores of the bonding material can be completely sealed off by its range of particle size distribution (He & Stephens, 2011). According to Oluyemi et al. (2006), changes in the PSD of a sand-producing formation during production may change the uniaxial compressive strength (UCS) of the rock. This change in UCS can weaken the rocks, resulting in formation damage. Consequently, Israeli and Emmanuel (2018), with the use of MATLAB, simulated the effect of PSD on formation weathering. It was observed that rocks with fine grains rapidly withered more but slowed down when the grain size increased. This reveals that particle size distribution strongly influences the rate of fluid-rock interactions. Even so, the study ignored physical processes such as fluid flow, diffusion, and the impact of oilfield chemicals and rock interfaces, making extrapolation difficult. On the other hand, Wuyep et al. (2019) reported the impact of the oilfield chemical and rock interface on the rock's mechanical strength with the combined use of uniaxial compressive and analytical tests. The results showed that there is a major difference between the particle size of brine and its effluent from reservoir samples. The increase in PSD observed may be caused by the dissolution/precipitation reactions, which can weaken grain-grain bonding and result in detachment. However, results from other reported research showed that rock strength can be linked with the composition of its minerals (Li, et al., 2014; Pan, et al., 2016; Sun, et al., 2017; Zhang & Liu, 2018), grain shape and

size (Sun, et al., 2017; Jin, et al., 2017), and its particle size distribution (Hussain, et al., 2006; Shimizu, et al., 2010). According to Jin et al. (2017), the shapes of rock materials and grain size contribute to the strength of cemented soil-rock mixtures. It is found that the cement-cemented soil-rock mixtures could have localized shear- and strain-softening bands with better strength and modulus than soil-rock mixtures without cement. In other words, the cement materials help to improve the strength and modulus of the soil-rock mixture. In general, the PSD is critical in evaluating the response of the reservoir rock formation to fluid interaction (Lade, et al., 1996; Yu, et al., 2016). By using DEM code to investigate the effect of PSD on the mechanical properties of the reservoir, it was found that the mechanical properties are influenced by the porosity of the formation and PSD (Shimizu, et al., 2010). As the small grains of the rock occupy the space between the larger grains, they are prevented from dislodging by opposing grains. Furthermore, Wu, et al. (2018) investigated the effects of grain size distribution on the structural and mechanical properties of cemented rockfills based on loading, and the results obtained showed that cemented rockfill with rough particles displays a decreasing microstructure with an early failure. This is attributed to the effect of PSD composed within the rock. In essence, particle size distribution plays a very important role in rock deformation (Wang, 1994; Zhang, et al., 2018), as well as changes in permeability and porosity (Seely & Johns, 2018; Chen, et al., 2018).

## 2.3 Geomechanical Properties

A comprehensive understanding of a rock's geomechanical properties, such as its elastic properties, which include elastic modulus, shear modulus, bulk modulus, Poisson's ratio, and Young's modulus, and its inelastic properties (e.g., fracture gradient and compressive strengths), is crucial for the successful application, storage, and stimulation of oil, gas, and shale reservoirs (Motra and Stutz, 2018). This is

necessary for the prediction of rock deformation and failure during fluid flow through the porous reservoir rock formation and fluid-rock interaction. This section of the study is devoted to the evaluation of the effect of fluid-rock interaction on the geomechanical properties of rock formations during the chemical injection. There has been extensive research to understand the importance and role of geomechanical properties such as Young's modulus, unconfined compressive strength (UCS), and confined compressive strength (CCS) in reservoir engineering.

This overall mechanical behavior of the rock due to external stress or load significantly depends on its geomechanical properties (Hussain et al., 2020). It is also dependent on several other parameters, which include temperature, pressure, nonhydrostatic stress, and failure history (Hussain et al., 2020). The elastic modulus, compressive strengths, and Young's modulus have been designated as critical parameters for describing rocks' geomechanical behavior under load. Makani (2014) observed a strong correlation between the elastic modulus and compressive strength of the rock. Also, it has been reported that the rock composition, geochemical, and petrophysical properties exert much greater control on their mechanical behavior (Hussain et al., 2017). In other words, the physicochemical and mechanical properties of the rock control its behavior in addition to the interaction with the reactive fluid and the flow. Therefore, rock texture characterization is needed to provide insight into microstructure and morphology. Engebretson et al. (1997) investigated how dodecyl trimethyl ammonium bromide (DTAB), polyethylene oxide (PEO), and aluminum chloride (AlCl<sub>3</sub>) affect the strength of sandstone reservoir rocks to establish fundamental knowledge that can be used to optimize chemically assisted fracking. This study was, however, limited in scope to static tests, and the chemicals used in the study were different from the chemistry of common oilfield chemicals. Jegarluei and co-workers (2010) reported the effect of cementation on the

mechanical properties of a reservoir rock, in which they noted that rock mechanical properties are significant parameters for modeling wellbore stability and sand production.

Geomechanics provides useful insight into the *in-situ* loads or stresses experienced in fluid flow and its interaction with the rock, including the stability and strength of the rock. The geomechanical properties of a rock formation combined with its petrophysical properties will help predict the rock's stability and the potential for fluid to flow through it. Oluyemi (2014) performed an experimental investigation on a clashach reservoir core to determine the type of interaction that occurs between a chemical inhibitor and clastic reservoir formation. Results from this investigation showed that the interaction of an inhibitor (phosphonate scale inhibitor (PTEMP) solution prepared in brine) with the reservoir formation can lead to a physically induced failure of the formation and the release of sand during production. This study, however, did not fully consider the numerical analysis, and it is recommended that further experimental work be done to confirm physicochemical models. It has been demonstrated that when oilfield chemicals are injected, the rock-fluid interaction will have a large impact on the determination of the geomechanical properties of the formation (Wuyep, et al., 2018 and 2019).

The effect of gas production-induced compaction and subsidence analyses was studied by coupling fluid-flow and geomechanics (i.e., stress-strain phenomena) by combining three numerical models: 1) a geological model representing the rock's structural and geological features; 2) a fluid-flow model simulating pressure evolution in space and time; and 3) a geomechanical model predicting the rock's stress-strain behavior (Giani et al., 2018). In the study, an experimental scale representing a typical off-shore, shallow, weakly compacted, and multi-layered gas reservoir of the Adriatic Sea was constructed, and data from an existing gas-bearing formation (off-

shore Croatia) were utilized. It was found that the rock stress-strain evolution remains within the elastic domain, the deformation is small, the compaction-induced porosity reduction is negligible, and the maximum permeability variation reaches 12%. The reason for the minimal impact on the rock's geomechanical and petrophysical properties could be attributed to the gas fluid and the weak compaction. In the case of oilfield chemicals, dissolution, and precipitation processes induced by fluid-rock interaction can change flow pathways and permeability, and as a consequence, rock deformation. The flow of fluids in porous rock formations occurs either through interconnected pores or through a network of natural, pre-existing, or induced rock fractures. The reactive fluid-rock interaction alters rock rheology, permeability, porosity, and geomechanical properties; hence, the resultant couplings of flow, reaction, and rock deformation need adequate consideration. Moreover, the chemicals could alter the stability of the stressed rock by eroding or mineralizing contact surfaces, leading to geochemically driven deformation (Pyrak-Nolte and DePaolo, 2015; Den and Spycher, 2019). This arises from volume changes caused by hydration, carbonation, oxidation, precipitation, and the dissolution of minerals embedded in rock that is confined under stress (Pyrak-Nolte and DePaolo, 2015). While mechanical and geochemical perturbations to reservoir rock may happen independently, the processes are often combined through fluid and mineral interactions (i.e., fluid-rock interaction). However, geochemical reactions can initiate and propagate cracks, alter fracture opening due to mineral dissolution, pore closing due to mineral precipitation, and cause volume changes and rock deformation (Pyrak-Nolte and DePaolo, 2015; Den and Spycher, 2019). At the same time, it could affect geomechanical processes. Hence, models that combine chemical-mechanical processes in stressed rocks are critical and valuable for predicting and monitoring dynamic changes to the state of the rock and its deformation evolution. Ultimately,

the morphology, petrophysical, and geomechanical properties of the rock evolve dynamically as a function of mineral precipitation and dissolution motivated by fluid motion and composition, temperature, and pressure variations.

## 2.3.1 Unconfined Compressive Strength (UCS) And Young's Modulus

Compressive strength refers to the rock's ability to withstand stress intended to reduce its size. The compressive strength is a very significant geomechanical property of the formation, mostly used to determine the stability of the structure when exposed to stress (Romana & Vásárhelyi, 2007; Gholami & Fakhari, 2017). The testdetermination approach involving core samples of rocks is destructive, costly, and time-consuming. To estimate UCS, various models have been proposed using mineralogical and petrographic characteristics and the rock's physical properties. In light of this, the strength of a rock is exponentially determined by its porosity, and this increases with a decrease in porosity, as demonstrated by Sarda et al. (1993). Thus, it is important not only for engineering designs but also as an important element of effective design and implementation (Aladejare, April 2020). Good knowledge and precise evaluation would improve proficiency in oilfield stimulations and other oilfield operations (Negara, et al., 2017). Rashidi et al. (2008), in their effort to enhance bit real-time wear with the use of an intelligent drilling advisory system, were able to demonstrate that the uniaxial compression strength (UCS) test may be affected by particle shape, grain size, sorting, mineralogy, size and shape of the test sample, and rate of loading. On the other hand, Sonmez et al. (2006) noted that compressive strength, which is an input in rock design, is essential in the prediction of the deformation modulus. Nevertheless, Palmstrom (1996) and Aladejare & Wang (2019) utilized a rock mass classification system that combines the rock mass Index (RMI) and rock mass rating (RMR) systems in evaluating the formation strength properties and rock mass deformation connected to respond to

load and its design. Tixier et al. (1973) proposed a simple correlation (Equation 2.5) to estimate formation strength from its mechanical properties, especially UCS and rock strength.

$$\rho b/\Delta t^2$$
......(2.5)

Where  $\rho b$  and  $\Delta t$  can be obtained through sonic and density logs.

Using a triaxial test, Yadav et al. (2016) investigated the changes in geomechanical properties of Berea shale and sandstone reservoir rock samples when they were interacting with oil-and water-based muds. It was shown that the oil-based mud (OBM) preserves the shale strength better than the water-based mud (WBM). Xu et al. (2018) empirically studied the influence of drilling fluid on tight sandstone hardness using WBM (water-based mud) and OBM (oil-based mud) and observed that after two hours, the hardness of the rock (sandstone) decreased by 22.9% and 10.1% with WBM and OBMs, respectively. It also showed that after 15 days, the sandstone hardness with WBM was observed to have decreased by 33.1% but remained unchanged with OBM. It was also noted that temperature has little influence on sandstone hardness with WBM, but temperatures of 50 °C and above decrease sandstone hardness with OBM. This means water exerts more impact on the geomechanical properties of the rock formation than oil. According to Wuyep et al. (2019), fluid-rock interaction resulting from mineral dissolution, precipitation, and geochemical reactions weakens reservoir rock grain fabrics of carbonate and sandstone. This decreased the UCS under the atmospheric and ambient conditions of the experiment. Kitamura and Hirose (2017) investigated the impact of distilled water on the strength of several reservoir rocks (sandstone) with the use of an indentation test in studying the hardness of the different sandstone rock samples.

Young's modulus refers to the rock's ability to withstand changes in length and deformation. This can be presented mathematically in the Equation (2.6).

Young's modulus and compressive strength were found to increase with a decrease in the porosity of the rock when the compressive strength was correlated with the ultrasonic wave velocity. Experimentally, Al-Osta (2018) evaluated the compressive strength of rocks using a correlation developed between the compressive strength and some important parameters gotten through indirect methods on the rock, such as ultrasonic pulse velocity, mass density, and point load strength index. The obtained results showed that the connection between ultrasonic pulse velocity and UCS compressive strength displayed the best match, followed by compressive strength and mass density, and lastly, point load index and compressive strength. Likewise, Muqtadir et al. (2018) explored how the mechanical properties of a sandstone formation with low permeability are affected by fluid saturation. The authors observed that the sandstone formation, when saturated in brine, becomes weaker compared to when it is saturated in oil. The investigation also showed a 9% reduction in the UCS and a 40% decrease in tensile strength (TS) when saturated with brine. But when the formation is saturated with oil, the reductions in the TS and UCS were discovered to be 25% and 10%, respectively. This suggests that oilfield chemicals exert a significant impact on the geomechanical properties of the reservoir rocks. Similarly, Smorodinov et al. (1970) explored correlations between some physical characteristics of rocks and rock strength, developing two relationships to estimate UCS based on porosity and density as direct determinants of rock strength, which are exponential functions of density and porosity. This indicates the possibility

of estimating the geomechanical properties of the rocks from their petrophysical properties. For instance, it has been generally shown that the rock's compressive strength is a function of mass density or porosity (Rzhevsky & Novick, 1971; ernik, et al., 1993; Horsrud, 2001). Conversely, other correlations are based on Poisson's ratio, rock strength, sonic wave velocity, and bulk density (Fjær, et al., 1992; Moos, et al., 1999).

It is therefore expected that the UCS decreases as the rock's porosity increases; hence, at a certain porosity, the rock will become weakened and merely a loose aggregate.

## 2.3.2 Confined compressive strength (CCS)

Rock failure occurs either through fracturing or deformation due to compression. The most commonly used mechanical test, compression, is crucial in determining the strength of rocks. The confining pressure (stress) below which a reservoir formation deforms is acknowledged as its confined compressive strength (CCS), at which point a breakdown in the rock gain structure begins, leading to compaction of the rock and a loss in porosity. The CCS of a formation is a very significant parameter in petroleum engineering for selecting drill bits and drilling process optimization, predicting the rate of penetration (ROP), and performing analysis (Shi, et al., 2015). It is also a general understanding that the heterogeneity at the rock grain scale, such as mineral stiffness and grain geometry, as well as particle and particle boundary micro-cracks (called micro-defects), will reduce the UCS of the rock (Bahrani & Kaiser, 2016). In considering rock strength, Rampersad et al. (1994) used a power function to develop a link between the CCS of the rock, the strength of the rock, and confining pressure. Nonetheless, the model proposed neglected the impact of porosity on the strength of the rock, which is a critical petrophysical property. Shi et al. (2015) considered the effect of porosity and nonlinear properties with increasing confining pressure for

selecting bits, predicting the rate of penetration (ROP), and drilling optimization, and developed a compressive strength model. The authors' model, when in combination with the equation for mechanical-specific energy, was used to optimize drilling parameters. Figure 2.3 shows the relationship between confining pressure and rock strength for different types of rock. It can be observed that the model can recognize unproductive drilling circumstances and is appropriate for both overbalanced drilling (OBD) and underbalanced drilling (UBD). However, the study was carried out on a dry rock sample, which therefore makes the result difficult to extrapolate when accounting for the rock's behavior when interacting with fluids.



Figure 2. 3: Curves for confining pressure and strength for different types of rock (Shi, et al., 2015).

The rock porosity is a function of peak stress at varying confining pressure, as presented in Figure 2.4. Both the elastic properties and the strength of the rock are significantly influenced by the porosity of the formation. Consequently, when the porosity of the rock is altered, so does the formation's capacity to support loads. The petrophysical parameters of the rock and, consequently, the geomechanical features, such as rock strength and UCS, are reportedly considerably changed when oilfield chemicals interact with reservoir formation.



Figure 2. 4: Peak stress and porosity at varying confining pressure (Shi, et al., 2015).

# 2.3.3 Poisson's Ratio

The ability of a material to deform in a direction perpendicular to the direction of the applied stress is defined by Poisson's ratio, a crucial rock feature. Unfortunately, as a result of the difficulty in accurately determining this rock property, it is rarely investigated (Logo & Vasarhelyi, 2022). The Poisson's ratio can be mathematically represented in the Equation (2.7).

Where axial strain is the strain in the x direction, and radial strain is the degree of deformation.

Poisson's ratios are ranged according to their ease or difficulty of fracture. Low Poisson's ratios are ranged between 0.1-0.25, whereas Poisson's ratios with ranges of 0.35-0.45 are referred to as high Poisson's ratios.

The authors (Xu, et al., 2015; Logo & Vasarhelyi, 2022) in their study related CCS to Poisson's ratio. Xu et al. (2015) reported the effect of increasing the lateral stress of an intact rock. The findings demonstrate that when lateral stress loading increases, the Poisson's ratio increases linearly. Other studies (Carneiro & Puga,

2018) examined several specimens by dynamic mechanical analysis, which was capable of monitoring instant load and displacement values to evaluate the specimens complex modulus, Poisson's ratio, and stiffness. According to the findings, a rise in temperature causes a rise in Posson's ratio. Furthermore, in considering poisson's ratio and porosity relations, Martin et al. (1996) explored the connection between porosity and poisson's ratio using sintered ZnO of various densities. The results show that the poisson's ratio is likely not dependent on porosity. Thus, it can be noted from the study why some porous materials have an approximately constant poisson ratio, regardless of the porosity of the material.

## 2.4 Chemical-Rock Interaction Mechanisms

The chemical-rock interaction during the flow of fluid in the porous rock medium could result in the following concurrent processes: 1) dissolution and precipitation of rock minerals; 2) dissolution and precipitation of salts from the chemical itself; 3) ion exchange between the rock and the chemical, leading to adsorption and desorption; and 4) nucleation and growth of precipitated minerals and solid deposition (Chang and Civan, 1991). However, the primary mechanisms by which fluid and rock interaction occurs are the dissolution and precipitation of mineral phases (William, et al., 2016). It is important to understand the mechanism behind chemical-rock interaction in order to determine the effect of their interactions on formation rock strength. The formulation of governing models will involve continuity, momentum conservation, and mass conservation, as well as several constitutive relations such as reaction rate laws and mass laws (Den and Spycher, 2019). Therefore, the formation rock damage model during chemical-rock interaction should be a combination of the fluid flow model, particle migration, and chemical reactions such as dissolution and precipitation. Both carbonate and sandstone rocks were evaluated under biocides, scale, and corrosion inhibitor interactions, and it was observed that

the chemical mechanisms such as mineral dissolution, precipitation, and ion exchange weakened the rock grain fabrics and, as a consequence, failure occurred (Wuyep et al., 2019). Guodong et al. (2017) investigated the effect of CO<sub>2</sub>-water-rock interactions on porosity and permeability. They noticed that an increase in the injection of CO<sub>2</sub> without commensurate pressure buildup influenced the porosity-permeability relationships. However, it was concluded that the increase in injectivity of CO<sub>2</sub> was responsible for the increased dissolution of the rock mineral (dolomite). Bertaux & Lemanczy (1987) studied the mechanism of interaction between the minerals of a sandstone reservoir rock and Sodium hydroxide (NaOH) and Potassium hydroxide (KOH). Whilst the rock-NaOH interaction precipitated crystalline zeolite, the rock-KOH interaction precipitated amorphous materials at 90°C and 200°C, respectively. These studies, therefore, confirm the basic mechanisms of dissolution and precipitation.

Horsrud et al. (1998) conducted research to predict borehole instability by exposing smectite-rich shale cores to KCL. The results revealed that shale shrinks due to ion exchange, thereby increasing the permeability and possibly the strength of the rock. The shrinkage effect was simulated, and the results showed that compressive stress decreases with an increase in KCL concentration. In another study carried out by El-Hajj and co-workers (2013), they flooded a carbonate reservoir core with carbon dioxide at reservoir conditions and evaluated the interaction between CO<sub>2</sub>-carbonate formation with an X-ray fluorescence (XRF) analyser, a scanning electron microscope (SEM), and an atomic force microscope (AFM). They found that the CO<sub>2</sub> dissolved some of the rock minerals at high pressure aging and that dissolved carbonate was precipitated. Similarly, Shiraki and Dunn (2000) experimentally investigated the impact of saturated CO<sub>2</sub> and brine on dolomite-anhydrite-cemented Tensleep

sandstone. After a week, they observed the dissolution of dolomite and K-feldspar, which led to the formation of kaolinite in the pore throat and a subsequent reduction in permeability. However, the chemicals used were not regular oilfield chemicals, and the duration of the experiment was short. By flushing a saturated NaCl core with dry CO2, Muller et al. (2009) performed hydrochemical studies on Berea sandstone rock and found that halite mineral precipitation caused a decrease in permeability. Conversely, when a calcite-dolomite cemented sandstone was studied and reported by Ross *et al.* (1981), it was discovered that an increase in the permeability of the formation was a result of the dissolution of carbonate minerals. This was attributed to an enhanced pore space modification because of the dissolution of carbonate cement bonding. In other words, these studies show that:

- Most of the experiments were done with limited short-term effects.
- Revealed nothing about fluid flow.
- Limited study on the long-term carbonic acid from CO<sub>2</sub> in brine reactions with minerals in the formation, such as calcite, siderite, dolomite, quartz, barite, etc.
- The use of chemicals with different properties or chemistry with different reactions has different geochemical effects on reservoir formation when injected into it.

#### 2.5 Numerical Modelling of Fluid-Rock Interaction

To successfully simulate and predict the geochemical behavior of a reservoir rock, it is important to experiment with a proper understanding of the dynamic processes involved (Marty, et al., 2015). Oilfield chemicals and formation rock interaction have a great impact on different geomechanical and geological developments such as hydrocarbon mineralization, diagenesis, migration, groundwater evolution, and sand production. To predict mineral dissolution and precipitation as a result of oilfield chemical and rock interaction, one needs to comprehend these processes by knowing the principles of heat transfer, fluid flow, chemical reaction kinetics, and mineral transportation (Bartels, et al., 2002).

#### 2.5.1 Fluid Flow in Porous Medium

Sedimentary rocks that make up hydrocarbon reservoirs typically have porosity values between 10 and 40% for sandstone reservoirs and 5-25% for carbonates. Porosity, which determines the reservoir storage capacity, is defined as the ratio of void space, commonly called pore volume, to bulk volume and is reported either as a fraction or a percentage (Coneybeare, 1967; Keelan, 1982).

These properties are significant rock properties that affect the quality of the reservoir rock (Jegarluei & Moazzeni, 2010). Whereas porosity determines the amount of fluid present, permeability controls the amount recoverable (Robert & Merrill, 1969). The connection between porosity, permeability, and rock strength has been established to some extent, but how the effect of oilfield chemicals affects this connection is not yet fully understood.

Fluid flow through a porous medium is a complicated process that cannot be described as flow through a pipe or conduit (Ahmed, 2010). Analyzing fluid flow through a porous medium has dramatically evolved over the years through experimentation and numerical analysis (Porges, 2006). As a result of the complex nature of fluid flow through a porous medium, Darcy's law can be applied to describe the process (Sheikholeslami, 2019). Darcy's law, as an expression of conservation of momentum, can be mathematically expressed in Equation (2.8).

Given:

The constant of proportionality, K as hydraulic conductivity; Q as the rate of fluid flow; A as column cross-sectional area, and dh/dl as the hydraulic gradient.

The above Darcy equation was later modified for a single-phase flow (Xinghui, et al., 1997) as shown in the Equation (2.9).

Given:

The fluid I= w or o; with k as rock permeability;  $k_{rl}$  as relative permeability and  $\mu$  the viscosity of the fluid; g is gravitational acceleration;  $\xrightarrow{z}$  is a unit for the upward pointing vector.

But for a process that involves rock mineral dissolution and precipitation as is expected from this study, the above equation has to be modified further to accommodate the processes of mineral dissolution and precipitation (Xinghui, et al., 1997) to the Brinkman's equation which is given in the Equation (2.10).

$$\rho \,\partial \mathbf{u} \,-\, \nabla .\, \eta(\vec{\mathbf{u}} \,+\, (\vec{\mathbf{u}})^{\tau}) \,-\, \left(\frac{\eta}{K}\mathbf{u} \,+\, \nabla \mathbf{p} \,-\, \mathbf{F}\right) = \,0 \,\ldots \,\ldots \,\ldots \,(2.10)$$

Given:

ρ is the density of the fluid (kg/m<sup>3</sup>); U the velocity vector (m/s); η is dynamic viscosity (Pa.s); p is pressure (Pa); k is permeability (m<sup>2</sup>); τ is tortuosity and F is minor compressible force effects (N/m<sup>2</sup>).

This research will use the Brinkman's equation to model flow through the porous media of the formation rock, taking cognizance of material dissolution and precipitation.

# 2.5.2 Chemical Reaction (Dissolution-Precipitation) and Rate Laws

Numerous phenomena happen in the reservoir. For instance, when fluids are injected into a formation, their purpose is to either treat the formation or increase productivity. But as a result of a difference in the composition of, or between injected fluid and indigenous fluid or rock minerals, their chemical reaction leads to an alteration of the rock properties, which contributes to the dissolution or precipitation of rock grains, the release of fine particles, and clay swelling (Chang & Civan, 1991). When a fluid diffuses across a porous medium, fluid minerals may precipitate, changing the fluid's characteristics. In addition, fluids' physical and chemical interactions with the matrix can also cause an increase in porosity and permeability (Caputo, 1999; Caputo, 2000; Hossain & Islam, 2006; Iaffaldano, et al., 2006). Chemical dissolution of minerals plays an important role in fluid-rock interaction geochemistry (Sri & Chakrapani, 2006), and most of the products of fluid-rock interaction are rock mineral precipitation and dissolution.

For every reaction, while the type of reaction is described by its thermodynamics, the reaction time and partway are described by its reaction kinetics. The Equation (2.11) is a general chemical reaction.

The rate law is given in the Equation (2.12), where a, b, c, and d, are the stoichiometric coefficients of the reactants and products.

Rimstidt & Barnes (1980) in considering the rate of a reaction when approaching chemical equilibrium, thought a zero-order rate would be inappropriate and then proposed a rate Equation (2.13) that incorporates a saturation state, thereby giving the rate equation as:

$$r_{qu=k_{qu}}\left(1-\frac{IAP}{K}\right)...(2.13)$$

Give  $k_{qu} 10^{-13.7}$  in mol/m<sup>2</sup>/s at 25°C,  $\Omega$  = IAP/K is saturation state, IAP is Ionic Activity Product, and K is solubility product. The term (1- IAP/K) has little impact when IAP/K < 0.1 and in that domain, the kinetics are linear in time, but the term gains importance as the quartz solubility is approached (Nagy & Lasaga, 1992).

But for mineral dissolution and precipitation, Appelo & Postma (2005) expressed the law of mass action, which is important in modeling mineral dissolution and precipitation as.

And the rate law as

Where A and B are chemical reactants, C, and D, are reaction products and a, b, c, d, are stoichiometric coefficients of reactants and products respectively.

For mineral precipitation and dissolution due to changes in solute concentration, the general rate law Equation (2.18) is considered (Appello & Postma, 2005).

Given R as reaction rate in mol/L/s, k, the specific rate in mol/m2/s, A<sub>0</sub>, the initial surface area of solid in m<sup>2</sup>, V, solution volume in m<sup>3</sup>, m<sub>0</sub>, initial moles of solid at a specific time,  $(m/m_0)^n$  is a reactive surface area during dissolution, n is 2/3 for a monodispersed population of uniformly dissolving cube, m is proportionate to volume and the surface area is proportionate to r<sup>2</sup>.

Xinghui et al. (1997) used a two-dimensional simulator (CIRF.A) and applied it to matrix acidizing analysis and design. The simulator couples fluid flow, species rock-fluid reactions and transport, and includes the effects of grain growth/dissolution, and the alteration of porosity and permeability due to mineral reactions. Their model consists of momentum conservation and mass equations with the conservation of mass equation augmented with the reaction rate equation. Results from the simulation laboratory experiments showed that acidizing treatment can cause formation damage as a result of precipitation of the products from the reaction between the acid and formation minerals. However, to model the dissolution and precipitation of formation minerals as a result of chemical-rock interaction, it will be important to add Equations (2.9) and (2.12) to give the reaction rate as:

$$\Gamma_{qu=k_{qu}} \left(1 - \frac{IAP}{K}\right) * \frac{A_0}{V} \left(\frac{m}{m_0}\right)^n \dots (2.19)$$

Therefore, equation 2.18 will be adopted for this work.

#### 2.5.3 Reactive Transport

Transportation in porous media is a very important aspect of oil exploration, underground water pollution control, filtering, pharmacology, and the manufacture of electronics. The process of transport in a porous medium is characterized by the presence of different constituents and a complex interface between these constituents. This process is therefore said to be heterogeneous when the interface of the constituents is visible (Merrikh & Lage, 2005).

Reactive transport modeling takes into account processes such as diffusion, dispersion, and advection (Seigneur, et al., 2019). These reactions in occurrence tend to affect the rock properties of porous media during subsurface mineral transport in a chemical reaction (Tenthorey & Gerald, 2006). The processes of mineral dissolution and precipitation can modify the solid phase structure of the formation. This modification can in turn significantly change the hydrologic properties and, structural parameters (porosity, tortuosity, surface area, etc.) and transport properties (permeability, effective diffusivity, etc.) of the porous media (Luquot & Gouze, 2009; Noiriel, et al., 2009). Using coupled reactive transport models, substantial research has been done over the last few decades on the interactions between fluid flow and mineral dissolution (Daccord, et al., 1993; Li, et al., 2008; Li, et al., 2010; Steefel, et al., 2005, ).

In a study, Yuan et al. (2019) used a three-dimensional (3D) numerical model to simulate a coupled process of fluid flow and chemical reactions in a fractured carbonate formation. The authors employed the Stokes–Brinkman equation for momentum balance and then coupled the Stokes–Brinkman equation with reactivetransport equations. The mass conservation equation (Equation 2.20) integrating flow, solute transport, and chemical reaction is given as:

In the equation above, v is the fluid velocity, D is the dispersion/diffusion coefficient, and  $\varphi$  is porosity. Np is the number of primary species.  $R^{min}_{\alpha}$  is the kinetic reaction rate of primary species a for mineral–water reactions.  $C_{T\alpha}$  is the total concentration of primary species.  $R^{min}_{\alpha}$  and CTa are nonlinear functions of the concentrations of primary species.

To model solute transport in a porous medium, as a result of its dual particle field nature (Succi, 2004) and additional features such as its good computational performance, ease of implementation for a porous medium, the Lattice Boltzmann method (LBM) is most well suited.

The general lattice Boltzmann Equation (LBE) (Equation 2.21) can be written as follows:

given ci as the i<sup>th</sup> discrete velocity of the lattice, with the left-hand side of the equation as the free-streaming part, and the RHS as the collisional relaxation towards a local thermodynamic equilibrium state, which happens on a timescale  $\tau = 1/\omega$ .

In recent times, a good number of advanced scientific research projects have applied the LBM method to porous media, including coupled LBM-finite volume methods for fluid-solid heat transfer (Chiappini, et al., 2015; Chiappini, 2018); heat transport in porous and fractured media (Ramadan, et al., 2016); dissolution (Gray, et al., 2016), modeling; simulation of surface catalysis in fractal porous media (Li, et al., 2013), simulation of gas diffusion layers in fuel cells at a pore level (Safi, et al., 2017).

Gray et al. (2016) presented a coupled transport and dissolution model for pore-scale modeling of seventeen (17) reactive transports in complex media such as carbon-storage injection operations. The authors used the lattice Boltzmann model for flow calculation with a finite volume method to solve nineteen (19) chemical transport equations. They also used an image of real porous limestone rock to compute the dissolution of rock samples injected with HCl and obtained dissolution patterns following twenty-eight (28) theories and experimental observations. However, these models do not consider the processes of diffusion, advection, chemical reactions, and changes in pore geometry. In order to simulate the flow and chemical dissolution of minerals in a porous medium while taking into consideration the interaction of forced convection, molecular diffusion, and chemical reaction for a system of two aqueous species in a porous medium, Kang et al. (2002) developed the Lattice Boltzmann's method (LBM). In a later year (KANG, et al., 2006), the authors used the LBM in consideration of diffusion, advection, homogeneous and heterogeneous chemical reactions with multiple aqueous species, and changes in the formation pore geometry due to mineral dissolution or precipitation.

Molins et al. (2012) noted that although the Lattice Boltzmann model (LBM) is widely useful and effective for transport and flow modeling, it does not consider a wide range of geochemical problems. The authors employed a direct numerical simulation method (Equation 2.21) to explain the transport and structural parameter changes when CO<sub>2</sub> brine is introduced into the formation in an effort to study the impact of pore-scale flow on typical geochemical reaction rates. Depending on the CO<sub>2</sub> content, distinct dissolving characteristics are induced when CO<sub>2</sub> brine is injected into carbonate rock.

$$\frac{\partial u}{\partial t} + (u.\nabla)u + \nabla p = v\Delta u \dots (2.21)$$
where  $\nabla . u = 0 \dots (2.22)$ 

$$\frac{\partial \rho C_k}{\partial t} + \nabla . \rho U C_k = \nabla . \rho D_k \nabla C_k + \rho r_k \dots (2.23)$$

Given u as fluid velocity,  $\nabla p$  as pressure gradient, ck is the total concentration of component k,  $\rho$  the fluid density, and v as kinematic viscosity, Dk is the diffusion coefficient of component k in fluid, rk as the rate contribution of mineral precipitation-dissolution reactions to component k per unit volume of fluid.
The above model considered flow, transport, and geochemical reactions at the pore scale using Navier-Stokes for incompressible flow and Advection-diffusion-reaction for scalar component concentration as given by the governing equations.

## 2.6 Causes of Sand Failure and Their Mechanisms

Sanding in rock formations has been studied in an effort to comprehend and anticipate it (Mohamed & El-Sayed, 1999; Yi, et al., 2004; Ian, et al., 2004; Xianjie, et al., 2008; Vahid & Yaser, 2012; Wang & Lu, 2013; Ferreira, et al., 2015; Adelina, et al., 2018; Ahmed, 2019; Faical, 2019). The most common failure mechanisms of rock have been classified as failure mechanisms caused by cohesion, shear, tensile, and compressive or pore collapse (Al-Awad, 2001). When the volume reduces due to an increase in stress, such as pore collapse, a rock may fail compressively. While cohesive force between formation grains is referred to as cohesion, it depends on the cement content and consolidation of the rock.

The tensile strength of the rock, the local in-situ stress, and the pore pressure are the three key elements that affect this phenomenon. Sanding is a frequent process in the extraction of hydrocarbons from weak sandstone formations. Sanding is the degradation of rock as a result of stress (for example, shear, tensile, compressive, and cohesive) and fluid movement. (Tronvoll Larsen, et al., 2004). The amount of stress is often what makes a rock fail. The sanding process, therefore, involves a three-stage process to develop progressively (Wu, et al., 2006; Abbas, et al., 2019); these are: rock failure around an open hole or perforated zone from where sand particles are produced; the disintegration of rock particles from failed rock; and transport of the disintegrated rock particles by the fluids inside the wellbore to the surface (Sunday Isehunwa, et al., 2010). To predict sanding onset, it is significant to correctly evaluate the sanding mechanism, which are either due to chemical processes or mechanical failure developments (Zhou & Sun, 2016), and their contributing parameters (Dehghani, 2016). The two major mechanisms that influence the sanding processes are tensile and shear failure. These mechanisms are associated with increased production rates (Fjær, et al., 2009). Tensile and shear stresses are important circumstances that aid rock particle failure, collapse, sand production. Other mechanisms for sand production include capillary cohesion, water sensitivity of the rock strength, pore pressure gradient, and multiphase flow (Papamichos, et al., 2010); producing time and fluid viscosity (Chin & Ramos, 2002); depletion, seepage, water cut, erosion, and material weakening (Wu, et al., 2006); triaxial stress conditions (Younessi, et al., 2013); water breakthrough, production rate, or changes in the gas–liquid ratio (Deghani, 2010; Ikporo & Sylvester, 2015). Also, rock failure is due to chemical and rock interfaces (Abass, et al., 2002; Wuyep, et al., 2018).

Chin & Ramos (2002) established a model to predict and manage sand production; this model integrates geomechanics and fluid flow during drawdown and bean-up in the depletion phase. The study shows that in weak formations, sand production is influenced by the strength of the rock, oil viscosity, flow rate, and producing time. At the same time, Han & Dusseault (2002) reported that the various likely mechanism for sand production may be generalized as: change in capillary force and surface tension lowers cohesive strength; chemical reaction between solid and fluid and the cementing material dissolution might deteriorate the rock; a decrease in the relative permeability with an increased water saturation may develop which may lead to a high pressure gradient; thus, a higher drag force and fluid velocity may weaken the rock; and grains that have been detached from the rock by the fluid and the swell of clay body's may obstruct pore throat thereby increasing pressure gradient within the vicinity and increasing the weakening force. In another report, Sunday Isehunwa et al. (2010), in their attempt to study sand production

mechanisms in reservoir formations in the Niger Delta, identified formation weakening possibly as a result of fatigue effects connected to repeated well shut-ins and loss in cohesion strength in the reservoir due to fluid losses in drilling, workovers, and completions as major contributing parameters to sanding. The authors identified the formation failure mechanisms as predominantly both cohesive and compressive.

The consequences of sanding have become a routine activity more than ever before to analyze rock failure and evaluate reservoir rocks for sand production potential. Papamichos et al. (2010) reported the sand production rate in three sandstone rock samples at varying fluid flow and saturation. The authors attributed the potential mechanisms for sand production to the strength-weakening effect of water, the pore pressure gradient during water breakthrough, and capillary cohesion in the failed zone. The authors observed that the strength-weakening impact of water is observed in early sand production initiation stress, water saturation, and water breakthrough, which led to an increased rate of sanding. Sanding is a phenomenon that occurs in three stages. These stages are initiated by reservoir rock failure, the detachment of the failed rock particles, and the transportation of the rock particles by the flowing fluid. The cyclic effects of start-up and shut-in, formation pressure depletion, operational circumstances, and drilling operations were indirectly linked to the causes of rock failure by the authors (Azadbakht, et al., 2012; Han, et al., 2002). As a result, a variety of elements, including production parameters, drilling operations, formation mechanical qualities, and rock mineralogy or composition, are involved in sand production (Ogunkunle, et al., 2018). To explore the impact of stress state and fluid flow, the development of rock fracture and processes for sand generation under genuine triaxial stress have also been documented (Younessi, et al., 2013). Regardless of the boundary stress state, it is discovered that a minimum

drawdown pressure is required to start sanding. Additionally, it was found that the development of the failure region in the borehole is dependent on the state of stress. Recently, Dehghani (2016) reported the mechanisms for sand production in a reservoir, discovered the main sanding parameters, and evaluated their influence on sand production. The results obtained demonstrate that mechanisms for sand failure and their contributory parameters were identified as grain movement, sand strength, tensile strength, and shear strength, with cohesive stress as the main sand failure mechanism. Al-Awad (2001) noted increased sand production after shutting in a well under simulated bottom hole stress-fluid flow conditions in a sandstone reservoir. The modelled bottom-hole stress-state test was set up to allow the determination of sand movement and fluid flow under modelled in-situ stresses. It was observed that, when a well is shut-in, the pore fluid pressure gets to an initial (maximum) value, which leads to a reduction in the effective confining stress. Although, repetitive fluctuations in the pore fluid pressure can really impair the cement material that bonds sand particles together, increasing the amount of sand produced. As a precedent, saline water may cause damage to sandstone cement bonding material, which may lead to an increased quantity of sand grains prepared to flow into the wellbore when related to the light oil situation (Al-Awad Musaed & Al-Misned Omar, 1997). Since the fluid in use is not typically a chemical utilized in oilfields for treatment processes, extrapolation is not possible because the chemistry would be different. According to research by Kuncoro et al. (2001), Aborisade (2013), and more recently, Ahad et al. (2020), rock failure, detachment, and particle transportation may be caused by known factors like reservoir fluid viscosity and the degree of consolidation or cementation, production rate, reduction in pore pressure, pressure drawdown, and increase in water cut.

#### 2.7 Sand Production and Transport

Once rock particles detach, they are carried through the perforations into the well. Sand produced during reservoir fluid production can either be transported through or deposited on flow pipelines. The transportation of sand depends on factors such as fluid viscosity, flow regimes, sand concentration, and particle size (Zhou & Lao, 2017). The deposition or transportation of produced sand has several negative economic effects on the transport facility, such as pipeline blockade and damage to the facility as a result of frictional pressure increase, reduction in flow path and production reduction, and corrosion development due to bacteriological activities (Zhou & Lao, 2017; Musi, et al., 2019). It is therefore important to maintain production at a rate that guarantees a lack of sand deposits in the transportation pipe (Fajemidupe, et al., 2019). Although Musi et al. (2019) posited that there is no reliable tool for the prediction of sand deposition and transport conditions, other researchers (Durand, 1953; Thomas, 1962; Oroskar & Turian, 1980; Yan, 2010) have reported that in order to manage sand production, a " Minimum Transport Condition" (MTC) of the transport system" has to be met. Fajemidupe et al. (2019) defined MTC as "the minimum combined mixture of velocities that permits continuous sand movement".

King et al. (2001) reported the effect of liquid viscosity using water, carboxyl methylcellulose, and oil on sand transport. The results show that particle transport is possible with low viscosity. Whereas solutions with high viscosity were not able to transport particle solids.

Oudeman (1993) experimentally reported a two-phase flow for sand transport and proposed a correlation. The author used a pipe of internal diameter 0.07m with varying particle sizes of 150, 300, and 690 microns ( $\mu$ m). The effect of small particles was evaluated using 0-20% void fractions with liquid velocities ranging from 0.1-0.2 m/s. For the effect of viscosity to be determined, a mixture of water and carboxymethyl cellulose was used to increase the viscosity. It is, however, observed that gas-liquid flow does have a direct impact on sand transport. More recently, Stevenson & Thorpe (2002) developed a correlation to experimentally evaluate the average velocity of sand particles in a smooth stratified flow pattern in slightly depressed pipes. This was done by using 0.04-0.07 m pipes slightly inclined horizontally with particle sizes 150-1180 µm. Najmi et al. (2015) performed a study to investigate the minimum flow rate required for sand transport in a pipe. This was done using 0.05 and 0.1 m pipes, particle sizes of 20-350 µm with water volume concentrations of 0.01 and 0.1%. The impact of concentration, grain shape, and size on transport was investigated. The authors concluded from the results that flow rate increases with increasing grain size and sand concentrations. The result also showed that particle shape had no impact on sand transport. Furthermore, Baghdadi et al. (2016) developed software for the management of sand production, sand erosion, and deposition in vital parts of the production system. The developed software was able to determine both rates of erosion and critical velocities for sand deposition in pipelines, chokes, bends, and tubing. However, the developed model was not validated to predict sanding rate as it was not linked to sand prediction software.

# 2.8 Sand Failure and Management

It has been established that the chemical-rock interaction affects rock properties and can eventually lead to its failure as a result of mineral dissolution and precipitation. As a consequence, the reservoir rock failure could result in sand production. Hence, sand production is a serious problem in the petroleum industry. The two-stage process of sand production involves the onset of failure due to stresses acting upon the rock and failed sand grains carried away by the fluid. Formation rock degradation

is the process that leads to sanding (Rahmati et al., 2013). The consequences of rock failure include loss of rock integrity, leakage of reservoir fluid, and a negative economic impact (Subbiah et al., 2020). The mechanical rock failure is caused by the evolution of stress in the rock driven by chemical-rock interaction. It is a major issue during oil and gas production from unconsolidated reservoirs, as it always has significant consequences for field development. Understanding the reason why reservoirs produce sand is a very important step towards sand production management (Acock, et al., 2004). Different approaches and models (continuum or discrete element models) have been developed to predict the onset of sand failure. In light of this, Rahmati et al. (2013) reported a detailed review of sand production prediction models.

When the production of sand is not properly managed or avoided to the barest minimum, the process has the possibility of increasing the cost of production as a result of facilities such as pipelines, valves, separators, and liners erosion (Rahmati, et al., 2012; Wang, et al., 2016), a decrease in production rate, and an expensive intervention (Tronvoll & Fjaer, 1994; Rahmati, et al., 2012). Well equipment deterioration and well integrity have "cumulative and culminating" adverse consequences (Eshiet, 2012), including wellbore failure and an increase in the cost of disposal and downtime (Penberthy & Shaughnessy, 1992). Sand production can have a very serious impact on the environment, health, and safety of personnel as a result of the release of erosive properties from sand-laden fluids due to the wear and tear of downhole and surface equipment failure (Penberthy & Shaughnessy, 1992). Before sand production, rock formations needed to fail. The prediction of the failure mechanism requires the coupling of two mechanisms: hydromechanical instability caused by a flow-induced pressure gradient and mechanical instability and

deterioration around the rock (Rahmati et al., 2013). Mechanically, the factors that control rock failure include the strength of the rock (UCS), the mean-effective stress acting upon the rock, and the stress distribution due to the fluid flow (Subbiah et al., 2020). Furthermore, the collapse of pores can be experienced in high-porosity rocks such as sandstone reservoirs. Thus, Awal et al. (2001) investigated rock failure due to pore collapse mechanisms resulting in sand production using sandstone from two deep wells. The finding shows that the pore collapse failure mechanism is viable and can cause a large amount of sand production. Also, sand production may also collapse the formation as a result of a substantial reduction in the pore pressure and compaction of the reservoir formation. These processes of reduction in pore pressure and compaction may lead to subsidence (Penberthy & Shaughnessy, 1992). In other words, it can cause substantial concerns about the quantity and quality of hydrocarbons produced, cost, downtime, environment, health, and safety. And as a result of the present global oil price, sand production is considered undesirable; therefore, its control is considered one of the major concerns in petroleum production (Grafutko & Nikolaevskii, 1998; Papamichos & Malmanger, 2001).

Typically, sandstone cementation occurs through a secondary geological process in which older sediments or deeper formations tend to be tighter than younger sediments or shallow formations. As a result, sand production is normally a problem associated with producing sand from shallow and younger sedimentary formations. These shallow or younger formations can be found worldwide in places such as North and South America (Gulf of Mexico, California, Venezuela), Africa (Nigeria, Egypt), Europe (France, Italy), Asia (Trinidad, China, Malaysia, Brunei, Indonesia), and others (Mahmud, et al., 2020). However, it occurs when the stress exerted on the formation exceeds the strength of the formation. Several studies on

the topic have been limited to the mechanical failure of reservoir rocks (Vardoulakis, et al., 1996; Rahmati, et al., 2013), in which the onset of sanding was attributed to mechanical instabilities of the rock and localized failure. However, researchers such as Morita & Boyd (1991), Tronvoll Larsen et al. (2004), Haavind et al. (2008), Isehunwa et al. (2010), Dehghani (2016), Wang (2017), Elnori Elhaddad, and Maruthi Reddy (2019), have considered different approaches to sand failure and management and found the most suitable technique used in the industry for its prevention and control. Eshiet et al. (2019) reported that an effective sand production management strategy can be achieved by manipulating drawdown, flow rate, or pressure gradient. Figure 2.5 displays sand production as a function of pressure drawdown. It is clear that as the pressure drawdown increases from 3.8 to 10.34 MPa, sand production also increases. Evidently, less sand production occurs with a small pressure drawdown around the well, whereas excessive drawdown can cause the formation to fail and produce sand at unacceptable levels.



Figure 2. 5: Sand production with increasing drawdown (Eshiet, et al., 2019).

Fluid flow and fluid-rock interaction can potentially change the pore pressure within the rocks, resulting in a modification of the effective stresses, leading to rock deformation and failure. Hence, a robust failure criterion is required to accurately capture the redistribution of stresses and strains within the rock during its interaction with fluid. The Mohr–Coulomb failure criterion is the most widely applied for the description of rock failure and rock-on-rock frictional sliding (Byerlee, 1968; Rutter & Glover, 2012).

#### 2.9 Sand Control

Sanding control in a production well is an approach designed to monitor and control the rate of fluid flow, pressure, and sand particle influx into the well as a result of mobility force. This is an important aspect of the life of a production line, as effective control will help operators reduce the cost of equipment replacement and production. Well deterioration of equipment and well integrity has an "increasing and culminating" adverse consequence(Eshiet, 2012), with wellbore failure and an increase in disposal and downtime costs (Penberthy & Shaughnessy, 1992). Sanding can also have a very serious impact on the environment, health, and safety of personnel as a result of the release of erosive properties from sand overburdened by fluids due to the deterioration of the surface and downhole equipment failure (Penberthy & Shaughnessy, 1992).

Eshiet et al. (2019) noted that an efficient sand production management approach may be realized by manipulating drawdown, pressure gradient, or flow rate. Figure 5 presents sand production as a function of pressure drawdown. It is clear that as the pressure drawdown increased from 3.8 to 10.34 MPa, the production of sand also increased. Evidently, less sand production arises with a minor pressure drawdown around the well.

Different strategies may be implemented to manage formation sand production in the petroleum industry. These strategies are applied based on several factors, not limited to skin factors and formation type. These techniques can be classified based on i) production rate 2) Downhole sand consolidation, and 3) Mechanical sand control. Table 2.1 shows a summary of the different sand control techniques.

Table 2. 1: Summary of re	views on sand management techniques.
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Techniques	Author	Method	Aim	Result
Production rate	(Rahim, et al., 2010)	geological,	To develop, optimize	Production at high
control		geomechanical, and	and	rate
		reservoir data	select a suitable	
			drilling and	
			completion technique	
	(Denney, 2011)	geo-physical, geological,	enhance production	High gas rates,
		and engineering data	and increase recovery	elimination of skin
				sanding and
				reduction of ESS
Downhole sand	(Nunez, et al., 2020)	High-rate water pack	To increase	Successful
consolidation		(HRWP) method	productivity	production of oil
			performance	sand-free

(Rahim, et al., 2010)	The use of geophysical,	Develop and optimize	well stability,
	geological, and	drilling and	sustained
	engineering data	completion technique	performance and
			enhanced rate
(Cespedes, et al.,	Sand Retention Tests	The influence of open	flow performance of
2020)	(SRTs), Finite Element	flow area (OFA) and	the screen is
	Analysis (FEA)	aperture size was	controlled, mitigate
		reported to determine	plugging
		flow and sand control	
		performance	
(Mason, et al., 2014)	Rate diversion	Remove well plugins	No sand production
		and improve	
		production rate	
(Kalgaonkar &	positive charge modified	prevent sand	good regain
Chang, 2017)	nanoparticles	production	permeability of the
			consolidated sand

	(Mahardhini, et al.,	organo-silane based	improve well	enhanced maximum
	2015)	chemical treatment	performance	sand free rate
				(MSFR) resulting in
				increased production
	(Izurieta, et al.,	step rate test	Sand production	zero to near zero
	2020)		control	sand production with
				almost no impact on
				well productivity
Mechanical sand	(Cespedes, et al.,	seamed slotted-liner	evaluate flow and	SRTs indicates
control	2020)	configurations, Sand	sand control	screen flow
		Retention Tests (SRTs)	performance, design	performance is
			sand control	controlled by slot
			mechanism for	aperture, mitigate
			horizontal oil well	plugging.

(Malau, et al., 2017)	well head de-sander, thru	reduce sand	Sand	control
	tubing sand screen	production	optimized	

#### 2.10 Failure prediction

Sand is produced by oil wells for many different causes, such as fluid flow, geological and geographic considerations, production rates, natural consolidation, porosity, and a decrease in relative permeability. Predicting sand failure is a crucial part of analyzing and evaluating reservoir formation (Mahmud, et al., 2020). Physical laws, such as Darcy's law, the constitutive law, the erosion law, the equation of state law, or the rule of conservation of mass, may be utilized to characterize reservoir fluid flow. There are several different kinds of mechanical failures. For example, tensile failure happens when the tensile stress is greater than the strength of the rock formation, whereas erosion failure happens when the hydrodynamic force overcomes frictional resistance, forcing sand grains to separate. Water-induced sand production reduces the inter-granular cementation of the rock formation, and as water sweeps the reservoir, it breaks through into the producer even though the Young's modulus of saturated rock is roughly 20–30% lower than that of dry rock. Therefore, it is crucial to evaluate the danger of reservoir rock collapse and sanding for the petroleum sector. Sanding prediction models are being created as a result, and they can now foresee when sand production will start. The prediction of sanding may help to recognize the most economical technique of sand management with the desired production rate (Zhang, 2016). This is significant due to the environmental, safety, and operational fears associated with producing sand grains that fill the pore holes, obstructing the wellbore and causing wear on downhole and surface equipment, thereby increasing the cost of operation. A reliable sand production prediction study provides a foundation for a design that might realize an appropriate strategy for sand management as a result of the negative effects. No single approach to sanding prediction is currently thought to be accurate and reliable in the sector (Moore, 1994). However, from a production standpoint, anticipating the start of sand production in

real time is crucial because it enables prompt formation management decisions about sand control strategies.

The approach to sand management as emphasized by Oyeneyin et al. (2005), considers sand production risk assessment through a predictive tool, selection of suitable sand control options, downhole sand grain and produced volume monitoring, and topside management. Although predicting the onset of sand production is essential for managing and controlling sand, doing so requires a thorough understanding of sanding mechanisms and failure behavior. There are several mathematical models that can be employed to predict the failure of sand and the subsequent assessment of sand output. The models that are based on different failure causes (Abass, et al., 2002), may be grouped into numerical models (Stavropoulou, et al., 1998; Papamichos & Malmanger, 1999; Vaziri, et al., 2002) and analytical (Risnes, et al., 1982; Weingarten & Perkins, 1992; van den Hoek & Geilikman, 2003). An important factor in causing tensile failure is flow rate, which the analytical models provide a framework for. The general constraints that boundary conditions, geometry, and complicated material behavior place on an analytical model have limitations. However, many of the shortcomings of the analytical models can be solved by the numerical models (Nouri, et al., 2006). Analyzing sand strength logs, mechanical property logs, and cores was part of an earlier attempt to create numerical and statistical models. Perforation geometry, water production, pore pressure depletion, pressure drawdown caused by skin influence, and variations of other crucial parameters were not always measured, so individual efforts to develop a predictive model were typically specific to the type and location of the reservoir being studied (Moore, 1994).

Tixier et al. (1975) used a ratio of shear modulus to bulk compressibility as a signal for sanding danger. The authors computed this ratio from acoustic log data. A ratio that the authors proposed showed a lesser likelihood of sand ingress if it was greater 0.8×1012 psi<sup>2</sup>. While readings below 0.7×1012 psi<sup>2</sup> suggested a higher likelihood of sanding. The use of collected field data was essential to this approach. However, it should be noted that there may be some degree of uncertainty in the model input parameters if one is simulating physical engineering processes, such as the prediction of sanding onset due to rock failure in fluid-rock interfaces (Ogunkunle, et al., 2018). This is because the Mohr failure criterion assumes that the quality of the rock mass is completely intact and does not take into account different levels of disturbance in terms of rock strength. To anticipate the stability of cavity perforation, the developed approach combines log analysis, reservoir characterization, and rock strength testing. Modeling the stability of the cavity at early stages throughout the well's life is made possible by combining rock strength with a reservoir simulator. Perkins & Weingarten (1988) looked into the factors that could cause an unconsolidated or poorly consolidated rock to fail or remain stable. The rock experienced a shear failure around the cavity as a result of the confining pressure. The shear failure zone at the outer border expanded as fluid flowed through the cavity more quickly, causing particles to disintegrate and the area to enlarge. When the model fails, a great deal of sand is created. The use of a Sand Production Management System (SPMS) to effectively anticipate, assess, deal with, and manage issues with sand production has been documented in the literature (Webster & Tovar, 1999). The SPMS approach uses a geomechanical model to incorporate the characteristics and stress of in situ rocks and then forecasts potential changes that could result from reservoir exhaustion. The study's findings showed improved drilling and production performance while reducing issues with sand production. Figure 2.6 depicts the finite

element simulation of sand production in conjunction with hydraulic erosion and reservoir matrix mechanical behavior based on empirical data (Zhou, et al., 2019). The generated model quite accurately represented the empirical data (Figure 2.6). Although the empirical findings indicate that weakly consolidated sandstone's borehole diameter increases with time due to erosion, weaker reservoirs typically yield more sand overall.



Figure 2. 6: Simulation and empirical results for sanding test (Zhou, et al., 2019).

The rock erosion criterion applied in the finite-element model is the criterion as proposed by Papamichos (2001), which is mathematically expressed as follows:

Given  $v_w$  pore fluid velocity, c transport concentration,  $v_e$  is erosion velocity, critical strain  $\varepsilon^c$ ,  $\phi$  porosity and  $\lambda$  as the sanding coefficient.  $\lambda$  depends on the equivalent plastic strain  $\varepsilon^p$ .

Other researchers have also implemented elastoplastic models in sand production analysis (Antheunis, et al., 1976); (Morita, et al., 1989); (Nouri, et al., 2006); (Azadbakht, et al., 2012). Papamichos and colleagues (2001) developed a sanding prediction model by fusing the pore-mechanical behavior of solid-fluid systems with the erosion of rock particles produced by fluid movement. The model takes into account the effects of external stress and fluid flow. Although the model accounted for the fluid-rock interface, it involved more input data in addition to the use of oil, which does not exhibit comparable reactivity to oilfield chemicals for the fluid-rock interface. A program that captured fluid-rock interaction combined with a finite-difference method was utilized to analyze the effects of uniaxial strain conditions on synthetic rock samples (Nouri, et al., 2003). However, the role of volumetric failure and the fluid-rock interface on the rock strength impact was not adequately integrated. The sanding prediction model should capture the fundamental mechanisms of rock failure that are reactive to fluid and rock interface systems. Further empirical research on the effects of water cuts on sand formation was conducted by Wu et al. (2005), and the findings revealed that sanding was dependent on the makeup of the rock minerals and the level of residual water saturation. A reactive fluid may both carry away sand particles and react with the reservoir media, depending on the flow rate. Furthermore, if a consolidated rock formation is under significant stress, it may collapse due to compressive failure, releasing rock fragments into the moving fluid as a result. Isehunwa and Olanrewaju (2010) developed an analytical model to forecast sand production using this viewpoint. The presumptions include that sand particles are spherical and immersed in a moving

fluid; that during flow, sanding will cause a cylindrical cavity's radius to increase until equilibrium is reached; that drag, and buoyant forces are continuously acting on sand particles; and that fluid flow is described by Darcy's law. The following factors had some influence on sanding rates: fluid viscosity, flow rate, density, and grain size. For the onset and volume of sand to be produced following failure, integrated formation failure, and flow-driven sand production mechanisms, Kim & Sharma (2012). To quantify important characteristics that control rock deformation and failure, including as internal friction angle, poisons ratio, young modulus, overburden stress, UCS, and pore pressure, Suez & Subbiah's (2014) sand prediction model was constructed. The model's validation findings indicate that if the drawdown pressure is kept within a certain safe range, the well will generate sand when BHP is lower than the reservoir pressure.

Khamehchi & Reisi (2015), on the other hand, developed a method that combines bulk compressibility, shear modulus, and the ratio of shear modulus to bulk compressibility. The shear modulus-bulk compressibility ratio was experimentally linked to sand influx. In a later investigation by Gholami et al. (2016), they reported an elliptical model based on the shape of the wellbore to predict sand production in a carbonate reservoir. The authors presented a shape factor parameter based on different failure criteria to evaluate variations in the borehole geometry as a result of shear failure. Furthermore, Gharagheizi et al. (2017) applied the least squares support vector machine (LSSVM) to identify the circumstances in which sand production may arise. The model accounts for various sand production parameters such as cohesive strength of rock (COH), transmit time (TT), bottom hole flow pressure (BHFP), drawdown pressure (DD), gas and water flow rates (Q<sub>g</sub>, Q<sub>w</sub>), Total vertical depth (TVD), etc. Li et al. (2018) offered a finite element-based method for simulating an accurate sanding process. The method considers the coupling of

hydrodynamic erosion and mechanical failure of the reservoir rock. The outcome of the numerical analysis demonstrated that the plastic strain and flow velocity surrounding the wellbore have the greatest impact on sand output. It was discovered that additional factors, including drawdown pressure, in-situ stress, and hole direction, significantly influenced the rate of sand generation. A sanding prediction analysis was recently carried out by Abbas et al. (2019) using quantified log data, laboratory data, and analytical and empirical estimates that are supported by outcomes from earlier sophisticated numerical codes. The outcomes demonstrate that the strategy was successful in accurately forecasting the beginning of sanding and that it agrees with both field observations and the history of sanding. These studies have shown that the fluid-rock interaction process may cause rock formation failure and, as a consequence, wear out reservoir grain fabrics as well as their unconfined compressive strength, leading to sand production. A few models for predicting sand failure are summarized in Table 2.2. Models can be used to classify, predict, categorize, and quantify how much sand is produced from oil and gas reserves.

Model	Approach	Equation	R <sup>2</sup>	Features
(Oluyemi &	Hoek Brown	$a^{p} = \sqrt{2} (N^{4} + 1) a^{p}$	0.78	predicts
Oyeneyin,		$\varepsilon_e = \sqrt{\frac{3}{3}} (N_r + 1) \varepsilon_{\theta i}$		sanding in
2010)				real time
				failure
(Adeyanju &	Griffitti	$CDDPc = \left[\frac{\sigma UCS + \sigma L - 3\sigma H}{1 - \sigma}\right]$	0.95	Predicts real
Oyekunle,		$- \left[ \nu(p^{i} - p^{c}) \right]$		time failure
2014)		$-\left[\kappa(I_r-I_r)\right]$		
(Azad, et al.,	Artificial		0.73	Onset
2011)	Neural			sanding
	Networks			prediction
	(ANNs)			
(Natalia,	Artificial		0.91	Sand
2016)	Neural			production
	Networks			
	(ANNs)			

Table 2. 2: Summary of existing sand failure prediction models.

# 2.11 Summary

This chapter addressed earlier research on the use of oilfield chemicals, how they interact with rock formations, and how the resulting geochemical reactions affect reservoir rock properties. The essence, therefore, is to identify and highlight existing knowledge and outline specific areas needing further research. This review offers new perspectives and directions upon which the study of chemical-rock interaction is built. The models and correlations necessary to analyze and interpret experimental data are also described and evaluated in terms of relevance to the subject. The limitations of the theories and models were discussed, which helped in formulating the context and areas into which this research fits.

It is also a fundamental part of the research design process. An extensive literature survey on numerical, experimental, and analytical work on oilfield chemicals and rock interaction effects as studied by many researchers.

# **CHAPTER THREE**

# **3 METHODOLOGY**

## 3.1 Overview

This chapter presents the details of the materials and methods used for the experimental (static and core flooding) and numerical modeling (COMSOL Multiphysics) conducted during this study. Both untreated and BCX oilfield chemical (Nitrate) treated samples were tested for UCS, elemental and mineralogical composition, PSD using mechanical testing, Scanning Electron Microscopy (SEM)/Energy Dispersive X-ray analysis, X-ray Powder Diffraction (XRPD) and Malvern Laser Mastersizer 3000E respectively. This test is done to evaluate any changes on the rock due to chemical-rock interaction. The choice for these methods is based on previous study's (Oluyemi, 2014; Wuyep, et al., 2020).

#### 3.2 Materials

Materials used for this experiment include carbonate and sandstone core samples. Bio-competitive Oilfield chemicals (Sodium Nitrate) and Brine. Details and descriptions of the properties for both static and flooding tests are presented in their respective sections below.

# 3.3 Test Fluids

Brine and Nitrate are the two fluids that were used in the experiment. The chemical salts highlighted in Table 3.1 with deionized water were used to prepare brine solutions to simulate formation brine with concentrations obtained from Oluyemi (2014).

Salts	Active ions	Concentration (PPM)
NaCl	Na <sup>+</sup>	10392
CaCl <sub>2</sub> 2.H <sub>2</sub> O	Ca <sup>2+</sup>	426
$MgCl_2.6H_2O$	Mg <sup>2+</sup>	630
KCI	K <sup>+</sup>	208
SrCI.6H <sub>2</sub> O	Sr <sup>2+</sup>	10

Table 3. 1: brine composition in a 500ml deionized water.

A plastic weighing boat was washed, dried, and properly cleaned before use. The weighing boat was then placed on a Mettler Toledo analytical balance (Figure 3.1). With the weighing boat on the weighing balance, the balance is set at zero. The weight of the various salts, as highlighted in Table 1 above, is measured, weighed, and then diluted in 500 ml of deionized water at a room temperature of 20 °C. The prepared brine was maintained in a 500 ml beaker and set over a magnetic stirrer. The magnetic stirrer is used to stir the prepared formation brine at a speed of 300 m/s, just enough to prevent splashing of the brine and properly stir the brine to ensure complete dissolution of the various salt components. After that, the brine is filtered using a 45 µm filter paper to stop any undesirable or solid particles from entering the system before use (Oluyemi, 2014).

Using a viscometer in ambient conditions, the solution's viscosity was determined.



Figure 3. 1: Mettler Toledo analytical balance.

# **3.4 Experimental Equipment**

The experimental core flood rig used had been designed and used previously in RGU to determine core permeability and porosity. The main components are namely, the injection pump, the core holder, and the pressure measuring and recording devices. A standard core holder already available was used for the displacement experiments. The core holder is designed for a cylindrical core sample of diameter 38mm and length 51mm. An inlet and outlet distribution port allow fluids to be injected and produced through the core sample. It is composed of stainless steel and can function at a temperature of 150°C and a pressure of roughly 5,000 psi.

The elemental compositions of the rock samples before and after chemical injection were determined using SEM/EDX scanners. Programmable pump; for injecting fluid into the core holder, vacuum filter; to remove air from the system, Malvern Mastersizer 2000; particle size distribution measurement, stop-watch; for timekeeping, beakers; for saturation, uniaxial cell; to evaluate rock strength before and after chemical injection. Panalytical X'Pert powder X-ray diffractometer to evaluate the mineral composition of rock samples.

#### 3.5 Strength Testing and Procedure

Determination of the rock strength before and after chemical injection is required, with length-to-diameter ratio correction factors implemented for static testing.

Treated samples were oven-dried and used for strength testing. The uniaxial compression test was conducted using mechanical test equipment Instron Model 3382 with a maximum load capacity of 100 kN at a displacement control rate of 0.5 mm/min. This is because researchers (Kohmura & Inada, 2006; Sun, et al., 2012; Fabjan, et al., 2015) have noted that increasing the loading rate will consequently result in increasing UCS values. Before and after the static and flooding tests, the core samples' UCS was measured and recorded.

As recommended by (ISRM), a built-in data logger attached to the test machine was used to continually record the load and displacement changes. The load-displacement data's strain result was used to calculate the UCS's related stress-strain curve, while the UCS plot was used to calculate Young's modulus.

## **3.6 Static Chemical Saturation**

Five (5) Bandera brown sandstone core samples and five (5) Edwards Brown Carbonate core samples, each purchased from Kocurek Limited, are used for this study (see Table 3.2).

The various core samples were placed in four different beakers to achieve saturation. Brine was added to two of the beakers containing carbonate and sandstone cores until the cores were completely covered. Similarly, 12.50g of sodium Nitrate was dissolved in 500 ml of brine and poured into separate beakers containing Carbonate and sandstone cores well enough to cover them. The cores were then left for seven (7) days. This is to allow sufficient saturation of the brine and Sodium nitrate respectively (Oluyemi, 2014; Wuyep et al., 2018). The cores are then removed from the Brine and Sodium nitrate filled beakers, aired, and oven-dried at 130 °C (Wuyep et al., 2020), before being prepared for strength tests and analytical studies. Table 3. 2: Parameters of the two different core samples.

Parameters Edwards Brown		Bandera Brown
	Carbonate	Sandstone
Length (mm)	51	51
Diameter (mm)	38	38
Porosity (%)	40	21-23
Permeability (mD)	60-300	30-45

# 3.7 Analytical Test

The determination of the elemental contents of samples as a result of static and chemical flooding was carried out to enable the study of any alteration after chemical injection.

## 3.7.1 SEM/EDX

This test gives a high-magnification and high-resolution image of the smallest features in core samples. It aided in examining authigenic clays and other cement associated with the pore systems of the samples. Analytical tests (SEM and EDX) preand post-chemical treatment were conducted on dried core samples. The sample is ground to bits, degreased with acetone and then placed on an SEM stub using a microspatula. The stub has a carbon pad on which the samples were placed. The grounded rock was then covered by coating it with carbon to a thickness of about 20 nm. The size of coating is to prevent interference with elemental analysis. The EDX and SEM analytical study is an integrated system which requires the use of a Zeiss EVO LS10 variable pressure scanning electron microscope that produces highresolution

images of test samples. This is done with the help of a focused beam of electrons and a synchronized display monitor. A "raster" focuses electron beam on the sample surface area with varying magnification (250X – 2.00KX). This is represented in Equation 3.1.

$$Magnification = \frac{length \ of \ line \ scan \ on \ monitor}{length \ of \ line \ scan \ sample} \dots \dots \dots \dots \dots (3.1)$$

Samples are grounded, degreased, and dried before being placed on a stub for analysis.

## 3.7.2 XRPD

To identify and measure the mineral phases present in the untreated and treated samples, clay fraction and bulk mineralogy analysis were explored using X-Ray powder diffraction (XRPD).

The rock samples are grounded in ethanol and dried with an air brush as used in Wuyep et al. (2018). using cobalt radiation, When the sample's minerals have lattice planes, the radiation intensity peaks. Each intensity peak has Ka1 and Ka2 reflections at 20 locations, which are measured at the peak's center at 80% height. The results are tabulated as peak positions at 20 and intensity (reported at peak heights). Quantitative analysis was made using a combination of Malvern Panalytical suit.

## **3.8 Particle Size Distribution (Malvern Laser Mastersizer 3000E)**

Using a Malvern Laser Mastersizer 3000E, Particle size distribution measurement is done to identify the various grain sizes in the static and flooding effluents from the experimental runs. Before the particle size test, deionized water is poured into the sampling compartment for calibration. After rinsing, the contaminated deionized water is removed and disposed of. Another beaker was placed under the sampling compartment to completely drain the contaminated deionized water. This calibration process is done about four times until the sampling compartment is completely clean. Clean deionized water is then poured into the sampling compartment, and a magnetic stirrer is used to stir the deionized water while a 20 ml dropper is used to drop the effluent sample inside the continuously stirred deionized water. The value of particles in effluents in measured in weight percent.

#### 3.9 Porosity measurement By Liquid saturation and Immersion

Porosity is a very significant property of a petroleum reservoir rock. The geomechanical behavior of a reservoir rock is directly impacted by its porosity (Kuila, et al., 2014). As a result, proper measurement is required to evaluate reserves. 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 (RP40, 1998) standards.

Ten (10) core samples in total, including five (5) sandstone samples and five (5) carbonate samples, were used for this test. Both the sandstone and carbonate core samples' results underwent five (5) rounds of replication to ensure the reliability of the results. 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 (Equation 3.3), and then Equation 3.4 was used to determine the porosity of the core samples. Equation 3.2 requires the brine's density to be determined by weighing a graduated cylinder and then adding a predetermined volume of brine in order to calculate the pore volume. 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's density. The pore volume is determined by the weight differential between the dry and wet core samples (Anovitz & Cole, 2015).

Before fluid saturation for seven days to allow for complete core saturation, the weight of a clean, dry core sample is measured (Oluyemi, 2014). To stop the core sample from draining fluid at the end of the saturation period, it was removed from the beaker and put in a plastic weighing boat. The plastic weighing boat's weight is recorded. The saturated core in the plastic weighing boat is then weighed. Where:

$$V_p = \frac{\text{weight of saturated core} - \text{weight of the dry core}}{\text{density of brine}} \dots (3.2)$$

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).

## 3.10 Materials for Core Flooding

Investigating the impact on the petrophysical and mechanical characteristics of sandstone rock by flooding the rock samples with various sodium nitrate concentrations.

For this test, eighteen (18) identical Leopard sandstone core samples were used. The source of these core samples was Kocurek Industries, Inc. in Texas, USA. The test was repeated four (4) times for each sample concentration. Table 3.3 shows the geometrical parameters for the core flooding test.

Table 3. 3: Geometrical parameters for core flooding experiment.

Parameters	Sandstone	
Length (mm)	102	
Diameter (mm)	51	
L/D	2.0	
Porosity (%)	20-22	
Permeability (mD)	1100-1300	

## 3.10.1 Procedure for Core-Flooding

A core flood system, which consists of a 220V injection pump, is used to supply injection fluid into the test core. The main feature of the pump is its wide flow rate (0.1-12.00 ml/min) and pressure (0-6000 psi) range with reliable performance at a flow accuracy of  $\pm 2\%$ . Figure 3.2 shows the schematic diagram of the flow process. The core flooding (convection and diffusion) was important to account for the effect of fluid flow thereby mimicking production from the reservoir rock.

The core sample was exposed to the saturating brine for six (6) hours at a flow rate of 1 mL/min in order to achieve full saturation. Using the estimated core sample pore volume (25 ml) based on core liquid saturation method, sodium nitrate (NIT) is subsequently introduced into the core sample at an injection rate of 0.25 mL/min until full saturation is achieved. Table 3.4 displays the various Nitrate injection concentrations made into the core samples. The choice of the concentrations used for flooding were based on previous work by Hubert and Voordouw (2007). A high-performance syringe pump (HPLC 1500), powered by 220 V, is used to inject NIT into the core at a flow rate of 0.25 mL/min. The NIT is then left to interact with the core sample for 24 hours after which brine is injected into the core holder to flush out the

NIT. The flushing out of NIT from the core is done at a rate of 0.25 mL/min to prevent any effect of particle release and flow (Ochi & Vernoux, 1998; Oliveira, et al., 2014; Wuyep, et al., 2020). A low-capacity 0-12.5 Validyne differential pressure transducer linked to a PC was used to electronically record the differential pressure of the inlet and outflow over time using a National Instruments data acquisition system (NIDAQ) (see Figure 3.2). For data logging and monitoring in the Laboratory Virtual Instrument Engineering Workbench (LabVIEW) program, the PC has an appropriate electronic interface. However, before the pressure transducer and NIDAQ device were used, they were first calibrated with a Druck DPI model 615IS hired from Scotia Instrumentation in Aberdeen, UK. Using Equation 3.6, which is obtained from Equation 3.5, the permeability of the core is determined.

Table 3. 4: Different Nitrate concentrations in 200ml (Hubert & Voordouw, 2007)

Compound	Concentration
	(ppm)
Nitrate (sodium	637.5
Nitrate)	850
	1062.4
	1275

As NIT flow is initiated, measurements of pressures and flow rates are recorded at regular time intervals. Following chemical saturation for 24 hours., brine was pumped through the core holder inlet to flush the NIT out of the core. At regular intervals, the produced effluent was measured, collected with an effluent collector at the exit, and analyzed. After that, the core is taken out of the core holder and given a deionized water rinse.



Figure 3. 2: Schematic diagram of Sodium Nitrate flooding.

# 3.10.2 Permeability Measurement

By sequentially passing brine through the core sample at rates of 2, 4, 3, and 2 ml/min, the permeability analysis process is established. Flow rate and differential pressure data collected through LabView are analyzed for the permeability of the core samples and determined through Equation 3.6.

Before measurement, the core holder and injection lines were tested for pressure leakages. After that, by pumping 2 mL/min of brine through the mounted core sample, its permeability was determined. The differential pressure of fluid flow from the pump to the core holder, which is sent by the DAQ to the LabView, was measured using a Validyne CD223 pressure transducer. Darcy's law (Equation 3.5) is used to calculate the permeability of the core before and after chemical saturation by measuring the pressure drop across the core, knowing the viscosity of the fluid, and knowing the core's size.

Where Q is the flow rate (cm<sup>3</sup>/sec), K is permeability,  $\mu$  is fluid viscosity (cP), and  $\frac{dP}{dL}$  is differential pressure with unit length (atm).

When the pressure differential of the flow was stabilized, the permeability of the sample was measured. The permeability of the sample before and after treatment with Sodium Nitrate was compared in order to assess changes in permeability.

#### 3.10.3 Porosity measurement For Flooding by ICP-OES Analysis

Both before and after the injection of sodium nitrate, the porosity of the core was assessed. Utilizing ICP-OES analysis of lithium tracer gathered from the sample's effluents, the porosity was determined. A technique used because of its inert nature, does not interfere with the reaction and is widely popular among researchers (Jordan, et al., 1994; Oluyemi, 2014; Wuyep, et al., 2018).

A lithium tracer from a stock of 10,000 ppm standard was made by diluting 2.0 ppm lithium in deionized water in order to determine the flooding test's core's porosity. The prepared Lithium tracer (500 ml) was calibrated with deionized water and analyzed following the standard (Figure 3.3). Although, using the liquid saturation method, the sample's pore volume was predicted to be 25 ml, 40 ml of the prepared 500 ml lithium tracer was injected into the core at a constant flow rate of 2 mL/min.
The effluent was collected and examined with ICP-OES every five minutes. This process was repeated first for brine and then for nitrate flooding at varying concentrations of 637.5 PPM, 850 PPM, 1062.4 PPM, and 1275 PPM.

The Normalized concentration values (C/Ch) were plotted against the cumulative volume. The Li tracer procedure was repeated after every chemical injection. The dead volume, pore volume, bulk volume (using equation 3.3), and porosity were calculated from the Li tracer profile data generated. To determine the porosity, Equation 3.4 is used. However, Equations 3.6 and 3.7 were used to determine the core sample's pore volume V<sub>p</sub> and dead volume V<sub>d</sub> respectively.

Where the total volume  $V_T$  is obtained by the product of the normalized concentration and the sample volume.

where  $S_v$  is sample volume

The dead volume  $V_d$  is the summation of the lengths of the tubes from the pump to the core holder (inlet) and outside the core holder (outlet).



Figure 3. 3: Lithium tracer profile.

### 3.11 Experimental Workflow

The methods used to undertake the experimental work for this study (Figure 3.4) were based on various conventional procedures that have been described in the literature. Static saturation and chemical flooding techniques are used in the experiment. The rock sample's UCS is evaluated before chemical saturation and flooding. After this, the crushed rock samples were then subjected to analytical tests to evaluate the original elements and mineral components before chemical saturation and flooding. Following chemical saturation and flooding, the impacts on the rock's UCS and petrophysical parameters are assessed. The primary work consists of core flooding experiments, although the following also includes details on related experimental efforts.

## WORKFLOW OF THE EXPERIMENT



Figure 3. 4: Workflow of experiment carried out to achieve aims.

## 3.12 Numerical Simulation

COMSOL Multiphysics 6.0, which can be used to simulate chemical reactions and heat transfer using a workflow in a single environment, was utilized to carry out the simulation. The relationship between fluid flow, chemical reactions, and mineral transport in response to nitrate chemical and reservoir rock interaction was established using the Chemical Reaction Engineering module. The choice to use COMSOL Multiphysics was based on its ability to simultaneously solve coupled Multiphysics phenomena in a single environment.

#### **CHAPTER FOUR**

# 4 STATIC SATURATION - EFFECT OF BIOCOMPETITIVE EXCLUSION CHEMICAL ON SANDSTONE AND CARBONATE ROCK

## 4.1 Introduction

Numerous studies have shown that oilfield chemical-rock interactions have an effect (weakening the formation grain fabrics and cementitious material, lowering the unconfined compressive strength (UCS), and altering permeability and porosity due to dissolution and precipitation) on the mechanical characteristics of reservoir formation. This interaction between rock surfaces and oilfield chemicals occurs by diffusion (Rijnaarts et al. 1993). Researchers Seto et al. (1997) and, Wuyep et al. (2020), have used Chemicals such as aluminum chloride (AlCl<sub>3</sub>), Polyethylene Oxide (PEO), dodecyltrymetyl bromide (DTAB), and biocide, respectively, to determine the interaction between chemical and rock effects on formation strength under static and dynamic conditions. However, the chemistry of these chemicals is different from that of a more environmentally friendly, cost-effective, and commonly used biocompetitive oilfield chemical, Sodium Nitrate (NIT).

This present work further explores the petrophysical and geomechanical effects of treating a sandstone and carbonate reservoir with a bio-competitive exclusion chemical (sodium Nitrate) and comparing any possible changes between BCX chemically treated and untreated sandstone and carbonate reservoir rocks.

This study considers the chemical effects on the petrophysical and geomechanical properties before and after chemical saturation of sandstone and carbonate reservoir rocks. In Section 4.3.1 of this Chapter, the porosity changes on both carbonate and sandstone samples following the fluid-rock interactions of brine and sodium nitrate are reported. While the effect on PSD is presented and discussed in Section 4.3.2.

Section 4.3.3 additionally looked into and reported on the impact of chemical-rock core interactions caused by the saturation on the compressive strength and Young's modulus of the rock. Using SEM-EDX and XRPD, the compositional changes in carbonate and sandstone brought about by precipitation and dissolution reactions due to chemical interaction with the rock were examined, and the results are described in Sections 4.3.5 and 4.3.4.

## 4.2 Materials and Chemical Treatment

The materials used for the static test and their properties are presented in Chapter 3. It was ensured that the samples surfaces did not have any significant visible cracks that would compromise their structural integrity.

#### 4.2.1 Strength Test

Cylindrical sandstone and carbonate core samples were used to determine the initial compressive strength of the cores. A detailed procedure for the strength testing is presented in Chapter 3. Edwards brown carbonate and Bandera brown sandstone cores obtained from Kocurek Industries in the USA were used for this study. The declared porosity for Edwards brown carbonate is 40% and the permeability 60-300 mD. While the declared porosity for Bandera brown sandstone is 21-23% and the permeability is 30-45 mD. Typically, Carbonate rock has poor permeability. However, secondary porosity may be the cause of the very high carbonate permeability that Kocurek declared (Lazim, et al., 2018).

## 4.2.2 Analytical Test

To identify the crystallinity, phases, and structure of both sandstone and carbonate before and after NIT treatment, they were assessed using X-ray diffraction (XRD). Also, the topology and textural morphology of the samples were studied with the aid of SEM/EDX. The EDX of the samples produced the elemental and mineralogical changes that may have occurred due to chemical treatment and interactions. Details of the analytical tests are presented in Chapter 3, Sections 3.7.1 and 3.7.2, respectively.

# 4.2.3 Static Chemical Saturation

Details of chemical saturation are presented in Chapter 3, Section 3.5.

# 4.2.4 Porosity Test

Details of porosity determination for both carbonate and sandstone core sample are

presented in Chapter 3, Section 3.8.

# 4.2.5 Particle Size Test

The procedure for grain size distribution analysis is detailed in Chapter 3, Section 3.8.

## 4.3 Results and Discussion

## 4.3.1 Effect of Chemical Saturation on Porosity

Table 4.1 displays the weights of dry carbonate and sandstone rock core samples as well as the weights of the corresponding saturated samples with brine and sodium nitrate chemicals to calculate the changes in porosity.

Table 4. 1: Saturation of Sandstone and Carbonate with Brine and Nitrate for PorosityMeasurement

Samples	Dry (g)	Brine wet (g)	Dry (g)	NIT wet
				(g)
Carb 1	88	104.8	98	113.6
Sand 1	113.2	125.4	113.2	125.8
Carb 2	97	119	97	110.4
Sand 2	113	124.9	113.2	125.4
Carb 3	98	114.8	98	114.4
Sand 3	113.3	124.9	113	125.4
Carb 4	88	104.9	97	110.4
Sand 4	113.2	125.5	113	125.4
Carb 5	88	104.8	98	113.6

The porosity of the untreated carbonate core is 40% (declared porosity), reduced to 29.03±0.6% and 26.8±0.4% for brine-and sodium-nitrate treated samples, respectively. This represents about 27% and 33.3% reduction for brine and sodium nitrate-treated samples. This reduction in porosity is an indication of pore space narrowing or blockage due to the creation of new minerals (precipitates) and fine migration. The duration of the interaction of the detached materials with other

particles within the chemical causes the precipitation of new materials. On the other hand, the porosity of untreated sandstone at 21% (declared porosity) is slightly enhanced from  $21.1\pm0.3\%$  to  $21.6\pm0.1\%$  upon brine and sodium nitrate treatment. This indicates an increase of about 2.9% for brine and sodium nitrate treatment, respectively. This finding that the porosity of the sandstone increased after chemical treatment alludes to a widening of the pore space brought on by the dissolution or disintegration of grain fibers. A similar observation has been reported for sandstone rock in the literature (Wuyep, et al., 2020). The increase was linked to the dissolution of the clay minerals in the sandstone rock matrix. The determined porosity (29.03%) of carbonate (Edward Brown) from Kocurek Industries is below the declared porosity of 40%. It is also worthy to note that the determined porosity of 21.10% for sandstone (Bandra Brown) is within range of the declared porosity (21-23%).

The results have shown that the interaction of NIT with the carbonate core led to a decrease in porosity. This decrease is simply an indication of the precipitation of new minerals, which may result in pore clogging (Wuyep, et al., 2020). It has also been reported that the precipitation of minerals is an indication of sulfate reduction (Visscher & Stolz, 2005; Vasconcelos, et al., 2006; Meister, et al., 2013) which is very key in the application of Nitrates for reservoir microbial treatment (sulfate-reducing bacteria). However, since there are not many heavily precipitated minerals, the impact of porosity on hydrocarbon production impairment and rock strength may be minimal. In contrast, an increase in the porosity of the sandstone core due to NIT interaction can be attributed to a major dissolution reaction. It is 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.

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#### 4.3.2 Chemical Effects on PSD

Figure 4.1 shows the particle size distribution profiles of (a) original brine, brinesand, and NIT-sand effluents from sandstone and (b) original brine, brine-carb, and NIT-carb effluents from carbonate rock samples. Table 4.2 summarizes the PSD from original brine, and effluents from both brine and NIT treated carbonate and sandstone rocks in terms of  $D_{10}$ ,  $D_{50}$  and  $D_{90}$ .



Figure 4. 1: Particle size distribution of (a) brine effluent and brine effluents from sandstone and carbonate rock samples and (b) brine effluent and NIT effluents from Sandstone and Carbonate rock samples.

Notably, in Table 4.2, there is no considerable difference in  $D_{10}$  and  $D_{50}$  values for both brine-sand (brine treated sandstone) and NIT-sand (nitrate-treated sandstone) effluents. However, the value of  $D_{90}$  for NIT-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. However, the PSD profiles of brine and nitrate effluents are almost identical for the carbonate core sample (Figure 4.1b). 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-NIT saturation decreased from 20 µm to 11 µm ( $D_{10}$ ), 75 µm to 52 µm ( $D_{50}$ ), and 126 µm to and 118 µm ( $D_{90}$ ) (Table 4.2). This shows a significant quantity of particles were eliminated from the sample's saturation stage. This is in agreement with the changes in the sample porosity reported in Table 4.1. However, integrating this result with the mechanical and analytical testing reveals that there was no failure effect in the sandstone samples that had been treated with NIT-sand. Table 4. 2: Particle size distribution from original brine and effluents from brine and NIT.

EB-Carbonate				
Effluents	Particle size			
	D10 (µm)	D50 (µm)	D90 (µm)	
Original Brine	22	80	127	
Carb-brine	18	58	127	
Carb-NIT	18	56	116	
BB-Sandstone				
Original Brine	20	75	126	
Sand-brine	11	56	124	
Sand-NIT	11	52	118	

Again, it is observed from the PSD profile in Figure 4.1b that there is a significant difference in the particle size distribution of the original brine and the brine-carb effluent in terms of the respective  $D_{10}$  and  $D_{50}$ , except for the  $D_{90}$  values, which remained unchanged at 127 µm (Table 4.2 and Figure 4.1b). Similarly, there was no

difference in the D<sub>10</sub> and D<sub>50</sub> values in the particle size distribution profile for brinecarb and NIT-carb effluents except for the D<sub>90</sub> value, which reduced from 127  $\mu$ m to 116  $\mu$ m respectively. The D<sub>10</sub> D<sub>50</sub> and D<sub>90</sub> values of the NIT-carb saturation with reference to the original brine had reduced from 22-18  $\mu$ m, 80-56  $\mu$ m, 127  $\mu$ m and 116  $\mu$ m respectively (Table 4.2). This again indicates that a considerable number of particles was removed at the NIT-carb saturation stage. There was a failure effect in the NIT-carb treated samples, according to further analysis based on the nitrate chemical failure effect in comparison to brine saturation for both sandstone and carbonate rock samples, and the integration of this result with the analytical (Section 4.2.2) and mechanical tests (Section 4.2.1).

Unlike the sandstone samples with reduced PSD for NIT, interaction, the carbonate samples had only a small impact on interaction with NIT which may be attributed to a reduction of the binding strength between grain particles, as seen in Figure 4.1. Hence, the bonding materials between the sand particles experienced minimal dissolution as a result of NIT interaction with the sandstone core sample. However, it should be emphasized that even though neither the sand-NIT treated effluents, nor the carb-NIT treated effluents released any particles, bond weakening was still likely (Oluyemi, 2014; Wuyep, et al., 2020), especially in the case of NIT-carb interaction. When the nitrate chemical's influence on both samples is compared, it is clear that the interaction of nitrate with carbonate has a stronger effect than the interaction with sand.

#### 4.3.3 Chemical Effect on Compressive Strength and Young's Modulus

The Uniaxial Compressive Strength (UCS) test was performed on cylindrical core samples to ascertain the initial strength of the homogenous core samples prior to chemical saturation. For both treated and untreated carbonate and sandstone core samples, Table 4.3 displays the corrected UCS measurements made using ASTM 0.93. Correction became necessary because the core length-diameter ratio was less than the standard length-diameter ratio of 2.5 (ASTM, 1991).

Carbonate (Edwards Brown)				
Parameters	Pre-treatment	Brine	Sodium Nitrate	
L/D	1.3	1.3	1.3	
UCS using ASTM 0.93	11.2	7.4	5	
(Mpa)				
UCS (MPa)	12	7	5	
Young's Modulus (MPa)	1.1	1.2	0.5	
Sandstone (Bandera Brown)				
L/D	1.3	1.3	1.3	
UCS using ASTM 0.93	21	20	19	
(MPa)				
UCS (MPa)	22	21	20	
Young's Modulus (MPa)	1.3	1.4	1.4	

Table 4. 3: Geomechanical results for Carbonate and Sandstone

From Table 4.3, the strength (10-12 MPa) of the untreated carbonate as declared by Kocurek Industries (2023) is in range of the determined strength of 12 MPa. However, the minimum strength (28 MPa) of sandstone as declared by Kocurek is outside the determined strength (22 MPa). This may be due to water imbibition and a deterioration of structural bonds (Durmekova, et al., 2003; Liu, et al., 2020; Zhang, et al., 2022).

Figure 4.2 shows the test results of stress-strain graphs for sandstone and carbonate core samples, both untreated and treated. The results reveal that the chemical

treatment reduced the strength of the untreated carbonate core sample from  $12\pm0.7$  MPa to  $7.4\pm3.2$  MPa and  $5\pm0.1$  MPa when treated with brine and NIT, respectively (Figure 4.2a). The carbonate core strength on exposure to brine saturation dropped to around 38% of that of the untreated core sample. The outcome is in line with earlier research by Zeng et al. (2023). The result suggests that the chemical-rock interaction could have weakened grain boundaries due to ion exchange and dissolution, which is evident as shown in the PSD analysis presented in Figure 4.1. This explains why the porosity decrease of the carbonate sample did not produce a similar increase in compressive strength as expected (Table 4.1).



Figure 4. 2: UCS test for untreated and chemically treated (a) Carbonate (b) Sandstone.

Conversely, the strength of the treated sandstone core sample decreased slightly following chemical treatment with NIT, as shown in Figure 4.2b, from  $22\pm0.4$  MPa to  $21\pm1.3$  MPa and  $20\pm1$  MPa when treated with brine and NIT, respectively. In real terms, with a 5% decrease in brine-treated sandstone and a 9% decrease in

sandstone treated with NIT, respectively, there was actually a negligible alteration in the NIT-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 NIT may be credited to the ability of sandstone to resist chemical alteration when quartz is the bonding material (Xi, et al., 2015; Huddersfield, 2022), which may have led to only a slight change in its compressive strength.

The carbonate core sample demonstrates a significant reduction in compressive strength when compared to the sandstone core sample following chemical interactions. This difference in compressive strength can be attributed to the interaction of the chemical with grain-particle bonds.

Based on the untreated sample results, it can be observed that the grain-grain connections in the carbonate (12 MPa) core sample are weaker than those in the sandstone sample (22 MPa); thus, the bonding strength is further decreased following contact with nitrate, resulting in a considerable drop in the compressive strength of the carbonate sample. Compared to the sandstone core sample, the compressive strength of the carbonate core sample declined rapidly due to grain-particle bonds (Piane, et al., 2015; Galindo, et al., 2022).

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 NIT, respectively. This is an indication that there was no chemical impact on the stiffness of sandstone upon brine or nitrate interaction. Likewise, as shown in Table 4.3, the measured Young's Modulus for both treated and untreated Edwards Brown carbonate samples shows a change of about 1.1 MPa in the untreated sample to 1.2 MPa to 0.5 MPa for brine-and nitrate-treated samples, respectively. The outcome is in line with earlier studies by Wuyep et al. (2018). This indicates that

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nitrate only has a slight influence on the Young's Modulus of the carbonate sample. Again, the strength of the sand particles boundaries has been adversely impacted by chemical interactions. Han & Dusseault (2002) reported the various mechanisms for rock failure to include a chemical reaction between fluids and rock, which includes precipitation and dissolution of minerals, resulting in weakened compressive strength of the rock.

#### 4.3.4 Chemical Effect on Sandstone Elemental and Mineral Composition

The impacts of sodium nitrate on sandstone and carbonate rocks were studied by looking at changes in mineralogical composition and morphologies of samples before and after chemical interaction using SEM. Table 4.4 displays the diversity in elemental composition of the examined samples. This is for sodium nitrate-treated sandstone compared to the brine-treated and untreated core samples. Figure 4.3 shows the SEM photomicrographs for the untreated sandstone (Figure 4.3a, b) sample and sample exposure to brine (Figure 4.3c, d) and sodium nitrate (Figure 4.3e, f) respectively. However, the variation in elemental composition among the samples analyzed is shown in Table 4.4. This is for sodium nitrate-treated sandstone compared to the untreated and brine-treated samples.

Element	Untreated Sand	Brine-Sand	NIT-Sand
	(wt.%)	(wt.%)	(wt.%)
0	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
К	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
Р	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			

 Table 4. 4: Elemental Variation of treated and untreated Sandstone

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 any significant change when compared to the untreated sample (Figure 4.3). However, unlike the brine-treated sandstone, the sodium nitrate-treated sandstone showed slight pitting (Figure 4.3e-f). This is consistent with and reinforces the result presented in Table 4.2 and Figure 4.1(a) on the particle size distribution of the sandstone sample due to detachment and release into the effluent.



Figure 4. 3: EDX scan for (a-b) Untreated Sand at 100  $\mu$ m and 200 $\mu$ m (c-d) Brine treated Sand at 100  $\mu$ m and 200 $\mu$ m (e-f) NIT treated Sand at 100  $\mu$ m and 200 $\mu$ m.

Compositionally, silica, feldspar, a considerable quantity of clay minerals (e.g., illite, kaolinite, chlorite, and montmorillonite, etc.), carbonates that act as cementing materials (containing divalent ions such as Ca<sup>2+</sup>, Mg<sup>2+</sup>, Fe<sup>2+</sup>, and Mn<sup>2+</sup>), and iron

oxides such as siderite (FeCO<sub>3</sub>) are the main components of sandstone reservoirs. On the other hand, due to the presence of salt-like minerals like dolomite  $(CaMg(CO_3)_2)$ , calcite (CaCO<sub>3</sub>), and magnesite (MgCO<sub>3</sub>) as well as other impurities, it is more difficult to generalize the composition of carbonate reservoirs (Isah, et al., 2022).

Based on the EDX elemental composition presented in Table 4.4, it is clear there is some elemental variation in the untreated sample of the Bandera brown sandstone, 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 Na, Mg, K, Fe, S, Ca, and Mn, while sodium nitrate produced major changes in Si, Fe, and Mn. These identified elements are consistent with the composition of a typical sandstone rock.

Furthermore, NIT treated Bandera Brown sandstone shows the presence of Na (0.85 wt.%), Mg (0.39 wt.%), AI (6.60 wt.%), Si (30.85 wt.%), CI (0.28 wt.%), K (1.68 wt.%), Ti (0.55 wt.%), Mn (0.51 wt.%), and Fe (14.71 wt.%). Clay minerals (K, AI, Fe, Na), as well as quartz (Si, O), are present, according to the EDX examination. Ti and Mg can also be found here. The results support the high concentrations of Si (30.85 weight percent) and O (43.59 weight percent). While the presence of AI (6.60 wt.%), Na (0.85 wt.%), K (1.68 wt.%), and Fe (14.71 wt.%) indicates the clay mineral and feldspar compositions. However, S and a major dolomite element, Ca, were found to have dissolved in the NIT-sand treated sample. This might be due to feldspar and pyrite dissolving, which could have resulted in enhanced pitting, as can be seen in Figure 4.3 SEM photomicrograph of the NIT-sand treated sample. The dissolution of feldspar is an important phenomenon which can affect rock quality

(Parson, et al., 2005; Yuan, et al., 2015) and lead to a reduction in the reservoir rock strength (Han & 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 30.85wt.% for brine and NIT treated samples respectively. The dissolution of Quartz content is consistent with the treatment of Betaine in the previous work (Wuyep, et al., 2018). By comparing the untreated and treated samples, it can be observed that Fe increased from 5.73 wt.% to 10.10 wt.% and subsequently to 14.71 wt.% after brine and NIT treatment, respectively. This suggests that ferrite minerals contained inside the sample may have precipitated due to the presence of the chemicals. On the other hand, because of brine treatment, P was dissolved and traces of Cl (0.41 wt.%) precipitated, which was then reduced to 0.28 wt.% when NIT was applied. This precipitation of Cl may be a result of the composition of brine.

The XRPD patterns of the untreated sandstone, brine, and sodium nitratetreated samples are shown in Figure 4.4. The observed changes in the mineralogical composition due to sodium nitrate and sandstone rock interaction is believed to have been orchestrated by dissolution and precipitation reactions. The chemical reaction between nitrate and sandstone rock is given in Equation (4.1).

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 20 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%. Whilst albite (i.e., common feldspar mineral with composition sodium aluminosilicate, NaAlSi<sub>3</sub>O<sub>8</sub>) mineral about 13% peaks occurred at 20 equals 22°, 28°, 31.4° and 34°. Another identified mineral from the XRPD pattern is wollastonite, which is calcium inosilicate mineral (CaSiO<sub>3</sub>), with Fe, Mg, and Mn peaks indicated at 20 = 28.7°, 33°,

39.5° and 50.5°. Finally, kaolinite (i.e., aluminum silicate mineral, Al<sub>2</sub>Si<sub>2</sub>O<sub>5</sub>(OH)<sub>4</sub>), which is about 8% of the sandstone, is indicated to peak at 12.5°, 26°, 38.2°, 70°, and 73°. Notably, a significant amount of albite and quartz is reduced after treatment with brine, whereas another clay mineral, illite, is formed. In other words, the alumino-silicate components of sandstone, such as kaolinite, albite, and quartz, dissolve and precipitate during brine-rock interaction (Figure 4.4b). This affirms the result shown in Table 4.4 for sandstone-brine interaction during treatment. However, upon sodium nitrate treatment, a new phase of sodalite can be identified in addition to illite. Although it is minimal, the formation demonstrates the impact of nitrate chemicals on sandstone, resulting in tectosilicate minerals (sodalite). 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 (Figures 4.4b, c).



Figure 4.4. a: XRPD for untreated sample based on Malvern Panalytics.



Figure 4.4. b: XRPD for brine treated sample based on Malvern Panalytics.



Figure 4.4. c: XRPD for NIT treated sample based on Malvern Panalytics.

# 4.3.5 Chemical Effect on Carbonate Elemental and Mineral Composition

The SEM photomicrographs of the brine and sodium nitrate-treated carbonate samples are shown in Figure 4.5. Table 4.5 shows the elemental composition obtained through SEM-EDX analysis of the samples. A range of particle sizes and pitting on

the particle lumps can be observed in the SEM images presented, confirming the particle detachment and dissolution would have happened during the saturation, which proves the size distribution result shown in Figure 4.2 and Table 4.3. The carbonate samples also exhibit pitting, which is an indication of particle detachment, grain particle boundaries weakening, ion precipitation, or dissolution of minerals upon interaction with the chemicals. Nevertheless, the mineral dissolution and precipitation reactions that occurred during chemical treatment are indicated by the pitting that can be noticed on the rock surfaces in the SEM images of the carbonate rock. The precipitated minerals observed on the NIT-treated carbonate are believed to be Albite.

Elements	Untreated Carb	Brine-Carb	NIT-Carb
	(wt%)	(wt%)	(wt%)
0	55.44	52.30	51.78
Na	ND	ND	0.52
Mg	9.34	7.02	7.41
AI	0.73	1.32	1.44
Si	1.99	3.97	4.46
S	0.13	0.06	0.08
К	0.35	0.73	0.66
Са	31.70	33.08	31.97
Fe	0.32	1.45	1.31
Cl	ND	0.07	0.37
	NC	-Not Detected	

Table 4. 5: Elemental composition of Carbonate sample.



Figure 4.5: 20 micrometers for (a-b) brine treated Carbonate (c-d) NIT treated Carbonate.

According to the EDX results (Table 4.5), the elemental composition of the untreated Edwards brown carbonate sample is as follows: O (55.44 wt.%), Mg (9.34 wt.%), Al (0.73 wt.%), Si (1.99 wt.%), S (0.13 wt.%), K (0.35 wt.%), Ca (31.70 wt.%), and Fe (0.32 wt.%). This confirms the makeup of carbonate rock. The outcome of brine treatment shows the same elemental composition as the untreated sample, but with traces of Cl (0.07 wt.%) precipitated. Again, this can be explained by the characteristics of brine. The EDX analysis from the NIT-treated Bandera Brown carbonate (Table 4.5) shows its elemental composition to include O (51.78 wt.%), Mg (7.41 wt.%), Al (1.44 wt.%), Si (4.46 wt.%), S (0.08 wt.%), K (0.66 wt.%), Ca (31.97 wt.%), Cl (0.37 wt.%), and Fe (1.31 wt.%). Also confirmed is the presence of high Ca and O content. Notably, Ca decreased from 33.08 wt.% to 31.97 wt.% and O from 52.30 wt.% to 51.78 wt.% for brine and NIT-treated carbonate samples,

respectively. This is due to the dissolution of the alite (i.e., tricalcium silicate) mineral component of the carbonate sample. The sodium nitrate-treated sample exhibits the precipitation of Na, which was absent from the untreated and brine-treated samples. This evidence of Na (0.51 wt.%) precipitation is an indication of interaction with the clay component of the carbonate rock. On the other hand, Fe in the brine-treated carbonate decreased from 1.45 wt.% to 1.31 wt.% upon NIT treatment. Based on their composition, carbonate rocks could be more reactive than their sandstone counterparts, resulting in more rock dissolution. This explains the reduction in the Fe component when treated with NIT chemicals.

The XRPD patterns of the untreated carbonate, brine-treated carbonate, and nitratetreated carbonate samples are shown in Figure 4.6. The interaction between sodium nitrate and carbonate rock has been found to alter the mineralogical composition. It is thought that ionic, dissolution, and precipitation reactions were responsible for these alterations. Equation 4.2 explains this reaction.

The result shows that carbonate rock exhibits good crystallinity. Consequently, the following mineral phases can be identified in the XRPD pattern: lime, silica/quartz, alite, iron pyrite, and magnesioferrite, respectively (Figure 4.6a). However, upon brine treatment, another phase, cristobalite, was observed, which is a mineral polymorph of silica (Figure 4.6b). On the other hand, the presence of sodium from the nitrate led to the formation of albite, which is a common feldspar mineral with the composition of sodium aluminosilicate, NaAlSi<sub>3</sub>O<sub>8</sub> (Figure 4.6c). Other phases identified after treatment with sodium nitrate include pigeonite, which confirms the

occurrence of dissolution and precipitation from carbonate mineral components of magnesioferrite, lime, and alite, respectively (Figure 4.6c).





Figure 4.6: XRPD based on Malvern Panalytics for (a) Untreated carb (b) brine treated carb (c) NIT treated carb.

The interaction of the chemical with the formation rock will result in variable degrees of rock disintegration, precipitation, weakening of particle grain boundaries, and fine migration depending on the type of fluids, their concentration, and the mineralogy of the reservoir formation. This chapter described the impact of sodium nitrate on interactions with sandstone and carbonate rocks. The impact on carbonate rock showed a decrease in porosity due to new materials formed via precipitation, while sandstone demonstrated a porosity increase because of mineral dissolution following their interaction with sodium nitrate. The findings also show a compositional change and phase mineral transition due to nitrate-chemical rock interactions, which have not been fully acknowledged. Consequently, UCS impact on carbonate rock showed a reduction in strength and an increase in Young's modulus, while sandstone demonstrated a negligible impact on both the UCS and Young's modulus following their interaction with sodium nitrate.

#### **CHAPTER FIVE**

# 5 FLOODING EFFECT OF BIOCOMPETITIVE EXCLUSION CHEMICAL CONCENTRATION ON SANDSTONE ROCK GEOPHYSICAL AND GEOMECHANICAL PROPERTIES

## **5.1 Introduction**

The effects of chemical interaction on the formation of both carbonate and sandstone reservoirs were discussed and reported in the preceding chapter. However, in this Chapter, the results of the effect of biocompetitive exclusion chemical concentration on sandstone petrophysical and geomechanical properties are looked at.

Oilfield chemical-rock interaction causes reservoir rocks to either dissolve existing minerals or precipitate new ones, thereby altering the rock's mineralogical and possibly petrophysical properties (Li & Aubertin, 2003; Yang, et al., 2017; Wuyep, et al., 2018). The extent of dissolution and precipitation reactions due to chemical-rock interaction is influenced by a variety of factors, including the concentration of the injected chemical. The rock's elemental and mineralogical composition, porosity, permeability, particle grain size distribution, UCS, and Young's modulus are all studied using sodium nitrate (NIT). These are key petrophysical and geomechanical parameters that define a reservoir rock. It is critical to assess how the concentrations of sodium nitrate affect these parameters to optimize the chemical formulation and predict impacts.

## 5.2 Materials and Chemical Treatment

The materials used for the flooding test and their properties are presented in Chapter 3.9. Again. it was ensured that the samples surfaces did not have any significant visible cracks that would compromise their structural integrity.

# 5.2.1 Strength Test

Cylindrical sandstone core samples were used to determine the initial compressive strength of the cores. A detailed procedure for the strength test is presented in Chapter 3.4. Bandera brown sandstone cores obtained from Kocurek Industries in the USA were used for this study.

# 5.2.2 Analytical Test

To identify the crystallinity, phases, and structure of sandstone before and after NIT treatment, they were assessed using X-ray diffraction (XRD). Also, the topology and textural morphology of the samples were studied with the aid of SEM and EDX. The EDX of the samples produced the elemental and mineralogical changes that may have occurred due to chemical treatment and interactions. Section 3.6 of Chapter 3 presents the details of the analytical tests.

## 5.2.3 Procedure for The Flooding Test

Details of the flooding test are presented in Chapter 3, Section 3.5.

# 5.2.4 Porosity Test

Details of the porosity determination for the sandstone core sample are presented in Chapter 3, Section 3.9.3.

## 5.2.5 Permeability Test

Details of the permeability determination for a sandstone core sample are presented in Chapter 3, Section 3.9.2.

# 5.2.6 Particle Size Test

The procedure for grain size distribution analysis is detailed in Chapter 3, Section 3.7.

#### 5.3 Results and Discussions

#### 5.3.1 Effect of Chemical Concentration on Particle Size Distribution

Figure 5.2 depicts particle size distribution (PSD) patterns under flooding at various concentrations. While the changes in the PSD  $D_{10}$ ,  $D_{50}$  and  $D_{90}$  determined using the Malvern Mastersizer 3000M are shown in Table 5.2. It can be observed that there are changes in particle size for original brine, brine uptake, and particles flooded with sodium nitrate at concentrations of 637.5 PPM, 850 PPM, 1062.4 PPM, and 1275 PPM. Notably, PSD profiles for flooding with sodium nitrate concentrations of 637.5 PPM and 850 PPM show a similar pattern. Likewise, the original brine and brine uptake are similar, while the trend profiles of sodium nitrate concentrations of 1062.4 PPM and 1275 PPM are similar (Figure 5.2). These similarities are evidenced in their respective particle sizes,  $D_{10}$ ,  $D_{50}$  and  $D_{90}$  shown in Table 5.2. Although there is a slight change in the PSD of brine effluent relative to the original brine in terms of D<sub>50</sub> and  $D_{90}$ , there is no indication that the grain fabric of the rock has been damaged either physically or chemically due to the brine-rock interactions. On the other hand, only a slight change in  $D_{50}$  from 72 to 80  $\mu$ m can be observed in the particle size for 637.5 PPM and 850 PPM concentrations of nitrate flooding, which indicates a slight chemical effect resulting from the fluid-rock interactions. The observed changes can be attributed to the dissolution. This suggests that sodium Nitrate at concentrations of 637.6 PPM and 850 PPM, on interaction with the rock, does not have any significant impact on particle size distribution. The particle size has, however, significantly changed compared to the concentrations of the core-flooded effluents at 1062.4 PPM and 1275 PPM. This is an indication that significant grain particles were detached from the core matrix upon chemical interaction and flushed out with the flushing fluid (brine). From the results, it is seen that fluid-rock interactions can cause particle detachment when sodium nitrate concentrations exceed 850 PPM. Fluid flow releases

rock particles that alter the porosity and permeability of the rock in addition to chemical reactions. It is anticipated that this separation of grain particles from the rock samples may change their porosity and permeability, which may have an impact on the rock's strength. The findings make it clear that as the concentration of nitrates increases, so does the extent of grain release from the rock.



Figure 5. 1: Grain size distribution profile for brine, 637.5 ppm, 850 ppm, 1062.4 ppm, and 1275 ppm sodium nitrate concentration flooded sandstone rock.

Table 5. 1: D10, D50 and D90 for original brine, brine uptake, 637.5 PPM, 850 PPM, 1062.4 PPM and 1275 PPM under flooding

Parameters	D <sub>10</sub> (µm)	D₅₀ (µm)	D <sub>90</sub> (µm)
Original Brine	10	36	80
Brine Uptake	10	40	82
637.5 PPM	20	72	118
850 PPM	20	80	120
1062.4 PPM	10	40	160
1275 PPM	10	40	220

## 5.3.2 Concentration Effect on sandstone porosity and permeability

The relationship between rock porosity and macro-mechanical characteristics like UCS and Young's modulus is therefore examined in this study. This is another objective of this Chapter. As a result, it was shown in Section 5.3.1 that, depending on concentration, chemical reactions with rocks can weaken, loosen, and detach sand grains. It is therefore expected that this phenomenon will alter the internal structure of the rock, especially the porosity. The lithium tracer profile, which was used to calculate the porosity of the sandstone rock sample, is shown in Figure 5.3. By flooding the core with brine and sodium nitrate at concentrations of 1275 PPM, 1062.4 PPM, 850 PPM, and 637.5 PPM, respectively, the lithium tracer effluent was produced. The average porosities obtained after flooding the rock core with brine and sodium nitrate concentrations of 12±2.4%. The similarity of porosity for sodium nitrate concentrations at 637.5 PPM and 850 PPM

the brine appear to be in agreement with the visual observations of detached particles. Correspondingly, no significant changes in rock permeability 68±4.3 mD, 69±0.6 mD, and 69±1.2 mD were noticed for the same chemicals for Brine and sodium Nitrate at concentrations of 637.5 PPM and 850 PPM, respectively. As the concentration of sodium nitrate was increased to 1062.4 PPM and 1275 PPM, the average porosity of the rock core increased to  $20\pm8\%$  and  $21\pm5\%$  following flooding. Likewise, significant changes were observed in the rock's permeability, which is 81±0.4 mD and 84±6 mD for 1062.4 PPM and 1275 PPM of sodium nitrate concentration treatment, respectively. The increase in porosity with a corresponding increase in permeability indicates a well-structured pore network because of the rock's pore space connectivity. As a result, a concentration of sodium nitrate less than 1062.4 PPM cannot be regarded as triggering chemical reactions capable of modifying the rock microstructure, such as grain detachment and pore size alterations. Thus, sodium nitrate's interaction with the rock samples is concentration dependent. As the concentration increases, both the rock's pore size and permeability increase. This observation suggests an increase in chemical reactions as concentrations increase. After being exposed to sodium nitrate concentrations of 1062.4 PPM and 1275 PPM, the core samples' porosity and permeability increased. This suggests that more rock particles may have dissolved or that the minerals in clay may have undergone a transformation (Torok & Vasarhelyi, 2010; Wuyep, et al., 2018). This chemical reaction caused by the higher concentration of sodium nitrate leads to mineral dissolution, which creates void space inside the rock and is predicted to reduce the rock's strength. The findings are consistent with previous research published in the literature (Irwan, 2021).

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Figure 5. 2: Lithium tracer profile for initial flooding, 637.5PPM, 850PPM, 1062.4PPM and 1275PPM sodium nitrate concentration flooding.

## 5.3.3 Concentration Effect on Elemental and mineralogical composition

Figures 5.4a-f show the SEM photomicrograph and EDX of the elemental composition for untreated, brine-treated sandstone, 637.5 PPM, 850 PPM, 1062.4 PPM, and 1275 PPM sodium nitrate concentration treated sandstone. The SEM images reveal pitting or indentations on the surface of the rock particles, confirming grain particle detachment and mineral alterations due to dissolution or precipitation resulting from the chemical-rock interactions. As the chemical concentration increases, the proportion of indentations or pits detected on the surface of the rock particles also increases. When compared to the 637.5 PPM sample, the sample treated with 1275 PPM NaNO<sub>3</sub> shows greater pitting. Table 5.2 displays the mineral changes and elemental composition of the samples subjected to various sodium nitrate concentrations. The EDX shows a significant amount of silica for both untreated and chemically treated materials.





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Figure 5. 3: SEM micrographs at 20  $\mu$ m for (a) untreated sandstone (b) brine treated (c) 637.5 PPM (d) 850 PPM (e)1062.4 PPM and (f) 1275 PPM.
	Untreated	Brine	1275	1062.4	850	637.5
	(wt.%)	(wt.%)	РРМ	РРМ	РРМ	РРМ
Elements			(wt.%)	(wt.%)	(wt.%)	(wt.%)
0	50.16	50.37	48.87	50.41	49.33	47.27
AI	3.51	2.56	2.48	4.08	4.08	7.97
Si	43.9	44.78	45.50	42.02	41.78	32.90
К	0.89	0.69	0.52	0.79	0.89	2.41
Fe	1.30	1.19	1.37	2.17	2.45	6.86
Mg	0.07	0.08	ND	0.11	0.12	0.55
CI	0.05	0.23	0.52	0.22	0.25	0.78
Ti	0.12	0.06	ND	0.05	0.39	0.25
Ca	ND	0.04	ND	0.05	ND	0.39
Na	ND	ND	0.31	0.05	0.12	0.45
Mn	ND	ND	0.43	ND	0.46	ND
S	ND	ND	ND	0.07	0.13	0.48
ND-Non detected						

Table 5. 2: Elemental composition of sandstone rock pre- and post-chemical flooding.

This is because a sandstone reservoir formation is well recognized as a siliciclastic sedimentary rock comprised of sand grains (i.e., silica) and other minerals that act as binding materials between the particles within the formation. As a result, clay mineral alteration and changes in dispersion can affect the permeability and porosity of rock formation, either increasing or decreasing them. The clay material therefore has a considerable impact on the formation's quality (Yustiningtyas, 2012). The clay phase in the sandstone rock may react at a rate different from that of silica. Thus,

the rate of dissolution along grain boundaries influences their detachment from the rock surface, depending on concentration. The grain boundaries responded at different rates depending on the mineral phase present (Israeli & Emmanuel, 2018). Notably, at 637.5 PPM of NaNO<sub>3</sub>, a significant reduction can be noticed in the amount of Si, which is due to the dissolution of minerals as revealed by the observed pitting on the SEM image (Figure 5.5c). On the other hand, the amounts of Fe, Cl, and Mg increased after chemical treatment, signifying a precipitation reaction resulting from chemical-rock interactions. Pitting that can be seen on the treated samples' SEM images in contrast to the untreated samples is the result of these chemical treatments. Figures 5.5a–f shows the XRPD patterns at 20 m and alterations in the mineral components of the brine-treated sandstone rock relative to the untreated sample at 637.5 PPM, 850 PPM, 1062.4 PPM, and 1275 PPM sodium nitrate. In the untreated sample, peaks at  $2\theta = 21^{\circ}$ , 26.5°, 40.5°, and 50° represent quartz, which is about 47%. Also, identified in the XRPD pattern are clay minerals such as kaolinite, whose peaks occurred at  $2\theta = 12.3^{\circ}$ ,  $22^{\circ}$ , and  $38.5^{\circ}$ . Furthermore, biotite minerals (about 16%) can be seen in the XRPD pattern (Figure 5.5a). However, the presence of wollastonite, a calcium inosilicate mineral (CaSiO<sub>3</sub>) that may include additional trace elements such as iron, magnesium, and manganese, can be observed in the brine-treated sample. Another observed mineral in the XRPD pattern is ferrierite-Mg, which has a similar composition to zeolite. Despite the fact that brine flooding caused only a little change in porosity, permeability, and particle size distribution, the XRPD pattern indicated phase changes and alterations on the surface of the rock sample that may be linked to the occurrence of both dissolution and precipitation reactions.







Figure 5. 4: XRPD mineralogy and clay composition for (a) untreated sandstone (b) brine treated (c) 637.5 PPM (d) 850 PPM (e)1062.4 PPM and (f) 1275 PPM.

The results show that a NaNO<sub>3</sub> concentration of 637.5 PPM causes more precipitation of quartz, approximately 83%, as indicated by the high peak intensity at  $2\theta = 21^{\circ}$  and 26.5°. Because of the dissolution and precipitation of minerals brought on by interactions between NaNO<sub>3</sub> and rock, the minerals lazurite and hercynite may be

identified from the untreated sample. Interestingly, moganite peak intensities are higher in the sample subjected to 850 PPM NaNO<sub>3</sub>, which is due to silica precipitation following quartz dissolution. The decrease in the peak intensity of quartz confirms its dissolution when the NaNO<sub>3</sub> concentration increased to 850 PPM. Consequently, it affirms that the rate of chemical reactions occurring increases as the concentration of NaNO<sub>3</sub> increases. This is further supported by the fact that the quartz component of the sample treated with a NaNO<sub>3</sub> concentration of 1062.4 PPM is much lower than the quartz component of the brine-treated sample. This suggests that the concentration. Conversely, the precipitation of a clay mineral, illite, can be observed on the XRPD pattern of the sample treated with a NaNO<sub>3</sub> concentration of 1062.4 PPM. However, when the sample was treated with NaNO<sub>3</sub> concentration of 1275 PPM, the formation of annite, which is an iron end member of the mineral biotite, occurred. This indicates that annite is a precipitate of dissolved biotite.

The results have shown the effect of increasing the concentration of biocompetitive exclusion chemical (i.e., sodium nitrate) flooding on the rocks' porosity, permeability, particle size, and consequently their UCS and Young's modulus. Rock strength is anticipated to decrease as sodium nitrate content rises due to an increase in the rate at which minerals dissolve or precipitate. This is in line with past research by Shellis et al. (2010), Lins et al. (2013), and Sanda & Taiwo (2016). The outcome of chemical deterioration and rock particle detachment is compatible with earlier efforts in the literature that have been published (Kahraman, et al., 2008; Wuyep, et al., 2020).

The results of this study indicate that the geomechanical strength of rock is adversely affected when the biocompetitive exclusion chemical is injected in greater amounts. Rock geomechanical strength has been shown to be related to porosity,

permeability, mineralogy, and particle size distribution (Plumb, 1994; Farquhar, et al., 1994; Li & Aubertin, 2003; Soroush & Tokhmechi, 2010; Silver, et al., 2015; Hill, et al., 2019; Khan, et al., 2019). The relationship between rock porosity and macro-mechanical factors like the UCS and Young's modulus is investigated in this study as a result.

### 5.3.4 Concentration Effect on Sandstone UCS and Young's Modulus

It is helpful to relate the effect of increasing sodium nitrate concentration to the rock's geomechanical characteristics, such as UCS and Young's Modulus, after showing how it affects sandstone porosity and permeability as well as changes in mineralogy.

The stress-strain profiles of the untreated and sodium nitrate-treated samples are depicted in Figures 5.5a and b, respectively, at concentrations of 637.5 PPM, 850 PPM, 1062.4 PPM, and 1275 PPM. The UCS of the untreated and brine-treated samples decreased from 34±0.7 MPa to 29±0.4 MPa, according to the profile that was produced. This demonstrates that the brine-rock interaction has only a little effect on porosity and particle size distribution, both of which impact rock strength, causing about a 5 MPa reduction in UCS. However, after treatment with sodium nitrate at concentrations of 637.5 PPM, 850 PPM, 1062.4 PPM, and 1275 PPM, the average UCS of the Leopard sandstone samples reduced from  $29\pm0.4$  MPa to  $23\pm0.1$ MPa, 18±4 MPa, 17±2 MPa, and 14±0.9 MPa, respectively, compared to the UCS of the brine-treated samples (Figure 5.5a). The decreased UCS with increasing sodium nitrate concentration is consistent with increased pore size due to higher chemical concentrations, as shown in sections 5.3.2 and 5.3.3, respectively. As the bonding minerals disintegrate, the sand grains separate, the rock becomes more porous and permeable, and the UCS decreases. The UCS can be seen to decline when the sodium nitrate concentration rises from 637.5 PPM to 1275 PPM. The outcome agrees with past research (Shukia, et al., 2013). The reduction in the UCS of the rock may be

related to the dissolution of the bonding minerals of the rock, thereby increasing porosity and permeability, as proven in Section 5.3.2. It is, however, worthy to note that the measured UCS of the untreated sample ( $34\pm0.7$  MPa) is outside the Kocurek Industries Ltd. declared UCS of 21–26 MPa.

As the concentration of sodium nitrate rose, the findings obtained, as shown in Figure 5.5a, demonstrated that the rate of mineral dissolution or precipitation increased. The results of this investigation are analogous to earlier studies that examined how chemical fluid interaction affects the porosity, permeability, and mechanical strength of rocks (Baba, et al., 2005; Safari, et al., 2009; Sanda & Taiwo, 2016).



Figure 5. 5: untreated, 637.5 PPM, 850 PPM, 1062.4 PPM and 1275 PPM NaNO3 treated sandstone for (a) UCS and, (b) Young's modulus.

Young's modulus mechanically gauges the rigidity of rock under tensile or compressive loads. Figure 5.58b displays the rock samples' Young's modulus. The results of the UCS test for the untreated rock sample, the brine-treated sample, and the samples treated with 637.5 PPM and 850 PPM sodium nitrate concentrations showed the following: According to Table 5.4, the Young's moduli are 216±4.8 MPa,

199±3.2 MPa, 170±7.4 MPa, and 196±2.1 MPa. However, when the samples were flooded with NaNO<sub>3</sub>, Young's modulus decreased by 46 MPa (637.5 PPM) and 20 MPa (850 PPM) relative to the untreated sample (216±4.8 MPa). But when the NaNO<sub>3</sub> concentration was increased to 1062.4 PPM and 1275 PPM, the Young's modulus of the treated samples decreased to 196±0.2 MPa and 106±0.9 MPa, respectively (Table 5.4). This represents about a 9% and 51% decrease in the Young's modulus relative to the untreated sample (216±0.8 MPa), which can be attributed to alteration in microstructure due to dissolution caused by fluid-rock interactions. The Young's modulus of both the 850 PPM and 1062.4 PPM nitrate-treated rock samples was the same, proving that both concentrations on interaction with the rock had same impact on the rock's modulus. It has previously been demonstrated that sodium nitrate interaction with rock samples resulted in substantial changes in microstructure, such as increased pore size and permeability compared to brine. This explains why sodium nitrate has a greater effect on the Young's modulus of the rock. Although the test conditions are different, the effect of sodium nitrate on sandstone rock strength is consistent with water saturation as reported previous study (Cai, et al., 2019).

Samples	UCS (MPa)	Corr. UCS (MPa)	Young's
			modulus (MPa)
Untreated	34±0.7	32±0.7	216±4.8
Brine	29±0.4	27±37	199±3.2
637.5 (PPM)	23±0.1	21±0.1	170±7.4
850 (PPM)	18±4	17±4	196±2.1
1062.4 (PPM)	17±2	16±2	196±0.2
1275 (PPM)	14±0.9	13±0.8	106±0.9
Cor. UCS = Corrected UCS; Correction is based on 0.93 ASTM correction factor			

Table 5. 3: UCS and Young's modulus of untreated and treated sandstone samples.

It is possible for the rock UCS characteristic to have a direct relationship with rock porosity, PSD, and elemental and mineral compositions. The results show that the samples flooded with the most NaNO<sub>3</sub> concentration (1275 PPM) have the lowest UCS of all the samples ( $14\pm0.9$  MPa). A second-order polynomial model with an R<sup>2</sup> coefficient of 0.961 offered the best fit for the concentration-UCS data, as shown in Figure 5.7. The model validates the experimental findings that, as the concentration of NaNO<sub>3</sub> rises, the UCS of the rock samples decreases. Although the second-order polynomial model is empirical, it can predict the UCS from the sodium nitrate concentration with an error of about 4%.



Figure 5. 6: Relationship between concentration and UCS.

#### 5.4 UCS-Petrophysical Properties Relation

It is critical to have knowledge of geomechanical strength based on the petrophysical characteristics of rocks. There are many previous studies that have sought to find and quantify the nature of the correlation between rock porosity and UCS (Hatzor & Palchik, 1998); (Reyer and Philipp, 2014; Wuyep et al., 2019). In order to achieve the best possible fit between the experimental data on sandstone and carbonate porosity and UCS, several models have been examined. These included logarithmic, linear, exponential, second-order polynomials, and power laws (Palchik, 1999; Wuyep, et al., 2018). Figure 5.7 shows that in the porosity range of  $10 \le \phi \le 21\%$ , most of the UCS-porosity is inversely and moderately correlated. Even though there are only a few data points (5) in this study, the UCS-porosity relationship found here is similar to that found in sandstone and carbonates by Reyer and Philipp (2014). In both cases, the power law model with an  $R^2$  coefficient of (0.6596) provided the best match for the UCS and porosity data of the rock. The rock samples showed what appeared to be a relationship between UCS and porosity. However, porosity alone is not the only determinant factor of UCS in sandstone and carbonate rocks. The

relationship can be mathematically represented by Equation 5.3. It is, however, worthy to note that the UCS and porosity relation, as shown in Equation 5.3, may be limited due to insufficient number of tested core samples for the data points (4).





Figure 5. 7: Relationship between (a) UCS and porosity (b) Young's modulus and porosity (c) UCS and permeability.

Figure 5.7(b) displays a plot of Young's modulus vs porosity. It was discovered that a second-order polynomial model with a coefficient of determination ( $R^2$ ) value of 0.719 provided the best fit for the Young's modulus-porosity data. Despite this, the correlation between Young's modulus and porosity of the rock is moderate. Similarly, experimental observations indicate a relationship exists between UCS and permeability (Ghanizadeh, et al., 2017). Several models were used to fit the UCS – permeability (k) data, including linear, logarithmic, power law, second-order polynomial, and exponential. The power law and second order polynomial models produced the largest  $R^2$  values of 0.614 and 0.622, respectively. It is clear that UCS – permeability follows the same second order polynomial order model as the UCS– porosity relationship. As mentioned before, the correlation is moderate due to the fact that UCS depends on several rock physicochemical features, not just permeability. The relationship can be mathematically represented in equation (5.4).

 $UCS = 4 \times 10^6 K^{-2.881}.$  (5.4)

It is worthy of note that the porosity-permeability relation can be direct, and that permeability can empirically be determined from porosity (Alexeyev, et al., 2017). The elemental and mineralogical composition of the reservoir rock, the degree of mineral dissolution and precipitation, porosity, permeability, particle size distribution, and fine particle migration, will all have an effect on the rock's strength depending on the chemical elements and their concentrations.

This chapter investigated the effects of flooding sandstone rocks with sodium nitrate at increasing concentrations on interactions with them. Due to minerals dissolving and precipitating when treating sandstone reservoir with sodium nitrate, sandstone responded to higher nitrate concentrations by increasing in PSD, porosity, and permeability. The results also demonstrate an alteration in elemental composition and changes in mineral phases as a result of nitrate-chemical rock interactions. As a result, compared to samples that had been treated with brine, UCS impact on sandstone rock displayed a decreasing strength and Young's modulus due to increasing concentrations of sodium nitrate.

The study indicates that an increase in the concentration of sodium nitrate for sandstone reservoir treatment may have a detrimental impact on the petrophysical and geomechanical properties of the rock and may lead to the reservoir producing sand when the concentration is further increased.

#### CHAPTER SIX

# 6 NUMERICAL SIMULATIONS OF BIOCOMPETITIVE OILFIELD CHEMICAL INJECTION IN SANDSTONE ROCK

#### 6.1 Introduction

Geochemical modeling has quickly developed since the first attempts to anticipate the quantities of dissolved chemical species in seawater were made in the early 1960s (Klunk, et al., 2021). Since then, a number of authors have come to the realization that in order to fully comprehend chemical reactions and their complexities, it is necessary to predict how various compounds would behave in various geologic contexts (Xiong, et al., 2016; Hu, et al., 2018). The reservoir quality in time and space can be characterized and predicted using numerical modelling of flow, chemical reactions, and mineral transportation (Ma, et al., 2017; Xi, et al., 2019; Guo, et al., 2019).

Oilfield chemicals and formation rock interaction have a great impact on different geomechanical and geological developments such as hydrocarbon mineralization, diagenesis, migration, groundwater evolution, and sand production. Liu et al. (1999) observed that fluid flow and porous medium interaction caused many engineering problems. Therefore, to be able to predict the dissolution of minerals and precipitation as a result of oilfield chemical and rock interactions, it is necessary to comprehend the developments by knowing the concepts of fluid flow, chemical reaction kinetics, and mineral transportation (Bartels, et al., 2002).

Researchers (Liu, et al., 1997; Appelo & Postma, 2005; Fritz, et al., 2010; Andersen, et al., 2012 ; Li, et al., 2017; Fagbemi, et al., 2018; Sun, et al., 2019), and more recently, Wuyep et al. (2020), have all numerically investigated the impacts of oilfield chemical and rock interactions. However, the mechanical effects of using

biocompetitive oilfield chemicals (Nitrates) in reservoir treatment have never been considered.

This chapter uses numerical analysis to couple fluid flow, chemical reaction kinetics, and mineral transportation in evaluating the geochemical effects of nitrate injection during formation treatment in a sandstone reservoir.

## 6.2 Numerical tool description

In this chapter, the simulation was performed with the use of COMSOL Multiphysics (Cammi, et al., 2011; Dickinson, et al., 2014; Luo, et al., 2021; Beepat, et al., 2022). COMSOL Multiphysics is a tool used to simulate structural mechanics, chemical reactions, and heat transfer using a workflow in a single environment (Daniel, 2020). This study used COMSOL Multiphysics 6.0 software to couple fluid flow, chemical reactions and mineral transport upon nitrate chemical and reservoir rock interactions.

#### 6.3 Geochemical Approach

The simulation's step-by-step approach to taking into consideration fluid flow, chemical reactions, and mineral transport is shown in Figure 6.1. The Chemical Reaction Engineering module, as used, can simulate chemical reaction kinetics in a well-defined environment. It is used to create and edit model and kinetic expressions, variables, and functions for understanding the system under study.

Build geometry (2D)

Generate the object to be modelled (cylindrical core samples). Specifying the angle and dimensions of the core.

Insert definition.

Defined parameters, express variables, and functions for the model

Geometry used to build the model

Materials (Nitrate and Sandstone core)

Specify the material to describe its properties. Nitrate properties used to define flow and transport

Defining the physics (chemical Reaction Engineering-Reacting flow in porous media)

Adding the physics (Brinkman equation, mass transport), diffusion and convection with chemical reaction

Meshing

Defining the geometry helps solve the problem in discrete points

Study (time dependent)

Computes and optimizes the solution over time

Result processing

Schematic interpretation of computed data

Figure 6. 1: Simulation Workflow

In modelling oilfield chemical and reservoir rocks, chemical injection (flow), reaction between the oilfield chemical and reservoir rock minerals, and transportation of dissolved or precipitated minerals were considered. This involved describing the processes of nitrate chemical-rock interaction using a 2D model with dimensions of 10m and 4m for length and width, respectively (Figure 6.2).



Figure 6. 2: A 2D mesh arrangement

A "very fine" mesh with different particle shapes and cells was selected in the model for a more consistent solution, with a size description of width 4m and Length 10m.

## 6.3.1 Nitrate Injection (Fluid Flow)

Reservoir porosity and permeability are significant rock properties that affect the quality of the reservoir rock (Jegarluei & Moazzeni, 2010). Whereas porosity determines the amount of fluid present, permeability controls the amount of fluid recoverable (Robert & Merrill, 1969). It is difficult to compare fluid flow through a porous material to flow through a pipe or conduit (Ahmed, 2010). As a result, through experimentation and numerical analysis, the study of fluid flow through porous materials has significantly advanced over time (Porges, 2006). Darcy's law cannot be

used to describe fluid flow through a porous material due to its complicated process (Sheikholeslami, 2019). Hence, mathematically speaking, Equation 3.5 in Chapter 3 can be used to express Darcy's law, which is also known as momentum conservation. The Darcy Equation, as shown in Equation 3.5 of this thesis, was later modified for a single-phase flow (Xinghui, et al., 1997), as shown in Equation 2.9 of Chapter 3. But for a process that involves rock mineral dissolution and precipitation, as expected from this study, the equation (Equation 2.9) has to be modified further (Equation 6.1) to accommodate the processes of mineral dissolution and precipitation (Xinghui, et al., 1997) to form the Brinkman equation, which is given in Equation 6.1.

$$\rho \,\partial \mathbf{u} \,-\, \nabla .\, \eta (\vec{\mathbf{u}} \,+\, (\vec{\mathbf{u}})^{\tau}) \,-\, \left(\frac{\eta}{K} \mathbf{u} \,+\, \nabla \mathbf{p} \,-\, \mathbf{F}\right) = \,0 \,\dots \,\dots \,\dots \,(6.1)$$
$$\nabla .\,\, u \,=\, 0$$

given:

ρ is the density of the fluid (kg/m<sup>3</sup>); U is the velocity vector (m/s); η is dynamic viscosity (pa.s); p is pressure (Pa); k is permeability (m2); τ is tortuosity; and F is minor compressible force effects (N/m2).

In this study, mineral dissolution and precipitation are included when modeling flow through the porous media of the formation rock using Brinkman's equation. The fluid flow throughout the bed is defined by the porous matrix properties in the transport properties node, which employ the Brinkman equation, an extension of the Navier-Stokes Equation. The porosity and permeability of the porous media are factors in the Brinkman equation. Additionally, inputs for temperature, density, viscosity, and input velocity are needed.

#### 6.3.2 Mineral Transport

A complicated interface between these constituents and the presence of several constituents characterizes mineral transport in a porous media. A two-dimensional (2D) advection-diffusion flow system can be used to represent the transport process in a porous medium when a chemical is introduced into the formation and interacts, causing the dissolution or precipitation of new species. The transport of mineral species in a porous medium is defined in the Transport Properties node through diffusion and convection. This requires inputs for the reaction rate variable, which is defined in the Variables table (table 6.1) as k, for the concentrations, which are defined in the inflow nodes, and for the diffusivity, which is defined in the Transport Properties node. The mineral transport equation as defined by the model is given by Equation 6.2.

Given the concentration gradient as  $\frac{\partial c}{\partial t}$ , fluid velocity u (m/s), concentration of the fluid C (mol/m<sup>3</sup>), and diffusion coefficient D (m<sup>2</sup>/s).

The mass transport properties are defined through diffusion and convection with chemical reaction kinetics. Heat transfer is not considered in this reaction, so it is assumed to be an isothermal condition. The model uses "Reacting flow in a porous media" in the "chemical reaction Engineering module to model flow.

### 6.3.3 Chemical Reaction and mineral Dissolution/Precipitation

When nitrate and sandstone interact, a new species is formed because of the dissolution or precipitation of the core sample, which is taken into consideration by

the Reactions node. With the help of the concentrations of nitrate and sandstone species, the reaction rate variable has been defined, and it does this.

The rate of equation is given as Equation 6.3.

But A is the concentration of reactant, and k is the rate constant  $(mol/(m^2/s))$ .

Quartz dissolution or changes in mineral precipitation are directly correlated with the rate of change in porosity. Hence, the rate of change in the rock's porosity (equation 6.4) applied in this model to describe mineral dissolution or precipitation as a result of Nitrate and rock interaction is obtained by a method similar to Mumallah (1991) and as used by Yan et al. (2015) and is presented as follows:

Where R*i* denotes the rate of reaction (mol/L\*s), SSA is specific surface area (1/m), k is the rate constant of silica (2.6967E-12 mol/(m<sup>2</sup>/s), and C is concentration (mol/m<sup>3</sup>).

Where k is given as

The rate of reaction is typically accepted to depend on surface area (Serafeimidis & Anagnostou, 2012). This is given as.

Where  $A_0$  is the surface area (m<sup>2</sup>) and V is (m<sup>3</sup>).

In the reaction node, in order to model mineral dissolution or precipitation, an ordinary differential equation (ODE) mathematical node is added in consideration

over the rate of changes in the porosity of SiO<sub>2</sub> content, time (Table 6.2). The ODE node allows for different models to be implemented for which the tortuosity factor is given as implemented (Millington & Quirk, 1961; Wuyep, et al., 2020):

 $\tau_{Fj = \theta^{-1/3}....(6.7)}$ 

Where  $\theta$  is the change in porosity.

However, the rate of porosity change can be obtained with the equation (6.8).

where  $R_i$  is the rate of reaction, M is the molecular mass of silica, and rho\_SiO<sub>2</sub> is the density of silica.

#### 6.4 Boundary Conditions

As depicted in Figure 6.3, the boundary condition used in this study designates the outflow flow as B and the entrance flow as A. For the purpose of examining how chemical flow affects the geoproperties of rock and solute transport, the flow rate at the inlet boundary is taken into consideration to be uniform, while the outlet flow pressure, B, is set to zero. The necessary pressure establishes the flow rate (velocity) at the inlet. Where there is no flow at the upper and lower borders and no fluid velocity at the walls, these boundaries are set to no flow. In line with Zou et al. (2017), these boundary criteria. Figure 6.3 shows a 2D schematic geometry of the modelled domain, which replicates the experimental flooding of the core sample as explored in Chapter 5.



Figure 6. 3: Layout of modelled domain

The governing equation for fluid flow is described by the Navier-Stokes equations (NSE). However, Brinkman's equation, which describes flow in a porous medium as shown in Equation 6.1, was used. The above Figure (6.3) represents a porous medium with dimensions of 10m x 4m and a uniform velocity through the porous medium.

## 6.5 Results and Discussion

Chemical Reaction Engineering Module with the interphase "Reacting Flow in Porous Media" is the COMSOL Multiphysics module that was utilized for this simulation. Equations that support fluid flow, chemical reactions, and mineral transport in a porous medium are integrated into the interphase. The model also takes into account porosity and permeability, with porosity change serving as a variable for changes in SiO<sub>2</sub> content.

In the simulation of the reaction between sandstone rock and nitrate, quartz is primarily employed to represent sandstone rock. Nitrate is the fluid in the model, and its properties are used to define the flow and mineral transport. The experiment provided additional parameters, including flow rate and nitrate concentration.

Tables (6.1) and (6.2) present the parameters and variables utilized for developing the model.

Table 6. 1: Model parameters.

u_in	0.02[mm/s]	2E-5 m/s	Flow rate
c0_Nitrate	0.0075[M]	7.5 mol/m <sup>3</sup>	Nitrate Conc.
R_const	8.314[J/mol/K]	8.314J/(mol.K)	Rate constant
D_NIT	1.6416e-4[m^2/s]	1.6416E-4 m <sup>2</sup> /s	Diffusion
			coefficient Nitrate
A	1[m/s]	1 m/s	Pre-exponential
			factor
Ea	66.1[kJ/mol]	66000 J/mol	Activation Energy
T_iso	298[K]	298 K	Temperature
k	2.6967E-	2.6967E-12	Rate constant
	12[mol/m^2/s]	mol/(m².s)	
M_SiO2	60.08[g/mol]	0.06008kg/mol	Relative molecular
			mass, Calcite
rho_SiO2	2.65[g/cm^3]	2650 kg/m <sup>3</sup>	Density, Silica
por	0.3	0.3	porosity, initial
SSA0	1.21e+05[m^-1]	1.21E5 1/m	Specific surface
			area
perm0	1e-11[m^2]	1E-11 m <sup>2</sup>	permeability,
			initial
p0	0.67	0.67	

Table 6. 2: Variables for reaction

Ri	(SSA)*(k)*c0_Nitrate	mol/(m³⋅s)	Rate of Reaction
SSA	SSA0*(por/(1-por))^p0	1/m	Specific surface
			area
k	A*exp(-Ea/(R_const*T_iso))	m/s	Rate constant
poro_change	Ri*M_SiO2/rho_ SiO2	1/s	Rate of Porosity
			change

Figures 6.4 and 6.5 below show the default results as a velocity profile and a pressure distribution profile. For mineral transport through the porous medium, Equation 6.1 accounts for fluid velocity (Figure 6.4) and pressure (Figure 6.5) defined at the input and outflow. The porous material exhibits a consistent distribution for the velocity parameter (Figure 6.4). Similar straight lines across the material output are shown in the pressure profile (Figure 6.5), which denotes steady pressure. Table 6.3 shows the mesh statistics with the 2484 and 288 triangular and quadrilateral elements that were utilized to represent the porous media.



Figure 6. 4: Velocity profile within material domain



Figure 6. 5: Pressure distribution within material domain

#### Table 6.3: Mesh statistics

Description	Value
Minimum element quality	0.3331
Average element quality	0.8296
Triangle	2484
Quad	288
Edge element	188
Vertex element	4

The transport of minerals within reservoir rocks is affected by chemical interactions between rock minerals and oilfield chemicals, which could have an impact on species concentration. It is important to keep in mind that differences in the mineral composition of quartz (SiO<sub>2</sub>), which represents the immobile species, and nitrate, which represents the mobile species, affect how sandstone minerals dissolve or precipitate.

Figure 6.6 shows how the concentration of nitrate varies as it moves from the input to the output upon reaction with quartz to create a new species through diffusion and convection. This result of the interaction and alteration of quartz and nitrate to form new compounds with differing chemical compositions is shown in Equation 6.3. It has been noted that the nitrate concentration is consumed entirely prior to output. The amount of nitrate consumed is determined by the Reaction interface. Equation 6.3 shows the outcome, which shows that the newly formed species from the reaction of nitrate and quartz has resulted in the formation of sodium metasilicate, a flaking solid having a variety of applications in the oilfield (Mbaba & Caballero, 1983; Samneange, et al., 2017). The concentration of the transformed new species was zero at input

but increased at output, in contrast to the concentration of nitrate, which was high at input and fully decreased to zero concentration before the output. The concentration of the newly transformed species at the output is shown in Figure 6.7.



Figure 6. 6: Change in concentration of Nitrate.



Figure 6. 7: Species Prod: Surface: Concentration (mol/m3) Streamline: Total flux.

Figures 6.8 and 6.9 depict the dissolution of quartz, which over time (0.4day≈9.6hrs) as nitrate is injected into the rock (sandstone), has changed the porous medium, and increased its porosity. According to earlier research (Voltolini & Ajo-Franklin, 2019; Harbert, et al., 2020), porosity increases with increased mineral dissolution and decreases with increased mineral precipitation. Depending on the shape of the pore spaces, the change in porosity caused by mineral dissolution and precipitation may negatively affect permeability changes (Nadeau, 1998; Shiranki & Dunn, 2000). It is important to remember that the rate of porosity change directly affects the rate of mineral dissolution or precipitation.



Figure 6. 8: Dissolution of quartz.



Figure 6. 9: Change in porosity with time.

This study replicates the injection of nitrates for reservoir treatment into sandstone reservoir rocks using COMSOL Multiphysics. It is significant to keep in mind that the rate of dissolution of minerals and precipitation is influenced by the rate of porosity change. When porosity changes have a positive value, minerals dissolve. However, when the value of the change in porosity is negative, mineral precipitation is indicated. According to the findings, nitrate and sandstone rock interacted during mineral dissolution at a porosity change  $\leq 3.14E-110 \leq -3.14E-11$  per second, increasing porosity and degrading grain structure, which may ultimately influence rock strength and cause sand failure. The results show how mineral dissolution and precipitation events occur simultaneously in porous media, increasing porosity. The experimental result obtained from the core flooding study (Chapter 5) validates the simulation results obtained. The porosity evolution for various simultaneous mineral dissolution and precipitation that have been previously observed in the literature is simulated using COMSOL Multiphysics modeling, and the outcome is compared to the relationship between porosity and strength (Wuyep, et al., 2018). The porositypermeability change affects the flow channel when a dissolution or precipitation zone spans the reservoir rock's cross-section and is perpendicular to fluid flow. The increased porosity changes the pore radii, increasing the pore volume. But the resulting increase in porosity has nothing to do with the dissolution zone. Precipitation impacts large pores and pore throats and dissolves micro pores and pore throats, reducing porosity and permeability. Dissolution is also conceivable when the situation is the opposite. Overall, it is discovered that considerable permeability changes can occur for a given change in porosity and that the sparse distribution of reactions in the pore network determines how permeability evolves (Sabo & Beckingham, 2021). Even though precipitation reduces the size of tiny pores and pore throats, permeability increases when dissolution predominates (Steinwinder & Bechingham, 2019; Sabo & Beckingham, 2021).

The model combined chemical injection (flow), chemical reaction (dissolution/precipitation), and mineral transport.

Results from the established model demonstrated that when nitrate was introduced into the sandstone rock, mineral dissolution occurred. Because of the mineral alterations, the sandstone rock's porosity has increased, weakening the rock formation. This demonstrates how it is possible to predict mineral dissolution using the rate of change in porosity. This study agrees with studies by Noiriel et al. (2004), Luquote & Gouze (2009), Min et al. (2016), and Wuyep et al. (2020). As a result of mineral dissolution, this study has demonstrated that adding nitrates to reservoir formations increases porosity, which could potentially impact the formation's geomechanics strength and lead to sanding.

#### **CHAPTER SEVEN**

## **7 CONCLUSION AND RECOMMENDATIONS FOR FUTURE WORKS**

#### 7.1 Conclusion

It has been established using experimental and numerical approaches on how the geochemical and geomechanical properties of carbonate and sandstone reservoir rocks are affected by the interaction of the reservoir rock and nitrate oilfield chemicals under static and flooding situations.

Based on the results and discussions from the current work, the following crucial conclusions have been drawn:

The weakening effect of oilfield chemicals such as sodium nitrate was utilized to assess the geochemical and geomechanical properties of carbonate and sandstone reservoir rocks under static settings. According to the study, nitrate's interaction with the rock caused a change in the elemental makeup of the mineral as well as a phase alteration. Sandstone's porosity increased as a result of mineral dissolution after the interaction with sodium nitrate, but carbonate rock's porosity decreased as a result of new materials produced during precipitation. The interaction of sandstone with sodium nitrate was not significant in terms of UCS; nevertheless, in static conditions, the strength of carbonate rock decreased. This suggests that while oilfield operators might think about using sodium nitrate to treat sandstone reservoirs under static conditions, treating carbonate reservoir rocks would not be the best idea due to the possibility of sanding. This study assumes that injecting chemical nitrate into the reservoir rock without introducing nutrients, chemical reaction will

take place. This study has shown the effect of the chemical on the reservoir rocks chemical and mechanical properties.

- The weakening effect of sodium nitrate oilfield chemical concentration on the geochemical and geomechanical properties of sandstone rock was assessed under flooding conditions to simulate reservoir production. The study found that the interaction between the chemical and the formation rock caused different levels of precipitation, fine migration, weakening of grain boundaries, and mineral dissolution, depending on the concentration of the oilfield chemical and the chemical makeup of the reservoir rock. As the concentration of sodium nitrate increased so did the PSD, and permeability of sandstone. The study reveals that an average concentration of 26% caused a 16% change in porosity. The strength of the rock decreases as a result of changes in rock characteristics brought on by increasing sodium nitrate concentration for treating sandstone reservoirs may have a negative effect on the rock's petrophysical and geomechanical characteristics and may cause the reservoir to produce sand at higher concentrations.
- Using COMSOL Multiphysics, a geochemical model based on the impact of chemical injection of sodium nitrate into oilfields on the rock of sandstone reservoirs was established in chapter six. The sandstone rock's porosity changed as a result of mineral dissolution brought about by the addition of nitrate, according to results from the model that was developed. According to this research, nitrate addition increases porosity in reservoir formations, which may have an effect on the formation's geomechanics strength and may cause sanding. This outcome aligns with the findings of the experiment. Therefore,

when planning a chemical injection, it's critical to take sodium nitrate's sanding potential into account for oil field operations.

#### 7.2 Recommendations for Future Works

In this work, static and flooding conditions were used to assess the petrophysical effects and subsequent geomechanical effects of the interaction between nitrate oilfield chemicals and reservoir rock. However, the following further analyses will be required for the study:

- In the current work, only the effects of the nitrate-sandstone rock interaction on the geochemical and mechanical parameters were investigated. It will be appropriate to expand the investigation to carbonate rocks in order to take into account the geochemical and geomechanical effects of exposing nitrate to carbonate rocks.
- Since rock is an accumulation of mineral particles, more research is required to determine the impact of variations in the diagenetic composition, volume, and shape of detrital particles and pore minerals on the mechanical properties of the rock formation.
- How reservoir temperature and nitrate pH affected geochemistry and strength properties was not discussed in the current investigation. Changes in these parameters were therefore not monitored during the experiment. To account for their role in the precipitation and dissolution reactions, the effects of these variables should be assessed.
- The weight of the rock sample is anticipated to change because of interactions between nitrate and rock that cause mineral dissolution and precipitation, grain particle detachment, and fine migration. Future research should take this into consideration.

- In order to assess the impacts of nitrate-sandstone reservoir rock interaction on the rock's geochemistry and geomechanical properties, this study used COMSOL Multiphysics. PHREEQC is advised to be utilized in future investigations to evaluate the rate of mineral dissolution and precipitation.
- The geochemical impact of nitrate-rock interaction was demonstrated in the current work using a 2D simulation. However, it is advised to employ a geomechanical model for a comprehensive examination.
- It is recommended to use a 3D geomechanical model to better understand and visualize the possible issues with managing sand production. This model should include well data and combine in-situ flow distribution, chemical-rock interaction, and mineral transport.

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