

Improving Hydrocarbon Productivity of Organic Rich Shale Using Thermochemicals

BY

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Dedicated to my grandparents and my family

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LIST OF ABBREVIATIONS

TCF	:	Thermochemical Fluids
TOC	:	Total Organic Carbon
HPHT	:	High Pressure High Temperature
XRD	:	X-Ray Diffraction
XRF	:	X-ray Fluorescence
RF	:	Recovery Factor
EIA	:	Energy Information Administration
AHP	:	Anhydrous Pyrolysis
HP	:	Hydrous Pyrolysis
S1	:	Free Hydrocarbons Volume
S2	:	Potential/Residual Hydrocarbon Volume
S3	:	Carbon Dioxide Released During Pyrolysis
S4	:	Oxidized Remaining Organic Carbon
S5	:	Carbon Dioxide Produced from Carbonate Minerals Breakdown
T_{max}	:	Maximum Temperature of Hydrocarbon Generation
HI	:	Hydrogen Index
OI	:	Oxygen Temperature
PI	:	Production Index
MgCl₂	:	Magnesium Chloride
CaCO₃	:	Calcium Carbonate
H₂O	:	Hydrogen Oxide
NaNO₂	:	Sodium Nitrate

NH₄Cl	:	Ammonium Chloride
NaCl	:	Sodium Chloride
ESEM	:	Environmental Scanning Electron Microscopy
CT-Scan	:	Computerized Tomography Scan
EDTA	:	Ethylenediaminetetraacetic acid
P_c	:	Capillary Pressure
pH	:	Potential of Hydrogen
BHP	:	Bottom Hole Pressure
ESP	:	Electric Submersible Pump
P	:	Pressure
ρ	:	Density
g	:	Gravity
h	:	Height
V_s	:	Shear Velocity
V_p	:	Compressional Velocity
IPR	:	Inflow Performance Relationship
VLP	:	Vertical Lift Performance

ABSTRACT

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The energy sector has shifted its focus to unconventional hydrocarbons such as tight oil, coalbed methane, and shale gas and oil due to the rise in global energy demand and improvements in extraction technology. Along with changing the industry, this change has also presented new opportunities and challenges. This study aims to improve the gas production from shale formations by injecting thermochemical fluids (TCF) to induce pressure and temperature changes, enhancing hydrocarbon productivity, and tackling one of the most common issues in gas wells, liquid loading.

This study investigates the use of TCF to enhance shale formation productivity. TCF are reactive fluids that generate heat and gas upon activation of their reaction. Shale samples with varying mineralogy and total organic carbon content (TOC) were subjected to artificial maturation under high-pressure (3000-3500 psi) and high-temperature (100°C) (HPHT) conditions, using different TCF volumes. Measurements to assess the impact on the samples were carried out pre- and post-treatment. The measurements included chemicals injection using core flooding, X-ray powder diffraction (XRD), X-ray fluorescence (XRF), compressional and shear velocities, computed tomography (CT) scans, gas chromatography (GC), and Rock-Eval pyrolysis. Additionally, laboratory experiments with a flow loop system assessed the effectiveness of TCF in resolving liquid loading issues in gas wells. The findings were then used in PIPESIM simulations to model and analyze the removal of liquid loading on a well scale.

Thermochemical-assisted maturation resulted in a decrease in TOC by 18-42% in the shale samples, indicating hydrocarbon generation. Moreover, artificial maturation altered the petrophysical, geo-mechanical, and geochemical properties positively. The porosity of the samples was enhanced and generation of microfractures was observed. The free

hydrocarbon volume (S1) increased by 1.3 folds, indicating a rise in the hydrocarbon reserves. Furthermore, the injection of TCF in gas wells that are suffering from liquid loading showed a promising result by removing more than 90% of the liquid holdup (liquid loading), which led to resuming the gas production.

This study aims to present a method to enhance oil and gas production by accelerating kerogen maturation. The use of thermochemical injections has shown promise in expediting this process in organic-rich shale. More efficient hydrocarbon recovery can be achieved compared to conventional maturation methods. This approach specifically enhances shale gas production by increasing kerogen thermal cracking and removing the liquid holdup. Ultimately, adopting this method could contribute to enhancing hydrocarbon production from organic-rich shale and maintain environmental stewardship.

ملخص الرسالة

الاسم الكامل: عبدالعزيز اليسع الصادق محمد علي

عنوان الرسالة: تحسين إنتاجية الهيدروكربونات من الصخر الزيتي الغني بالمواد العضوية باستخدام السوائل الحرارية الكيميائية

التخصص: هندسة النفط

تاريخ الدرجة العلمية: نوفمبر، 2024

قطاع الطاقة قد حوّل تركيزه نحو الهيدروكربونات غير التقليدية مثل النفط المحكم وميثان طبقات الفحم وغاز ونفط السجيل بسبب الزيادة في الطلب العالمي على الطاقة وتحسينات تقنيات الاستخراج. هذا التوجه لم يغير الصناعة فحسب، بل قدم أيضاً فرصاً وتحديات جديدة. تهدف هذه الدراسة إلى تحسين إنتاج الغاز من تكوينات السجيل عن طريق حقن السوائل الكيميائية الحرارية (TCF) لإحداث تغييرات في الضغط ودرجة الحرارة، مما يعزز إنتاجية الهيدروكربونات ويعالج إحدى المشكلات الشائعة في آبار الغاز، وهي تراكم السوائل.

تبحث هذه الدراسة في استخدام السوائل الكيميائية الحرارية (TCF) لتعزيز إنتاجية تكوينات السجيل TCF. هي سوائل تفاعلية تولد حرارة وغازات عند تنشيط تفاعلها. تم تعريض عينات السجيل، التي تختلف في تركيبها المعدنية ومحتوى الكربون العضوي الكلي (TOC)، إلى عملية نضج اصطناعي تحت ظروف الضغط العالي (3000-3500 رطل لكل بوصة مربعة) ودرجة حرارة عالية (HPHT) (100°C)، باستخدام كميات مختلفة من TCF. تم إجراء قياسات لتقييم التأثير على العينات قبل وبعد المعالجة، وشملت هذه القياسات حقن المواد الكيميائية باستخدام نظام تدفق اللب، واختبارات حيود الأشعة السينية (XRD)، وفلورية الأشعة السينية (XRF)، وقياس السرعات الانضغاطية والقصية، وفحوصات التصوير المقطعي (CT)، وكروماتوغرافيا الغاز (GC)، وتحليل روك-إيفال للتكسير الحراري. بالإضافة إلى ذلك، أجريت تجارب مختبرية باستخدام نظام تدفق لدراسة فعالية TCF في حل مشاكل تراكم السوائل في آبار الغاز. ثم تم استخدام النتائج في محاكاة باستخدام برنامج PIPESIM لنمذجة وتحليل إزالة تراكم السوائل على مستوى البئر.

أدى النضج المساعد بالمواد الكيميائية الحرارية إلى خفض TOC بنسبة تتراوح بين 18-42% في عينات السجيل، مما يشير إلى توليد الهيدروكربونات. علاوة على ذلك، أدت عملية النضج الاصطناعي إلى تحسين الخصائص البتروفيزيائية والجيوميكانيكية والجيوكيميائية بشكل إيجابي، حيث تم تحسين مسامية العينات وتم ملاحظة تولد شقوق دقيقة. كما ارتفع حجم الهيدروكربونات الحرة (S1) بمقدار 1.3 مرة، مما يشير إلى زيادة في احتياطيات الهيدروكربونات. بالإضافة إلى ذلك، أظهرت عملية حقن TCF في آبار الغاز التي تعاني من تراكم السوائل نتائج واعدة بإزالة أكثر من 90% من السوائل المترakمة، مما أدى إلى استئناف إنتاج الغاز.

تهدف هذه الدراسة إلى تقديم طريقة لتعزيز إنتاج النفط والغاز من خلال تسريع عملية نضج الكيروجين. وقد أظهرت الحقائق الكيميائية الحرارية نتائج واعدة في تسريع هذه العملية في الصخور الغنية بالمواد العضوية، حيث يمكن تحقيق استرداد أكثر كفاءة للهيدروكربونات مقارنة بطرق النضج التقليدية. يعزز هذا النهج إنتاج غاز السجيل بشكل خاص عن طريق زيادة تكسير الكيروجين

الحراري وإزالة تراكم السوائل. في النهاية، يمكن أن يسهم تبني هذه الطريقة في تعزيز إنتاج الهيدروكربونات من السجيل الغني بالمواد العضوية مع المحافظة على الاستدامة البيئية.

CHAPTER 1

INTRODUCTION

1.1 Background

Unconventional hydrocarbon sources have come under industrial and academic study as traditional fields' oil and gas reserves are depleting and the world's primary energy consumption is expected to rise markedly over the coming decades (Economides et al., 2009; Vedachalam et al., 2015; Bellani et al., 2021). Shales that are rich in organic material have grown in significance as an energy source because they have a high potential for the generation of gas and oil. There is a tremendous amount of immature kerogen in organic-rich shale formations which are available in certain countries around the world (Gafurova et al., 2021).

Immature kerogen undergoes a lengthy and complex process requiring considerable heat and pressure before it can be transformed into oil or gas. This process is called natural maturation and it involves gradual transformation of organic matter within sedimentary rocks into hydrocarbons (oil and gas) over geological time, driven by increased temperature and pressure deep within the Earth (Panahi et al., 2019). In shale oil reserves, kerogen is a complex material comprised of an amorphous porous carbon structure with pores that range in size from a few angstroms to micrometers (Bousige et al., 2016). Based on its composition, kerogen can be divided into four categories, which will be discussed in a later

chapter. Each category affects the type of petroleum that is generated, if any; in other words, the process differs slightly from one kerogen to another (Mccarthy et al., 2011).

Different types of hydrocarbons are present in immature shale formations, including free (S1) and potential (S2) hydrocarbons. Free hydrocarbons (S1), which are mostly found in inorganic and organic pores, as well as adsorbed and absorbed hydrocarbons in the organic material, make up the hydrocarbon content in shale oil formations (Sang et al., 2018). The hydrocarbon potential (S2) demonstrates the amount of hydrocarbons that a source rock could yield as if thermal maturation took place (Mccarthy et al., 2011). The opportunity to use chemical injection methods in organic-rich shale reservoirs is provided by the incentive to create plans to increase the oil shale's ability to recover hydrocarbons. One approach to facilitate the maturation of kerogen in organic-rich shale is to gradually increase the temperature and pressure over time by using some chemicals (Bernard et al., 2012; Agrawal et al., 2018(a); Agrawal et al., 2018(b)) REF.

1.2 Problem Statement

Current extraction methods primarily focus on obtaining free hydrocarbons from organic-rich shale formations, leaving the adsorbed and absorbed components within kerogen untapped (Li et al., 2016). The study of kerogen geochemistry has been ongoing for some time, with research now concentrated in two key areas: hydrocarbon extraction (e.g., Curiale & Curtis, 2016) and the analysis of kerogen within shale (e.g., Luik et al., 2014). These investigations aim to assess the degree, quality, and thermal maturity of kerogen in shale and explore techniques for pyrolyzing or hydrogenating kerogen in oil shale to generate hydrocarbons, whether ex-situ or in situ (White et al., 2005; Sang et al., 2016).

Given the significant potential of kerogen to yield hydrocarbons, there is a valuable opportunity to convert a substantial amount into oil or gas through in-situ maturation. However, there has been little experimental effort directed towards artificially maturing kerogen to enhance hydrocarbon productivity.

1.3 Objectives

The objective of this work is to improve the hydrocarbon productivity of organic-rich shale using chemical injection techniques. An in-situ maturation approach using an injection of chemicals to accelerate the maturity process for unconventional shales was followed. The impact of in situ maturation on the structure and characteristics of shale rocks was investigated. The detailed objectives of this study are listed as follows:

1. Studying thermochemical fluids effect on accelerating the kerogen maturation.
2. Capturing the impacts of thermochemical fluids assisted maturation on the petrophysical, geomechanical, and geochemical properties.
3. Tackling the issue of liquid loading in gas production wells.
4. Assessing the improvements in hydrocarbon productivity after the chemical treatment.

CHAPTER 2

LITERATURE REVIEW

2.1 Background

Whether dealing with gas or oil, the formation of hydrocarbons begins in the source rock. Source rock is defined as any fine-grained, organic-rich rock that has the potential to generate petroleum when subjected to sufficient heat and pressure (Welte et al., 1965; Helgeson et al., 2009; Guo et al., 2022). When sand, mud, and organic matter (plants and animals) are buried and heated, different types of rock, such as sandstone (tight sandstone and porous sandstone), carbonate rocks, and shale form. Over time the organic matter is converted due to thermal cracking into petroleum or coal which are called 'fossil fuels'.(Tissot et al, 1973; Akramkhodzhayev et al., 1986; Shixin et al., 2006; Bjørlykke et al., 2010; Liang et al., 2019).

The volume, organic content, and thermal maturity of a source rock are all intimately correlated with its hydrocarbon-producing capability. The amount and type of organic stuff that rock contains is referred to as its organic richness (McCarthy et al., 2011). Thermal maturity is the result of a source rock's prolonged exposure to heat. Petroleum is created by a source rock through thermal cracking which leads to the alteration of organic materials. Petroleum resources are divided into two categories:

1. Conventional petroleum resources: a term used to describe oil and natural gas trapped in porous, permeable rock. Oil and natural gas can flow freely up a petroleum well

due to the underground rock formation's natural pressure. The porosity between the rock grains is connected in order to permit fluids to flow through the rock during conventional petroleum production (Zhao et al., 2022).

2. Unconventional petroleum resources (such as oil shale, coal, and gas hydrates) are sources that require a paradigm shift in the exploration and production compared to conventional resources to achieve economic recovery rates (Zou et al., 2017; Division et al., 2018).

For the unconventional system, only a little amount of the source rock must be broken down and there must be enough overburden to reach thermal maturity. Following the breakdown of organically rich sediments, part of the organic material is converted by microbial activities into biogenic methane gas. According to the temperature gradient of the basins, deeper burial is followed by a rise in heat. This heat causes the organic matter to progressively change into an insoluble organic substance known as kerogen. Kerogen is defined as a complex substance made of an amorphous porous carbon structure with pores ranging in size from a few angstroms to micrometers, it is found in shale oil reserves (Bousige et al., 2016).

Shale rocks have two different types of pores: pyrobitumen pores and organic pores which are shown in **Figure 1** and **Figure 2**. When organic matter is thermally matured, hydrocarbons are released that solidify and fill tiny, asymmetrical gaps in the rock, creating pyrobitumen pores. On the other hand, organic matter itself has pores because of the porous nature of its structure and composition. These pores, which are normally small, add to the shale's overall porosity. Hydrocarbons that have been solidified fill the holes of

pyrobitumen, whereas air or fluid phases are present in organic pores. While both kinds of pores are important for preserving hydrocarbons, pyrobitumen-filled pores are difficult to extract because the hydrocarbons are solidified, whereas organic pores allow greater fluid movement and are therefore better for producing hydrocarbons (Katz and Arango, 2018).

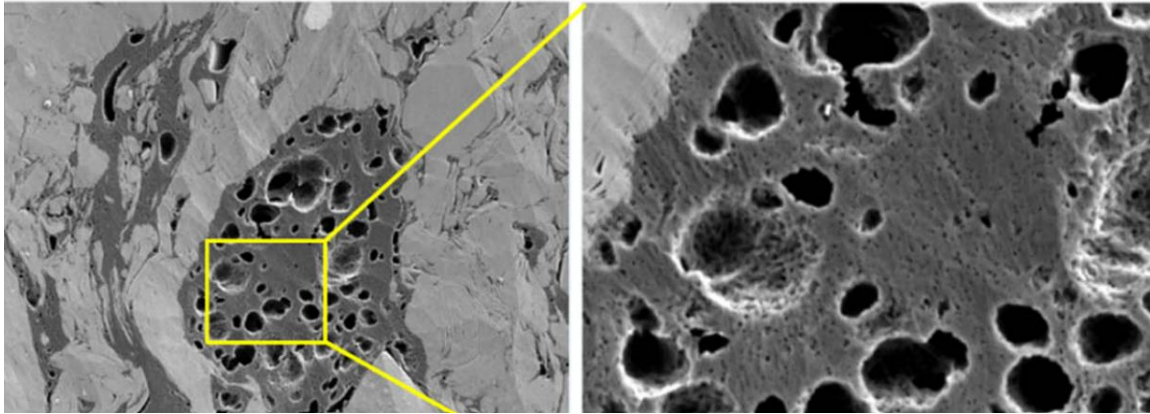


Figure 1: FIB-SEM experimental images of the pyrobitumen pores in the organic-rich shale (Zhang et al., 2020).

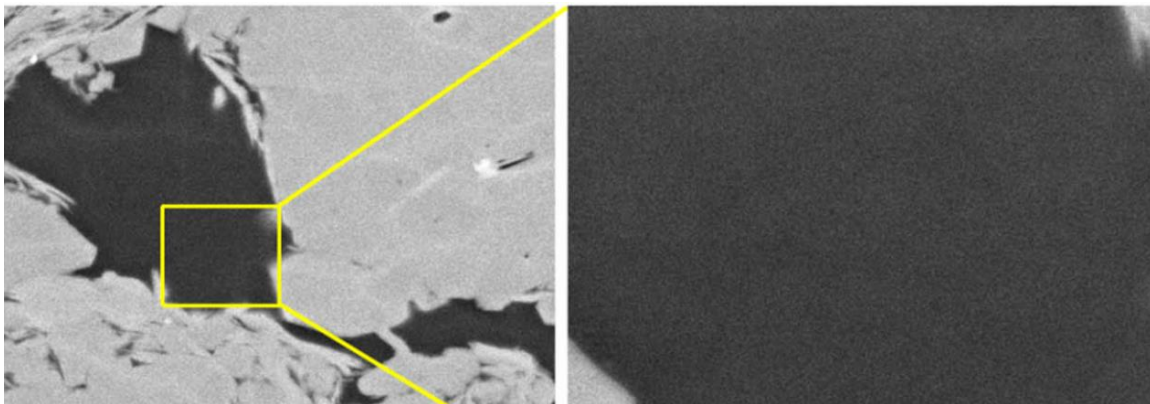


Figure 2: FIB-SEM experimental images of the organic pores in organic-rich shale (Zhang et al., 2020).

Unconventional reservoirs (with exceptionally low porosity and permeability) have changed the game when it comes to oil and gas production in the past ten years. However,

the majority of unconventional reservoir wells experience a rapid drop in production rates, which results in low recovery factors (RF) and a limited return on the significant investments made in horizontal drilling and hydraulic fracturing. As a result, there has never been a greater need to boost or improve oil recovery, which makes it extremely difficult to create efficient solutions to do so. The necessity for quick and precise assessments of thermal maturity and forecasting the locations of oil, wet gas and condensate, and dry gas production zones has arisen as a result of increased hydrocarbon exploration in shale formations (Wang et al., 2017; Hackley and Lünsdorf, 2018).

Measurements of the reflectance of organic matter, which in thermally mature shales is primarily made up of solid bitumen, are frequently used to estimate the thermal maturity of a shale. As the temperature rises, the kerogen continues to change, and these changes in turn cause the petroleum components to evolve and be generated. Kerogen is converted by additional heating into bitumen and petroleum. The organic material that results from the conversion of kerogen to petroleum and the transformation of once-liquid oil is known as solid bitumen (Thompson-Rizer, 1987; Wood et al., 2018; Sanei, 2020). As petroleum compounds age, their complex molecular structures gradually simplify. This transformation typically progresses in stages: first from oil to wet gas, and eventually to dry gas (Magoon and Dow, 1991). Continuous production technology advancements allow for the investigation and development of new plays. Current technologies only aim to produce free hydrocarbons from organic-rich shale zones, not the adsorbed and absorbed portion in kerogen (Li et al., 2016).

Natural gas trapped in organic-rich shale formations, also known as shale gas, has become an important source of energy in many countries. Shale gas is extracted from fine-grained

sedimentary rocks known as shale that contain large amounts of kerogen. When shale formations are subjected to high heat and pressure over time, the kerogen breaks down and releases hydrocarbons in the form of natural gas (primarily methane). In this self-contained petroleum system, the petroleum that is produced does not migrate but rather gets trapped in the microscopic pores and cracks of the low-permeability source rock (Allix et al., 2010).

Estimates of technically recoverable shale gas resources have increased dramatically in recent years. According to the Energy Information Administration (EIA), total world technically recoverable shale gas resources increased by 86% between 2011 and 2013, largely due to increased estimates in the US and Canada (EIA, 2013). In the US alone, shale gas production has increased from 1.1 trillion cubic feet in 2006 to over 15 trillion cubic feet in 2018, making up about two-thirds of total US natural gas production (EIA, 2019).

Organic-rich shale gas has become increasingly important in recent years due to advancements in extraction technologies and the decline of conventional hydrocarbon reserves. Artificial maturation, a technique that accelerates the conversion of organic matter into hydrocarbons, has been proposed as a method to enhance gas recovery from these unconventional resources (Song et al., 2020).

Several experimental studies have been conducted to evaluate the feasibility of artificial maturation and its impact on gas recovery from organic-rich shale. Geochemical, petrophysical, and geomechanical factors should all be studied in order to reduce uncertainty in exploration and production from unconventional shale plays. Geochemical parameters are particularly important for managing storage capacity and hydrocarbon

concentrations. The necessity to fully comprehend and describe every part of the potential petroleum system has become more pressing (Zhao et al., 2019).

By characterizing the components and processes that govern the richness and distribution of petroleum resources, understanding petroleum geochemistry increases the effectiveness of exploration and production. This information is also useful for modeling petroleum systems and basins (Al-Hajeri et al., 2009).

2.2 Natural Thermal Maturation

As pressure and temperature rise with burial depth, sediments slowly cook. Organic materials can be trapped and converted into kerogen with enough heat, pressure, and time. Based on the components used to create it, **Table 1** shows kerogen types which can be divided into four categories as follows:

Table 1: Kerogen types based on the provenance of its source materials (McCarthy et al., 2011).

Kerogen type	Source material	The general environment of deposition	Potential Hydrocarbon
I	Mainly algae	Lacustrine setting	Mainly Oil (some gas)
II	Mainly plankton (some algae)	Marine setting	Oil and Gas

III	Mainly higher plants	Terrestrial setting	Mainly dry gas (coals)
IV	Reworked, oxidized material	Varied setting	No oil or gas

The type of petroleum generated, if any, depends on the specific kerogen type, meaning that each kerogen undergoes slightly different processes. The Modified Van Krevelen diagram in **Figure 3** illustrates how kerogen changes with increased temperature during burial, as described by Vandenbroucke (2003):

Type I: rich in hydrogen and low in oxygen, it is oil-prone but depending on its stage of thermal evolution can also produce gas.

Type II: rich in hydrogen and low in carbon, it can generate oil or gas with prospective heating and maturation.

Type III: It produces dry gas because it contains more oxygen and less hydrogen than type I & II. Type III is present in most coals.

Type IV: poor hydrogen content and high carbon content. It seems to have no potential to produce oil or gas.

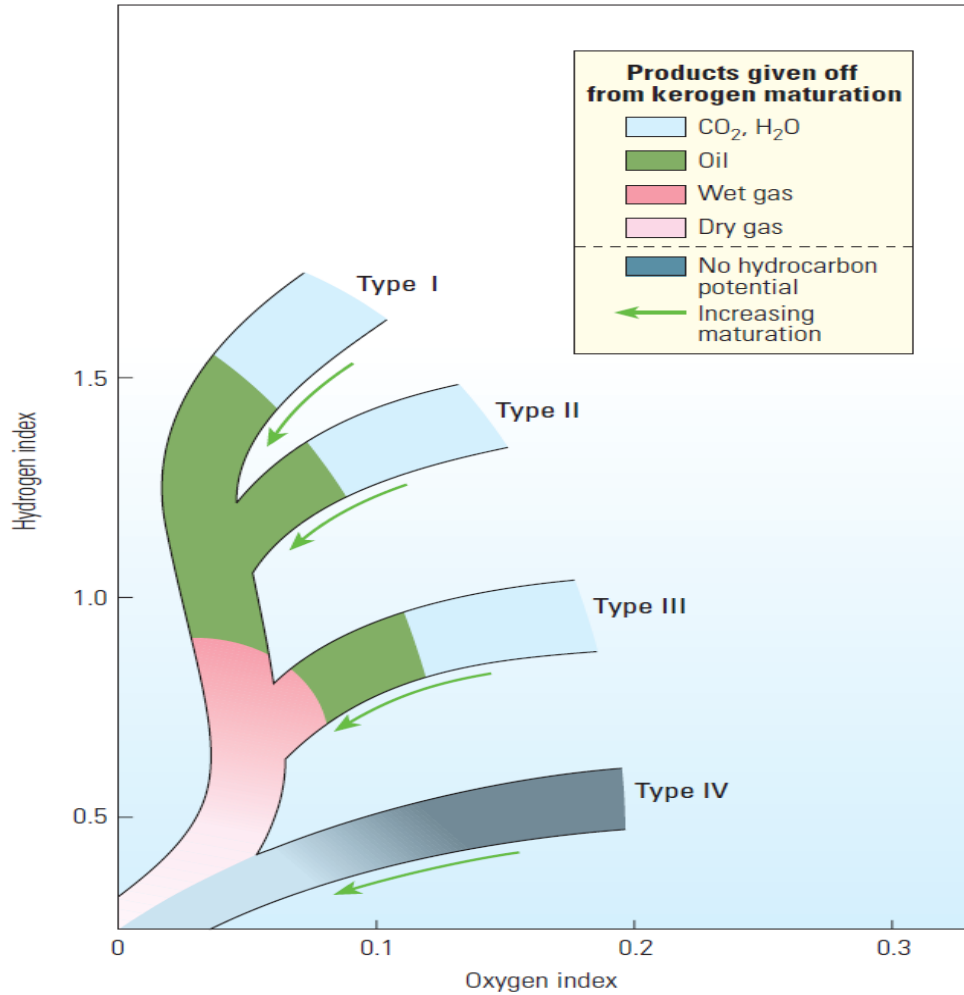


Figure 3: Modified Van Krevelen diagram demonstrates kerogen alterations with increasing heat after burial (Vandenbroucke, 2003).

Under adequate pressure, temperature, and burial depth, the degree of thermal transformation of deposited organic matter into petroleum is referred to as thermal maturity (Chapman, n.d., 2008; Tissot and Welte, 2013; Wood and Hazra, 2017; Zhao et al., 2019).

Oil and hydrocarbon gas are often produced by kerogens with high hydrogen contents, while kerogens with low hydrogen contents will just create hydrocarbon gas. No matter

how much accessible carbon is there, if the kerogen's hydrogen supply is exhausted, the production of hydrocarbons will stop (Baskin, 1997).

Organic materials emanate oil and gas after burial as temperature and pressure rise. Overall, this thermal maturation process results in a series of smaller, more volatile, and hydrogen-rich hydrocarbon molecules, culminating in methane gas. Additionally, the kerogen gradually transforms chemically as it reaches thermal maturity, becoming a carbonaceous residue with a declining hydrogen content (Hood et al., 1975). There are three stages of natural thermal maturation, which are shown in **Figure 4**, and they are as follows (McCarthy et al., 2011):

1. Diagenesis (temperature of 50°C): Methanogenic bacteria produce dry gas in this process. The organic stuff gradually transforms into bitumen and, to a lesser extent, kerogen as temperature and pH rise.
2. Catagenesis (temperature of 50 to 150°C): Types I & II create both gas and oil, but Type III mostly produces hydrocarbon gas.
3. Metagenesis (temperature of 150 to 200°C): A significant amount of the kerogen is transformed into methane and a carbon residue by additional heat and chemical changes.

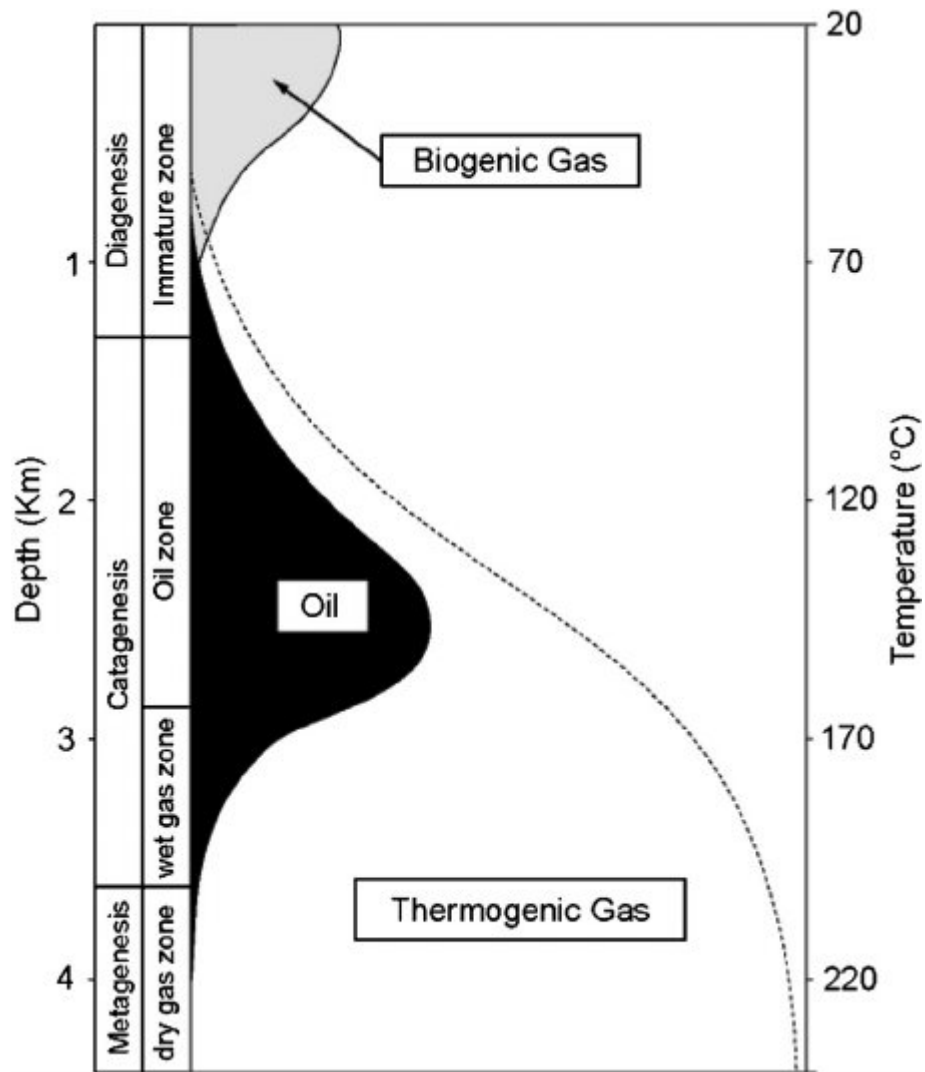


Figure 4: General scheme of hydrocarbon generation window (Meslé et al., 2013)

Gas is typically released during early diagenesis for kerogen type III, mostly through biological activities. Further burial causes catagenesis, which results in the release of gas and oil. Any leftover oil is fractured during metagenesis as depth and temperature rise, initially emitting gas and then simpler types of dry gas (Peters et al., 2004).

These stages directly affect the maturity of the source rock. Although diagenesis has altered thermally immature, or prospective, source rocks, they have not yet been exposed to

enough heat to produce thermally produced hydrocarbons. The thermal processes necessary to produce petroleum have been completed in source rocks that are or were in the oil window and are thermally mature or effective. These rocks are currently producing petroleum. Source rocks that are thermally post-mature, or spent, have reached the gas window and produced petroleum before; as a result, they have used up all the hydrocarbon required for additional oil or gas generation. As a result, subsurface rock samples may include incompletely reacted organic materials and produced hydrocarbons. In the laboratory, some of the processes can be observed and studied. One of the possible processes is the pyrolysis of organic matter, which can be used to identify organic materials and imitate changes in the subsurface (Zhao et al., 2019).

2.2.1 Artificial Thermal Maturation

The acceleration of kerogen maturity, also known as artificial thermal maturation or in-situ kerogen maturation, has been the subject of several investigations recently (Rosenberg et al., 2020; Amjed et al., 2024; Moh-Ali et al., 2024). The process of applying sufficient heat and pressure to organic matter in order to accelerate and control its thermal maturity is known as artificial thermal maturation (Behar et al., 1997; Moh-Ali et al., 2024). **Table 2** summarizes the most recent methods that have been utilized to artificially accelerate kerogen maturation.

Table 2: Summary of recent artificial maturation methods of shale formations.

Reference	Utilized method	Objective	Observations

Gao et al., (2022)	Hot air injection	Evaluating production performance estimation of in-situ conversion of shale oil by hot air injection	The more air injected, the more kerogen pyrolysis
Liu et al., (2023)	Steam injection	Investigating properties variations of shale with artificial maturation using anhydrous pyrolysis (AHP) and hydrous pyrolysis (HP)	Steam has no significant effect over the maturation
Zheng et al., (2023)	Electric heating installations	Studying an energy-efficient method for heating oil shale deposits in situ underground	Underground in-situ electric heating requires large amounts of electrical energy, and is not economically feasible
Hassan et al., (2023)	Mixture of superheated gases	Studying the impact of injecting super-heated gases on geochemical properties of shale	hydrogen and methane gases showed the best maturation performance
Moh-Ali et al., (2024)	Supercritical carbon dioxide	Investigating the effect of supercritical carbon dioxide on hydrocarbons generation	Led to hydrocarbon generation and CO ₂ sequestration

2.3 Source Rock Analysis

The presence of carbon is essential for any organic substance, making the measurement of a rock's carbon content a key method for evaluating its organic richness. Total Organic Carbon (TOC) measurement is prioritized in source rock assessments, followed by supplementary screening techniques such as pyrolysis and vitrinite reflectance analysis. TOC measurement serves as the initial screening method to assess organic richness by quantifying the amount of organic material present, though it does not provide insight into the quality of that material. If the initial TOC results indicate sufficient organic content, further tests are necessary to evaluate the quality and maturity of the organic matter (Merrill, 1991). Several methods can be employed to assess the age and quality of organic matter (McCarthy et al., 2011; Zhao et al., 2019). Some examples of these techniques include:

1. TOC Analyzer: This test quantifies the carbon content of organic materials. Estimating the amount and type of organic matter in a sample using TOC measurements
2. Rock-Eval Analysis: In this test, organic matter is heated to high temperatures, and the amount of CO₂, hydrocarbons, and other gases that are emitted are measured. This data can be used to evaluate the organic matter's thermal maturity and hydrocarbon potential.
3. Vitrinite Reflectance Analysis: A crucial diagnostic tool for determining maturation is. One of the most important tests for identifying a rock's thermal maturity is the amount of light reflected by vitrinite marcells.

2.3.1 Rock-Eval Analyzer

Rock-Eval pyrolysis analyzer is one of the most powerful equipment that are used to determine the quality and maturity of organic matter. Subjecting rock samples to high temperatures allows researchers to get data that, in a sedimentary basin, would have taken millions of years to gather. The most recent version heats samples in a controlled series of stages between 100 and 850°C using both pyrolysis and oxidation processes. Samples are heated during the Rock-Eval pyrolysis process in a helium- or nitrogen-based inert environment. During each stage of heating, organic molecules are detected by a flame ionization detector (FID). During pyrolysis and oxidation, sensitive infrared (IR) detectors measure CO and CO₂. Samples are heated in a helium and nitrogen-inert environment. They are first heated for several minutes at 300°C, then heated according to a schedule at 25°C per minute to a peak temperature of 850°C. **Figure 5** represents a pyro gram, where a series of peaks show the heating schedule (Carvajal-Ortiz and Gentzis, 2015).

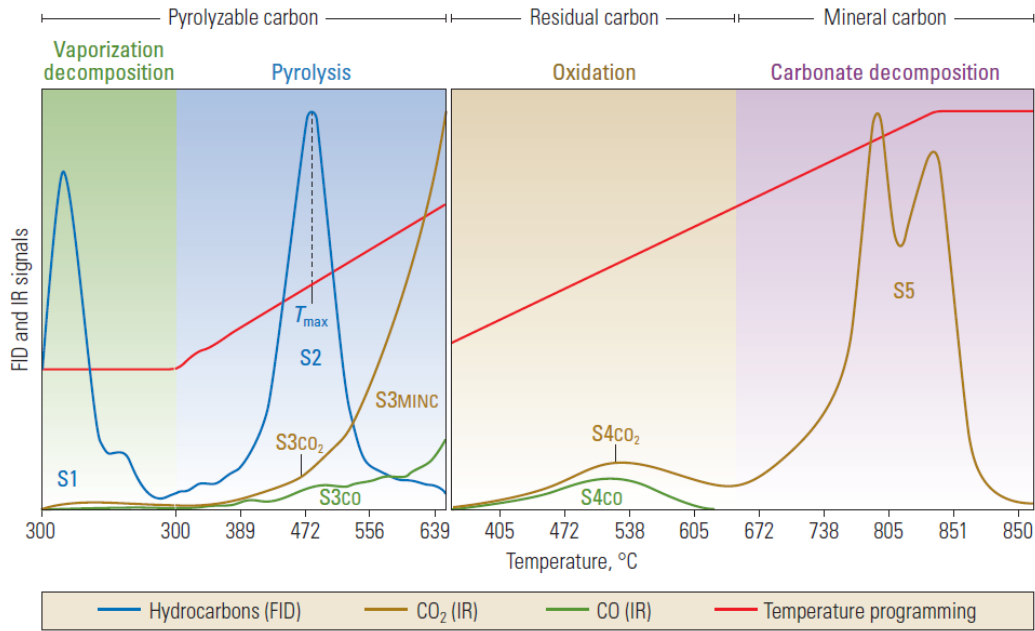


Figure 5: Programmed pyrolysis results (Mccarthy et al., 2011).

The peaks shown are defined as follows:

S1: relates to the volume of free oil or gas from the rock sample during the first stage at 300°C without kerogen cracking. It indicates the amount of free hydrocarbons that can be thermally distilled from one gram of the material in milligrams.

S2: represents hydrocarbons released from the sample during the second programmed heating phase of pyrolysis. These hydrocarbons are produced from the breakdown of heavy hydrocarbons and the thermal decomposition of kerogen. It measures the amount of residual hydrocarbons indicating the potential hydrocarbon yield the source rock could produce if thermal maturation progresses further. This measurement is significant for assessing the potential of oil shales.

S3: The S3 peak represents the total amount of CO₂ released when kerogen in the rock undergoes thermal decomposition. It is a measure of the oxygen content within the organic matter and provides insights into the oxidation level of the kerogen.

S3CO₂: This peak specifically measures only the CO₂ component of the S3 peak, excluding other potential gases that may evolve. S3CO₂ is a more refined measurement of the CO₂ released during the thermal breakdown of kerogen and often represents the more direct combustion of carbon within organic material.

S4: is created by oxidizing the remaining organic carbon in a separate oven. It can be split into two peaks, S4CO₂ and S4CO, respectively.

S5: is a distinct CO₂ peak that shows CO₂ produced by the breakdown of carbonate minerals in the sample.

T_{max}: Refers to the temperature of the pyrolysis oven at the time of maximum hydrocarbon production. It is attained at the second stage of pyrolysis when heavy hydrocarbons and kerogen fracture to produce the S₂ peak. It should not be combined with geologic temperature, although it can be used to characterize how organic matter changes thermally.

Collectively, these pyrolysis peak measurements offer valuable insights into the chemical composition and maturity of the organic matter within the source rock. The relationships between these components provide various indices used to interpret the rock's characteristics, and they are as follows:

1. **The Hydrogen Index (HI)**: which measures the amount of hydrogen in the kerogen, is inversely correlated with the possibility of oil production (Hazra et al., 2018). This index can be used to determine the kerogen type. It is calculated from the hydrogen to TOC ratio:

$HI = 100(S^2/TOC)$	1
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Where:

HI: the amount of hydrogen within the kerogen (HCs mg/rock g).

S2: possible quantity of hydrocarbons the rock could still generate if thermal maturation continues (HCs mg/rock g).

TOC: total organic carbon present in the sample (wt.%).

2. **The Oxygen Index (OI):** which measures the quantity of oxygen in kerogen, helps determine the kind of maturation of kerogen. It is obtained from the CO₂ to TOC ratio using the formula:

$OI = 100(S3/TOC)$	2
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Where:

OI: the amount of oxygen within the kerogen (CO₂ mg/rock g).

S3: carbon dioxide weight in the rock (CO₂ mg/rock g).

3. **Production Index (PI):** Because it rises with depth for fine-grained rock, the production index (PI) is employed to describe the evolution of organic materials. It derives from the link between the hydrocarbons generated in the first and second stages of pyrolysis.

$PI = \frac{S1}{S1 + S2}$	3
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Where:

PI: the ratio between free hydrocarbons produced to the total hydrocarbons (dimensionless).

S1: the amount of free hydrocarbons that can be thermally distilled from the rock (HCs mg/rock g).

Hydrocarbon Potential: This term refers to the highest amount of hydrocarbons that a source rock with enough maturity could produce. Expressed as kilograms of hydrocarbon per metric ton of rock.

Hydrocarbon Potential = S1 + S2	4
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Where:

Hydrocarbon Potential: the maximum quantity of hydrocarbons that sufficiently matured source rock might generate (HCs mg/rock g).

Immature shale deposits contain a variety of hydrocarbons, including free (S1) and potential (S2) hydrocarbons. The hydrocarbon content of shale oil formations is made up of free hydrocarbons, the majority of which are present in inorganic and organic pores, as well as adsorbed and absorbed hydrocarbons in the organic material (Sang et al., 2018).

Current technologies mostly aim to produce free hydrocarbons from organic-rich shale zones. Current technologies focus mainly on producing hydrocarbons from organic-rich shale zones primarily focusing on hydraulic fracturing and horizontal drilling. These methods aim to economically extract hydrocarbons by creating pathways for the hydrocarbons to move from the shale matrix to the wellbore. However, there are several challenges and advancements in this field (Li et al., 2016).

To assess the viability of artificial maturation and its effect on gas recovery from organic-rich shale, several experimental studies have been carried out. To reduce uncertainty in

exploration and production from unconventional shale plays, it is important to fully understand and define geochemical, petrophysical, and geomechanical factors. One of the three primary categories of qualities that should be researched is geochemical parameters, which are controlled by hydrocarbon concentrations, kerogen structure, and storage capacity (Zhao et al., 2019).

2.4 Thermochemical Fluids

2.4.1 Definition

Thermochemical are substances or compounds that go through considerable variations in temperature and/or heat energy together with chemical reactions and transformations. The chemical composition and physical characteristics of the substances involved are changed as a result of these reactions, which represent the absorption or release of heat energy (Carson, 2002). Chemical bonds are broken and formed during thermochemical reactions, which are fueled by heat energy and transform reactants into products with various chemical structures and thermodynamic properties. TCFs are frequently used in many different applications, such as heat storage systems, catalysis, energy conversion, and chemical synthesis (Bartel et al., 2019; Babaev et al., 2020). Fuels, explosives, specific reactive gases, and substances utilized in high-temperature reactions or heat exchange procedures are examples of thermos-chemicals. TCF usually consist of two chemicals such as combinations of $\text{MgCl}_2 \cdot 6\text{H}_2\text{O}$, $\text{CaCl}_2 \cdot 2\text{H}_2\text{O}$, NaNO_2 , and NH_4Cl . These chemicals exerts heat and their reaction is called an exothermic reaction. The exothermic reaction of some chemicals can generate high temperatures which range from 150 to 750°F and high pressure ranges between 1,500 to 7,000 psi depending on the chemical volume and concentrations (Alade et al., 2019; Aljawad et al., 2020).

TCFs were first utilized to solve problems in unconventional gas reservoirs (Al-Nakhli et al., 2013). It was used to increase hydrocarbon production by using exothermic reactions to create heat in situ at reservoir conditions. The heat produced will turn the liquid condensate into gas, significantly reducing the viscosity of the fluid. Additionally, the pressure around the wellbore would rise as a result of in situ heat generation, which would have a favorable impact on overall gas production (Liu et al., 2020; Xu et al., 2021).

2.4.2 Applications

Several studies and research were carried out in the field of using thermos-chemicals in industry. For instance, Al-Nakhli et al., (2013) worked on overcoming unconventional gas challenges by creating synthetic sweet spots and increasing drainage area. They demonstrated a brand-new stimulation technology that uses mechanical and thermal forces to build synthetic sweet spots. In order to produce microfractures in confined core samples, localized heat and pressure were produced using an electrified fluid. The volume of the reservoir was stimulated, permeability was greatly raised, and porosity was also increased. The new treatment technique allows for the creation of a synthetic sweet spot close to a wellbore or fracture location. With the new treatment method, the permeability of the tested cores significantly increased as assessed by the core flood system. As a result of the treatment, communication between macro and micro pores was enhanced. No hydrocarbons were used in the process, and there were no lift overs or possible hazards. The generated high temperature and pressure can be used to eliminate potential damage such as condensate banks that may be present around the wellbore or fracture networks. The proposed treatment method was evaluated using the core flood system and tight core samples obtained from tight reservoirs. Environmental scanning electron microscopy

(ESEM), and computerized tomography (CT-scan) analyses were utilized to show the development of microfractures and improvements in porosity and permeability.

Another study was done by Hassan et al., (2018) to eliminate gas condensation in gas condensate reservoirs using TCFs. They concluded that when TCFs were injected, pressure and temperature formation surrounding the wellbore increased. The condensate phase behavior was significantly impacted by the heat and pressure that were created. By raising the pressure over the dew point pressure, the pressure generated will change the condensate liquid into the gaseous phase. According to the liquid drop-out profile, increasing the pressure close to the wellbore leads to a reduction in the condensate volume. The capillary forces are significantly impacted by the thermochemical treatment. The resulting thermochemical reaction product had a negligible effect on the behavior of the hydrocarbon phase. Due to the greater value of Nitrogen gas minimum miscibility pressure (N_2 -MMP), no appreciable change in the phase behavior was seen as a result of nitrogen production. More condensate liquids were transformed into the gas phase when the injection period was increased since it will exponentially expand the radius of the heated area.

In drilling application, Mahmoud (2019) conducted a study on the use of a fluid that combines thermochemical/chelating agents for well cleanup. The results that can be drawn are as follows: Cakes made of barite oil and water can be successfully removed in a single step using a thermochemical/EDTA chelating agent solution. Higher elimination efficiency was achieved as a result of the thermochemical reaction's pressure pulse in addition to temperature. As a result of the reaction, the generated high pressure and temperature are primarily localized at the formation. Additionally, the formulated products of the reaction are safe to handle and do not present any risk of corrosion.

Hassan et al. (2019a) used thermochemical for water blockage removal. In tight sandstone formations, water blockage causes significant formation destruction. The confined fluids were released, and the flow conditions were improved, using thermochemical treatment as a stimulant. The core conductivity significantly increased after TCF were injected into constrained samples. The treatment also reduced capillary forces, increased the production index by a factor of 1.94, and reduced drawdown pressure. The capillary pressures were decreased, and microscopic fractures were created as a result of the pressure and heat produced by the thermochemical reaction, which also enhanced the productivity index. Ultimately, the trapped water was evacuated, and the productivity index was raised by injecting TCF into tight sandstone.

Additionally, Hassan et al., (2019b) studied the usage of TCF for eliminating condensate banking was introduced. They looked at how thermochemical treatment could increase gas mobility and decrease condensate saturation. Their research suggests that TCF treatment can eliminate more than 65% of condensate banking. In reducing the condensate damage and the amount of chemicals injected, the huff and puff mode outperformed continuous chemical injection. Condensate banking removal increased gas-effective permeability. The tight sandstone was fractured by the pressure pulse brought on by the reaction and the high temperature. The injection of TCF increased the gas mobility by lowering the condensate viscosity and increasing gas effective permeability. With the help of thermochemical treatment, the hydrocarbon's viscosity was decreased, and the capillary pressure was dropped. It was discovered that the maximum increase in hydrocarbon mobility would be when the reduction of capillary forces and fluid viscosity were combined.

A methodology to reduce the strength of high-stress-tight gas reservoirs using thermochemicals was introduced by Al-Nakhli et al. (2019). It was particularly efficient to lower the breakdown pressure of tight reservoirs. Thermochemical treatment resulted in significant changes in mechanical parameters and rock strength, according to laboratory measurements. The strength and other mechanical parameters of the rock samples were impacted by the micro-scale fractures that the thermochemical treatment led to in the treated samples. In highly stressed tight gas reservoirs, innovative thermochemical reagents may be used to lower the breakdown pressure. The use of the innovative thermochemical would significantly reduce the work required for hydraulic fracturing procedures, making them more efficient and affordable. The reactive thermochemical may be activated by the thermal energy of reservoirs to injection of weak acids.

Thermochemical removal of condensate banks from carbonate, sandstone, and shale layers was investigated by Hassan, et al., (2020a). The study found that TCFs are capable of both increasing gas production and condensate removal. The findings as a whole point to thermochemical treatment as a potential method of boosting gas production in tight reservoirs.

A field-scale simulation was provided by Hassan, et al. (2020b) to quantify how well thermochemical injection works to remove the condensate bank and increase gas recovery. They concluded that the thermochemical technique was discovered to be significantly more effective in handling production-related condensate-banking concerns than traditional gas-injection techniques. The wellbore's surrounding pressure rose as a result of the thermochemical exothermic nature's heat and pressure release, which also heated the fluids

nearby. The thermochemical reaction caused a pressure pulse that encouraged the development of microfractures and a corresponding drop in the capillary pressure.

Tariq et al., (2020) demonstrated that TCFs are an effective approach to stimulate unconventional formations. In order to comprehend thermochemical reactive behaviors and results, the study integrated both experimental and mathematical techniques. A mathematical model for the static thermochemical reactor was proposed. It has been found that TCFs can produce artificial sweet spots by causing numerous microfractures near the wellbore. Compared to traditional approaches, the thermochemical treatment assisted in lowering the breakdown pressure more effectively. Acid was used to start the TCF, which assisted also in etching the fracture surfaces. Therefore, in contrast to the thermochemical reaction without acid, fracture conductivity was preserved at high closure stresses. To replicate the pressure pulse behavior, a mathematical model was developed and tested against experimental results. For sensitivity analysis, a field-scale thermochemical reactive transport model was created. It was discovered that thermochemical concentration is the primary element in regulating the magnitudes of pressure and temperature.

Hassan et al., (2021) demonstrated a novel and effective technique for boosting the gas productivity of shale formations using TCF injection. Multiple measurements were taken to evaluate the suggested treatment efficacy. The findings revealed that injecting TCF into shale rocks can increase the pore size, create new fractures, and boost gas productivity. The thermochemical treatment resulted in an increase in gas production, an increase in the absolute open flow, and a drop in the capillary pressure (P_c). Moreover, TCF can interact with shale rocks and partially dissolve the matrix, leading to a significant increase in the formation porosity and gas productivity. The study claims that additional increases in gas

productivity can be achieved by performing thermochemical treatment cycles repeatedly. This is considered to be the first study to suggest using TCF to increase gas productivity in shale reservoirs.

In summary, a series of studies were conducted by researchers to investigate various applications of TCF in the field of hydrocarbon recovery. The recent experiments that used TCF in the petroleum industry are summarized in **Table 3**.

Table 3: recent studies that utilized thermochemical fluids in the petroleum industry.

Reference	Objective	Observations
Al-Nakhli et al., (2013)	overcome difficulties posed by unconventional gas by creating synthetic sweet spots and increasing drainage area.	used electric fluid to create microfractures and demonstrated improved recovery of hydrocarbons.
Hassan et al., (2018, 2019)	reducing condensate reservoir gas condensation and enhancing gas production.	condensate phase behavior is impacted by elevated pressure and temperature near the wellbore, which encourages a transition from liquid to gas and improves mobility.
Mahmoud, (2019)	using chelating agents and TCF to clean wells.	89% of Barite filter cakes were successfully removed in a single stage for drilling fluids based on water.

Al-Nakhli et al. (2019)	reducing the high-stress-tight gas reservoirs' breakdown pressure.	notable changes to the rock's strength and mechanical characteristics. It has the potential to increase hydraulic fracturing efficiency.
Alade et al. (2019)	kinetics analysis of the TCF to improve heavy oil and liquid condensate recovery.	it was verified that the TCF were suitable for enhancing the recovery of heavy oil and condensate.
Tariq et al. (2020, 2021)	stimulating unconventional formations. Reduction of breakdown pressure through filter cake removal.	reduced breakdown pressure, many microfractures created, and filter cake removal.
Hassan, et al. (2021)	presenting a novel method for increasing shale formation gas productivity.	lowered capillary pressure, increased gas production in shale reservoirs, and developed new microfractures.
Al-Taq et al. (2023)	using TCF to improve the performance of breakup fluids and clean up fractures.	the emission of a great deal of heat and nitrogen gas cleansed the fractures efficiently.
Al-Jurf et al. (2024)	treating rich organic shales with thermochemical fluids to increase their production.	TCF stimulation converts kerogen into hydrocarbons, it can lower the overall organic content

2.5 Liquid Loading and Slugging Challenges

Gas wells suffering from liquid loading issues are incapable of removing the liquid associated with produced gas from the wellbore (Falcone et al, 2013; Liu et al., 2018; Guan et al.,2023). Natural gas wells can experience liquid loading, particularly as they age (Wang et al., 2013; Lea et al., 2019; Burrows et al., 2020). An annular or mist flow occurs in a vertical well when the gas velocity is high enough to carry the liquids to the surface without any buildup (Liu et al., 2020; Alsanea et al., 2022). The inability of produced liquids to be removed from the wellbore by produced gas is known as liquid loading of a gas well (Lea et al., 2019). The well's upward gas velocity must fall below a threshold level for this phenomenon to occur, at which time the liquid that was initially flowing upward starts to sink back (Phillips et al., 2009; Fan et al., 2020). This liquid builds up at the bottom of the well, where it reduces the production rate, destabilizes multiphase flow in the well (after changes in flow regime), increases hydrostatic back pressure on the reservoir, and, in extreme situations, kills the well (Falcone et al., 2013). A high gas flow rate is used at the beginning of the normal liquid loading sequence to effectively move all liquids to the surface (Luan et al., 2012; Khan et al., 2023). However, some liquid starts to flow back into the wellbore as the gas velocity drops or the liquid content rises. The accumulated liquid in the wellbore may re-enter the area of the near wellbore when downhole hydrostatic pressure rises (Liu et al., 2017). By deliquifying the well, all liquids are carried to the surface by gas as the well begins to flow once more (Croce et al., 2020). This cycle keeps on until reservoir potential drops or liquid yield rises, which causes the sporadic behavior seen in liquid-loaded gas wells (Veeken et al., 2011). There are numerous issues with liquid loading in marginal wells (Argawal et al., 2015; Tugan et al., 2020; Feng et al., 2020;

Alsanea et al., 2022). This usually happens when the production rate and reservoir pressure drop. Liquid loading can eventually cause the well to fail by causing irregular gas production and a drop in generated liquids. Turner et al., (1969) presented the first attempt to forecast the beginning of liquid loading. They proposed two different mechanisms for the loading initiation: droplet-flow reversal and film-flow reversal. They concluded that the droplet-reversal model performed better when compared with field data. This droplet-reversal model is widely used in the industry to predict the critical flow rate. In essence, the Turner droplet-reversal model is based on the minimum gas rate required to sustain the largest possible liquid droplet and assumes that the liquid loading is independent of the pipe diameter (Turner et al., 1969; Coleman et al., 1991; Skopich et al., 2015). Riza et al. (2016) conducted a study to understand liquid loading in gas wells. They concluded that the most crucial factors in establishing the essential liquid loading rate and the liquid loading onset are the tubing inner diameter and the well productivity index. One of the most used techniques to analyze liquid loading and well performance is system nodal analysis (Parsi et al., 2014; Adaze et al., 2019; Alsadoun et al., 2020). The whole well system is divided into two subsystems by nodal analysis at a particular location called the nodal point, and the pressure will be determined at each nodal point (Mahmud et al., 2017). In the oil and gas industry, PIPESIM software from Schlumberger is frequently utilized for nodal analysis (Yaqoup et al., 2016; Mohamed et al., 2023). It is a multiphase, steady-state flow simulator that is frequently used for gas and oil system design and diagnostics. In particular, PIPESIM is used to simulate multiphase flow from the reservoir to the wellhead, which helps to optimize injection and production processes. Furthermore, PIPESIM offers a range of modeling choices specifically designed for liquid loading scenarios (O'Brien et

al., 2010; Yaqoup et al., 2016). Numerous corrective lifting options have been developed for field use; some unloading methods (like velocity strings) rely on the system's inherent energy, while others (like downhole pumps) provide energy to raise the water to the surface and so lessen the liquid loading issue. An alternative to producing water from a gas well is to inject water into a zone beneath the gas reservoir. Pumps and techniques utilized for this purpose are referred to as injection systems. Water can be injected into a gas well using a variety of techniques. Injection systems are powered by electrical submersible pumps (ESPs), some of which allow an ESP to pump water below a packer. Water injection can also be done by bypassing the seating nipple. This involves employing concentric vertical holes in the bypass seating nipple to allow water pressure to be pumped up through the tubing and impose pressure on an injection zone below the sucker-rod pump (Lea et al., 2004). The appropriateness of each remedial approach varies based on the well's characteristics and state because each has unique technical characteristics. A detailed technical evaluation of tried-and-true methods for mitigating the impacts of liquid loading was reported by several studies (Lea et al., 2004; Falcone et al., 2013; Burrows et al., 2020; Alsanea et al., 2022). The best approach is the one that is most cost-effective over the course of operation. Also, the most suitable approach will be chosen based on a number of factors, including vendor equipment availability, equipment reliability, manpower requirements for operating the equipment, lifting capacity, and effective approaches employed in related fields (Lea et al., 2004; Alsanea et al., 2022). **Table 4** lists some of the most popular unloading solutions along with some of their benefits and drawbacks.

Table 4: Common solutions for unloading gas wells (Alsanea et al., 2022; Tugan et al., 2022; Binli et al., 2009)

Method	Advantages	Disadvantages	References
Plunger lift	Suitable for larger well tubing.	Difficult to remove huge liquid volumes. Requires gas or air injection in some cases.	Chava et al. (2010) Zhu et al. (2019)
Jet hydraulic pumps	Low maintenance cost, simple to install, and can handle high flow rates.	High initial cost and excessive electricity could be needed.	Yan (2013) Kalwar et al. (2017)
Compression	Decreasing the wellhead pressure. It can assist different methods	Expensive equipment and may not be financially feasible.	Veeken and Belfroid (2011) Lea and Rowlan (2019)
Injection systems	Feasible solution to increase the pressure and improve gas production	More effective for water or liquid injections compared to gas injections	Ali et al. (2023) Gu et al. (2021)
Gas lift	Can run constantly, delivering consistent rates of production.	Feasible in the presence of high-pressure gas.	Hernandez (2016) Sahu et al. (2021)
Foaming	Wide range of applications and costs	Functions best with water alone and might require huge volumes of costly surfactants.	Christiansen (2006) Veeken and Belfroid (2011) Adaze et al. (2019)

Slugging refers to the intermittent flow patterns characterized by alternating liquid slugs and gas pockets (shown in **Figure 6**). Slugging, which can result in fluctuating production rates, pressure spikes, and potential mechanical damage to the production equipment, can happen as a result of the dynamic interplay between liquid and gas phases in the wellbore. Slugging frequently occurs in long horizontal wellbores with complex fracture networks,

where flow limitations and shifting reservoir characteristics make the flow instability worse. The intensity and occurrence of liquid loading and slugging issues in unconventional wells are influenced by a number of variables. Reservoir heterogeneity, multiphase flow dynamics, liquid condensation and imbibition into the matrix, water blockage, and liquid buildup in cracks are some of these issues. These elements interact in a complex way, making it difficult to forecast and control liquid loading and slugging occurrences (Karami, 2022).

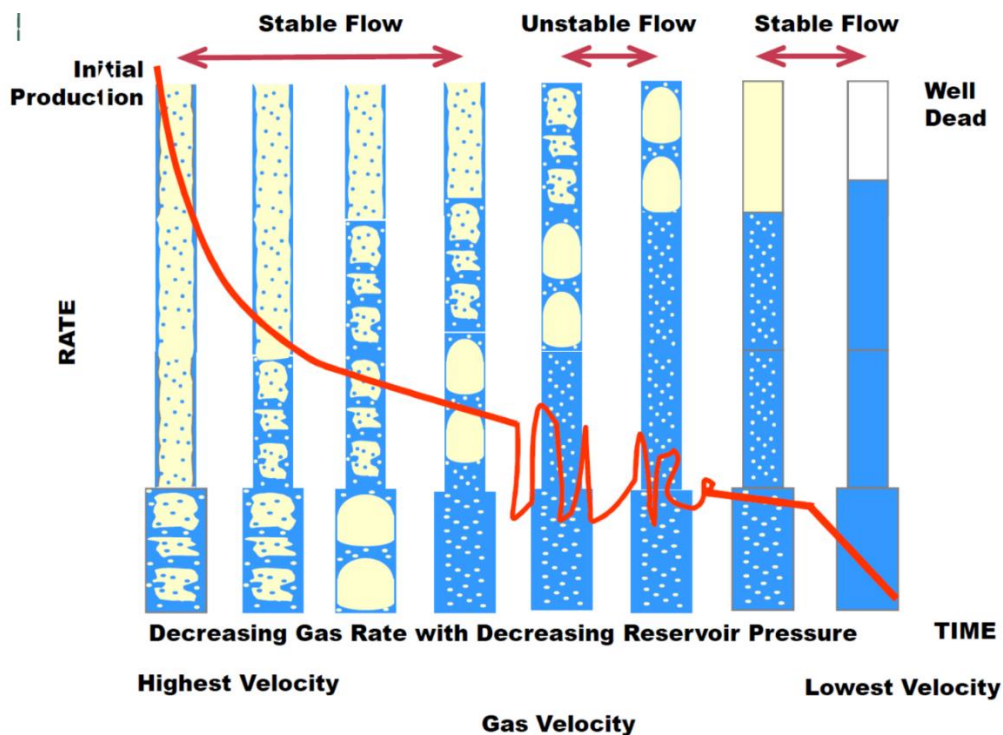


Figure 6: Illustrating excellent depiction of multiphase flow in the wellbore as well moves towards liquid loading (Hearn, 2010).

Multiple strategies have been suggested and put into practice to reduce the issues with liquid loading and slugging. To improve gas-liquid separation and lift the collected liquids to the surface, these techniques involve the employment of artificial lift techniques like gas

lift or plunger lift. It has also shown potential to increase reservoir connectivity through hydraulic fracturing design in order to lessen liquid buildup. In addition, chemical and surfactant injection, production rate optimization, foam and gel treatments, and operating procedures are used to lessen the impacts of liquid loading and slugging (Kannan et al., 2019).

Despite the progress made in understanding and mitigating these issues, further research is needed to refine predictive models, develop advanced monitoring techniques, and explore novel mitigation strategies. The optimization of unconventional well performance requires a comprehensive understanding of the mechanisms and impacts of liquid loading and slugging, enabling operators to optimize production and maximize hydrocarbon recovery from these challenging reservoirs.

2.6 Summary

The effects of kerogen maturation were studied by several research from geological aspects. In addition to that, the thermal maturation of organic-rich shale represents a technique that accelerates the conversion of organic matter into hydrocarbons to enhance overall recovery from unconventional resources. The usage of chemicals in the petroleum industry witnessed growth as it was used to develop effective technologies for improving hydrocarbon recovery by solving lots of issues in different aspects. TCFs assisted maturation has a good potential due to the additional increase in pressure caused by the reaction, which does not exist in heating-only maturation. This high pressure will increase heat flow and speed up the operation. Furthermore, the application of TCF across various petroleum engineering fields has shown promising results, particularly in well cleanup and production enhancement. This highlights TCF's strong potential for use in deliquifying gas

wells, reactivating dead wells, and extending the productive lifespan of gas-producing wells.

CHAPTER 3

Methodology

To capture the petrophysical changes in the organic-rich shales before and after TCF injections, porosity measurements, and micro CT-scan techniques were combined. Additionally, X-ray diffraction (XRD), X-ray Fluorescence (XRF), and compressional and shear velocities were combined to have insights into the mineralogy of the samples and the geo-mechanical impact of TCFs, respectively. Finally, a Vinci Rock-Eval 7S pyrolysis analyzer was utilized to assess the geochemical characteristics. The samples were artificially matured utilizing TCF under different HPHT settings throughout many treatment durations after they had been initially characterized. Furthermore, by assessing the rock characteristics following the various maturation processes, the effects of the induced shale maturation on the petrophysical, geo-mechanical, and geochemical parameters were interpreted. The chemicals were injected under reservoir conditions by using core flooding in order to carry out in-situ maturation and enhance hydrocarbon productivity.

Moreover, to address the liquid loading issue using TCF, a two-stage approach was conducted: experimental laboratory work followed by process simulation with PIPESIM software.

In the experimental phase, a horizontal flow system was designed to simulate conditions in a horizontal well section. Pressure gauges were strategically placed across the system to monitor pressure variations accurately, and a back-pressure valve, set at 350 psi, simulated

the wellhead pressure. Nitrogen gas cylinder with low pressure (50-300 psi), representing a gas reservoir experiencing liquid loading, was introduced to observe fluid flow under these simulated reservoir conditions. At the system's outlet, graduated cylinders collected produced fluids, enabling continuous monitoring of liquid production as a function of time. For TCF injection, a dual-cylinder syringe pump was utilized to ensure consistent and controlled fluid delivery from accumulators.

The second stage involved scaling the experiment to field conditions using the PIPESIM modeling program. This simulation modeled the liquid loading removal process under realistic conditions, providing insights into TCF's efficacy at a larger scale and helping to predict field application performance. This two-stage methodology provided a comprehensive evaluation of TCF's potential to address liquid loading, combining empirical data with predictive modeling.

3.1 Materials

To assess the impact of TCF on shale, four organic-rich shale samples with distinct characteristics were selected. The first sample was intact, while the second was artificially fractured by drilling a hole in the middle of it. The last two samples had natural fractures at varying fracture intensities. This variation allowed for a thorough examination of TCF impact across different fracture types.

In place of liquid holdup, gas condensate was used, with a density of 0.746 g/cm³, API of 57°, and a dynamic viscosity of 0.631 cP.

TCF (a combination of NH₄Cl and NaNO₂) generated pressure and heat in situ, with the reaction triggered by pH control. A detailed kinetic study was recently reported by Al-Taq et al. (2023), and the chemical reaction can be described as follows:

$NH_4Cl + NaNO_2 \rightarrow NaCl + 2H_2O + N_2 + \Delta H \text{ (heat)} [\Delta H = -7.66 \times 10^{11} C_o^{2.45} e^{(-91.44 \text{ kJ/mol})/RT}]$	5
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All TCF formulations, particularly this combination, are environmentally friendly. TCF treatments are highly adaptable, as they allow precise control of the solution's behavior by adjusting fluid concentration and pH, and adding inhibitors (Al-Ghamdi et al., 2023).

3.2 Method and Phases

The experimental work was generally conducted in two phases, one for capturing TCF impact on shale formation, while the other for testing TCF performance on liquid loading removal. The two phases are explained below.

3.2.1 Phase-I: TCF Impact on Organic Rich Shale

The goal of this step was to investigate the changes that the TCF will make to the shale matrix. There are three successive steps to this phase. Prior to performing the treatments, the initial step was to characterize the geo-mechanical, geochemical and petrophysical properties in order to understand the shale matrix. Applying the treatments to the shale samples was the second step. To replicate the reservoir conditions, core flooding techniques were used during this stage. The final step was the evaluation of the shale samples following the chemical treatment and providing important information about the alterations induced by the thermochemical treatment. The three stages are detailed below:

3.2.1.1 Stage-I: Characterization of Samples Pre-treatment

For the purpose of capturing the impact in the organic-rich shales prior to TCF injections, micro CT-scan, porosity measurements, Rock-Eval, and compressional and shear velocity

measurements were combined. The samples' mineralogy, elemental composition, and geochemical characteristics were studied by cutting and powdering the samples for use in XRD, XRF, and Rock-Eval analyzer, respectively. The identification, quantification, and structural analysis of minerals and elements in samples were done using XRD and XRF analyses. On the other hand, Rock-Eval analysis offered useful details regarding the source rocks' geochemical properties.

3.2.1.2 Stage -II: Applying TCF Treatment

During this stage, the samples were treated with TCFs under various pressure and temperature settings for varying aging times. At this point, reservoir conditions were simulated using a core flooding system. Temperatures between 100 to 250°C and pressures from 3000 to 3500 psi were the conditions used, with time intervals between (6 to 24 hours). The TCF were injected separately and not allowed to interact until they reached the inlet of the core holder. **Figure 7** shows the flooding setup that was used in this study. TCFs were injected using injection dual pumps, the treatment temperature was regulated

in the oven, and the pressure of the inlet and outlet were tracked and recorded by a data gathering system during the process.

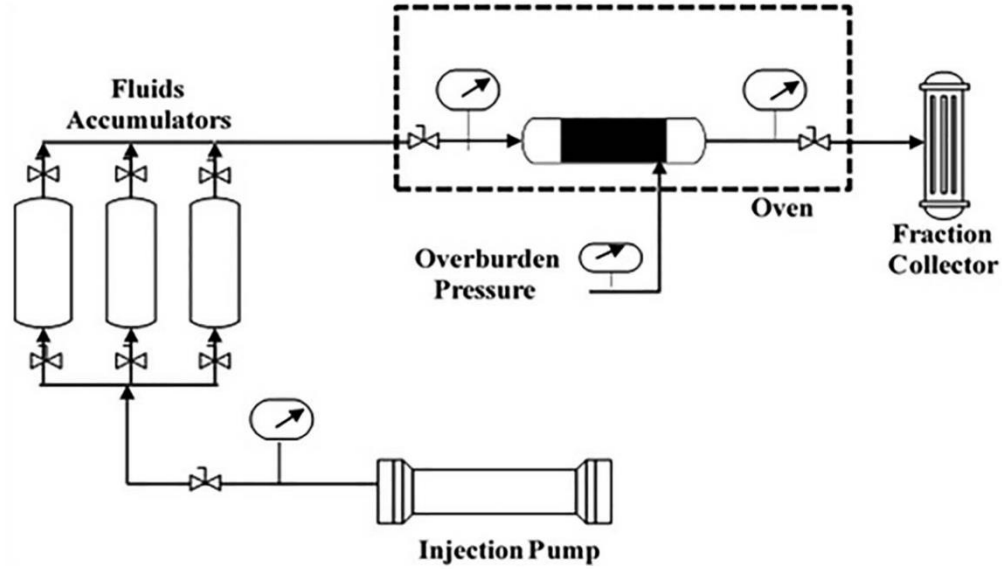


Figure 7: Flooding setup that was used for the TCF injections (Hassan et al., 2021).

TCFs were injected simultaneously via different flow lines. High pressure and high temperature conditions were present during the flooding experiments. In order to ensure that no pores are bypassed and the core is fully saturated with chemicals, a backpressure regulator (at 400 psi) was used at the outlet. The system temperature was also controlled to be between 60 and 100 °C. Additionally, an overburden pressure of 4500 psi was applied. Several cycles of TCFs were injected with providing enough time for soaking the sample and till the pressure across the core stabilizes. Moreover, two additional artificial maturation techniques were used for comparison. Supercritical carbon dioxide was used as per literature for aging the samples for different durations at a pressure of 3000 psi and temperature of 250°C. The second technique was heating in a closed system pressurized to 3000 psi using nitrogen gas, at a temperature of 250°C.

3.2.2 Phase-II: TCF Impact on Removal of Liquid Loading

In this phase, the liquid loading removal was tested in two different ways. Experimental work in the lab by using a small tube and filling it with condensate, then a gas flow with small pressure was controlled to mimic the issue. The best conditions that were interpreted in stage-III were used to test their effect on the liquid loading removal process. The TCFs were injected and were not allowed to react until they were in bottom of the tube below the liquid that had already stopped the well from producing. The process was repeated several times to determine the best conditions. After that, PIPESIM software was used to simulate the process of liquid loading removal on a large scale. More details about the two stages are provided below;

3.2.2.1 Stage -I: Experimental Work

A condensate liquid was placed in the line to represent the liquid loading and sealed with a back pressure of 350 psi, and then nitrogen gas was injected at ranges between 50-300 psi to check for flow. Initially, TCFs were injected to fully occupy the line to observe if they could generate pressure and heat that were sufficient to overcome the back pressure and enable the liquid removal and resume the gas flow. The experiments were conducted at different volumes of condensate liquids to mimic multiple liquid loading cases. The experiments were conducted when condensate was holding 50, 60, and 70% of the total available volume. Different injection cycles were studied, and the removal efficiency for each cycle was determined. The experimental procedures were kicked off by thoroughly cleaning the half-inch pipeline and preparing the system. Then, a precise amount of condensate was pumped into the pipeline, and the system was sealed with a backpressure valve at the output while maintaining a 350 psi pressure. Furthermore, to mimic the

reservoir whose pressure is not enough to lift the liquid that is holding the system, nitrogen gas was injected at different pressures ranging from 50 to 300 psi. TCFs were injected separately at various volumes suitable for each cycle to keep the pipeline full and ensure continuous pipeline occupancy in order to prevent gas compression during pressure buildup due to the system being fully occupied, which will lead to gas being compressed. TCFs were controlled to only meet at the bottom of the system, below the liquid that is loading the well, to ensure the highest removal efficiency of the liquid holdup. A dual pump with 50 cubic centimeters (cc) per minute fluid capacity was used. The pump's cylinders can each carry up to 100 cc of fluid. The system was consistently injected with the entire volume of TCF needed at a rate of 1 min every cycle. For instance, the system had a total capacity of 100 cm³. In the first scenario, 50% (50 cm³) of the system was filled with a mixture of nitrogen gas and gas condensate, then 50 cc of TCFs were injected. The pump was configured to pump at a rate of 50 cc/min. It is connected to both TCF accumulators. This indicates that it pumped 25 cc from each accumulator in a minute. Sequential injection cycles were used, with each cycle starting once the flow ended and pressure had stabilized at the end of the previous cycle. Throughout the duration of each experiment, pressure profiles were continuously recorded as a function of time. Finally, the experiments were conducted in a different number of cycles to optimize the removal efficiency.

Figure 8 illustrates the steps that the system goes through until it is deliquefied. Schematics show the following: (a) The system was at its initial stage, where the condensate had been loaded in the line and gas with low pressure was injected from the gas cylinder to represent when gas is not able to flow because of the liquid loading the system. (b) TCFs were injected through tubing to make sure the fluids reached the desired location below the

liquid that was loading the system. (c) The TCF below the liquid that is loading the system, all of this is while they are being injected separately to make sure the reaction is not triggered during the injection. (d) Once the TCFs reach the specified point, the tubing is pulled, then the reaction is triggered, and heat and pressure (nitrogen gas) are generated. (e) The pressure increases the BHP and helps the reservoir (gas cylinder) to overcome the liquid column pressure, which enables the lifting of the liquid that is holding the system and allows gas to flow again. (f) The system resumes production, and gas can flow to the surface again.

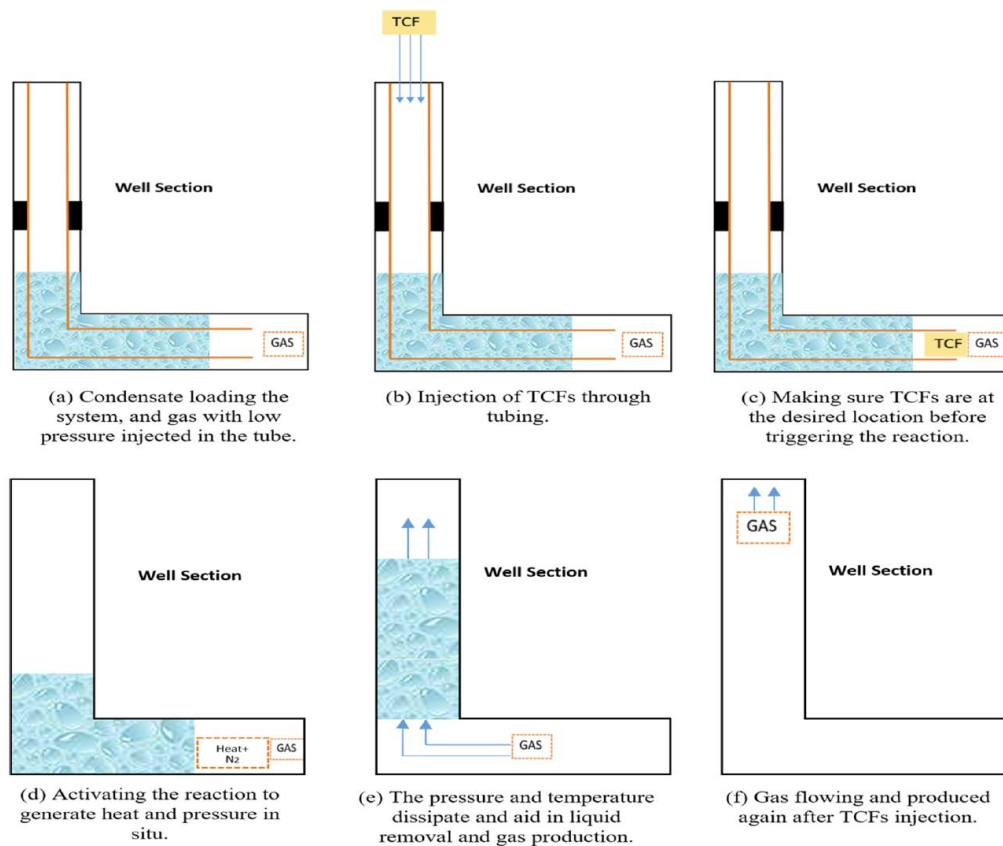


Figure 8: Schematics showing the experimental process followed to remove liquid loading issue using thermochemical fluids injection.

3.2.2.2 Stage -II: Simulation Work

The nodal analysis software (in PIPESIM), which is designed to simulate fluid flow in pipelines and wells, was used to assess thermochemical treatment on a large scale. The study involved a systematic approach to replicate the real conditions within a controlled environment. To do this, the data associated with the system includes information about dimensions and pressures. The line length was scaled and multiplied by the proper quantity to convert from centimeters to thousands of feet in order to ensure that it was suitable for modeling a well. Furthermore, the hydrostatic liquid column in the line, which functioned as the well, was used to adjust pressures. The pressure that was holding the system was scaled and calculated by using the hydrostatic pressure equation. The formula is shown below in **equation 6**:

$P = \rho gh$	6
---------------	----------

Where:

P: hydrostatic pressure

ρ : fluid density

g: acceleration due to gravity

h: height of the fluid column

This meticulous process guarantees that the well model used in the simulation adheres to the desired scientific criteria to accurately depict a real-world scenario. Scaling is a critical step as it allows the creation of a model that accurately reflects the characteristics of the original system but on a different scale. In the next phase, a well was constructed to mimic the shape and characteristics of the original system. This well was designed to mirror the

pipeline's geometry to ensure that it accurately represented the conditions under study. Furthermore, the pressure settings associated with the back-pressure valve, which originally existed at the top of the system, were adjusted to serve as the wellhead pressure. A gas condensate composition was used to construct a new fluid composition system that simulated the behavior of the liquid inside the well. The purpose of this simulated liquid was to replicate the function of the real liquid in the system that was holding up the well. Nodal analysis function was used to plot the line deliverability by using the data of the system. These parameters had been scaled, and a well was constructed using them, as shown in **Figure 9**. Finally, modifications were made by injecting TCF to make use of their ability to produce temperature and pressure, which makes it easier to remove gas condensate that has been building up inside the system. This was done in order to produce conditions that were almost exactly like those that existed during each injection cycle of TCFs, enabling a more precise and representative analysis of the behavior of the system.

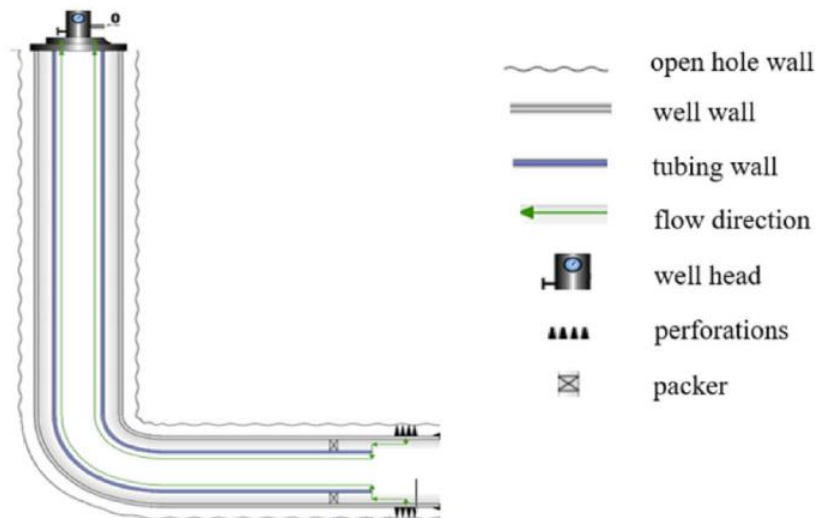


Figure 9: A well-constructed using the system parameters using PIPESIM.

CHAPTER 4

RESULTS AND DISCUSSIONS

In this chapter, the findings are presented and analyzed after applying TCFs in two primary aspects: the artificial maturation of organic-rich shale and the mitigation of liquid loading issues in gas wells. The results are structured according to the distinct experimental phases outlined in the methodology, allowing for a comprehensive understanding of each stage's outcomes.

Firstly, we examine the effects of TCF on the geochemical, petrophysical, and geo-mechanical properties of organic-rich shale samples. The artificial maturation process was expected to accelerate kerogen breakdown, enhancing hydrocarbon potential generation. Results are presented in terms of changes in shale composition, hydrocarbon content, and reservoir properties.

Secondly, we discuss the effectiveness of TCF in resolving liquid loading issues in gas wells. Through both laboratory-scale experiments and simulation models, we explore the impact of TCF injection on liquid removal and pressure regulation within the system, providing insights into real-world applications.

Each phase defined in the methodology is thoroughly discussed, with results interpreted to highlight the efficiency, limitations, and implications of using TCF in these contexts. This structured approach enables a detailed assessment of TCF as a dual-benefit solution in unconventional reservoir enhancement and flow assurance.

4.1 TCF Performance for Pressure and Temperature Generation

To evaluate the performance of TCFs in generating adequate pressure and temperature, TCFs were injected into a closed system where in-situ measurements were taken over a designated observation period. The goal was to assess the capacity of TCF to build sufficient pressure and heat which are the key parameters for the artificial maturation of shale and mitigation of liquid loading in gas wells.

A continuous data collection process recorded pressure and temperature changes over time, allowing a comprehensive view of TCF performance throughout the reaction. **Figure 10** illustrates the measured in-situ temperature and pressure variations, demonstrating that both parameters increased substantially during the reaction. As shown, the temperature rose from an initial value of 160°F to a peak of 600°F, while pressure built up from 100 psi to a maximum of 3100 psi.

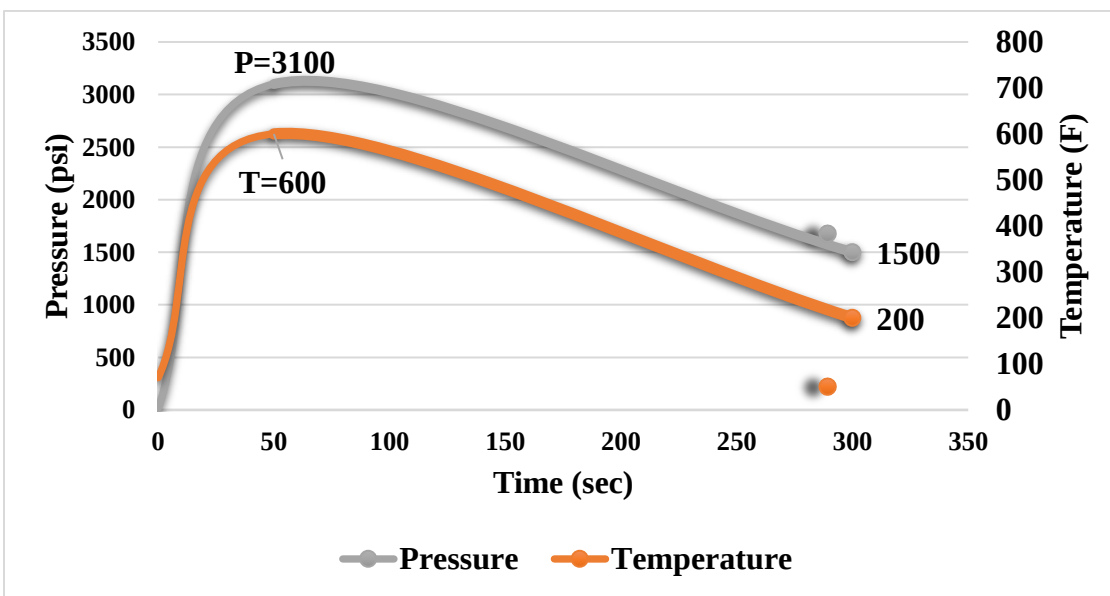


Figure 10: The values of in situ temperature and pressure generated at different times during TCF reaction.

These results confirm that TCFs are highly effective in generating the necessary heat and pressure conditions within a closed environment. The significant increase in temperature is conducive to enhancing kerogen breakdown in organic-rich shale, promoting hydrocarbon release. Simultaneously, the substantial pressure buildup aligns with the requirements for displacing accumulated liquids in the gas wells, indicating TCF's potential to address liquid loading challenges. This performance assessment thus supports TCF as a viable dual-function solution, capable of inducing favorable conditions for both shale maturation and fluid displacement in gas reservoirs.

4.2 TCF Impact on Organic Rich Shale

The impact of TCFs on organic-rich shale was investigated through core flooding experiments designed to simulate in-situ conditions. In these tests, TCFs were injected into shale core samples to evaluate their effectiveness in enhancing hydrocarbon productivity by inducing thermal and pressure changes. Four organic-rich shale samples with distinct fracture characteristics were prepared to evaluate the impact of TCF on various fractured samples. The samples included one intact shale, one artificially fractured by drilling, and two naturally fractured samples with differing fracture intensities. This range of fracture conditions enabled a comprehensive assessment of TCF performance across different structural contexts within the shale. The first sample was intact and almost no fractures were detected. For the first sample, all characterization methods post treatment showed that there were no significant changes to the sample, indicating that the treatment did not cause any petrophysical, geochemical, and geomechanical properties. More discussion is provided below:

4.2.1 Impact on Petrophysical Properties

In this section, the focus is on the analysis of porosity changes in shale samples. Helium Porosimeter was used to measure the porosity of the samples before and after apply the TCF treatment, also micro CT-scan of the samples was conducted to assess the impact on shale samples petrophysical properties.

Figure 11 shows the results of the micro-CT scan of the sample, the images before and after show that there were no significant changes to the samples petrophysical properties. The sample's lack of connectivity restricted fluid penetration, thus preventing in-situ pressure and temperature generation essential for artificial maturation and enhancement of petrophysical characteristics.

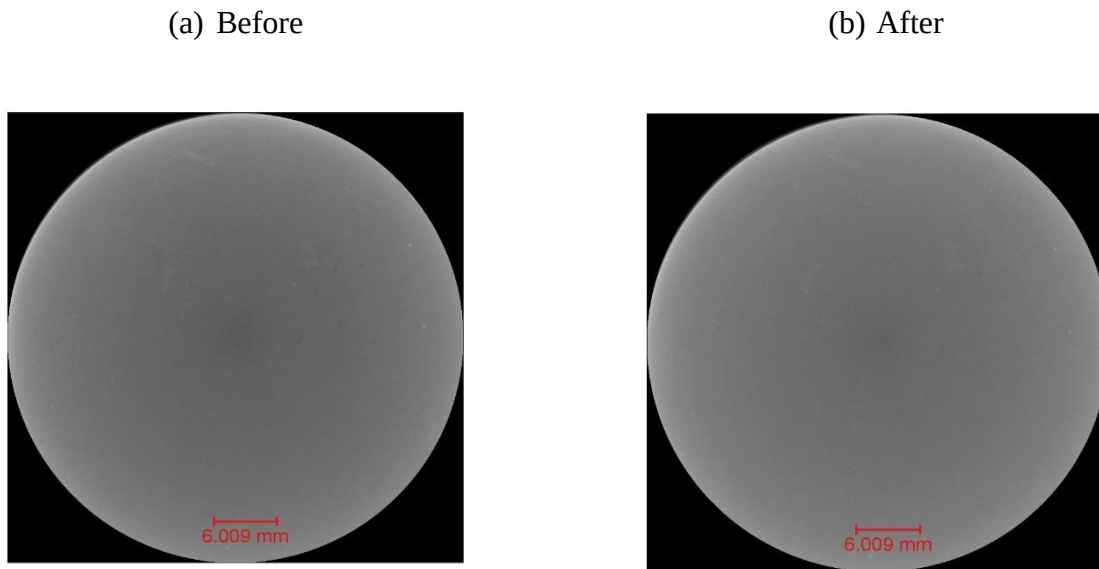


Figure 11: Micro CT scan for sample 1 before and after TCF- assisted maturation.

In Sample 2, an artificial fracture was created by drilling, as illustrated in **Figure 12**. The hole was drilled to act as a man-made fracture to investigate the effect of the fracture on

the responsiveness of the shale sample to the treatment. The sample showed better response and fractures started to appear

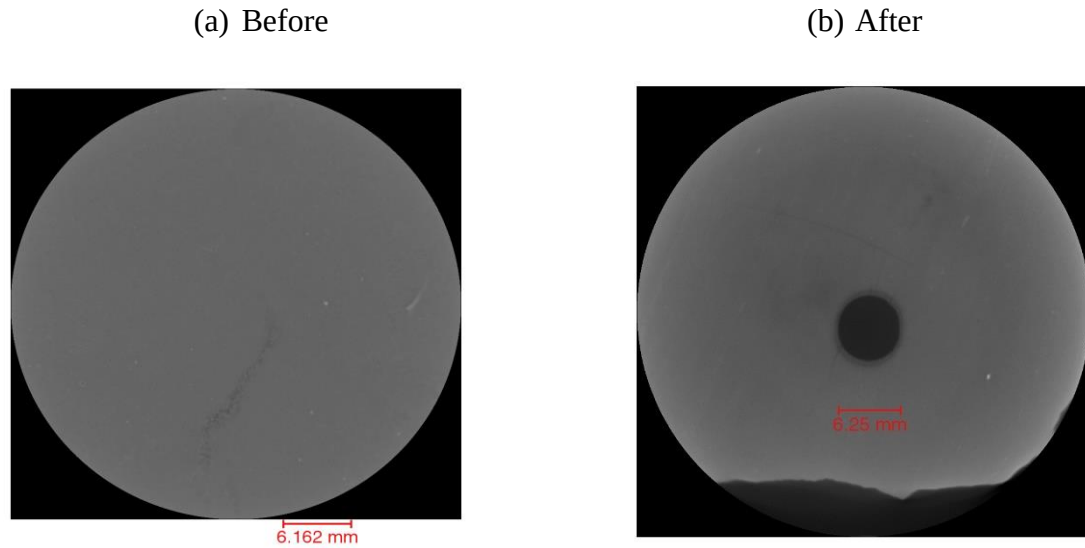


Figure 12: Micro CT scan for sample 2 before and after TCF- assisted maturation.

For Sample 3, which contained moderate natural fractures with higher intensity than Sample 2, as shown in **Figure 13**. This increased response highlights the influence of natural fractures in facilitating TCF treatment effectiveness. Moreover, the samples were segmented before and after applying TCF treatment (depicted in **Figure 14**) and we can see that the fractures volume increased. The volume of fractures was 16.3% of the samples total volume before the treatment, while after the treatment it increased to 27.7%, the total increase was 70%. The enhanced porosity in this sample suggests that moderate fracture intensity promotes better TCF fluid reactions within the pores and fractures of the samples, resulting in notable maturation and structural changes within the shale.

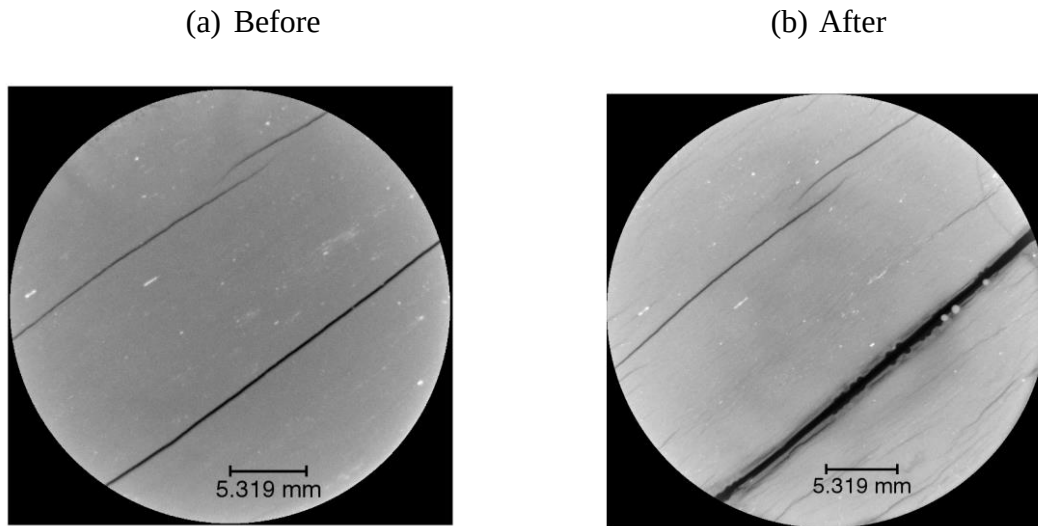


Figure 13: Micro CT scan for sample 3 before and after TCF- assisted maturation.

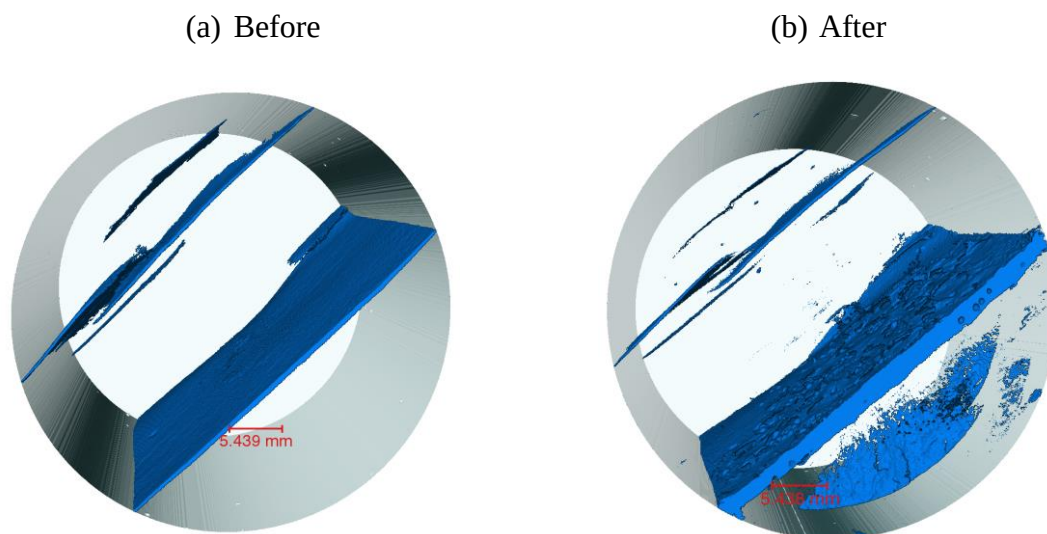


Figure 14: Micro CT scan segmentation for sample 3 before and after TCF- assisted maturation.

Sample 4, which had the highest natural fracture intensity (**Figure 15**), showed the greatest responsiveness to TCF treatment. The treatment resulted in the formation of new fractures and yielded improved outcomes, as will be discussed in subsequent sections.

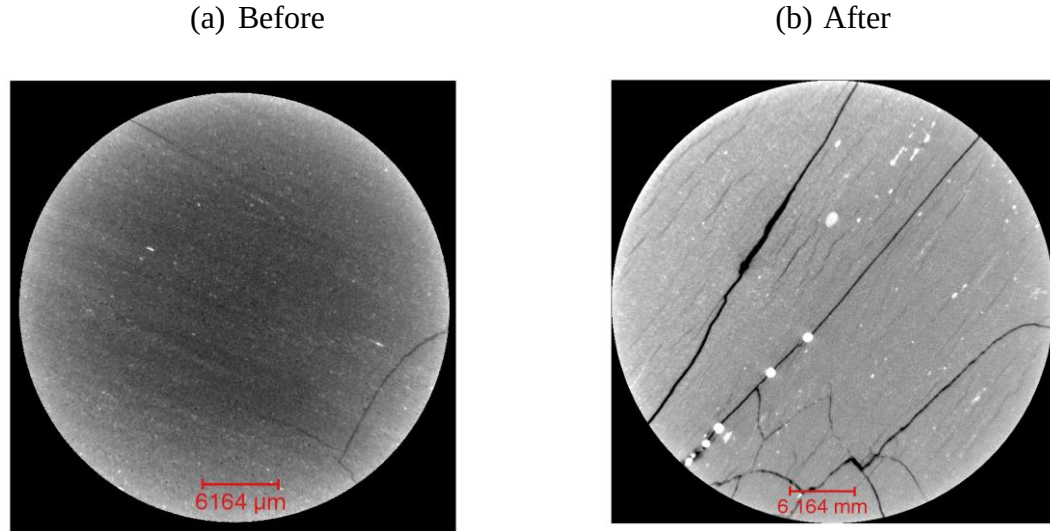


Figure 15: Micro CT scan for sample 4 before and after TCF- assisted maturation.

The effectiveness of the TCF treatment on the shale samples was significantly influenced by their fracture intensity, with more fractured samples exhibiting a greater impact from the treatment. Samples with higher natural fracture density provided more pathways for the TCF to penetrate, react, and generate heat and pressure within the pores. This facilitated the development of additional microfractures and enhanced porosity, resulting in improved hydrocarbon generation and fluid mobility. In contrast, samples with lower fracture intensity demonstrated a more limited response to the treatment due to restricted fluid penetration. **Figure 16** below presents the micro-CT scan images of the samples, illustrating the variation in fracture intensity and highlighting the extent to which TCF treatment enhanced the internal structures of the samples. These findings underscore the critical role of pre-existing fracture networks in determining the efficacy of TCF treatment.

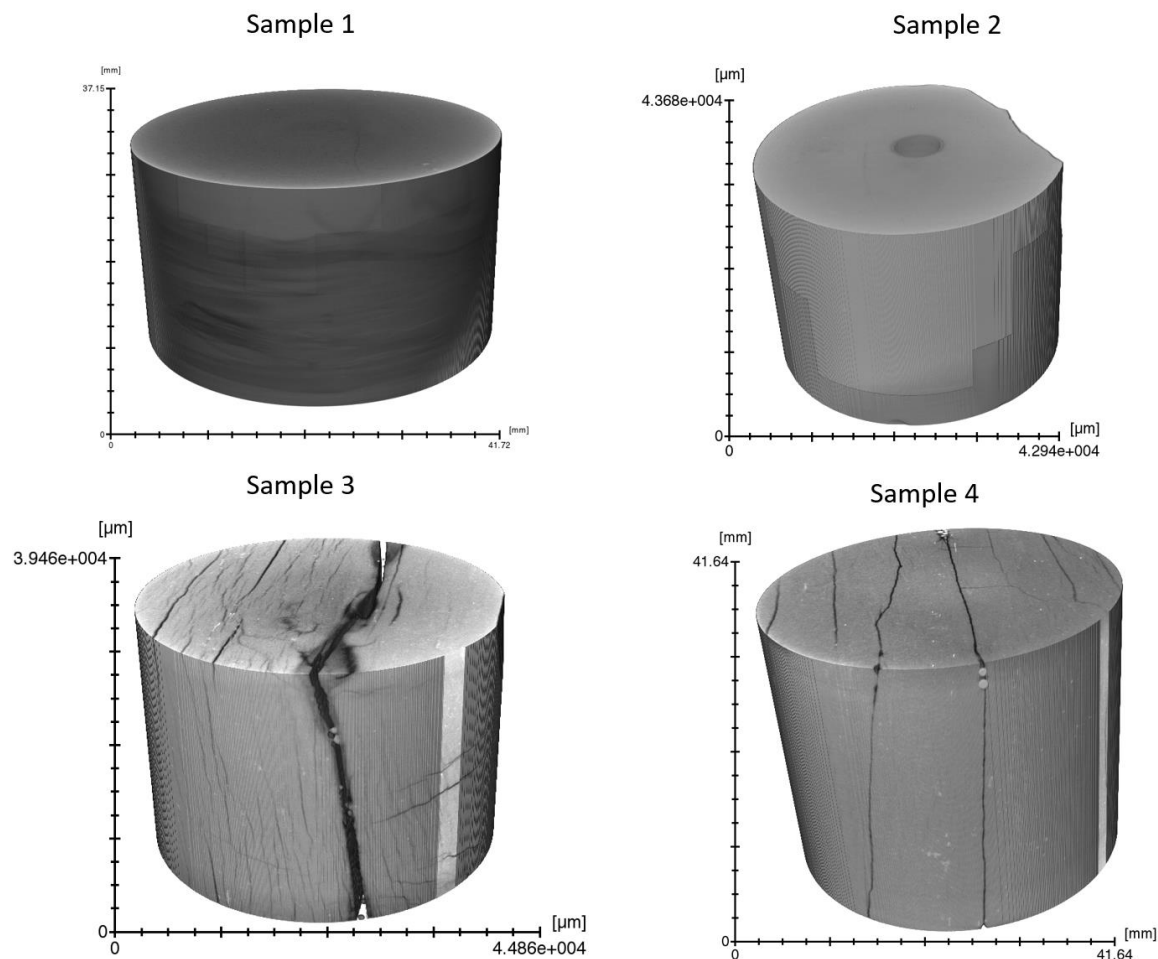


Figure 16: Micro CT-scan 3D images of the shale samples.

The porosities of the samples were measured before and after TCF treatment using a helium porosimeter. The results, as shown in **Table 5** below, indicate an increase in the initial porosity of the samples following the treatment. This increase can be attributed to the thermochemical fluid (TCF) reacting within the pores, which led to the creation of microfractures, improved conductivity, and an overall increase in the size of existing pores. The expansion of pore sizes is primarily due to the conversion of organic matter residing in these pores into hydrocarbons, a process facilitated by the TCF treatment. This conversion not only enhances the pore network but also contributes to the overall increase

in porosity. The detailed implications of this conversion and its connection to hydrocarbon generation will be discussed further in the geochemical properties section.

Table 5: Porosity of the samples pre and post TCF treatment.

Sample	Porosity (%)	
	Before	After
1	1.4	1.3
2	8.8	9.7
3	11.3	13.1
4	15.2	18.2

4.2.2 Impact on Geochemical Properties

In this section, the interpretations of the Rock Eval results were carried out to evaluate the HI, $T_{\max}$, TOC, S1, and S2 of the samples. These factors were used to provide a description of the impact of the TCF treatment. Each parameter provides insight into the organic richness, hydrocarbon production potential, and effectiveness of TCF treatment on shale samples.

4.2.2.1 Kerogen Typing

To analyze kerogen types and maturation levels, HI values against $T_{\max}$ values were plotted for each sample, before and after TCF-assisted artificial maturation. In kerogen typing, HI (y-axis) and $T_{\max}$ (x-axis) are typically plotted in a scatterplot to distinguish kerogen types and assess maturity levels (Hart and Steen, 2015; Adesina et al., 2017; Amjed et al., 2024). As shown in **Figure 17**, the used samples primarily fall between the kerogen Type I and Type II regions, indicating a tendency toward oil-prone kerogen, which is known for its high potential in hydrocarbon generation. Samples 2, 3, and 4 demonstrated higher

responsiveness to TCF-induced artificial maturation compared to Sample 1, evidenced by a more significant shift in their HI and $T_{\max}$ values.

The initial high HI and relatively low $T_{\max}$ values suggest that the samples have high-quality shale with substantial hydrocarbon-generating potential. Post-treatment, a decrease in HI and an increase in $T_{\max}$ values were observed, indicating increased thermal maturity as the kerogen progresses toward the oil window. Sample 1 exhibited minimal change in its HI, with almost no variation in $T_{\max}$, suggesting that the thermal maturity of the sample remained unchanged. In contrast, Samples 2, 3, and 4 demonstrated more significant changes in both HI and $T_{\max}$, indicating an increase in their thermal maturity. For Sample 2, the HI decreased from 769 to 649, while the $T_{\max}$ increased from 412°C to 436°C. Sample 3 exhibited even greater changes, with the HI decreasing from 754 to 657 and the $T_{\max}$ increasing from 410°C to 432°C. Finally, Sample 4 showed the most substantial changes, as the HI decreased from 759 to 606 and the $T_{\max}$ increased from 413°C to 445°C. These variations reflect the progressive thermal transformation of organic matter within the samples, with greater changes in HI and $T_{\max}$ correlating to a higher degree of thermal maturity. To further validate these maturity changes and the associated hydrocarbon generation, additional geochemical parameters were analyzed in the upcoming sections, providing supportive evidence for the enhanced hydrocarbon yield potential in these samples.

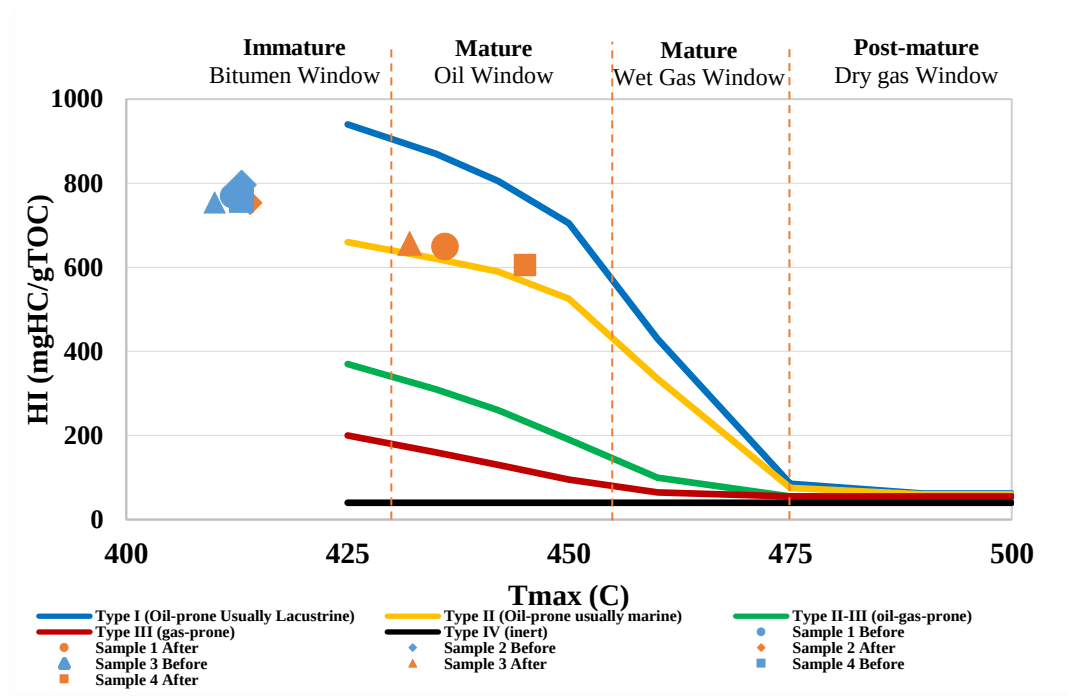


Figure 17: Kerogen typing for the shale samples before and after TCF maturation.

4.2.2.2 Total Organic Carbon

The TOC values indicate the organic carbon percentage of the samples, which is associated with the amount of kerogen in them. Different responses to TCF treatment are observed between the unfractured and fractured samples, as shown in **Figure 18**. The first sample, which has no fractures, shows minimal change in TOC, with only a slight reduction of about 3 % from its initial value. Specifically, the TOC decreased from approximately 14.34 to 13.88 wt.% at the inlet section, while the middle and outlet sections of the sample exhibited no significant change. This limited reduction suggests that the TCF treatment did not fully penetrate the sample's internal structure, likely due to its low permeability, which restricts fluid flow through the sample matrix. In contrast, the other three samples, which were fractured, show substantial reductions in TOC, indicating that the TCF treatment was

effective in accelerating kerogen maturation within these samples. TOC reductions range between 18 and 42 %, and there is a clear relationship between fracture intensity and TOC reduction. The second sample, which has a hole drilled at the center, shows a moderate reduction in TOC from 12.92 to 10.51 wt.%, suggesting partial fluid penetration. The third sample, which has medium-intensity natural fractures, shows a decrease from 12.96 to 9.59 wt.%, reflecting a more pronounced effect as the fractures allow improved fluid entry and reaction with the kerogen body. The fourth sample, which is highly fractured, exhibits the greatest TOC reduction from 15.74 to 9.17 wt.%, supporting the idea that increased fracture intensity enhances fluid penetration, facilitating substantial organic matter conversion. These observations suggest that TCF treatment primarily impacts TOC in samples with sufficient permeability or induced fractures, as greater TOC reductions are associated with better fluid access.

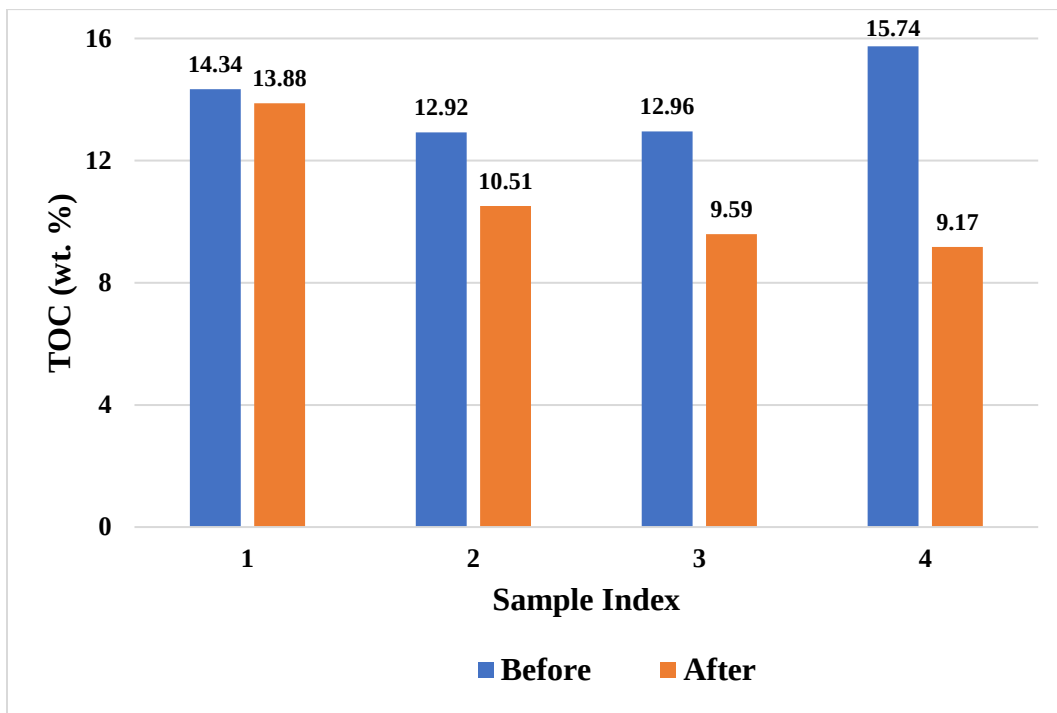


Figure 18: The TOC values for the shale samples before and after TCF treatment.

4.2.2.3 Volume of Generated Hydrocarbons

The S1 parameter measures the free hydrocarbons generated in the samples, providing an indication of the hydrocarbons readily available for production (shown in **Figure 19**). The analysis of S1 values shows minimal change in the unfractured sample with an increase of only around 10% at the inlet only, similar to the TOC results, suggesting that low permeability limited the penetration of TCF fluids. In contrast, all fractured samples display a substantial increase in S1 values in the range of 80% to 130%, aligning with the TOC reductions observed earlier. This increase in S1 suggests that kerogen was transformed during TCF treatment, resulting in hydrocarbon generation. The second sample shows a moderate increase in S1 (82.3%), correlating with its relatively low fracture intensity. The third and fourth samples, however, reveal progressively larger S1 increments of around 106.8% and 129.8% respectively, matching their higher fracture intensities and thus better fluid access. This increase in generated hydrocarbon volume is a clear indicator of effective kerogen conversion, with highly fractured samples allowing TCF fluids to flow, react, and generate hydrocarbons, resulting in a measurable S1 value increase.

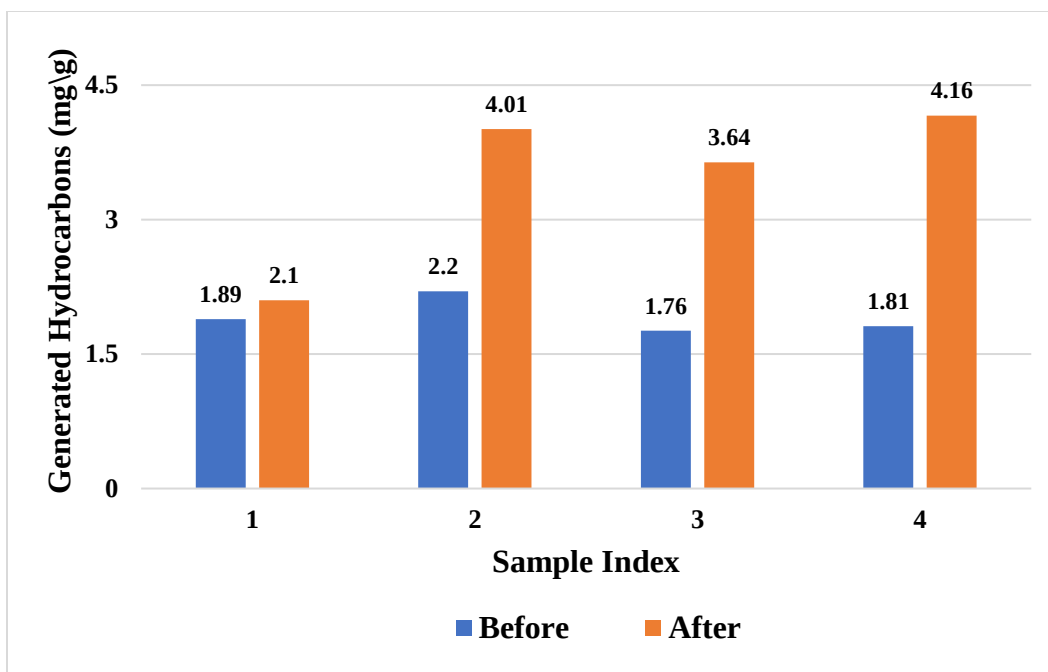


Figure 19: The volume of free hydrocarbons (S1) in shale samples before and after TCF treatment.

4.2.2.4 Volume of Potential Hydrocarbons to be Generated

The S2 values which are shown in **Figure 20** represent the potential amount of hydrocarbons that might be generated from the samples if the treatment continued, derived from kerogen that has not yet been transformed into hydrocarbons. High S2 values are generally indicative of greater potential for hydrocarbon generation upon additional thermal treatment. In the unfractured sample, the S2 value remains relatively unchanged, due to the absence of fractures that impact TCFs treatment on kerogen within this sample. Conversely, the fractured samples exhibit a significant decrease in S2 values post-treatment (15% to 30%), suggesting effective kerogen conversion. The second sample shows a moderate reduction of around 16%, consistent with its previous TOC and S1 results, which provided some access for TCF treatment. The third and fourth samples, with medium and

high degrees of fracturing, demonstrate the largest S2 reductions, 20% and 27%, respectively. This pattern suggests a more extensive transformation of kerogen in samples with enhanced fluid penetration, reducing the sample's remaining hydrocarbon-generating potential. A reduction in S2 after TCF treatment signifies successful kerogen conversion into hydrocarbons, with more significant changes observed in samples with better fluid access.

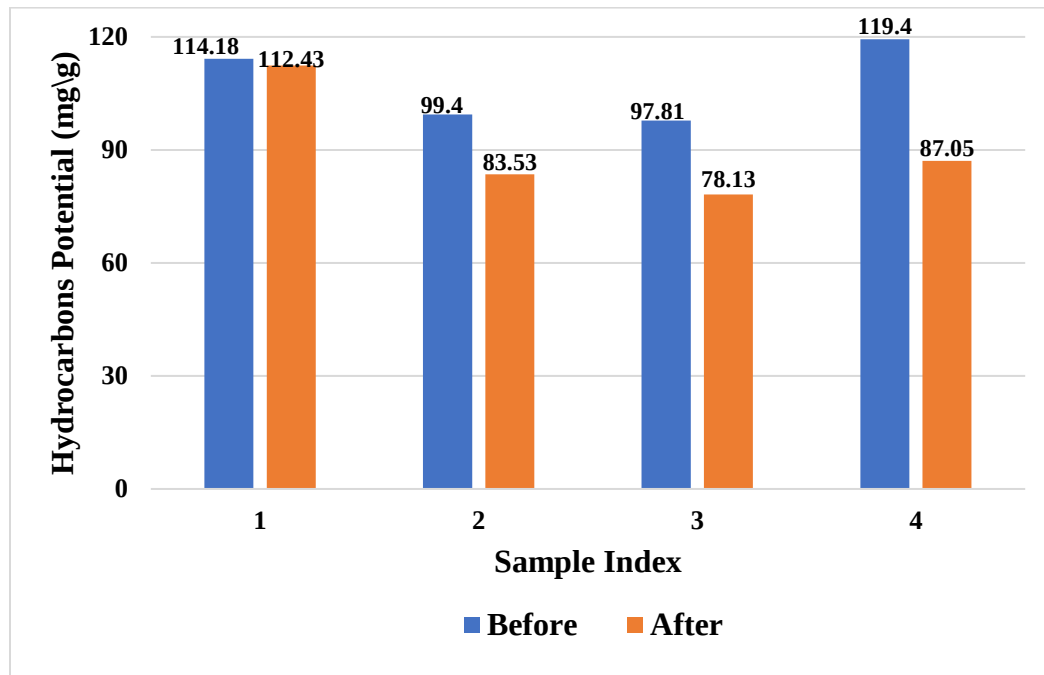


Figure 20: The volume of potential hydrocarbon generation (S2) for shale samples before and after TCF treatment.

In summary, the Rock-Eval data reveal that TCF treatment is most effective in fractured samples. Samples with intense fracturing exhibit the highest reductions in TOC, S1, and S2, indicating substantial kerogen transformation into hydrocarbons. This transformation is facilitated by improved fluid access through fractures, which enables the TCF fluids to penetrate and react within the sample matrix. The results highlight that the efficacy of TCF

treatment depends on the sample fracture intensity, which is essential to maximizing organic matter breakdown and hydrocarbon yield.

4.2.2.4 Gas Chromatography Analysis Results

Gas chromatography (GC) was employed to analyze the effluents collected from the core flooding experiments following treatment with TCF. The purpose of this analysis was to validate the generation of hydrocarbons during the artificial maturation process. **Figure 21** presents a visual representation of one of the effluent samples, where traces of hydrocarbons can be observed. However, to confirm and quantify these hydrocarbons, GC was utilized for a more precise chemical analysis.



Figure 21: Sample of the collected effluents of core flooding following TCF treatment.

The GC results revealed that the carbon fractions in the effluents were predominantly concentrated in the middle range (as seen in **Figure 22**), which is characteristic of light

hydrocarbons. These light hydrocarbons are typically generated during kerogen maturation due to the breakdown of complex organic matter under the heat and pressure conditions induced by TCF treatment. The presence of these hydrocarbons is significant as they are widely used in various applications, including energy production, petrochemical manufacturing, and as raw materials in everyday products like fuels and solvents.

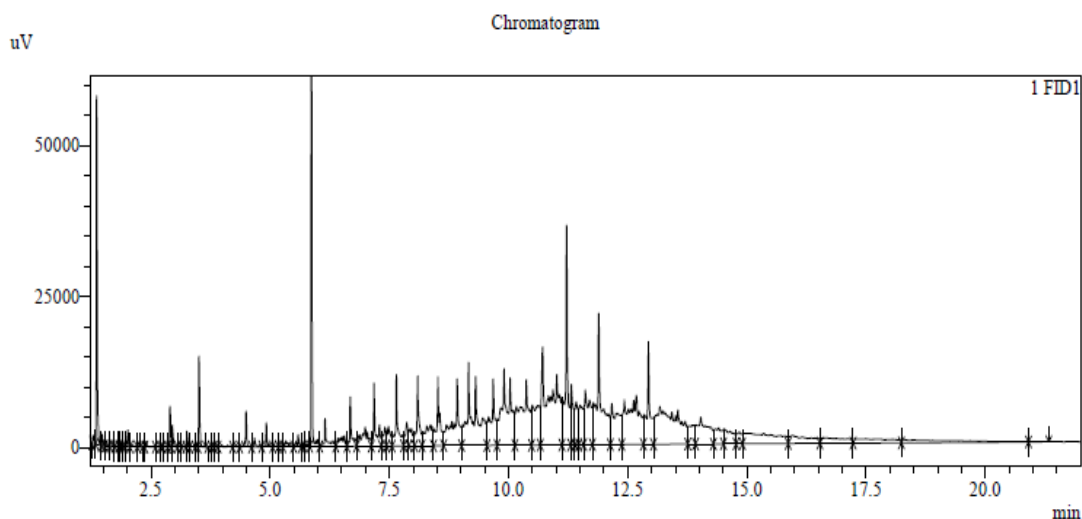


Figure 22: Gas chromatography analysis result for the core flooding effluent after TCF treatment.

The results not only demonstrate the effectiveness of TCFs in generating hydrocarbons from organic-rich shale but also emphasize its potential to enhance hydrocarbon recovery in unconventional reservoirs. The generation of light hydrocarbons further underscores the sustainability of this process, as these compounds are highly valuable in the energy sector and industrial applications. This finding provides compelling evidence that TCF treatment is a promising approach for enhancing resource recovery while simultaneously producing usable hydrocarbon fractions.

4.2.3.1 XRD and XRF Analysis

The effects of TCF on the mineralogical and elemental composition of the shale samples were analyzed through XRD and XRF techniques, with the results summarized in

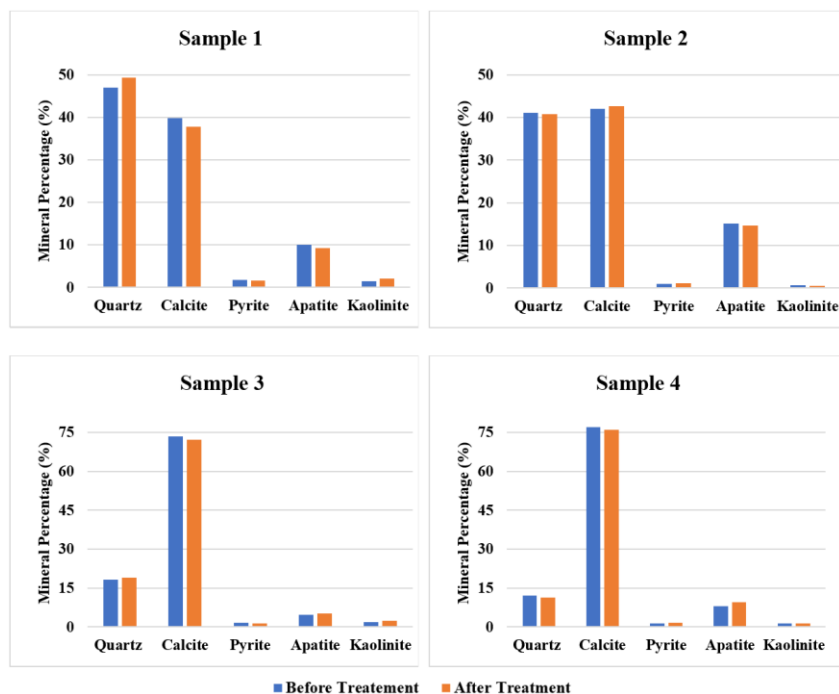


Figure 23: XRD results for the shale samples before and after the treatment. and **Table 6**, respectively. Both XRD and XRF data were obtained before and after TCF treatment to detect any alterations in mineral and elemental composition. Post-treatment analysis revealed negligible changes in the XRD and XRF results, indicating that the TCF application did not alter the primary mineral phases or elemental makeup of the shale. This stability suggests that TCF can effectively enhance hydrocarbon generation without compromising the rock integrity of the shale formations. These findings highlight TCF's potential for applications in unconventional reservoirs, which is done by preserving the natural mineral structure and elemental balance is crucial for maintaining long-term reservoir integrity and environmental standards.

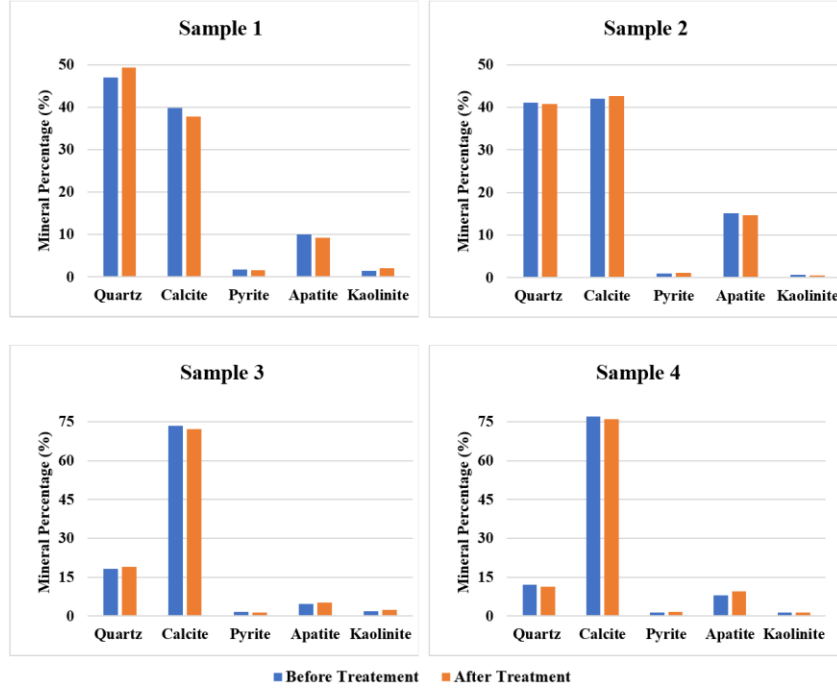


Figure 23: XRD results for the shale samples before and after the treatment.

Table 6: XRF results for the shale samples before and after the treatment.

Main Element	Mg		Al		Si		Ca		S		Fe	
Sample	Before	After	Before	After	Before	After	Before	After	Before	After	Before	After
1	0.63	0.6	5.65	5.4	31.2	31.3	38.9	39.4	11.2	11.0	7.3	7.5
2	0.66	0.63	3.84	3.97	26.16	25.50	47.55	47.21	11.15	11.47	4.53	4.90
3	0.43	0.45	6.00	5.87	18.09	18.85	55.03	55.43	10.19	10.03	6.76	6.36
4	0.15	0.17	4.08	4.88	11.63	11.01	60.56	60.37	12.32	12.52	6.73	6.86

4.2.3 Impact on Geomechanical Properties

In this section, we used the inorganic geochemical test XRD and XRF to assess the geomechanical properties changes of the shale core samples before and after treatment with TCF, interpreting the effects of the treatment on these properties. Moreover, the compressional and shear velocities were also measured and estimated to give insights into the geomechanical properties by calculating the brittleness index.

4.2.3.2 Compressional and Shear Velocities

The compressional velocity (V_p) of the shale samples was measured using the NER benchtop device. From these compressional velocity measurements, we estimated the shear velocity (V_s) of the samples using Castagna's empirical formula (**Equation 7**) for shales (Castagna et al., 1985):

$V_s = 0.86 \times V_p - 1.172$	7
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where both V_s and V_p are expressed in km/s. This empirical relationship provides a reliable approximation for shear wave velocity in shales, particularly useful when direct V_s measurements are unavailable.

We then analyzed the V_p/V_s ratio, a key parameter in interpreting geomechanical characteristics of rock formations (Castagna et al., 1985). **Table 7** below displays the V_p/V_s ratios for each sample, both before and after TCF treatment. Notably, the ratio increased post-treatment for the samples that were more responsive to the treatment (2, 3, and 4), indicating a rise in fracturing within the rock matrix. This increase is likely attributed to the internal pressure generated by nitrogen within the pore spaces, as fractures are known to reduce shear wave velocity more significantly than compressional velocity. Furthermore, the thermal stress induced by TCF, due to heat generation during treatment, has contributed to microfracture development, further elevating the V_p/V_s ratio.

Table 7: Values of the ratio V_p/V_s used for interpreting the geomechanical properties of shale samples.

Sample	V_p/V_s	
	Before	After
1	2.06	2.07

2	2.27	2.49
3	2.04	2.63
4	2.07	2.68

4.2.3.3 Poisson's Ratio

Another crucial metric for evaluating the geomechanical behavior of the shale samples is Poisson's Ratio (ν). Poisson's ratio is a fundamental parameter in geomechanics, offering valuable insights into the elastic properties and deformation behavior of rocks under stress. In the context of organic-rich shale, this ratio is particularly significant as it reflects how the material responds to stress-induced changes in its volume and shape. The Poisson's ratio is essential for understanding the geomechanical properties of shale formations, especially when assessing their ability to withstand subsurface stresses during hydrocarbon production or reservoir stimulation processes. For this study, we estimated Poisson's Ratio using Mukabi et al., (2008) formula, which is shown in **Equation 8** below:

$\nu = 0.5 \times \left[\frac{V_p}{V_s} \right]^2 - 1 / \left[\frac{V_p}{V_s} \right]^2 - 1$	8
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Table 8 below presents the estimated Poisson's ratio for the shale samples before and after TCF treatment. These measurements provide a comparative analysis of how the samples reacted to the TCF application. The data indicate that the samples which responded to the treatment exhibited an increase in Poisson's ratio post-treatment. This observed increase can be attributed to two key mechanisms induced by the TCF treatment: thermal stress and the generation of microfractures.

Table 8: Values of the Poisson's Ratio used for interpreting the geomechanical properties of shale samples.

Sample	Poisson's Ratio (ν)	
	Before	After
1	0.35	0.35
2	0.38	0.40
3	0.34	0.42
4	0.35	0.42

Thermal stress plays a crucial role in altering the geomechanical behavior of the treated shale. During TCF treatment, the injected fluids generate heat, resulting in localized thermal expansion and stress within the rock matrix. This thermal stress can lead to a redistribution of the rock's internal structure, increasing its ductility and modifying its elastic properties, thereby contributing to the observed rise in Poisson's ratio. Additionally, the generation of microfractures within the rock due to TCF treatment further influences the Poisson's ratio. The creation of microfractures alters the rock's mechanical framework, enhancing its ability to accommodate deformation without significant volumetric changes. This phenomenon leads to a more pronounced lateral expansion relative to axial compression under stress, resulting in an increased Poisson's ratio. The presence of these microfractures also suggests improved fluid mobility within the rock, a desirable characteristic for hydrocarbon production and unconventional reservoirs stimulation.

The results underscore the impact of TCF treatment on the geomechanical properties of organic-rich shale. By increasing Poisson's ratio, the treated samples exhibit modified elastic behavior that improve their performance during reservoir operations. These findings

highlight the potential of TCF treatments to enhance not only hydrocarbons productivity but also the mechanical resilience of shale formations, making this a valuable approach for optimizing unconventional reservoir development.

4.3 TCF Impact on Removal of Liquid Loading

4.3.1 Initial Conditions

The experimental system was configured with gas condensate holding up the line, and the gaseous phase was introduced from the nitrogen gas cylinder. Additionally, a back-pressure valve served to act as the wellhead pressure. Subsequently, it was observed that the supplied gas proved incapable of displacing the liquid filling the line, effectively functioning as a reservoir in the case of liquid loading. This cylinder/reservoir's pressure was unable to surpass the pressure exerted within the well by the gas condensate accumulation. In the next steps, TCF was injected into the system to generate pressure and temperature that can lead to removing the liquid loading and enabling gas production.

4.3.2 Removal Efficiency

In this section, the main goal is the evaluation of the performance of TCF for liquid loading removal, the system was filled with gas condensate at 50%, 60%, and 70% of its total volume. The pressure profiles over time for each injection cycle, along with the corresponding removal efficiencies, are presented in **Figure 24**, **26**, and **Figure 2628**, respectively.

The sequence of steps required to remove 50% of the gas condensate volume obstructing the system's gas production are demonstrated in **Figure 24**, and three cycles were needed

for this purpose. The first cycle removed 15% of the condensate volume and increased pressure to about 2460 psi, as seen in **Figure 25**. The pressure then increased to about 2525 psi during the second cycle, and the volume removed increased to 65%. This shows that 50% of the gas condensate volume that was initially in the system was successfully removed by the second cycle. The pressure increased to approximately 2800 psi and more than 97% of the volume was removed in the third cycle. The reason for variations in the amount of condensate extracted in every cycle is due to the pressure buildup induced by the injection of more TCF into the system. The volume of injected TCF matches the initial 50% condensate fill level since the system is initially filled to 50% capacity. The volume of condensate removed is added to the thermochemical fluid injection in the second cycle after the first cycle, in which 15% of the condensate was removed. As a result, in the second cycle, the injected volume of TCFs was more than the one from the previous cycle, hence increasing the amount of pressure and temperature generated with each cycle.

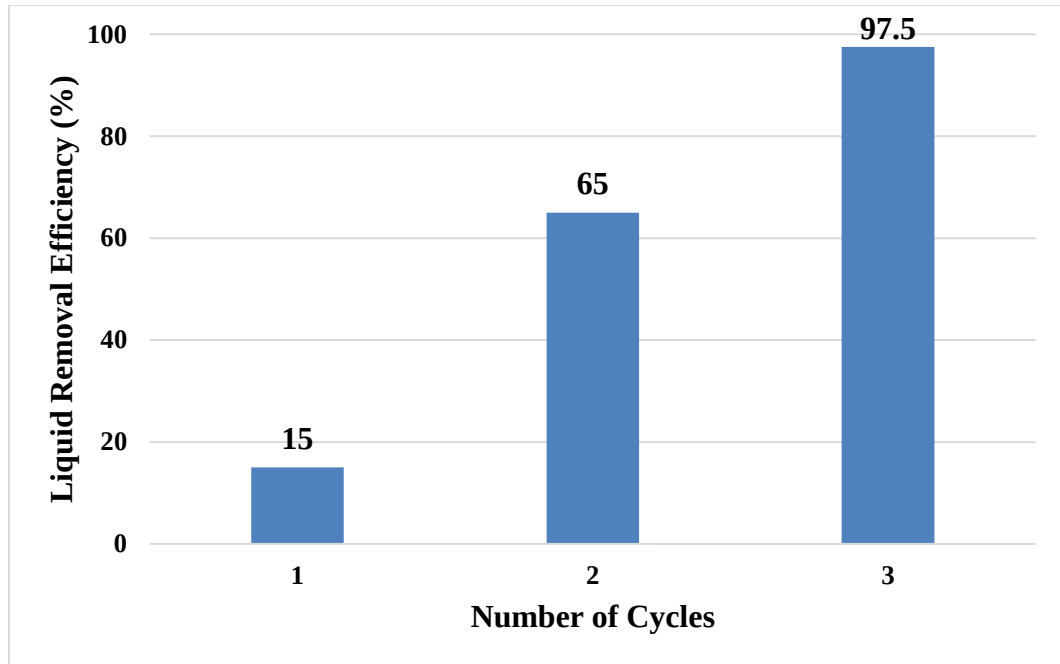


Figure 24: Removal efficiency of the first case where the liquid loading volume occupied 50% of the capacity of the system.

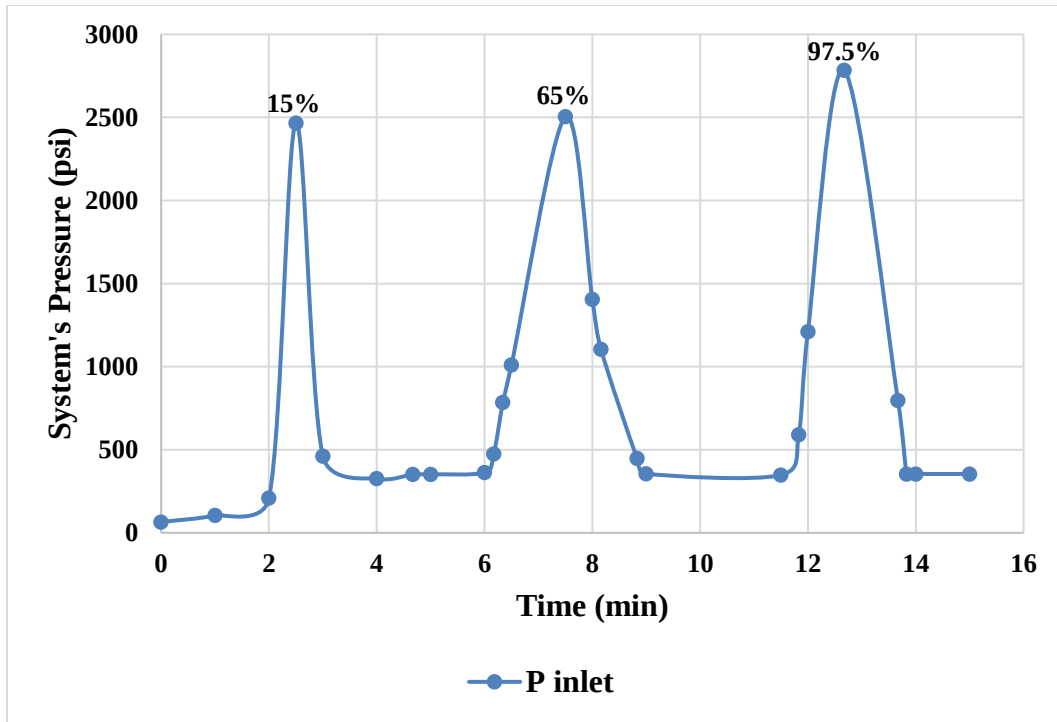


Figure 25: Pressure of the first case where the liquid loading volume was occupying 50% of the capacity of the system.

Figure 26 illustrates the removal efficiency of four cycles that were injected to remove 60% of the liquid volume that was obstructing the gas production system. In order to reach sufficient removal efficiency, an additional cycle was found essential. **Figure 27** shows that 17% of the condensate volume was removed during the first cycle, which increased the pressure to about 1200 psi. Later, during the second cycle, the pressure rose to about 1250 psi while the condensate volume was decreased by 31.25%. In the third cycle, the pressure increased to about 1580 psi, which caused 73% of the volume to be removed. To improve the removal efficiency, a final cycle was implemented where the pressure was to 2460 psi and more than 95% of the liquid loading was removed. The pressure buildup caused by the addition of more TCF to the system is responsible for the improvement in

condensate removal during each cycle. The goal is to fill the system with condensate and TCF at each cycle. Initially, 60% of the system's volume was occupied by gas condensate, while the remaining 40% was filled with the injected TCFs. Each cycle of TCF injection resulted in the removal of additional condensate, progressively increasing the available volume for subsequent TCF injections. This cyclic injection process enhanced the generation of pressure and temperature with each cycle, significantly aiding in the deliquification of the well.

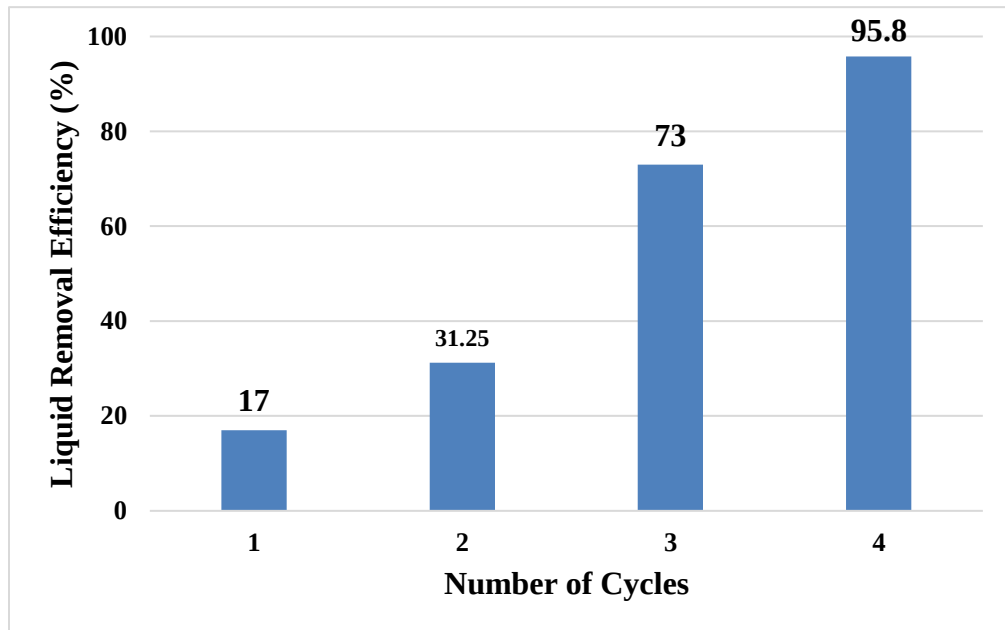


Figure 26: Removal efficiency for the second scenario with a liquid loading volume that filled 60% of the system's capacity.

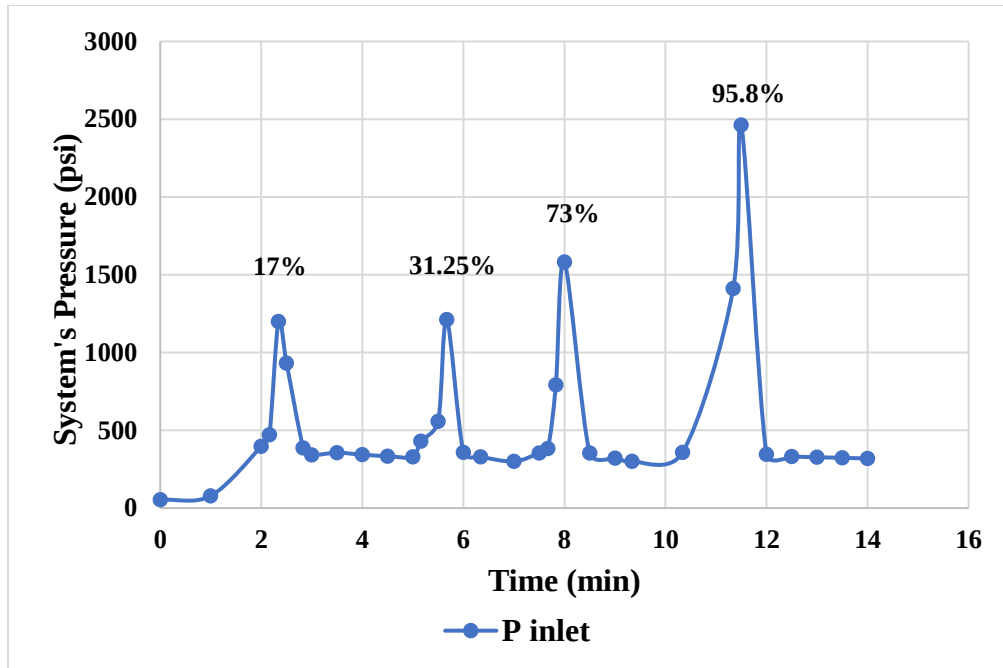


Figure 27: Pressure profile against time and the volume removed at each cycle for the second scenario with a liquid loading volume that filled 60% of the system's capacity.

Figure 28 demonstrates the cycles needed to eliminate 70% of the liquid volume obstructing the production of gas from the system. In this case, five cycles were required to achieve sufficient removal efficiency. **Figure 29** demonstrates that 14.3% of the condensate volume was extracted in the first cycle, which resulted in a pressure increase to about 900 psi. The pressure then rose to about 1000 psi during the second cycle, which was accompanied by a 21.4% increase in the removed volume. In the third cycle, the pressure increased to around 1100 psi, which caused about 45% of the volume to be removed. A pressure of about 1600 psi and an extraction of over 70% of the condensate volume were obtained in the fourth cycle. The pressure rose to 1840 psi during the final cycle, allowing for the targeted removal efficiency and the removal of 91% of the liquid loading. The variation observed in the amount of condensate collected during each cycle is attributed to

the pressure increase caused by the injection of more TCF into the system. During each cycle, as previously explained, the system should be fully saturated with condensate and TCF. At the start, gas condensate occupied 70% of the system's volume, with the remaining 30% filled by TCF. Each TCF injection cycle removed a portion of the condensate, creating additional space for subsequent injections. This process progressively increased the pressure and temperature generated, playing a crucial role in effectively deliquifying the well.

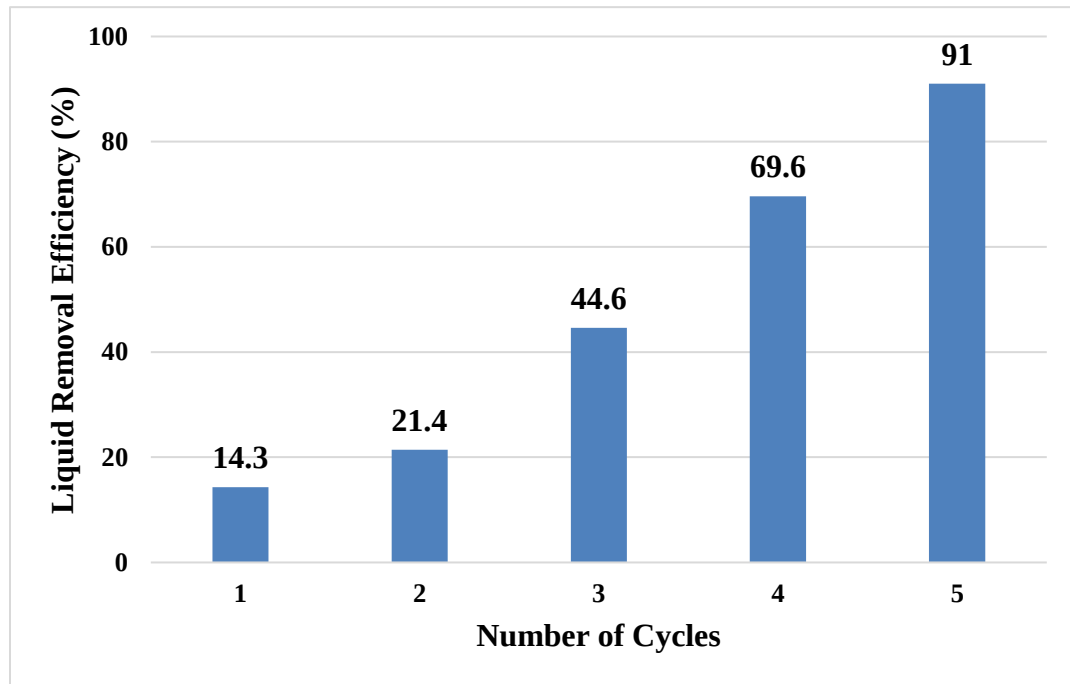


Figure 28: Efficiency of removal for the third case where 70% of the system's capacity was filled with condensate.

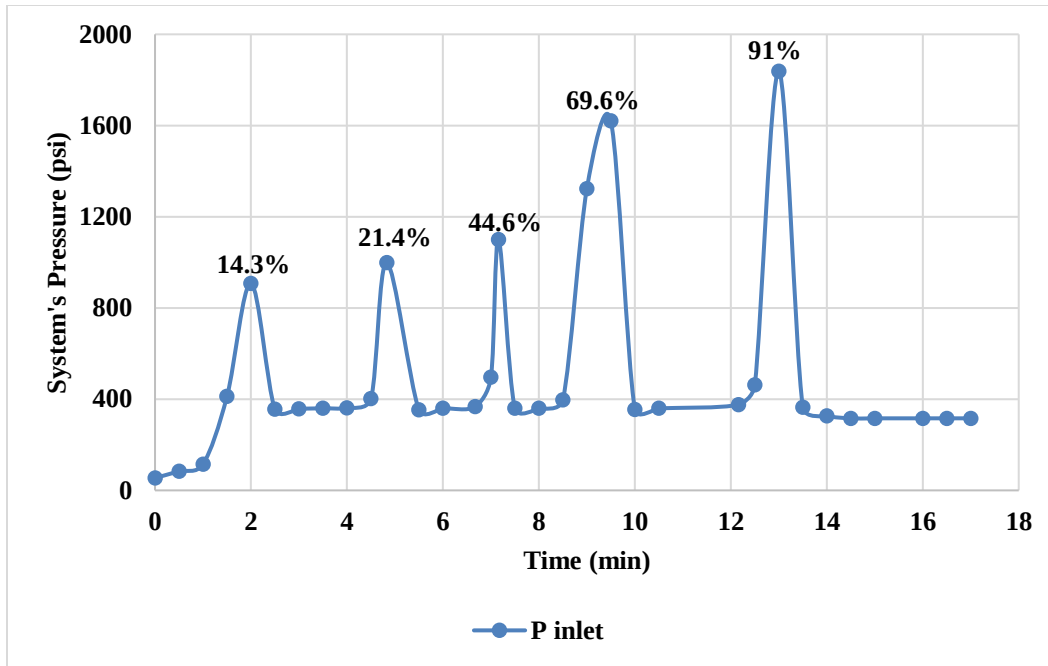


Figure 29: Pressure profile versus time and volume removed at each cycle for the third case where 70% of the system's capacity was filled with condensate.

Figure 28 show that as the liquid volume loading the system decreases with each cycle, the pressure peaks are shown to grow over time (from left to right). The gradual increase in thermochemical fluid volume that was injected into the system with each cycle is the driving force behind this trend. The system is designed to maintain full occupancy while gas condensate is extracted throughout each cycle, which means that extra TCFs are injected to replace the volume of gas condensate that has been removed. In every cycle, a rise in pressure peaks was observed because the volume of TCF injected increased, and more pressure was generated. The figures above show that the more the volume of the liquid holding up the system, the more cycles of TCF injection are required to remove it. The first cycle reaction seems to have not generated enough gas/pressure to enable the overcoming of liquid column pressure. It is evident that an increased number of injection cycles enhances removal efficiency, as it is more probable for the generated pressure to

alleviate well loading. In all of the scenarios, the condensate's mobility was enhanced, and its removal from the system was made simpler by the decrease in viscosity, which was achieved by the heat produced by the reaction of the TCFs.

4.3.3 Fate of Reaction Residuals

Sodium chloride and water were produced as a result of the chemical reaction. **Equation 5** can be used to calculate the amount of salt by using the chemical process. The used chemical concentration is 1 molar for each reactant. The reaction model has an order of one, which means that 1 mole of the reactants can produce 1 mole of the products. Therefore, for every milliliter of injected fluid, 1 mole of NaCl is created, or around 0.058 g. But because 2 moles of hot water are produced for every mole of NaCl (refer to the chemical reaction), the NaCl that is produced is entirely dissolved. Together with the gas condensate that was loading the system, water, and sodium chloride were produced for each experiment.

4.3.4 Deliverability Enhancement

To assess the validity of the methodology utilized, the data were transferred to PIPESIM to simulate the mechanisms occurring in the system. Below is the first case presentation of the results that were acquired from the software. Plotting the inflow performance relationship (IPR) and vertical lift performance (VLP) showed that no operating point was reached while the well was suffering from gas condensate accumulation. **Figure 30** provides a graphic representation of the VLP and IPR in the initial condition where the system was facing a liquid loading issue. Significantly, there was no intersection between the VLP and IPR curves, indicating that the well was non-flowing. The well's operational

flow is obstructed by the presence of gas condensate holdup, which is the cause of this no-flow condition.

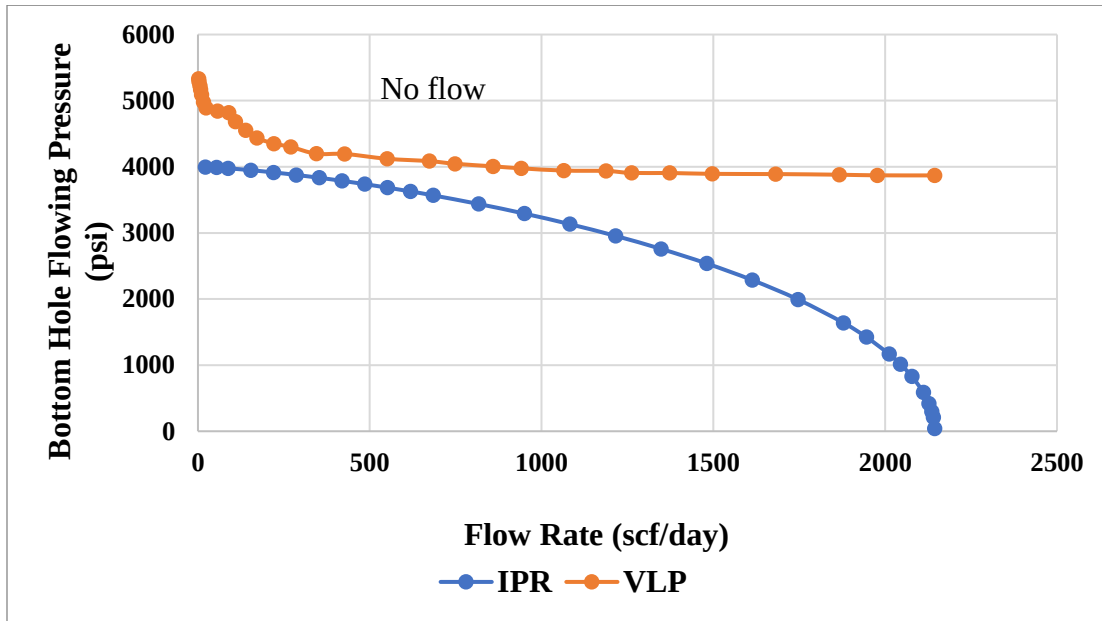


Figure 30: Well deliverability of the well in its initial condition when liquid loading took place.

Then, the reduction in the well hydrostatic pressure was calculated, and the change of the VLP curve was replotted after each cycle (as shown in **Figure 31 - 33**) to have a better understanding of the efficiency of TCFs in enhancing the well deliverability. **Figure 31** shows that when the first cycle injection was completed and after the reaction of the TCF, there was a significant intersection at a flow rate, which is called the operational point, and was about 674 (scf/day). The point at which the IPR and VLP curves converge indicates that the well has started to flow and that the gas condensate obstruction preventing gas from reaching the wellhead has been removed. It is noted that the IPR remained steady; however, the downward shift that led to the intersection was seen in the VLP curve. This occurrence can be explained by the well-targeted effect of thermochemical fluid injection

and the reaction that followed, which affected the well without stimulating or damaging the reservoir. Moreover, it is also observed that the two curves intersected twice; nevertheless, the initial intersection is regarded as a pre-equilibrium unstable production rate (Lea et al., 2008; Yadua et al., 2020). When the well is producing at a rate that is out of balance with the conditions of the reservoir, it is said to be operating at the initial intersection point of the IPR and VLP curves. This indicates that the reservoir pressure is neither long-term stable nor sustainable at this production rate. Since the system is not yet in a steady-state balance, this state is frequently referred to as a “pre-equilibrium” state.

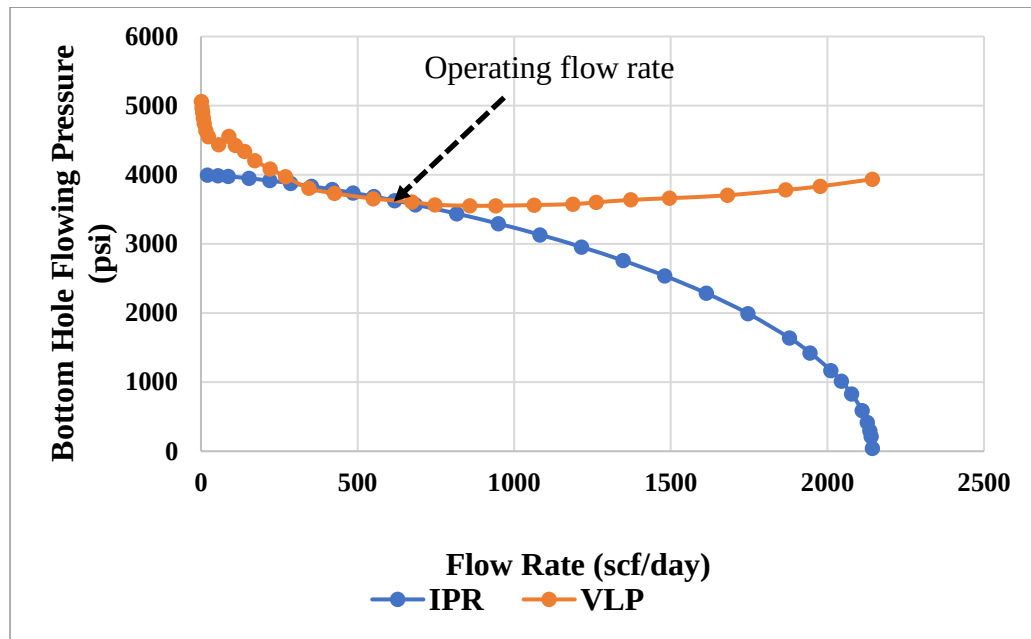


Figure 31: Improvement in VLP after the first cycle injection, the operating point is achieved.

Regarding the second cycle of TCF injection, **Figure 32** shows the deliverability of that cycle. Analysis of the figure indicates that the injection of this cycle resulted in a better improvement in the well’s VLP. This enhancement is ascribed to the increased generation of heat and pressure resulting from the reaction between TCF. Compared to the first cycle,

there has been a noticeable rise at the operating point, yielding a flow rate of about 941 (scf/day).

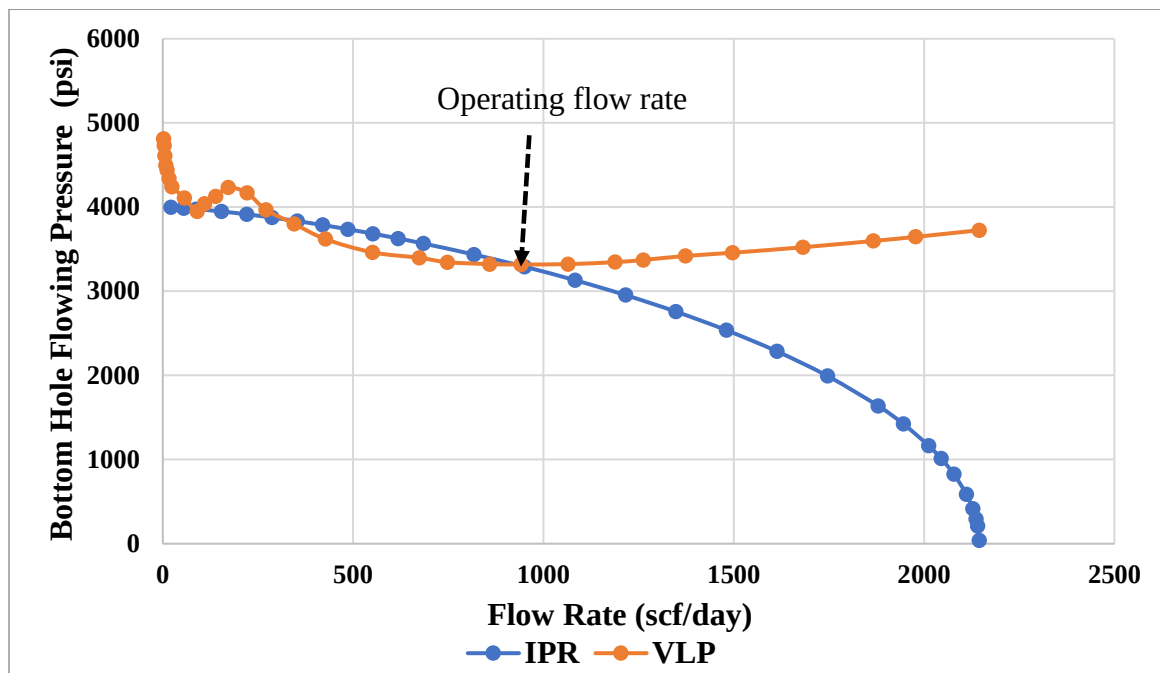


Figure 32: Improvement in operating flow rate due to the second cycle injection.

As for the last cycle, **Figure 33** illustrates the deliverability of the system after the reaction. During this cycle, there is a significant improvement in the well's VLP due to the injection. This improvement can be ascribed to the TCF reaction, which again produces more heat and pressure at each cycle. Compared to the second cycle, the operational point has increased even more, resulting in a flow rate of about 1188 (scf/day). This improvement in performance highlights how successfully the thermochemical fluid injection works to increase the well's operating production rate, resulting in a higher flow rate within the given operating parameters and well condition.

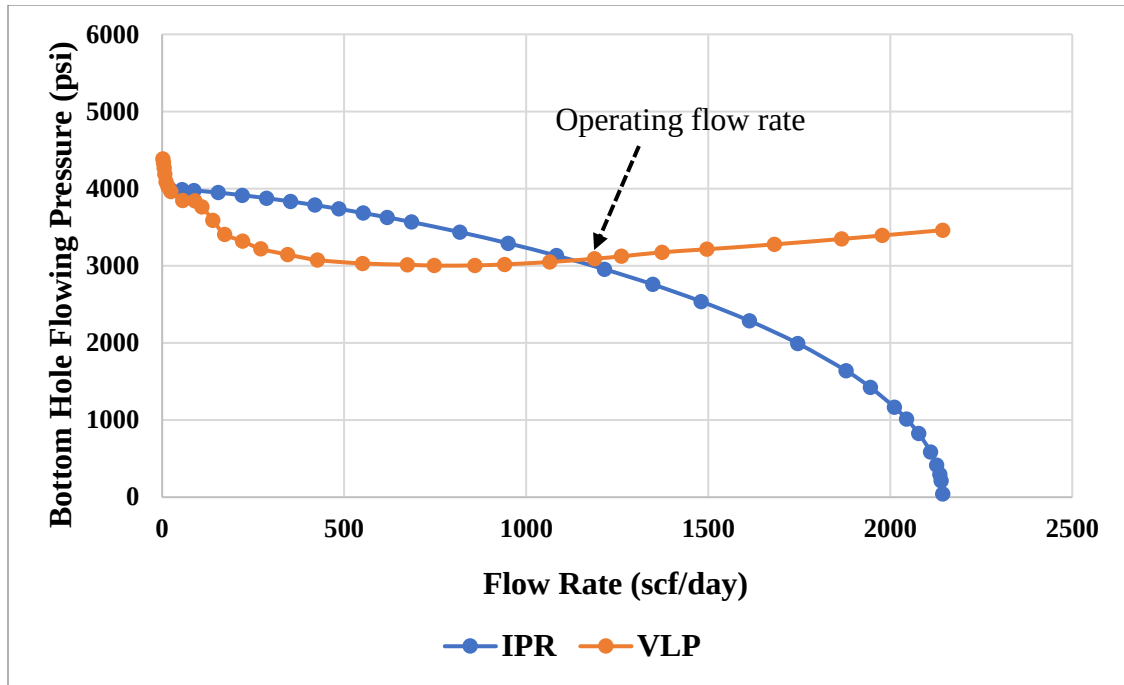


Figure 33: Enhancement of the removal efficiency after the third cycle injection and its corresponding operating conditions.

The aforementioned figures show that the TCFs enhance the VLP greatly as they make the operating flow rate of the gas increase and go beyond the critical flow rate that was calculated via PIPESIM. The change in the operating flow rate and operating flowing pressure due to the injection of TCF in cycles is shown in **Table 9**. Each cycle resulted in an augmentation of the operational flow rate, beneficial for the well life, along with an enhancement in removal efficiency, indicative of the well's return to an optimal operational state due to the additional downhole pressure generated. Simultaneously, the heat generated serves to forestall the occurrence of condensation phenomena. The operating flow rate was increased by around 74%, from 674 to 1188 (scf/day), by applying three injection cycles.

Table 9: The alterations in the operational flow rate and the operational flowing pressure.

Stage	Liquid Removal Efficiency (%)	Operating Pressure (psi)	Operating Flow Rate (scf/day)
Initial condition (liquid loading issue)	0	0	0
First Cycle	15	3564	674
Second Cycle	65	3322	941
Third Cycle	97.5	3048	1188

CHAPTER 5

CONCLUSIONS AND FUTURE WORK

5.1 Conclusions

This study explored the use of Thermochemical Fluids (TCF) to enhance the maturation of immature organic-rich source rocks and address liquid loading issues in gas wells. Through laboratory experiments and simulation modeling, the findings demonstrated TCF's effectiveness in improving both the geochemical and geomechanical properties of shale samples and in efficiently removing liquid loading. The results highlight TCF as a promising, environmentally friendly, and cost-effective solution for enhanced hydrocarbon recovery.

The samples were characterized pre-treatment and post treatment to assess the impact of TCF treatment, which was applied through core flooding. TCF demonstrated a notable impact on the geochemical, petrophysical, and geomechanical properties of shale samples. The key findings of TCF impact on shale samples are as follows:

- TCF accelerated kerogen maturation by 18-42% through the generation of in-situ heat and pressure, and increased the free hydrocarbon volume in the samples by 80-130%.
- The in-situ generated heat and pressure promoted microfracture development, leading to enhanced porosity by 10-20%.
- Gas chromatography analysis revealed the presence of light hydrocarbons in the effluent after treatment, confirming the conversion of kerogen into hydrocarbons.

- XRD and XRF analyses showed no significant changes in mineralogical or elemental composition, ensuring the preservation of the reservoir's integrity.
- The V_p/V_s ratio increased by 8-30% due to thermal stress and pressure generation within the pores, further enhancing the geomechanical properties of the samples.
- The Poisson's ratio of the samples increased in a range of 5-25%, indicating that the samples are less stiff after the treatment, making the samples more susceptible to fracturing.

Impact of TCF on liquid loading removal was investigated by conducting experimental work in the lab by using different volumes of liquid to load the system to test various scenarios. Then PIPESIM simulations were carried out to validate the field applicability of TCF. The key findings of TCFs impact on tackling liquid loading are as follows:

- TCF removed over 90% of liquid hold-up across all tested scenarios, demonstrating its efficiency in deliquifying gas wells.
- The number of injection cycles required to deliquesfy the well, increases with the volume of liquid that is loading the system.
- Early intervention upon detecting liquid loading minimizes the required number of cycles and optimizes gas production.
- PIPESIM simulations validated the field applicability of TCF, showing a 74% improvement in gas production rates after treatment.
- TCF is a rapid and cost-effective solution, producing non-hazardous, biodegradable byproducts (nitrogen gas, and NaCl brine), making it environmentally friendly for field applications.

5.2 Future Work Recommendations

While this study provides promising results for the application of TCF for organic-rich shale maturation and liquid loading removal, several directions for future research could further enhance our understanding and broaden the applications of TCF in unconventional reservoirs. Here are some suggestions for future potential work:

- Firstly, the influence of different TCF concentrations on shale rock response requires additional investigation. Variability in the chemical concentration can affect the heat and pressure generated within the rock matrix, potentially increasing the efficiency of hydrocarbon generation and liquid removal. Optimizing TCF concentrations for various shale compositions would contribute to a more tailored approach, improving the adaptability and effectiveness of TCF treatments across diverse geological formations.
- This study employed gas condensate as the liquid - liquid interactions. Future studies could evaluate the effectiveness of TCF with a wider range of fluids. Testing TCF performance with other types of condensates and liquids would provide a comprehensive assessment of its applicability under different well conditions and fluid properties, informing best practices for TCF use across varying production environments.
- Finally, exploring the integration of TCF with other reservoir stimulation techniques for maximizing resource recovery and efficiency. Combined approaches could enhance TCF's unique ability to generate in-situ pressure and temperature while enhancing fracture networks, creating a more comprehensive solution for unconventional resource development.

These recommended areas of future work would significantly advance our knowledge of TCF's capabilities, extending its application potential and contributing to sustainable and effective resource extraction methods.

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List of Journal Publications (Thesis Related):

- Elyasa, A., Hassan, A., Mahmoud, M., Gajbhiye, R., El-Husseiny, A. and Abu-Mahfouz, I.S., 2024. Mitigating Liquid Loading in Gas Wells Using Thermochemical Fluid Injection: An Experimental and Simulation Study. ACS omega, 9(28), pp.31081-31092. **(Published)**.
- Elyasa, A., Hassan, A., Mahmoud, M., Gajbhiye, R., El-Husseiny, A. and Abu-Mahfouz, I.S., 2024. Thermochemical Fluids Dual Benefit: Enhancing Hydrocarbon Productivity & Liquid Loading Removal **(In preparation)**.

List of Journal Publications (Non-Thesis Related):

- Elyasa, A., Hassan, A., Mahmoud, M., Gajbhiye, R., El-Husseiny, A. and Abu-Mahfouz, I.S., 2024. Carbon Dioxide Induced Organic Rich Shale Maturation: A Dual Benefit of Carbon Dioxide Sequestration and Hydrocarbon Production Enhancement **(In preparation)**.

List of Conferences and Symposiums Publications:

- Moh-Ali, A.E.E., 2024, September. Thermochemical Fluids Dual Benefit: Enhancing Hydrocarbon Productivity in Organic-Rich Shale and Liquid Loading Removal from Gas Wells. In SPE Annual Technical Conference and Exhibition (p. D011S999R001). SPE.
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