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Application of Gas-Assisted Gravity Drainage (GAGD) Process for Enhancing Recovery from Unconventional Resources

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APPLICATION OF GAS-ASSISTED GRAVITY DRAINAGE (GAGD) PROCESS FOR ENHANCING RECOVERY FROM UNCONVENTIONAL RESOURCES

A Dissertation

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by
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Nomenclature

A	Area, ft^2 or in^2
BOPD	Barrel Oil per Day
BV	Bulk volume
CGI	Contionous Gas Injection
CH_4	Methane
CMG	Computer Modeling Group
CMOST	A CMG reservoir engineering tool that conducts automated history matching, sensitivity analysis, and optimization of reservoir models
CO_2	Carbon Dioxide
ρ_o	Oil Density
ΔP	Pressure Differences
ECLIPSE	ECL´s Implicit Program for Simulation Engineering by Schlumberger
EOR	Enhanced Oil Recovery
°F	Degree Fahrenheit
GAGD	Gas-Assisted Gravity Drainage
GEM	Reservoir Simulator for compositional, chemical, and Unconventional reservoir developed by CMG
HC	Hydrocarbon
HCPV	Hydrocarbon Pore Volume

IFT	Interfacial Tension
IOIP	Initial Oil In Place
k	Permeability, md
L	Length, ft or in
m	Slope of Straight Line
μ	Viscosity, centipoise (cp)
Mcf/day	Thousand Cubic Feet per Day
md	Milli Darcy
MMP	Minimum Miscible Pressure
MMscf/day	Million Standard Cubic Feet Per Day
Mscf	Thousand Standard Cubic Feet
μd	Micro-Darcy
nd	Nano-Darcy
N_2	Nitrogen
N_2O	Nitrous Oxide
OOIP	Original Oil in Place
Φ	Porosity
Q	Injection Rates, cc/m

PSD	Pore Size Distribution
PSI	Pounds per Square Inch
PV	Pore Volume
PVT	Pressure Volume Temperature
RF	Recovery Factor
STBOPD	Stank Tank Barrel Oil per Day
SRV	Stimulated Reservoir Volume
SW-GAGD	Singel Well Gas-Assisted Gravity Drainage
VIT	Vanishing Interfacial Tension experiments
V_{So}	Saturated Oil Volume
WAG	Water-Alternating-Gas
WC	Water Cut
W_{dry}	Core Dry Weight
W_{exp}	Core Experimental Weight
W_{opc}	Original Preserved Core Weight
W_{sat}	Core Saturation Weight
WinProp	An Integral component in advanced reservoir simulation modeling by CMG

Abstract

The oil recovery with hydraulic fracturing has played an important role in hydrocarbon production and energy support last decade from unconventional resources. Characteristically, the significant production decline and low recovery factors from these reservoirs triggered the need for new EOR techniques to compensate for the decline and help sustain the production. In this study, an experimental investigation of the Gas-Assisted Gravity Drainage (GAGD) process in the presence of fractures as EOR process was conducted using Nitrogen (N_2) and Carbon Dioxide (CO_2) in Berea Sandstone (BSS) and Tuscaloosa Marine Shale (TMS).

Core flooding and EOR experiments were used to determine the rock petrophysical properties and investigate the performance of several EOR processes such as continuous gas injection (CGI) and GAGD. The effects of injection direction, reservoir, and operational conditions were extensively studied on BSS cores. The effect of introducing fracture and fracture configuration on EOR was investigated by injecting N_2 into BSS core plugs and injecting CO_2 into large BSS core samples at optimum operating conditions. The tight core plug TMS was used to study the effects of low permeability (ultra-low permeability) on the EOR process. The mechanisms of oil displacement in porous media are discussed to understand their impact on the EOR process.

The results showed that the N_2-GAGD process with fractures can effectively improve the reservoir productivity from unconventional resources by gravity drainage and oil displacement mechanisms. The CO_2-GAGD showed promising EOR potential through gravity force, diffusion, evaporation, and lowering oil viscosity, interfacial tension (IFT), and capillary pressure. Introducing fracture in the BSS cores for EOR experiments generally increased the stimulated reservoir volume (SRV). The EOR experiments showed that up to 82% of oil-in-place (OIP) can be recovered using the CO_2-GAGD process with fractures from BSS while the oil recovery can reach up to 7.63% OIP from very tight (Shale) TMS core by CO_2-GAGD process. The study showed that the GAGD process can be effective in enhancing recovery from fractured reservoirs of low and ultra-low permeabilities found in unconventional shale reservoirs.

Chapter 1. Introduction

In this chapter, the problem statement, the research objectives, and the motivation of the study were presented. A glance at the methodology, procedure, and an overview of the chapters to follow at the end was given.

1.1. Problem Statement

The enhanced recovery of unconventional resources has played an important role in hydrocarbon production and energy support for a decade, leading the United States to become one of the world's top producers. Together with the multistage hydraulic fracturing treatment, enhanced oil recovery (EOR) triggered the success in developing unconventional reservoirs as well as becoming a necessity due to the characteristic of tight reservoirs possessing low porosity and ultra-low permeability (Zhang et al. 2018b). The fracture networks in the ultra-low permeabilities reservoirs created by the interaction of the hydraulic fractures and the existing natural fractures offer adequate flow paths for oil to be extracted from these tight reservoirs. Nevertheless, the production starts at high rates and rapidly declines due to the poor fluid transport through the extensive tight matrix.

Typically, most of the oil is produced within the first year and the production rate decreases to less than 10% to 20% of the original production rate. More than 90% of the original oil in place (OOIP) of the unconventional hydrocarbon remains in the reservoirs after the oil production falls below the economic line. The injected water during the hydrofracking stages highly fluxes through the fractures after a couple of months which causes plug and abandonment (P&A) due to high water cut (WC). The low oil recoveries from these reservoirs are mainly triggered by the sole reliance on primary depletion. The enhanced oil recovery technologies should be applied as early as possible, as EOR could play an essential role in compensating for the decline and sustaining production of unconventional resources.

The application and use of enhanced oil recovery techniques in unconventional reservoirs are not well understood (W. Yu, Lashgari, Wu, & Sepehrnoori, 2015). The existing techniques showed that the most likely value for the recovery factor is less than 10% (Sheng, 2015) and (Du & Nojabaei, 2019). And with recent activities in Permian Basin, Eagle Ford, Bakken, and other shale plays, companies, universities, and research centers around the world are in a race to obtain the advanced positions in the shale oil industry and unlock the potential of 30 billion barrels from approximately 24 tight oil reservoirs. Competitors are looking for developing a low-cost method to improve overall recovery from unconventional resources and apply it on a larger scale to add reserves from formations where most of the resources (about 90%) will be left behind after primary depletion. The results from various studies showed that the gravity drainage mechanism has a much greater significance than previously thought when compared to the effects of phase behavior or the miscibility alone. Not surprisingly, vertically stable, downward displacement resulted in better performance compared to horizontal displacement in all cores and bead-packed tubes in our experiments (Adel et al., 2018). The concept of the gas-assisted gravity drainage (GAGD) process proved its ability to improve the hydrocarbon drainage through the gravity segregation and lower the cost through the application of single-well gas-assisted gravity drainage process (SW-GAGD) in Cuu Long Basin, offshore Vietnam as conventional (but tight oil) resource (Dinh et al., 2017). Will GAGD EOR techniques work in shale and ultra-tight oil plays?

The proposed Gas-Assisted Gravity Drainage (GAGD) process with fractures is a modified process from SW-GAGD which is developed from the conventional GAGD process to implement the secondary and/or tertiary enhancing oil recovery from the mature oil field in the Gulf of Mexico

(GOM) by Rao and co-workers (Saikia, 2016). After experimentally demonstrating that the SW-GAGD is a novel design and cost-effective to highly enhance oil recovery from conventional reservoirs for both immiscible and miscible, an extension of applying the GAGD with fractures process in the unconventional reservoirs is suggested. The proposed process is designed to use a single well to inject the gas into the targeted formation in a gravity-stable manner and to produce the oil through the horizontal lateral at the bottom of the pay zone. One main feature of placing the horizontal well in GAGD is that when the natural drive of oil is depleted, gravity forces will take over to become the main energy source (Dinh et al., 2017). As in conventional reservoirs, the injected gas is going to accumulate at the top of the reservoir due to gravity segregation resulting from the difference in fluid densities. This accumulation creates a transitional zone and provides a gravity stable front to displace and drain the oil to the fractured horizontal production section at the bottom of the pay zone which leads to better volumetric sweep efficiency and higher ultimate oil recovery (Mahmoud & Rao, 2007).

It is challenging to unlock the hydrocarbon from unconventional resources because of the extremely small pore size, low porosity, and ultra-low permeability of these resources. However, the injected gas in the fractured shale reservoirs by the GAGD EOR process dissolves in the saturated shale oil, swells its volume, reduces its viscosity, and flows through the pathways provided by the complex fracture system (Gamadi, Sheng, & Soliman, 2013) and (Hawthorne et al., 2013). The schematic drawing of the GAGD process is shown in Figure 1.1.

This proposed research aimed to experimentally demonstrate the application of the GAGD process to enhance oil recovery from unconventional reservoirs. Factors such as gas-injection types, miscibility, reservoir, and operational constraints were optimized to enhance oil recovery from these resources efficiently. Experimental procedures included core preparation, rock property determination, core flooding, and EOR experiments.

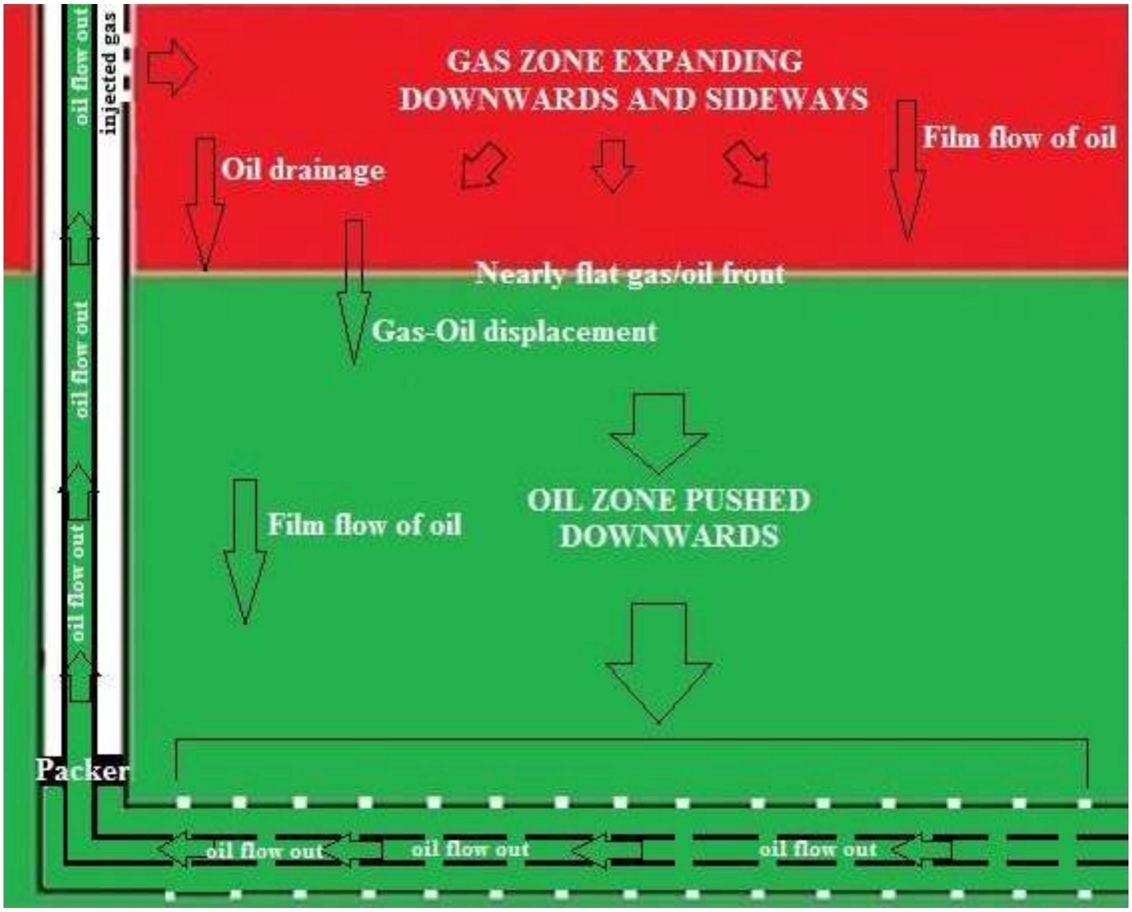


Figure 1. 1. Schematic Drawing of the Single-Well Gas-Injection Gas-Assisted Gravity Drainage (GAGD) Enhanced Oil Recovery (EOR) Process (Saikia, 2016)

1.2 . Research Objectives

The main motivation of each study is its objectives. The determination of the objectives must follow some critical points. The most important point is that the research goals must be inspired by the needing of what other researchers have done and it should add something new to their theories. That was exactly the starting point. The objectives of the study are:

1. To test the feasibility of enhancing oil recovery from unconventional resources using Gas-Assisted Gravity Drainage (GAGD) by carrying out comparative evaluation with the conventional continuous gas injection (CGI) mechanism in unconventional resources.
2. To determine the preferred operating conditions, and appropriate injection gases to improve oil recovery by studying the effects of operational factors like injection pressure, production back pressure; and the effects of varying injection gases on GAGD performance in unconventional reservoirs.
3. To carry out analyses of gathered experimental data and gain an understanding of predominant recovery mechanisms; displacement and/or drainage.
4. To gain an understanding of the effect of having fractures and fracture configurations on the gas injectivity and the resulting performance in these types of tight oil reservoirs by creating artificial fractures in the core samples before running EOR experiments.

1.3 . Motivation

Recently, unconventional resources have been receiving significant attention in the oil industry with the current increased production from the shale formations in Bakken, Eagle Ford, and Permian Basin fields. Only less than 10 % of the original oil in place (OOIP) can be recovered from the shale formations with the existing primary oil recovery technique. The petroleum companies, research institutes, and universities are expending a great effort seeking to improve oil recovery techniques to increase the oil recovery from these complex inevitable resources. Most of the work of developing these techniques for unconventional resources has to be initiated in the research laboratory to understand the fundamental mechanisms before upscaling them to the field scale by the numerical simulation modeling or even applying them in actual fields through field pilots. At LSU, the GAGD process has been invented, studied, experimentally tested, and numerically simulated to prove its effectiveness in conventional oil reservoirs. The GAGD process handles many complex problems both at the reservoir or field level through its fluid flow mechanisms, well completions, and field facility planning.

The GAGD process improves oil recovery by accomplishing better sweep efficiency and higher microscopic displacement taking advantage of the natural tendency of fluid gravity segregation to recover the bypassed oil from unswept regions in the reservoir. Besides, the process results in delaying and minimizing water production as the horizontal production well is located at the bottom of the pay zone and above the oil-water contact level. Also, the GAGD process is cost-effective because of the usage of a single well to inject the gases in the reservoir and produce from the reservoir without the need to have multiple wells to achieve various improving oil recovery patterns, especially in the offshore and/or mature fields. GAGD process reported improving the oil recovery to ultimate level compared with the other processes experimentally and simulation modeling in conventional samples (Munawar, Rao, & Khan, 2017), (Dinh et al., 2017), (Saikia, 2016), and (Paidin, 2013). Will the process work in unconventional samples? Is it going to open a new era of improving oil recovery? Are the recoverable reserves going to be double or triple the current numbers?

To address these questions, this study aimed to examine the applicability of the GAGD process in tight and shale oil reservoirs through laboratory experiments designed to understand the mechanism of improving the recovery of unconventional resources. Different schemes were performed experimentally with different operating conditions and injected gases. The gases that have been investigated over the last decade from different studies were CO_2, N_2, and enriched natural gas (Alfarge et al., 2017).

1.4 . Methodology

The application of the gas-assisted gravity drainage (GAGD) process in unconventional resources in this research was performed through laboratory experiments using shale oil and tight core plugs and samples. The experimental work aimed to determine the viability of the GAGD process to enhance the oil recovery from unconventional oil reservoirs. The laboratory experiments aimed to demonstrate the optimum EOR mechanism, injection scheme, injection gas, and operating conditions. From the literature review it was evident that most laboratory works were conducted on small samples of shale chips or small core plugs with a diameter range of 1" – 1.5" and length of 1" - 4" placed inside a wide annulus to simulate a natural fracture. This setup appears to be an unrealistic representation of the real field cases. The proposed plan intended to implement GAGD on tight, ultra-tight, and shale core plugs and samples with a lab experimental setup that has more reasonable dimensions to mimic the real reservoir cases. This plan is composed of the following parts:

1. Core sample selection.
2. Core sample preparation includes cutting, cleaning, drying.
3. Core flooding and petrophysical rock properties determination.
4. Conducting EOR experiments in different injection modes using different gases.
5. Analyzing experimental results to understand the dominant recovery mechanisms.

1.5 . Chapters Review

This dissertation consists of five chapters. Chapter no. 1 is an introduction in which the problem was stated, research objectives were listed, and the motivations were discussed. Chapter no. 2 is the literature review where the unconventional resources and the gas injection methods as enhancing oil recovery mechanisms were studied extensively. Chapter no. 3, described the methodology of core preparation, core-flooding, set up, and procedure of the apparatus to perform enhanced oil recovery experiments at different conditions. The described experiments were designed to meet the prementioned research objectives. Chapter no. 4 illustrated, discussed, and summarized the results of the core-flooding and gas-injection enhanced oil recovery experiments from different cores performed in the previous chapter. In this chapter, the results were analyzed further and various effects were discussed. Chapter no. 5 summarized the results of this study, came up with conclusions, and recommendations to improve future research studies.

Chapter 2. Literature Review

In this chapter, the first part started by reviewing the unconventional resources, characteristics, types, and unproved quantity of unconventional resources. To identify the research opportunities, the literature review studied the reservoir drive mechanisms then narrowed them to the existing enhanced oil recovery methods. The study emphasized the research of the gas injection schemes to improve the recovery of these resources. The review studied in detail all previous experimental work performed by Dr. Rao's research team and the first field application GAGD process. To understand the research activities on gas injection to enhance oil recovery from unconventional reservoirs, the research extended the review over time which helps to set the context chronologically for later studies. This was followed by a review of existing experimental, simulation studies, and field applications in subsequent years.

2.1. Unconventional Resources

Recently, the production from unconventional resources has drawn significant attention and gradually become a critical hydrocarbon source. The Society of Petroleum Engineers (SPE) and other associations and councils recognized that they have to review the old definition of unconventional resources to meet the requirements of current development in the oil and gas industry. They defined unconventional resources as the hydrocarbon resources that exist in petroleum accumulations that are pervasive throughout a large area and are not significantly affected by hydrodynamic influences also called "continuous-type" deposits (SPE et al., 2018).

Unlike the conventional resources; these accumulations lack the required porosity and permeability to flow without stimulation at economic rates. From an operation point of view, these accumulations require special extraction technology and significant processing to be able to be produced such as hydraulic fracturing stimulation, steam and/or solvent, and others. Extraction of these resources cannot be economically developed without horizontal drilling and hydraulic fracturing (Han, 2016). In other words, “unconventional” is used as an umbrella term referring to hydrocarbon resources that cannot be produced at economic flow rates or that do not produce economic volumes without artificial stimulation and special recovery processes and technologies (Ahmed & Meehan, 2016). Six types of resources are laid under this umbrella including shallow and deep gases, shales, hydrates, coalbed methane, and heavy oil & bitumen (Du & Nojabaei, 2019). The unobvious structural and stratigraphic trap of unconventional resources creates the need to increase spatial sampling density to define uncertainty of in-place quantities, variations in reservoir and hydrocarbon quality through different evaluation techniques than the conventional resource.

The unconventional resources functioned as the source rocks for the conventional reservoirs, and while much oil migrated out to fill higher permeability reservoirs, even more hydrocarbon remained at the source rock. These resources are distinguished from the conventional reservoirs by a combination of reservoir/fluid properties and the need for advanced drilling and completion technology to economically exploit them. These reservoir properties include low matrix permeability (less than 0.1 md), ultra-fine pore structures, high organic matter content, and fluid storage by sorption in organic matter (Clarkson & Pedersen, 2011). The reservoirs with good quality and permeability are classified as conventional resources while the other poor quality reservoirs and permeability less than 0.1 md resources are considered unconventional resources according to the Canadian Society for Unconventional Resources (Resources, 2012) as shown in Figure 2.1.

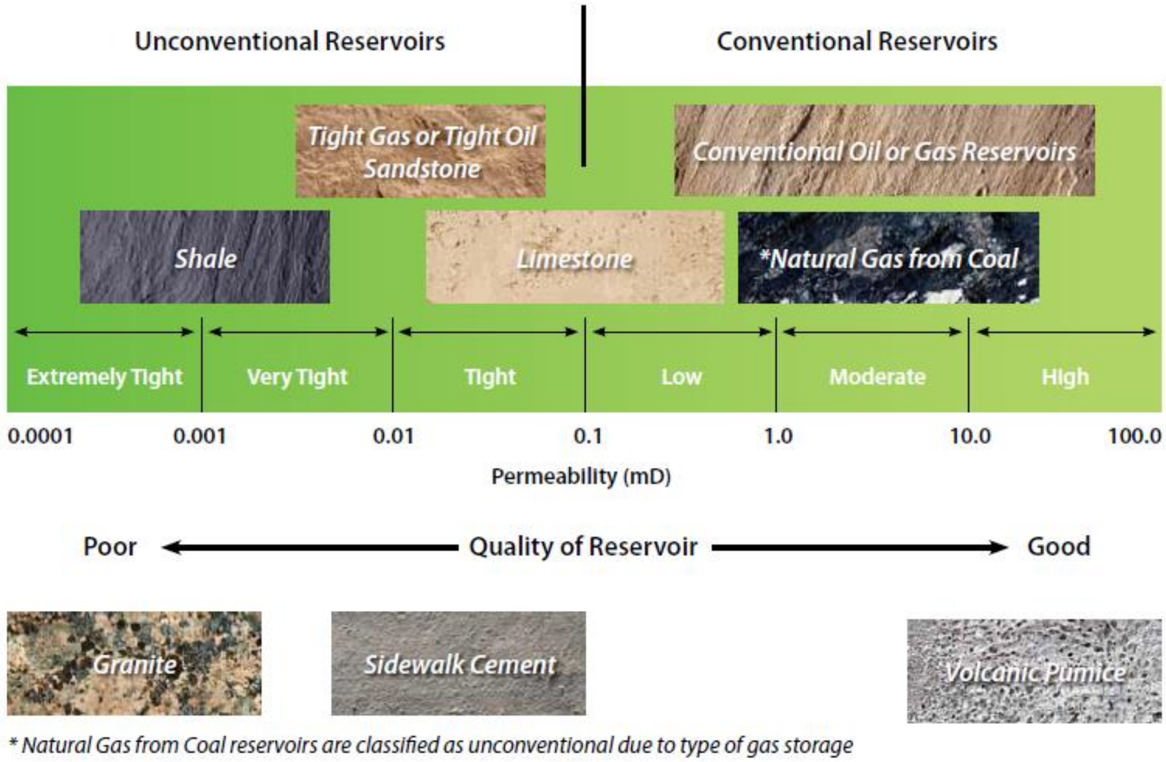


Figure 2. 1. General Hydrocarbon Resources Classification of Petroleum Reservoirs According to Quality, Mineralogy, and Permeability (Resources, 2012)

In general, the unconventional hydrocarbon resources accumulate in continuous zones while the conventional hydrocarbon resources accumulate in local zones. Caineng et al. (2012) Compared the hydrocarbons in unconventional reservoirs with hydrocarbons in conventional traps and they found that there are distinct characteristics between these hydrocarbons as shown in Table 2.1. These unconventional hydrocarbons, primarily in continuous accumulation traps, exist mostly in source rocks, reservoir basin centers, or slopes by primary migration or short distance secondary migration near-source rocks. This type of hydrocarbon exhibits no obvious boundary between traps and covers, poor phase separation, no uniform oil-water interface or pressure system, the large difference in oil saturation and multiphase coexisting oil, gas, and water. The evaluation of the hydrocarbon in the unconventional resources is based on the theoretical resources in place, proven reserves in place, and economically recoverable reserves.

Table 2. 1. Unconventional Hydrocarbon Resources Characteristics and Features (Caineng et al., 2012)

Character	Features
Accumulation units	Unclosed traps without obvious boundary or trapping action
Characteristics of reservoirs	Unconventional nano-sized pore-throat reservoir with obvious retention
Configuration of source and reservoir	Large-scale coexisting source and reservoir or connected source and reservoir
Hydrodynamism	Unobvious, poor fluid segregation, and buoyancy restricted
Migration pattern	Primary migration or short-distance secondary migration
Seepage mechanism	Dominated by non-Darcy percolation
Oil-gas-water relation	No uniform oil, gas-water interface, or pressure system, a large difference in saturation, and coexisting oil, gas, and water
Distribution and accumulation	Large-scale quasi-continuous (continuous) distribution in basin centers or slopes
Technical application	Specialized technologies, such as horizontal multilateral well and separate-layer or staged fracturing

Unconventional resources' oil is classified into three categories due to the reservoir/fluid properties including halo oil, tight oil, and shale oil, Figure 2.2 (Clarkson & Pedersen, 2011). The reservoir permeability for halo oil is relatively high compared with other categories ($k>0.1$ md) and the oil has migrated from the source rock to the reservoir which is comprised of clastic or carbonate rocks. This category represents portions of conventional light oil pools that don't meet traditional Petro-physical cutoffs and pay criteria. The tight oil reservoir permeability is less than 0.1 md ($k<0.1$ md) (Yang, Li, & Liu, 2016) and the oil migrated from different source rock interbedded with or adjacent to source rocks. As halo oil, the reservoir of tight oil is comprised of clastic, or carbonate rocks and the tight oil reservoirs are analogous to tight gas reservoirs. The tight oil accumulations are usually absorbed by formation rocks or present at the dissociative state and have not migrated through long distances (Han, 2016). The shale oil reservoir permeability is very low (k<<0.1 md) and the source rock and the reservoir are the same or finely interbedded. The reservoir is containing a high percentage of organic matter with a possibility that some hydrocarbon fluids are retained in the sorbed state on these organics. These category reservoirs are like the shale gas reservoirs with a higher permeability cutoff used to acknowledge the higher viscosity of the fluid.

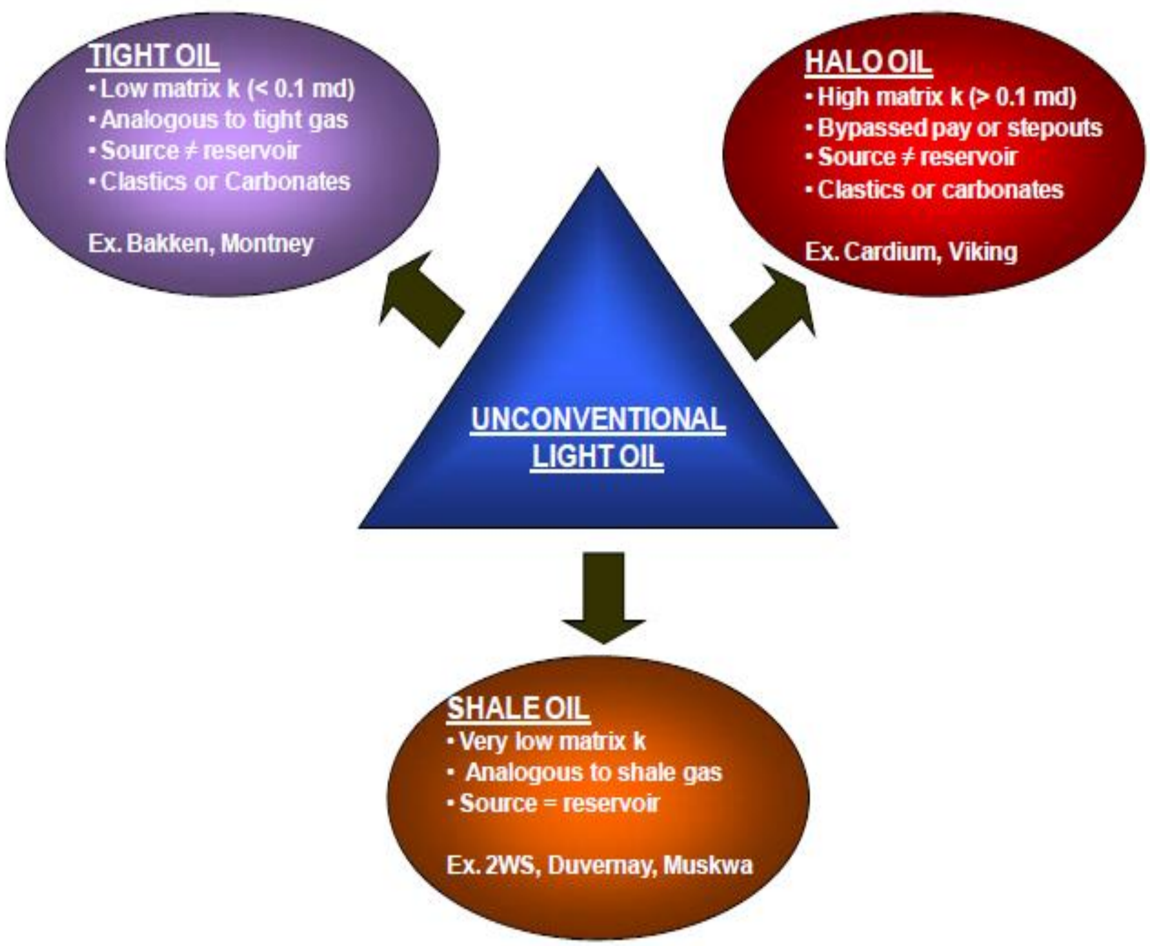


Figure 2. 2. Unconventional Resources' Oil Classification in Terms of Matrix, Pay and Source (Clarkson & Pedersen, 2011)

The most important unconventional fossil fuels are shale gas and tight oil which are produced by horizontal drilling and hydraulic fracturing. At present, the only United States and Canada producing natural gas and oil from shale formations on a commercial amount while several countries have conducted exploratory tests, and China is just starting commercial production (Erbach, 2014). The production from US unconventional resources have been rapidly increased in recent years which made the US is the world's largest producer of natural gas (two thirds from unconventional gas) and one of the largest crude oil producer (a third from tight oil) in 2013 (US Energy Information Agency, 2012).

In 2015, the U.S. Energy Information Administration (EIA) conducted an initial assessment of world shale oil and gas resources including 46 countries. Worldwide, the unproven technically recoverable tight oil was 418.9 billion barrels, and the unproven technically recoverable wet shale gas was 7,576.6 trillion cubic feet (EIA, 2015). According to the EIA estimation, the US unproven technically recoverable shale gas and tight oil was 622.5 trillion cubic feet and 78.2 billion barrels, respectively (EIA, 2015). This unconventional gas accounted for more than two-thirds of US gas production while unconventional oil accounted for more than a third of US crude oil production (Erbach, 2014). The latest released unproved technically recoverable wet shale gas and tight oil for the reported 46 countries are revealed in Table 2.2 as published by U.S. Energy Information Administration 2015 Independent Statistics Analysis report.

Table 2. 2. Global Unproved Technically Recoverable Reserves of Unconventional Resources *Source:(EIA, 2015*)

Country	**Wet Shale Gas (Trillion cubic feet)**	**Tight Oil (Billion barrels)**	**Date updated**
Canada	572.9	8.8	2013
Mexico	545.2	13.1	2013
U.S.	622.5	78.2	2015
Australia	429.3	15.6	2013
Argentina	801.5	27.0	2013
Table Cont©.			

Country	Wet Shale Gas (Trillion cubic feet)	Tight Oil (Billion barrels)	Date updated
Bolivia	36.4	0.6	2013
Brazil	244.9	5.3	2013
Chile	48.5	2.3	2013
Colombia	54.7	6.8	2013
Paraguay	75.3	3.7	2013
Uruguay	4.6	0.6	2013
Venezuela	167.3	13.4	2013
Bulgaria	16.6	0.2	2013
Lithuania/Kaliningrad	2.4	1.4	2013
Poland	145.8	1.8	2013
Romania	50.7	0.3	2013
Russia	284.5	74.6	2013
Turkey	23.6	4.7	2013
Ukraine	127.9	1.1	2013
Denmark	31.7	0.0	2013
France	136.7	4.7	2013
Germany	17.0	0.7	2013
Netherlands	25.9	2.9	2013
Norway	0.0	0.0	2013
Spain	8.4	0.1	2013
Sweden	9.8	0.0	2013
United Kingdom	25.8	0.7	2013
Algeria	706.9	5.7	2013
Egypt	100.0	4.6	2013
Libya	121.6	26.1	2013
Mauritania	0.0	0.0	2013
Morocco	11.9	0.0	2013
Tunisia	22.7	1.5	2013
West Sahara	8.6	0.2	2013
Chad	44.4	16.2	2014
South Africa	389.7	0.0	2013
China	1115.2	32.2	2013
India	96.4	3.8	2013
Indonesia	46.4	7.9	2013
Mongolia	4.4	3.4	2013
Pakistan	105.2	9.1	2013
Thailand	5.4	0.0	2013
Kazakhstan	27.5	10.6	2014
Jordan	6.8	0.1	2013
Oman	48.3	6.2	2014
U. A. E	205.3	22.6	2014
Total	**7,576.6**	**418.9**	

2.2. Reservoir Drive Mechanisms

Since the demands for energy and hydrocarbon products were dramatically increased with the development of human civilization and industry, the need for enhancing the knowledge and awareness of extracting and recovering hydrocarbon mechanisms was increased especially in the modern oil industry. The production from petroleum resources is achieved mainly by three main methods called recovery mechanisms. The first recovery mechanism is termed "primary production" in which the initial production of the existed hydrocarbon from the underground reservoirs is accomplished by the use of natural reservoir energy (Terry, 2001) and limits the oil to naturally rise to the surface without any external artificial lift methods (Vaswani, Iqbal, & Sharma, 2015). Primary oil recovery methods include solution-gas drive, gas-cap expansion, gravity drainage, rock expansion, water drive processes, or their composition (Sandrea & Sandrea, 2007) and (Alagorni, Yaacob, & Nour, 2015).

After the natural reservoir energy has been depleted, it becomes necessary to enhance the natural energy with an external source. The use of an injection/flooding mechanism is called a "secondary recovery" operation. When water flooding is the secondary recovery process, the process is referred to as water flooding. In gas injection, the immiscible gas is injected into the reservoir to maintain the reservoir pressure. The main purpose of either a natural gas or water injection process is to re-pressurize the reservoir and then maintain the reservoir at high pressure. Hence, the term pressure maintenance is sometimes used to describe a secondary recovery process. Often injected fluids also displace oil toward production wells, thus providing an additional recovery mechanism. The hydrocarbon recovery by primary recovery mechanisms is ranging between 5% and 15% and does not exceed more than 20% in most cases while the recovery by secondary mechanism ranges between 10% and 20% and does not exceed more than 25%. Hence, the resulting global oil recovery combined for both; primary and secondary recovery ranges between 35-45% of the reservoir (Vaswani et al., 2015).

Other production mechanisms are called "tertiary recovery" processes have been developed for application in situations in which secondary processes have become ineffective. The term "enhanced oil recovery" was introduced and has become popular about any recovery process that, in general, improves the recovery over what the natural reservoir energy would be expected to yield. The Society of Petroleum Engineers has defined the term enhanced oil recovery (EOR) as the following: "one or more of a variety of processes that seek to improve recovery of hydrocarbon from a reservoir after the primary production phase" (Bull, 2018). The tertiary oil recovery processes are classified mainly into four categories: miscible gas flooding processes, chemical flooding processes, thermal flooding processes, and others (Larry W, 1989). Figure 2.3 shows the classification of oil recovery mechanisms as defined by the Society of Petroleum Engineers (Kokal & Al-Kaabi, 2010), (Alagorni et al., 2015), (Vaswani et al., 2015) and (Stosur, Hite, Carnahan, & Miller, 2003). On average, primary and secondary production methods will produce from a reservoir about 30% of the initial oil in place. The remaining oil, 60%-65% or more of the initial resources, is a large and attractive target for enhanced oil recovery techniques to recover (Vaswani et al., 2015). Also, the rate of replacement of the produced reserves by discoveries has been declining steadily in the last years. Therefore, enhancing the oil recovery from the old fields under primary and secondary production will be critical to support the growing energy demand in the coming years (Alvarado & Manrique, 2010).

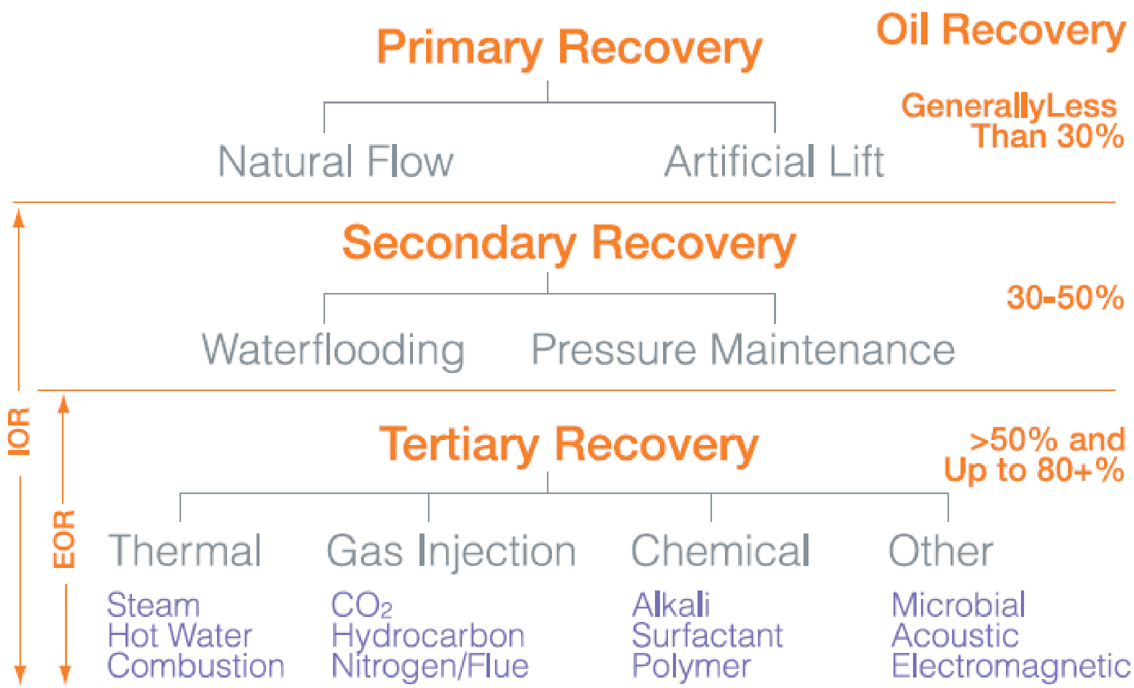


Figure 2. 3. General Classification of the Oil Recovery Mechanisms (Kokal & Al-Kaabi, 2010)

2.3. Enhanced Oil Recovery

Enhanced Oil Recovery (EOR) applies to methods used for recovering oil from a petroleum reservoir beyond that recoverable reserves by primary and secondary methods (Mathiassen, 2003) and (Tunio et al., 2011). What makes EOR different than the former recovery mechanisms is that the EOR methods involve the injection of fluids to supplement the natural energy in the reservoir to displace oil toward the producing wells (Dandina N. Rao, 2001). The main objective of all methods of EOR is to increase the volumetric (macroscopic) sweep efficiency and to enhance the displacement (microscopic) efficiency, as compared to the ordinary waterflood (Hansen, 2009) and (Verma, 2015). One mechanism is to increase the volumetric sweep by reducing the mobility ratio between the displacing and displaced fluids. The other mechanism is targeted at the reduction of the amount of oil trapped due to capillary forces. By reducing the interfacial tension between the displacing and displaced fluids, the effect of trapping is lowered. It is generally accepted that approximately 30% of the oil present in a reservoir can be recovered using enhanced oil recovery (EOR) technologies (Tunio et al., 2011). These techniques of enhanced oil recovery were designed to recover the residual oil that cannot be extracted by both the primary and secondary recovery techniques.

In general, EOR technologies fall into four groups of the following categories: gas miscible recovery, chemical flooding, thermal recovery, and other techniques including microbial as demonstrated previously in Figure 2.3. The category of miscible displacement includes single-contact and multiple-contact miscible processes using different natural gases and/ or inert gases like N_2 and CO_2 as injectants. Chemical processes are polymer, micellar polymer, alkaline flooding, and microbial flooding. Thermal processes include hot water, steam cycling, steam drive, and in situ combustions (Masoud, 2015). Generally, thermal processes are applicable in reservoirs containing heavy crude oils, whereas chemical and miscible displacement processes are used in reservoirs containing light crude oils. Screening all IOR/EOR methods indicated that the enhanced water flooding, thermal and other methods are not suitable for deep-buried, low-porosity, and low-permeability unconventional oil reservoirs. The gas injection methods seem to be better candidates (Jin et al., 2016) compared with other existing methods.

2.4. Gas Injection Enhanced Oil Recovery Mechanisms

Enhanced Oil Recovery by gas flooding has been the most widely applied recovery method for different types of oil reservoirs due to three main advantageous (Han, 2016), (Alfarge et al., 2017), and (Liu et al., 2019). First, the interfacial tension force (IFT) between the injected gas and the reservoir oil decreases to zero or a small value when miscibility or near-miscibility formed as well as the residual oil of the gas swept area to minimize the trapping of oil in the rock pores by capillary or surface forces (Rao, 2001). Second, the injected gas can easily spread into a nanoscale pore throat in tight oil reservoirs and achieve well displacement since the gas viscosity and molecular diameter are minuscule. Third, injected gas increases reservoir pressure, dissolves in oil, swells oil volume, reduces oil viscosity and density, reduces interfacial tension, modifies rock wettability, affects the phase behavior and the vaporization of oil molecules (Rao, 2001), (Lake et al., 2014), (Tunio et al., 2011), (Ma et al., 2016), (Pu et al., 2016a) and (Perera et al., 2016). CO_2 has lower miscibility pressure with shale oil rather than other gases such as N_2, methane (CH_4), flue gas, or natural gas (Kovscek et al., 2008), (Zhang, 2016) and (Liu et al., 2019) with a controversial minimum miscible pressure (MMP) range between 2,500 psi to 3,300 psi (Kurtoglu et al., 2014).

The injection fluid is normally natural gas, enriched natural gas, flue gas, nitrogen (N_2), or carbon dioxide (CO_2). These fluids are not first contact miscible with reservoir oils, but with sufficiently high reservoir pressure, they achieve dynamic miscibility with many reservoir oils. The CO_2 flooding has proven to be among the most promising EOR methods, especially in the United States because it takes advantage of available naturally occurring CO_2 reservoirs (Mathiassen, 2003) and lower miscibility pressure (MMP) compared with other gases (Zhang et al., 2017) which make CO_2-EOR techniques are mostly applied in the USA. The primary purposes for injecting CO_2 into the hydrocarbon reservoir are rejuvenating producing fields and storing it in depleted or unused reservoirs; these processes contribute to the global effort to minimize climate change (Ansarizadeh et al., 2015). The CO_2 was selected for enhanced oil recovery mechanism among other available gases like methane, water vapor, nitrous oxide, and other chemical products in most gas-injection EOR projects. The reason behind the selection is that the gas of CO_2 is in the global spotlight because it is the largest source of US greenhouse gas emissions, followed by methane (CH_4) and Nitrous oxide (N_2O) (Lee & Kam, 2013). The CO_2 EOR mechanism has many advantages compared with other mechanisms using different gases such as methane and nitrogen. If injected CO_2 creates miscible flooding with the reservoir fluids by satisfying the miscibility condition, then the interfacial tension becomes negligible (IFT = Zero) and there is no oil trapped by capillary forces (Holm & Josendal, 1974). This will result in a reduction of the remaining oil saturation to almost near zero during the miscible CO_2 injection and improve the oil recovery. If the injected CO_2 mixes with and dissolves into reservoir oils, the volume of the oleic phase increases. This swelling effect, combined with pressure surges, yields more oil production (Yellig & Metcalfe, 1980).

The concept of carbon dioxide enhanced oil recovery process is as the pressure increases; the carbon dioxide extracts a greater fraction of low molecular weight hydrocarbons from the oil. The carbon dioxide-rich phase is the less viscous phase and so flows more readily through the rock, contacting fresh crude oil. This new mixture forms two phases, but more and more of the oil is dissolved in the CO_2. An oil/CO2 mixture may be formed that is completely miscible with the reservoir oil. The pressure at which this is first achieved is called the Minimum Miscibility Pressure (MMP) (Yellig & Metcalfe, 1980). In the field, complete miscibility is rarely, if ever, achieved, because other processes force the injectant and crude oil to mix in non-ideal, immiscible proportions. Experiments of a miscible flood 85-98% of the residual oil to water flooding can be displaced, but in the field, about 25-40% of the remaining oil can be recovered. In the field, the overall efficiency is affected by other keys, such as the geology of the reservoir and the density and viscosity differences of the fluids (Turek et al., 1988).

The enhanced oil recovery mechanisms were demonstrated below using CO_2 as miscible/immiscible solvent for crude oil since CO_2 injection processes are the most promising solvent IOR/EOR techniques (Meyer, 2005), (Alfarge et al., 2017) and (Liu et al., 2019). Also, the CO_2 injection process was recognized as the second-largest EOR process in the world after the thermal process used in heavy oil fields (Kulkarni, 2003) as illustrated in Figure 2.4. The choice was based on the fact that CO_2 is having great potential to improve oil production utilizing geological storage of carbon dioxide to reduce greenhouse emissions (Abedini, 2014). The same concepts and methods are applicable for other gases such as N_2, flue gas, and natural gas or mixtures of these gases (Shayegi, Jin, Schenewerk, & Wolcott, 1996) with a notice that the nitrogen needs a very high pressure to be miscible with the hydrocarbon. Many injection schemes using CO_2 as liquid and/or gas have been suggested such as the continuous gas injection (CGI), water-alternating-gas injection (WAG), and cyclic gas injection (huff and puff) methods as the most applied in the industry (Adel et al., 2018). The concept of gas-assisted gravity drainage was presented in this chapter briefly as the proposed method for this research.

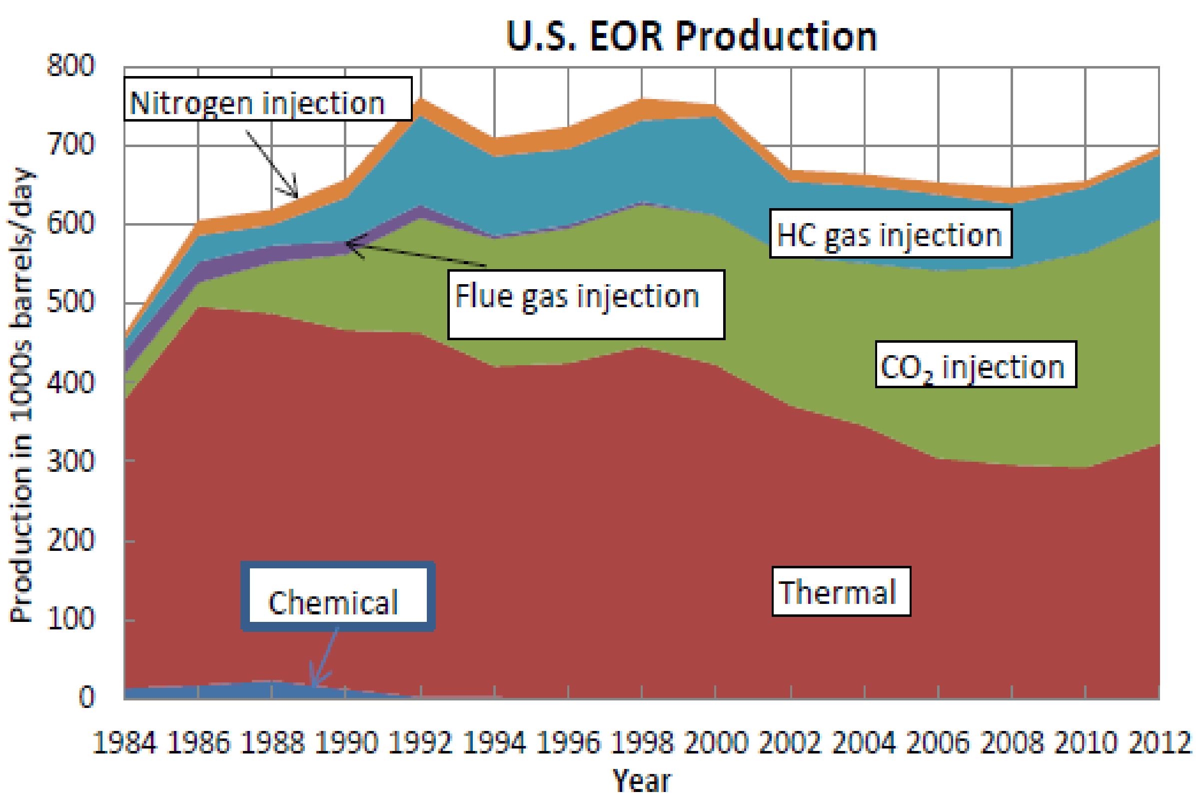


Figure 2. 4. The U.S. Oil Production (bbl/day) Associated with Enhanced Oil Recovery Methods (Verma, 2015)

2.4.1. Continuous Gas Injection (CGI)

The continuous gas injection (CGI) mode was first introduced by Whorton and Kienschnick in 1950 as a result of improving recovery studies of the gas-condensate system (L P Whorton & Kieschnick, 1950), (Leonidas P. Whorton, Brownscombe, & Dyes, 1952), (Meyer, 2005), and (Stalkup, 2007). The Continuous CO_2 Injection process requires continuous injection of a predetermined volume of CO_2 with no other fluid as shown in Figure 2.5. Sometimes a lighter gas, such as nitrogen, follows CO_2 injection to maximize gravity segregation. This approach is implemented after primary recovery and is generally suitable for gravity drainage of reservoirs with medium to light oil as well as reservoirs that are strongly water-wet or are sensitive to water flooding. Figure 5 demonstrates the Continuous CO_2 Injection for the EOR process as presented by Khan, G. Continuous CO_2 Injection is an important process to identify displacement mechanisms but is not likely to be economic in practice unless significant recycling of gas is employed. Inherent in all gas injection processes is the lack of mobility and gravity control (areal and vertical sweep) necessary to sweep significant portions of the reservoir (Klins, 1984). In other applications, the continuous CO_2 Injection process is followed by water. In this process, the continuous CO_2 injection process except for chase water follows the total injected CO_2 slug volume. This process works well in reservoirs of low permeability or moderately homogenous reservoirs as optimization processes from the CGI CO_2 process (KHAN, 2009).

2.4.2. Water-Alternating-Gas (WAG)

The Water Alternating CO_2 Injection process is an oil recovery method initially proposed in 1958 to improve sweep efficiency during gas injection (Caudle & Dyes, 1938). In this process, the CO_2 is injected in injection wells or re-injected in water injection wells to improve oil recovery and pressure conservation. This injection process has the potential for increased microscopic shift efficiency. Thus, the WAG injection process can lead to improved oil recovery by combining better mobility control and contacting upswept zones, and by leading to improved microscopic displacement. In the conventional WAG process, a predetermined volume of CO_2 is injected in cycles alternating with equal volumes of water. The water alternating with CO_2 injection helps overcome the gas override and reduces the CO_2 channeling thereby improving overall CO_2 sweep efficiency. This process is suitable for most of the reservoirs with permeability contrasts among various layers as shown in Figure 2.6.

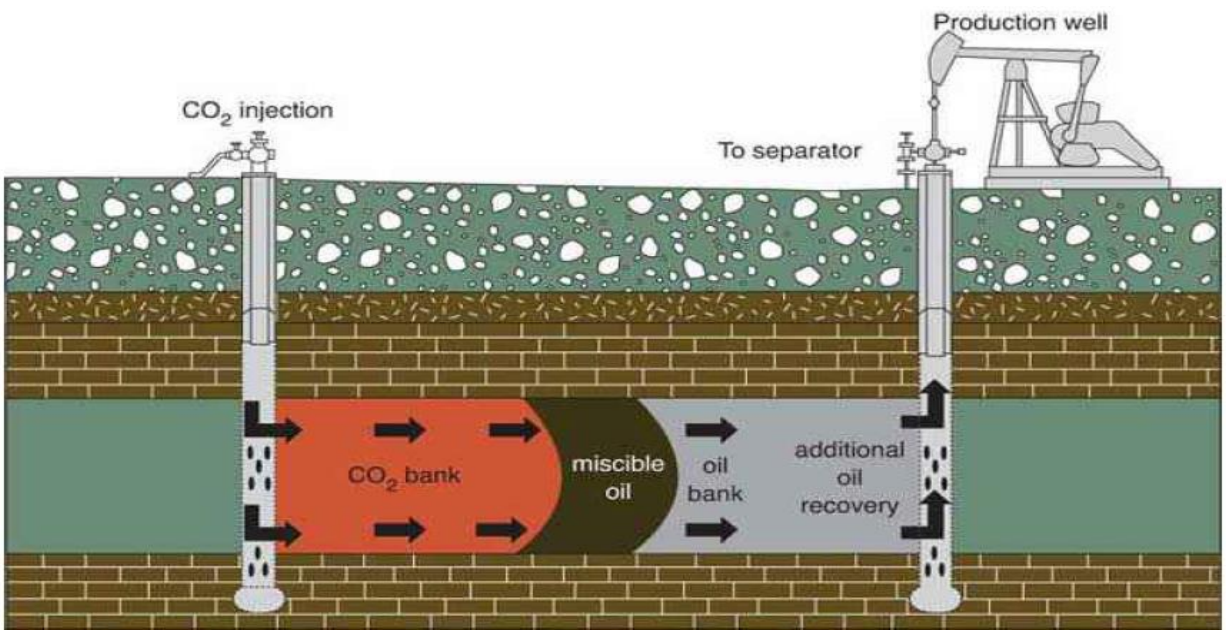


Figure 2. 5. Continuous Carbon Dioxide Injection (CO2-CGI) EOR Process (Khan, G., 2009)

The latest studies showed that the number of cycles in the WAG injection process affects the recovery of oil from the circle sample. These studies observed the effect of gases and revealed that the CO_2 with the 5-cycle WAG process gives an incremental displacement efficiency of 40 % of hydrocarbon pore volume (HCPV), which is much higher than the displacement efficiency of 19 % of HCPV in the 5-cycle WAG process using hydrocarbon gas (Sanchez, 1999). Figure 2.7

illustrates how injecting CO_2 produces oil as WAG-CO_2- EOR mechanism (Global CCS Institute, 2012) and (Whittaker & Perkins, 2013).

The WAG process was improved with time and enhanced new phases like tapered WAG, and WAG followed by a slug of gas. The tapered WAG is designed similarly in concept to the conventional WAG but with a gradual reduction in the injected CO_2 volume relative to the water volume to improve CO_2 utilization. Tapered WAG is the method most widely used today due to its design that improves the efficiency of the flood and prevents early breakthrough of the CO_2, thus less recycled CO_2, and better oil recoveries. The CO_2 utilization is defined as the volume of CO_2 used to produce a barrel of oil and reported as either a gross volume, including the recycled CO_2, or a net volume. The other method is the WAG followed by gas which is a conventional WAG process followed by a chase of less expensive gas (for example air or nitrogen) after the full CO_2 slug volume has been injected.

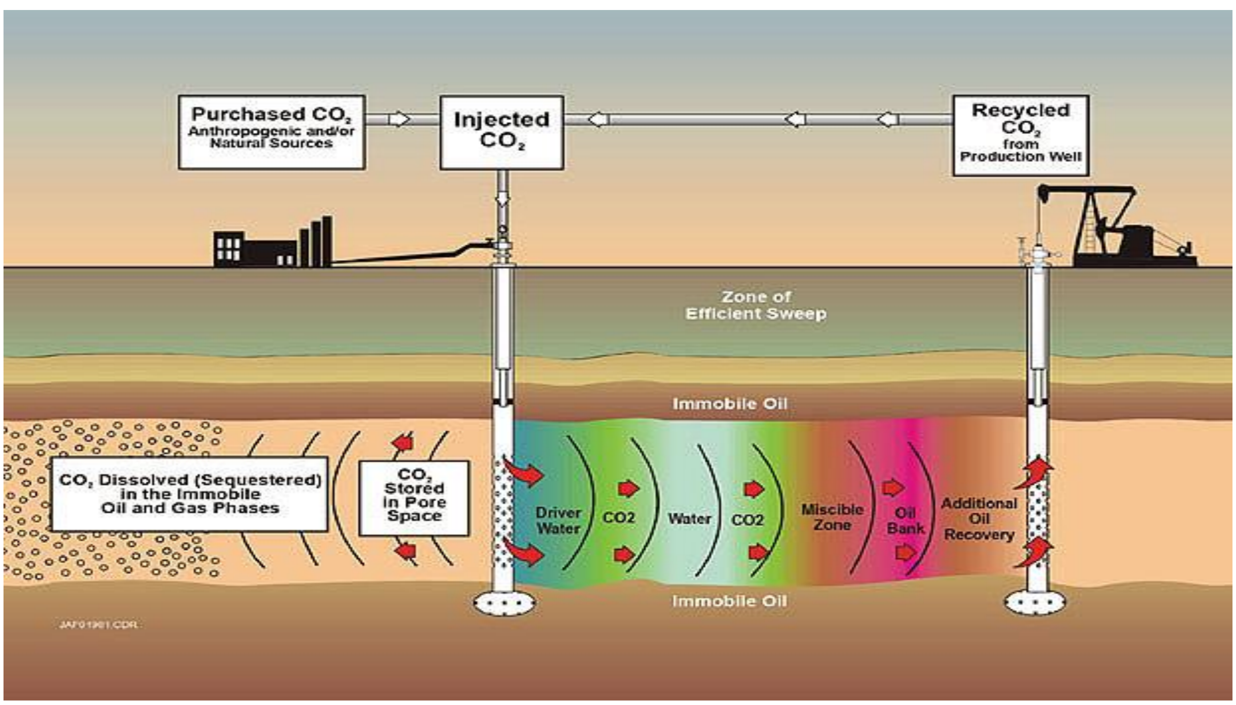


Figure 2. 6. Water-Alternate-Carbon Dioxide Injection (CO2-WAG) EOR Process (Global CCS Institute, 2012)

2.4.3. Cyclic Gas Injection (Huff-n-Puff)

The cyclic gas injection, cyclic stimulation, or Huff and Puff injection process are considered as one of the most successful processes to increase oil recovery since it was proposed initially in 1984 by Monger and Coma at Louisiana State University (Monger & Coma, 1988), (Thomas & Monger-McClure, 1991) and (Karim, Berzins, Schenewerk, Bassiouni, & Wolcott, 1992). To maximize the oil recovery from CO_2 Huff and Puff process, the operating conditions and the design parameters including CO_2 injection rate, injection time, and soaking time (Jeong & Lee, 2015) are optimized, Figure 2.7. Through the optimization process, the oil recovery is increased, and the oil viscosity decreases through the CO_2 soaking area. The concept behind the Huff and Puff process is to have a single well (Shayegi et al., 1996) being used as both injector and producer. This process mainly follows three steps: gas injection, shut-in for soaking time and reopening to produce as presented in the following figure by Global CSS Institute (Whittaker & Perkins, 2013).

During the injection stage of the huff and puff process, the injected CO_2 remains immiscible and bypasses the oil, either by displacing moveable water or oil. By the end of the injection stage, the CO_2 is dispersed throughout the reservoir and mass transfer between the CO_2 and crude oil occurs. During the soak period, the mass transfer between crude oil and CO_2 occurs. The oil phase swells in volume and intermediate hydrocarbons are extracted into the CO_2. In the production stage, oil production occurs because of oil swelling, viscosity reduction, extraction, lower interfacial tension force, and relative permeability shifts due to the displacement of the moveable water by CO_2. Oil swelling occurs throughout the contacted region rather than at the flood front as in a continuous flood, and the relative permeability of the oil is increased as a result. The lower viscosity and interfacial tension force also enhance the oil migration more easily

(Murray, Frailey, & Lawal, 2001). More usually, fields targeted for CO_2 EOR are relatively large involving tens to hundreds of existing wells and which have already undergone a secondary process for oil recovery (Edwards, Anderson, & Reavie, 2001).

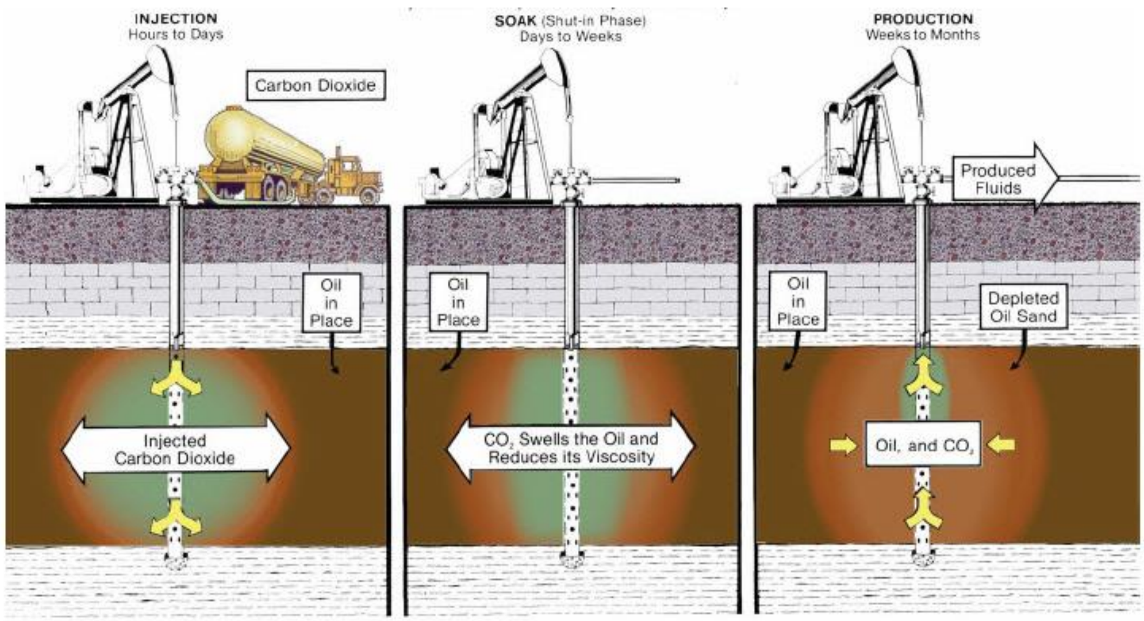


Figure 2. 7. Cyclic CO2 Injection (Huff-n-Puff) EOR Process (Whittaker & Perkins, 2013)

2.4.4. The Needs of Developing a Novel Gas Injection Scheme

The previous three figures displayed the ideal operation of the existing gas injection modes but in reality, they are not working as perfectly as demonstrated. Each method has its deficiencies that required developing a novel method to overcome its cons. Injecting gas into extra-low permeability reservoirs continuously faces early breakthrough times and poor sweep efficiencies while the water flooding proves to be unfeasible in tight unconventional formations. In the ultra-tight shale matrix, the continuous gas injection horizontally is less effective because of the low gas injectivity compared to highly developed natural or effective hydraulic fractures which alleviate the injection gas to migrate from the injection well to the production. The injected gas tends to rise to the top of the formation due to gravity effects as seen in Figure2.8. The wide variations in porosities and permeability within the reservoir caused by stratification may affect the EOR process. The reservoir homogeneities can affect oil recovery by the gas injection horizontally as some of the displacing fluid may not be able to reach the lower permeability formations (Gbadamosi et al., 2018). The limitations include gravity override, channeling, and poor mobility leading to an early gas breakthrough. Figure 2.8 (a) shows a schematic of the actual displacement pattern in continuous gas (CO_2) injection (Gbadamosi et al., 2018). Because of differences in density and viscosity between the injected fluid and the reservoir fluids, the gas injection processes often suffered from poor mobility as a result viscous fingering, channeling, and gravity override frequently occurred (Miri et al., 2014). Also, the production performance of the reservoirs in the existing gas injection EOR processes is highly affected by the reservoir heterogeneities and is attributed to the failure of the EOR projects. In stratified reservoirs, economical gas injection is not possible, due to the early breakthrough and high gas cycle rats.

The CO_2-WAG injection resulted in a decrease in recovery efficiency due to early gas breakthrough and a decrease in fluid injectivity as increasing the cycle time during the water injection period as seen in Figure 2.8 (b). In shale reservoirs, the field pilot tests proved that the water injection performance is not as good as a gas injection because of the low water injectivity in reservoirs. Generally, the major practical challenges in most field applications of WAG include early breakthrough of the injected gas, injectivity loss, corrosion of equipment and tubing, and asphaltene and hydration formation (Afzali et al., 2018). The improvement of recovery by the WAG scheme is not good as hoped since the injected gas and brined tended to separate due to density differences, with the gas flowing along the top of the porous medium and the brine along the bottom of the targeted zone. An excessive amount of injected gas in WAG implementation leads to viscous fingering and gravity override of gas, whereas too much water could lead to the trapping of reservoir oil by the water (Terry, 2001).

Enhancing the recovery through the cyclic injection scheme has several disadvantages including the long shut-in period which would result in a shorter production time and cause uncompensated production loss. The localizing operation of the huff-and-puff wells needs many numbers of wells to enhance the production from a specifically limited zone which requires enormous cash flow. Moreover, the different studies and field tests proved that the cyclic gas injection method resulted in a lower oil recovery than continuous gas injection methods. Another important issue in the cyclic gas injection mechanism is that the injected solvents could extract the light components from the oil through a miscible process leading to viscosity and interfacial tension increment and the swollen-diluted oil much harder to be recovered due to altering fluid properties. Another concern is that the injected gas during the huff period will be re-produced during the puff period which lowers reservoir fluid production. In the fractured reservoir, the pressure sharply decreases, oil saturation and viscosity increase slightly during the puff period (Sheng, 2015). The increases in oil saturation refer to the flowing of the oil in the matrix to the fractures and the increase in oil viscosity due to less gas mixed with the oil as a result of decreasing pressure.

However, the main challenges that have been discussed for all the gas injection schemes have prompted a need to think about other schemes such as GAGD with the expectation of better gas mobility control sweep efficiency. GAGD process, therefore, delays gas breakthrough leading to reduced gas-oil ratios and increasing net-gross ratio. Moreover, the crossflow created by capillary imbibition that caused a nightmare for the existing gas injection EOR schemes can assist the vertical sweep efficiency in a displacement in heterogeneous systems by the GAGD process.

Generally, EOR techniques in fractured reservoirs are challenging for the petroleum industry. Due to early breakthrough and flow channeling in the fractures, the injection flow directly goes from the injection wells to the production wells, but these fractures are considered advantages to the GAGD process which will enhance the spreading of the injected gas at the top of the injection zone.

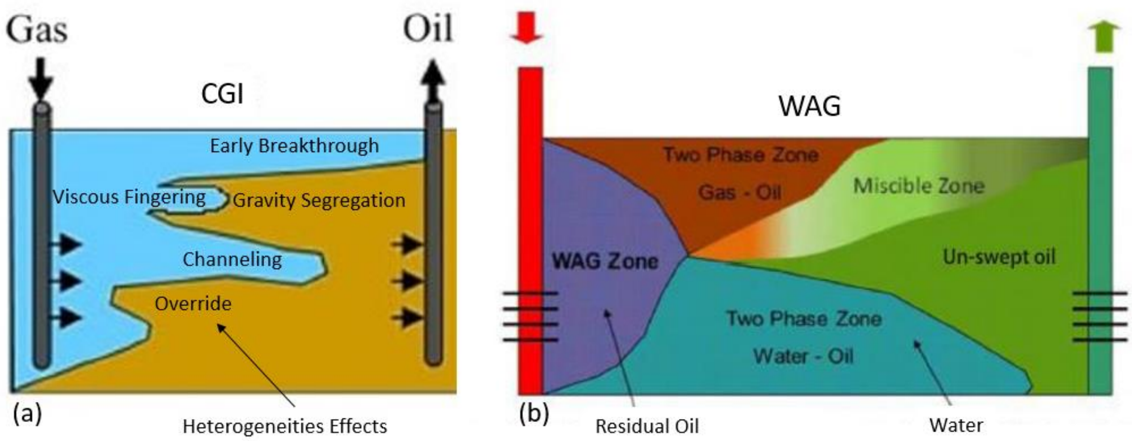


Figure 2. 8. Schematic of Challenges for Continuous Gas Injection (CGI) and Water-Alternate-Gas Injection (WAG) Mechanisms. modified after (Afzali et al., 2018)

2.4.5. The Gas-Assisted Gravity Drainage (GAGD) Process

The gas-Assisted Gravity Drainage (GAGD) process is a new, promising enhanced oil recovery method initially developed by Dr. Rao and his team for more than a decade. The GAGD process has been suggested for improved oil recovery in secondary and tertiary modes for both immiscible and miscible gas flooding processes. The process concept is to place a horizontal producer at the bottom of the pay zone above the oil-water contact (OWC). Then, the gas is injected either immiscible or miscible in a gravity-stable mode through the vertical wells from the top of the formation (D N Rao, Ayirala, Kulkarni, & Sharma, 2004). Due to the gravity segregation resulting from the distinct fluid densities at reservoir conditions, the injected gas accumulates at the top of the pay zone providing gravity stable oil displacement that drains down towards the horizontal producers (T. Mahmoud & Rao, 2007) and (T N Mahmoud & Rao, 2008). The schematic drawing of the GAGD process is shown in Figure 2.9 (Satake, 2015).

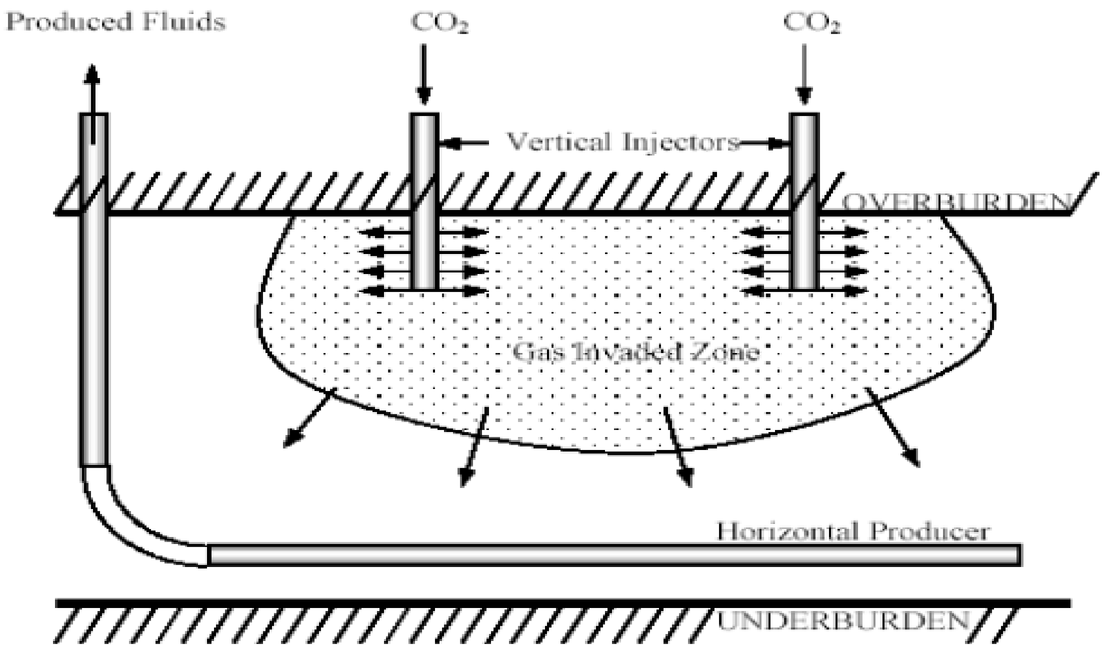


Figure 2. 9. Gas Chamber Grows and Sweeps Oil in GAGD Process. (D N Rao et al., 2004)

In the GAGD process, the formulated gas cap, the fluids gravity segregation, and the oil drainage towards the bottom of the pay zone lead to better sweep efficiency and higher oil recovery. The CO_2 gas is preferred for injection because it attains high volumetric sweep efficiency with high microscopic displacement efficiency, especially in miscible injection mode. Additionally, the high volumetric sweep efficiency assures delaying CO_2 breakthrough to the producer (Rao et al., 2006). Delaying or eliminating the gas breakthrough results in diminishing concurrent gas-liquid flow, and then leads to increase gas injectivity and maintains the injection pressure.

2.5. Gas-Assisted Gravity Drainage (GAGD) Process

In this section, A comprehensive study and in-details full review of the GAGD process were conducted including the mechanism of the gravity drainage in enhancing the hydrocarbon recovery from the reservoir. The development of the process over the period through the performed M.Sc. and Ph.D. research of Dr. Rao team at LSU and the first pilot test of the GAGD process were discussed.

2.5.1. Mechanism of GAGD Process

The concept of the GAGD process was introduced by Dr. Rao in 2003 to find an effective alternative method to improve oil recovery that used the advantage of the natural segregation of injected gas from crude oil in the reservoir and to be applicable in different reservoir types in both secondary and tertiary modes (D N Rao et al., 2004). The GAGD process consists of injecting the CO_2 or chosen gas of interest through the vertical wells at the top of the pay zone and producing oil through horizontal wells placed near the bottom zone. The use of horizontal producers increases the areal exposure to the reservoir thus leading to increased well productivity. The injected gas accumulates at the top of the pay zone due to gravity segregation and displaces oil that drains to the horizontal producer. The gas chamber at the top of the reservoir grows downward and sideways as the injection continues and sweeps a larger portion of the reservoir without an increase of water saturation in the reservoir resulting in maximizing the volumetric sweep. This gravity segregation phenomena delays or even eliminates the gas breakthrough to the producers and prevents the gas phase from competing for flow with the oil. Moreover, the oil displacement efficiency could be maximized by keeping the pressure above minimum miscibility pressure (MMP) which helps in achieving low interfacial tension (IFT) between the oil and the injected gas that in turn results in low capillary pressures and low residual oil saturations in the swept region. The process is capable to eliminate the main problems faced with other conventional improving recovery methods: poor sweep and water shielding and increases oil saturation and consequently improved oil relative permeability near the producing wellbores.

2.5.2. Research and Development of GAGD Process

In the development project of the GAGD process in 2004, a scaled physical model was constructed to demonstrate the GAGD process, to identify suitable reservoirs parameters, and to examine the effect of various factors such as GAGD/WAG, miscibility, wettability, heterogeneity, and others (Rao et al., 2004). In this project, they used de-ionized water, n-Decane, paraffin oil, and air to perform the designated experiments. In the first run, the Decane was injected into the model that was initially saturated with water to test free gravity drainage with the Decane experiment. The experiment resulted in a high ultimate oil recovery percentage (> 80%) and showed that the production rate was almost constant in the first ten minutes, after which it decreased significantly. In the second run, the paraffin was injected into the model in free gravity drainage manner to compare with the Decane. The experiment allowed us to observe the air-oil interface and its movement with the model. They concluded that the high oil recovery potential of the GAGD process compared to the WAG process and the miscible CO_2 flood process had outperformed the immiscible floods in all three modes of gas injection.

Sharma (2005) in his research of the GAGD process, conducted a series of visual experiments to investigate the effect of dimensionless parameters on the process performance by conducting many displacement experiments in a Hele-Shaw type model. Sharma studied the effect of bond number, capillary number, mobile water saturation, and different operation conditions. He concluded that the bond and capillary numbers are a good correlation with the cumulative oil recovery and these correlations are valid for both miscible and immiscible GAGD floods. The constant gas pressure injection resulted in slightly higher cumulative oil recovery (7-8%) and a higher rate of recovery as well compared to constant rate gas injection and the type of gas injectant does not affect the oil recovery in immiscible mode. This research agreed with the previous project conducted by Rao et al. (2004) with the fact of the immiscible GAGD floods can yield recoveries up to 80% of the IOIP in secondary mode, as opposed to about 5-10% by WAG process (Rao et al., 2004) and(Sharma, 2005).

Kulkarni (2005) conducted an experimental study where he injected CO_2 in WAG, CGI, and (GAGD) modes. Kulkarni compared the performance of these different modes and investigated the number of parameters with relation to the GAGD process. He examined the effects of gas injection rate, injection miscibility type, injection recovery mode, reservoir heterogeneity, gravity segregation, spreading coefficient, reservoir wettability, injection fluid type, gas cap control, and the existence of fractures in the reservoir (Kulkarni, 2005). Also, he performed an extensive dimensionless analysis and literature review to prove the concept of the GAGD process, demonstrate the high oil recoveries resulting from the floods, and modify Li and Horne's model to accurately predict the recoveries from the GAGD process. Kulkarni concluded that the GAGD process could potentially outperform all the presently practiced commercial modes of gas injection, namely CGI, WAG, and Hybrid-WAG, as verified by scaled laboratory core floods. He noticed that all the miscible GAGD core floods conducted in this study resulted in near-perfect oil recoveries, (almost 100% ROIP) irrespective of core properties or experimental conditions. In tertiary recovery mode, The GAGD flood behavior demonstrated significantly higher (nearly 2 to 3 times) gas utilization factors as compared to other methods. The study observed that the GAGD process was immune to the effects of reservoir heterogeneity and the presence of vertical fractures in the reservoir could be beneficial to the process as from near-perfect recoveries for miscible floods, and higher immiscible recoveries for fractured and un-fractured GAGD core flood experiments.

Paidin (2006) extended the previous work by Sharma in his research and conducted a study evaluating the effect of wettability of the porous medium, injection strategy, and the presence of a vertical fracture on GAGD process performance utilizing a physical model consisting of the Hele-Shaw model, glass beads or silicon sand (Paidin, 2006). The two series of gas displacement experiments showed a significant improvement of the oil recovery in the oil-wet experiments versus the water-wet runs, both in the secondary and the tertiary modes by an increase of 12.7% OOIP. The fracture simulation experiments had also shown an increase in the effectiveness of the GAGD process with an average incremental of 7.8% OOIP. By using CO_2 as injected gas, he found that affects the performance of the GAGD process when using an oil-wet porous medium in the physical model experiments by an increase of 10.9% OOIP while Sharma (2005) showed that the type of gas does not affect the GAGD performance when the experiments are conducted in a water-wet porous medium. Also, Paidin concluded that the constant pressure gas displacement of the oil in the experiments results in a slightly higher recovery (2.6-3.0 %OOIP) compared to the constant rate displacement, the bond number seemed to have less of an influence in oil-wet porous media while the increase in capillary number improved the oil recovery in a logarithmic relationship than in water-wet media.

Mahmoud (2006) built a visual glass model filled with Ottawa Silica sand and designed it to fit different vertical well configurations to visually discern the mechanisms operative in the GAGD process and the effects of various parameters: injection depth, injection rate, viscosity, fracture, wettability, and others (Mahmoud, 2006). Mahmoud used naphtha as the oil phase and Decane as the miscible gas phase in performing the miscible secondary injection experiments to simulate the miscible GAGD process. The conducted experiments showed a close to 100% microscopic sweep efficiency in the miscible GAGD process and enabled the identification of the possible mechanisms that are responsible for high oil recoveries: Darcy-type displacement until gas breakthrough, gravity drainage after breakthrough, and film drainage in the gas invaded regions. He concluded that the GAGD process is a viable process for secondary and tertiary oil recovery with a high percentage of recovery in immiscible injection mode as 83% IOIP for secondary and 54% for tertiary recovery. The model showed that the gas injection depth may not influence oil recovery as long there is vertical communication between reservoir layers whereas the presence of the fracture and the viscosity are helping to improve the recovery from naturally fractured and higher viscosity oils as well by 76% IOIP and 64% IOIP in secondary immiscible mode, respectively. Mahmoud's study research proved that the GAGD process works with gravity domination and further gravity force overcomes and permeability heterogeneity, which leads to better seep efficiency resulting in higher oil recovery.

Paidin (2013) conducted a study evaluating the first application of the GAGD EOR process in the Buckhorn field in the state of Louisiana through visual models and core flooding experiments, a field-scale numerical simulation, and economic analysis to determine the operating parameters that would lead to the best options of implementing a field trial based on the maximum oil recovered. The reservoir condition core flooding experiments were performed in secondary mode CO_2-GAGD to clarify the pertinent data to the field application of the SW- GAGD process which is used in a field-scale numerical simulation model to optimize the process regards to maximum oil recovery by investigating the best well location configuration and production strategies. The results from the experiments and simulation models were compared with the other commonly implemented EOR methods, like CGI and WAG. The study revealed that the multiwell GAGD process resulted in the highest oil recovery (> 50% IOIP) and profit compared with the other methods.

Saikia (2016) developed and demonstrated a novel design in the form of the SW-GAGD process addressing the cost and oil recovery in the Gulf of Mexico in 2016. In his design, Saikia used a single well to inject gas in the reservoir in a gravity stable manner and produce the oil through the horizontal lateral of the same well that is placed at the bottom of the pay zone (Saikia, 2016). He demonstrated the efficacy of the SW-GAGD process utilizing partially scaled visual glass models and material balance calculations. The experiments resulted in high recovery factors: 70% and 90% in immiscible and miscible modes, respectively as a result of excellent volumetric sweep efficiencies encountered in top-down, gravity stable flood in the proposed processes and high microscopic sweep efficiencies of the gas flood. Saikia found that the process is an order of magnitude faster compared to a free gravity drainage process, is highly immune to reservoir heterogeneities and hence recovery factors seen at laboratory scale are much more likely to be reproducible in the field.

Al Riyami (2017) performed a study evaluating the compositional effect on the Gas-Oil ratio on miscibility and the GAGD EOR process in 2016. In his research, Al Riyami considered the fluid-fluid interaction results from the Vanishing Interfacial Tension experiments (VIT) in GAGD process core flood experiments. He conducted three sets of GAGD core flood experiments using different injection gases: CO_2, N_2, and flue gas; and tested at three different pressures: 500, 1,000, and 2,000 psi and 100 °F (Al Riyami, 2017). The core flooding results showed an oil recovery of around 49% for the immiscible mode of remaining oil after water floods and a high recovery percent of 100% for miscible mode at 2,000 psi. He concluded that GAGD had superiority over other gas injection methods that are currently practiced, such as WAG and CGI, using CO_2 or any other gas.

Sombolestani (2018) built a Microfluidics Platform for Visualizing Oil-film Formation in GAGD Processes. In the study, the platform had been developed for making a microfluidic device out of a transparent polymer with high chemical and physical resistance to facilitate visualization experiments for EOR applications. The microfluidic device made of NOA81 (Norland Optic Adhesives 81) was designed and fabricated capable of studying 3-Phase fluid flow in a pore network like that of consolidated water-wet porous rock. The pore network is designed to represent sandstone reservoirs. Sombolestani injected two different sets of fluids with positive and negative spreading coefficients into the device to visualize the interaction between the phases and potential oil films. The experiments resulted in visualizing thinner oil layers in the positive spreading system and an experimental analysis confirmed the significance of the difference. He conducted that lower oil film thicknesses in positive spreading systems were caused by film flow, which will cause higher recovery. In a positive system, double drainage is dominant which will lead to a higher oil recovery while in a negative is not seen as common which causes the creation of oil banks. The microfluidic device was utilized to study different EOR processes through observation of different drainage mechanisms for different cases.

The application of the GAGD process in carbonate rocks is studied by Shah in 2018. Alok's study focused on the impact of the type of gas injected, the gas injection rate, and the grain size of the porous media. He conducted the laboratory experiments utilizing a Hele-Shaw glass model filled with carbonate rocks as the porous media, water, and n-Decane for oil (Shah, 2018). The results from Shah's study showed that using N_2 as an injectant provides slightly higher recovery for the GAGD process in carbonate rocks compared to theCO_2 and the optimal injection rate is at an intermediate injection rate that didn't disturb the stable front which can create an earlier breakthrough at higher injection rates. The study concluded that the larger grain size shows a significant improvement in overall oil recovery since increasing grain size diameter increases the permeability and thus overall oil recovery was obtained with an oil recovery ranging from 70.9% to 87.7% of OOIP.

Dzulkarnain investigated the displacement and fluid-fluid interaction mechanisms for oil recovery using the GAGD process in 2018. He conducted laboratory experiments and performed a simulation of mathematical modeling to address the film spreading mechanism that was not considered by the former mathematical models of gravity drainage aiming to understand the role of film formation in GAGD (Dzulkarnain, 2018). He used spreading and non-spreading oils in sand packs, where the sand is either water-wet, oil-wet, or fractional-wet and then evaluated the existing models to account for observations obtained from the experiments. Dzulkarnain's study showed that the oil recovery is higher in spreading fluid systems in water-wet sands while the recovery is higher in the non-spreading fluid system in oil-wet sands and fractional wet sands. At the pore level, oil recovery was higher for spreading fluid systems in water-wet whereas oil-wet experiments are similar for both spreading and non-spreading fluid systems regardless of the pore-level fluid configurations. The Oil-wet and fractional-wet experiments with Decane showed higher recovery for the non-spreading fluid system but the oil recovery for the spreading fluid system was lower in the water-wet experiments.

Al-Tamimi, in 2019, studied the effect of fractional wettability and fluid spreading interactions on the GAGD process. He conducted an experimental study using sand packs containing various oil-wet sand ratios with different spreading conditions of Decane as non-spreading oil and Soltrol as spreading oil (Al-tameemi, 2019). He used the core-scale models to describe the pore-scale mechanism for evaluating the reservoir-scale problems. His study showed that the highest recovery occurred in both complete water-wet sand with the spreading system and complete oil-wet with the non-spreading system. On the other hand, the lowest recovery occurred in both complete water-wet sand with the non-spreading system and complete oil-wet with the spreading system. The second highest recovery was in 12.5% fractional-wet with spreading oil (Soltrol). The second-lowest recovery was in 12.5% fractional-wet with non-spreading oil (Decane). He also found that similar oil recoveries were obtained in 25% fractional-wet and 12.5% fractional-wet, either in spreading conditions or non-spreading conditions. He concludes that the oil recovery in 62.5% fractional-wet sand in both the spreading and the non-spreading system was alike due to the resultant of 73% oil recovery which approximately is close to 100% water-wet sand pack in the spreading system and 100% oil-wet sand pack in the non-spreading system.

Figure 2.11 summarizes the development of the GAGD process over time starting from 2003 to 2019. About 11 experimental research of master theses and Ph.D. Dissertations were performed in developing and implementing the process in conventional reservoirs. In this research, the implementation of the GAGD process in the unconventional resources was examed using different cores.

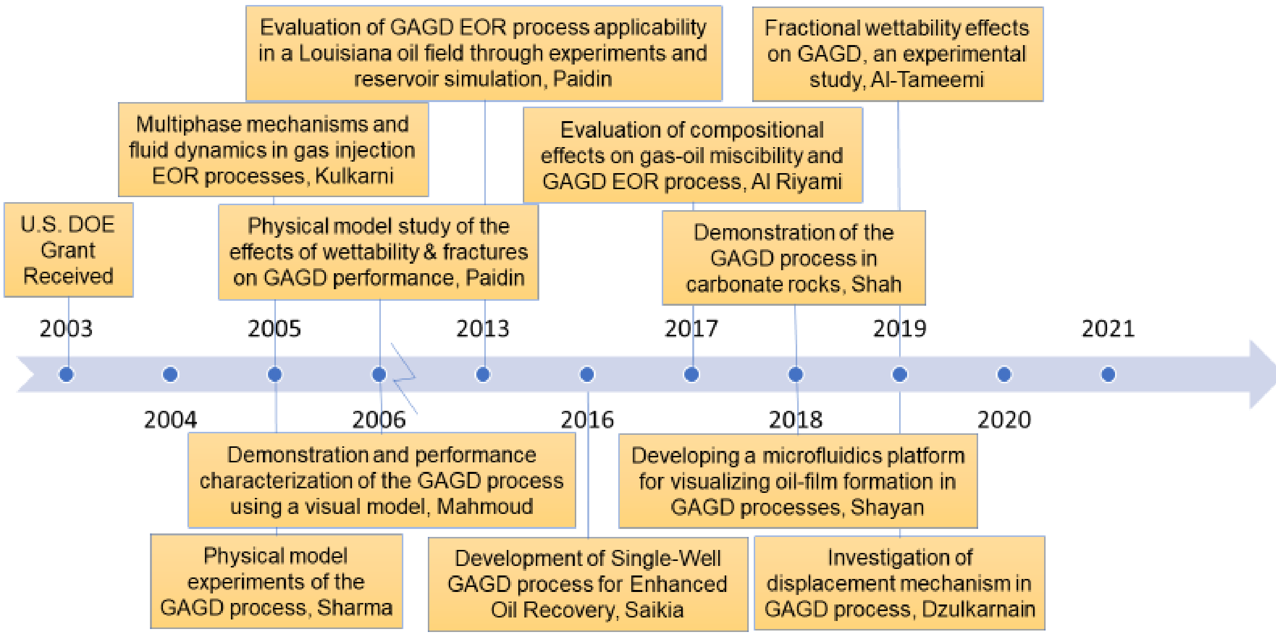


Figure 2. 10. Experimental Types of Research and Development of GAGD Process in Rao's Research Team at Louisiana State University (LSU)

2.5.3. Application of GAGD Process

The first successful application of the GAGD process was performed by Long Joint Operating Company to improve oil recovery from a fractured basement reservoir (13% porosity, 15-20 md permeability) in Cuu Long Basin, offshore Vietnam in 2015. The conventional GAGD process was conducted in a Huff 'n' Puff mode (cyclic gas injection) and consisted of 4 cycles in which dry gas was periodically injected into an existing production well in an isolated area (Dinh et al., 2017). This oil reservoir had several challenges, including:

- The fractured basement is a system of fractures, faults, and permeable activities.
- Small fractures develop along with major fractures, with a small aperture of 0.01 – 0.1 mm.
- The effective reservoir porosity and permeability reduce as the depth increases.
- The oil production decreases significantly, and the water cut increases as the water influxes from the aquifer into the reservoir.

- The water cut increases greatly with continuous production which makes the capacity of gas lift insufficient to support field production.

Dinh et al. (2017) found that the field needs other possible EOR techniques to increase oil production from the field. With all the challenges, they selected the GAGD process to be implemented for the complex nature of fractured basement reservoirs to improve the oil recovery.

Before full implementation of the GAGD process in the Y-field, a pilot test was designed for an isolated region of the Y area with two wells: Y-12P and Y-24P to evaluate the method, its associated risks, and potential problems. They conducted tests on well Y-24P for 54 days showed a significant increase in oil production starting from 250 STBOPD to approximately 1,500 STBOPD and a significant decrease of water cut (WC) from 91% to 15.7% demonstrating a very effective displacement process. Dinh et al. (2017) reported that the well Y-24P even reached the highest oil rate of 4,500 BOPD one week after reopening. The initial oil production of well Y-12P after reopening was only 50 STBOPD with primarily gas production then the oil production increased dramatically to 3,000 STBOPD with almost no water cut and then the production rate declined to 2,000 STBOPD with increasing in water cut. The GAGD process proved it is principally responsible for the reduction of water cuts and improved performance. From the test, they concluded that the gas injection volume is well correlated with cumulative water-free oil production and the final incremental oil gain of each cycle depended upon gas injection volume, gas injection time, shut-in time, and other factors.

GAGD process increased the net-to-gross of the whole tested reservoir area of implementation in both miscible (click) and immiscible (click) injection scenarios by pushing the OWC downward, Figure 2.12. The beauty of the GAGD process is it can be applied in different injection modes, miscibility conditions, and use various injectants.

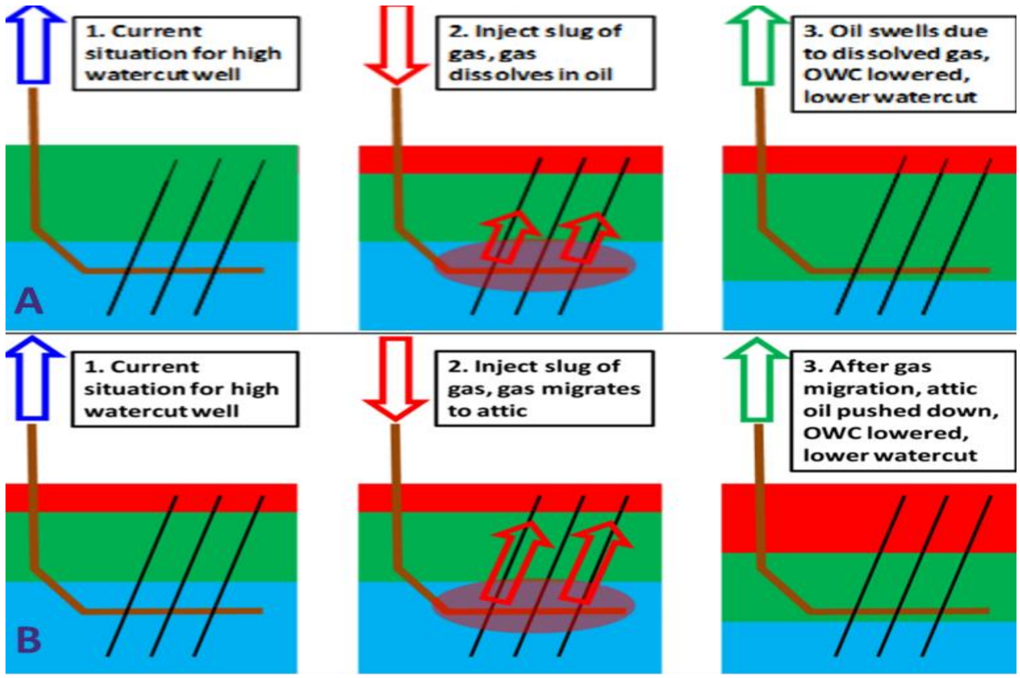


Figure 2. 11. The GAGD Process Application in (A) Under-Saturated (B) Saturated Fractured Reservoir in Vietnam (Dinh et al., 2017)

The successful implementation of the GAGD pilot proved that it could be a simple and effective EOR method for fractured basement reservoirs (Dinh et al., 2017). It can be a foundation for further application of the GAGD process in different phases and modifications to be suitable to go over the existing issues and difficulties may face in the future of EOR applications.

2.6. Enhance Oil Recovery in Unconventional Resources

The unconventional resources have played a significant role in changing oil industry plans recently but the predicted primary recoveries are still low as less than 10% OOIP and their production lives are short as less than 10 years (Jia et al., 2019). Therefore, seeking for improved oil techniques to increase oil recovery in these complex plays is inevitable (Alfarge et al., 2017) without these techniques, operators will not be able to develop these fields efficiently. Unlocking the potential from these unconventional resources requires considerable laboratory experimental work before performing numerical simulation or any field test. Understanding the mechanisms of gas injection EOR mechanism is going to enlighten the future for the development of unconventional, tight reservoirs. Unlike conventional reservoirs, the ultra-tight matrix and high-conductivity microfracture network conditions make many traditional improved recovery technologies extremely challenging to be implemented (Jin et al., 2016). The observation from different experiments reported in the literature indicates that the mechanisms of EOR in unconventional reservoirs could be substantially different than those of conventional reservoirs (Jin, Sorensen, et al., 2016a). The early-published studies of improving the oil recovery from unconventional resources started last decade. These studies showed that the much lower viscosity injections such as CO_2 or mixed with hydrocarbon (HC) gases, compared with water alone, can provide much higher injectivity and more suitable technique than water flooding to unlock the potential of the unconventional liquid reservoirs (ULR) in terms of technical viability (Wang et al., 2010), (Lim et al., 1996), (Nelms & Burke, 2004), (Dong & Hoffman, 2013), (Taber et al., 1997), (Zhang et al., 2017) and (Schmidt & Sekar, 2014). Following, the review of the published studies was conducted and discussed chronically and categorized into three groups: laboratory experiments, simulation models, and pilot tests.

2.6.1. Experimental Studies of Gas Injection EOR in Unconventional Resources

One of the earliest experiments of enhancing oil recovery from unconventional resources was conducted by Gamadi et al. (2013) to investigate and quantify the potential of improving the oil recovery by Nitrogen (N_2) in cyclic gas injection mode and Mineral oil (Soltrol 130) as saturated oil. They used unfractured shale core samples from Barnett, Mancos, and Eagle Ford fields to perform the experiments at a fixed temperature (95 ^oF) and investigate the effects of different cyclic gas injection parameters on oil recovery like injection pressure, soaking time, and the number of cycles. The study showed that the oil production was increased drastically when the operating pressure change from immiscible conditions to near miscible pressure which led to the ultimate recovery (Gamadi et al., 2013). Also, the study proved that the soaking period affected the recovery factor when the operating pressure reached miscible conditions where more shut-in time was needed for miscibility and the peak of production was in the first cycle and keep increasing till equilibrated. This laboratory experimental work showed that the cyclic N_2 injection process could improve oil recovery by about 33% in Marcos's shale, 60% in Barnett shale, and 73% in Eagle Ford shale. They conclude that oil recovery can be improved by utilizing nitrogen as cyclic gas injection and re-pressurizing the reservoir near miscible conditions.

Hawthorne et al. (2013) investigated the mechanism beyond increasing the oil recovery by injecting CO_2 to understand the difference of CO_2 EOR mechanistic processes' applications in unconventional resources from those controlling oil recovery in conventional reservoirs. They performed various laboratory experiments on unlike-size core samples from three different formations in the Bakken field with porosities ranging from 4.5% to 8.1% and permeabilities from 0.002 to 0.04 millidarcy at reservoir conditions (5,000 psi and 230 ^{o}F). the minimum miscible pressure (MMP) values for the collected crude oil samples determined by capillary rise Vanishing Interfacial Tension technique (Ayirala & Rao, 2006) ranged from 2,800 to 3,000 psi. The recoveries from the experiments under static CO_2 exposure for 96 hours were surprising with 90% from middle Bakken within 4 hours and 60% in 96 hours for tighter samples from lower Bakken. The recovery from the upper and lower Bakken barley achieved 40% after 24 hours of dynamic CO_2 exposure. The effect of hydrocarbon molecular weight on recovery rates was examined and revealed that there is a great degree of preference for CO_2 recovery of lighter versus heavier hydrocarbons, as is especially evident from the tighter Upper and Lower Bakken shales (Hawthorne et al., 2013). Their experiments proved that the diffusion mechanism is the main mechanism for CO_2 to increase oil recovery in very tight shale complex formations such as the Bakken field. They conclude that extraction of oil from this matrix by CO_2 requires long time exposure combined with large contact areas. Based on the study, a numerical simulation model was constructed for the Bakken field including various parameters representative of a multistage hydraulically fractured well to evaluate the effect of produced gas injection on enhancing the oil recovery process (Jin et al., 2017). The EOR process was modeled for the study as cyclic gas injection and designed for different simulation cases with a maximum injection pressure of 6,500 psi, injection and soaking periods of 15 days, and a production period of 150 days. The simulation model study showed that the CO_2 was making the best performance to increase oil production followed by $CH_4/C2H_6$ mixture which effectively increased the cumulative production by 50%.

Gamadi et al. (2014) extended their laboratory experimental work conducted in 2013 in improving the oil recovery from unconventional resources by implementing CO_2 as an injectant in cyclic injection mode on fractured cores from Mancos and Eagle Ford fields to investigate the potential of CO_2 injection and compare it with the N_2 injection. In this experimental study, they considered many design parameters such as soaking period, soaking pressure, and numbers of cycles under miscible conditions and temperature maintained at 95 ^{o}F to evaluate the feasibility of the cyclic CO_2 injection process. The dimensions of the cores were: diameter of 1.5 inches and length of 2 inches with the average porosities of 5% and 7.7% for Mancos and Eagle Ford, consecutively, saturated with C_{10}-C_{13} Iso-alkanes (Gamadi et al., 2014). The experiments showed that injecting CO_2 at near miscible conditions had a great impact on the recovery factors compared to the injection at the immiscible condition in which the recovery factor had increased from 20 % to 65 % in Eagle Ford cores and from 10 % to 29% in Manco's cores. By increasing the soaking periods, the recovery factors were increased to about 9 % in Manco's cores and 12% in Eagle Ford with less effect on the latter. The study revealed that more repeated injection cycles were needed to achieve the highest oil recovery when CO_2 was injected at and above MMP with the same soaking time. They observed a difference in the performance of cyclic CO_2 injection on the two shale core plugs even when identical operation conditions were used. The experiments resulted in improving the oil recovery from 33% to 85% depending on the shale core type and other operating factors (Gamadi et al., 2014).

To compare the performance of different gases on the improving oil recovery process in unconventional resources, Alharthy et al. (2015) conducted different cyclic gas injection processes using solvents such as CO_2, N_2, CH_4, CH_4-C_2H_6 mixture, and a mixture of wet gas on core samples from middle and lower Bakken field. The experiments were performed at a constant injection pressure of 5,000 psi and maintained a temperature of 230 ^oF to reach miscibility conditions for all experiments. The space between the inside of the extraction vessel wall and the cylindrical cores was acting as fracture surrounding the core matrix and the process was repeated up to 24 hours to recover most of the saturated hydrocarbon. The experiments resulted in improving the oil recovery by 40% from lower Bakken cores and 95% from middle Bakken cores using CO_2 as injectant solvent. The same result was achieved utilizing the solvent mixture CH_4 (85%) and C_2H_6 (15%) as of using CO_2 but the recovery of hydrocarbon with CO_2 was faster during the early parts of the fluid exposure. The hydrocarbon recovery factor using CH_4 or N_2 solvent soaking in middle Bakken cores are 92% and 26% at 24 hours respectively (Gamadi et al., 2014). The CO_2 soaking experiment for the lower Bakken core resulted in less oil recovery (32%) in 24 hours which was much lower compared to the Middle Bakken core. The huge difference between the two results refers to the difference in lithology, total organic content, and reservoir properties like porosity and permeability. They conclude that gas mixtures could perform as well as the CO_2 under miscibility conditions, longer soak times yield only a small additional oil recovery compared to short soaking times, and recoveries are enhanced by higher exposed surface areas. Also, the counter-current flow of oil from the matrix and molecular diffusion across the fracture-matrix interface were the main mechanisms for these gases for incremental oil production in CO_2 or NGL solvent soaking EOR process.

Yu & Sheng (2015) and Yu et al. (2016) conducted immiscible cyclic N_2 injection experiments to study the impacts of injection pressure, pressure depletion rate & time, soaking time, and production time on the recovery efficiency on shale core samples from Eagle Ford field. The core's average porosity was 8.5% (Yu & Sheng, 2015), measured average helium porosity was 9.7% and the nitrogen permeability ranges from 300 nD to 500 nD (Yu et al., 2016). These cores were cut in equal dimensions (diameter of 1.5 inches and length of 2 inches) and saturated with Soltrol 130 Iso-paraffin Solvent or dead oil from Wolfcamp shale play after vacuumed for an adequate time at a temperature of 70 ^{o}F. The predesigned experiments were performed at 1,000 psi and 104 ^{o}F and examined different soaking, depletion times, and injection pressures. As in the former experiment design, the annulus space between the core outer boundary and the inside wall of the vessel was acting as an artificial fracture. The ultimate recovery achieved for 10 cycles and soaking time one day was 50.51% while the soaking time of 3 days improved the oil recovery by little, 51.33% only (Yu & Sheng, 2015). Increasing the injection pressure from 1,000 psi to 5,000 psi resulted in higher oil recovery from the first cycles compared with the later cycles and ultimate recovery of 26.8% in nine cycles which would be achieved by more cycles with lower injection pressure. They found that there exists an optimum soaking time to produce the maximum amount of oil after each cycle. They conclude that the oil can be recovered rapidly during the first two hours during each cycle, the oil recovery increased as the pressure depletion time & rate increased.

The oil recovery factor raised with longer soaking time only within a certain period because while further longer periods did not present a better performance. As a result, there exists an optimum soaking period that is beneficial to improve oil recovery and shorten the operation time; and applying a higher injection pressure could increase the ultimate RF with a fewer number of cycles and thus shorten the development period (Yu, Y. et al., 2016).

Yu & Sheng (2016) and Yu, Y. et al. (2016) extended their previous experimental evaluation of improving shale oil recovery from Eagle Ford using N_2 in a CGI mode to investigate the effect of flooding time and injection pressure on the recovery factor. The dimension of the cores was the same as former experiments but they were tighter with a measured average helium porosity of 5.21% and the nitrogen permeability of 70 nD. The experiments were performed at room temperature of 71 ^{o}F, flooding time ranged from 1 to 5 days in increments of 1 day for one group, injection pressure ranged from 1,000 psi to 5,000 psi in increments of 1,000 psi for other group and backpressure was set at atmospheric pressure to achieve maximum oi production (Yu, Y. et al., 2016). The cores were prepared by placing them in a vessel, vacuumed for 24 hrs. and then saturated with dead oil at a constant operating pressure of 1,000 psi for another 24 hrs. The experiments observed that the cumulative recovery factor can be improved up to 31.6% after a 5-day flooding process and could reach up to 33.6% at an injection pressure of 5,000 psi. Oil was produced fast on the first flooding day, then the rate dropped gradually until no more oil came out which demonstrated that the oil recovered in the first day accounted for approximately 50% of total production in five days (Yu & Sheng, 2016). The incremental recovery factor was based on the greater pressure gradient which creates extended flow channels (enlarge the stimulated area) and improves the plug conductivity. The results from these experiments showed that more oil could be produced with a longer flooding time, but the incremental recovery factor decreased with the increase of flooding time. The oil recovery increased with injection pressure, but the gas breakthrough time became shorter with the increase of injection pressure. The study concluded that the N_2-CGI could be applied as a short-term IOR solution, and the flooding time and injection pressure were significantly improved the shale oil recovery in shale reservoirs with ultra-low permeability.

Li et al. (2015) conducted cyclic gas injection experiments using CH_4 to investigate the influence of different operating parameters and optimize the recovery in unconventional shale reservoirs. In this study, core plugs from Wolfcamp formation in Apache's Lin field saturated with oil from the same field were used with the same length of 2 inches and different diameters ranging from 1 to 4 inches at an injection pressure of 2,000 psi and constant temperature of 95 ^{o}F. The cores' measured average helium porosity was 6%-8% and the nitrogen permeability ranges from 300 nD to 500 nD (Li & Sheng, 2017). The experiments study the effect of the core sizes on the performance of improving the oil recovery process. The experiment results of ultimate oil recovery in five cycles were 40.07%, 39.17%, 38.34%, 36.08%, 33.79, and 32.31% for the cores with the diameter of 1, 1.5, 2, 3, 3.5, and 4 inches, respectively (Li & Sheng, 2016, 2017), which point out that the accumulate oil recovery in smaller cores is higher than that in larger size cores under the same operating schedule. Also, they found that the core length does not influence the oil recovery and the oil recovered in the later cycle is less than that of the former cycle for all different size core plugs which agreed with previous experimental studies (Y. Yu, Li, et al., 2016; Y. Yu & Sheng, 2015). They conclude that the main parameters determining the oil recovery were the apparent surface-to-volume ratio and the pressure gradient along the radius of the core.

Based on the results from this laboratory experimental study, a field-scaled cartesian compositional model was created to investigate the influence of different operating parameters and optimize the outcome of the cyclic methane injection process to enhance the oil recovery from shale oil fields (Li et al., 2016). The model grid block size was 18 x 18 x12 with operation constraints of 2,000 psi as maximum injection pressure and 10 Mcf/day of maximum surface gas injection rate. To study the effect of the field size, the lab-scale model was enlarged to two different sizes: the first model was expanded to 10^4 x and the second model was increased to 10^6 x. The effect of operating parameters including gas injection time and injection rate, gas production time and production rate, soaking time, and gas injection pore volume were studied using the field-scale models. The study showed that the most effective optimization is to increase the pressure gradient during huff and puff periods by increasing injection pressure or decreasing production pressure while other parameters showed less significant oil recovery increment. They concluded that there are an optimum injection rate and an optimum production rate for the cyclic gas injection process when the rate is less than the optimal value, the oil recovery increases as the operation rate increases. On the other hand, when the operation rate is higher than the optimal value, increasing the injection rate will lead to a decline in the oil recovery, while further increasing the production rate will cause an insignificant oil recovery increase. Later, a numerical analysis was conducted via CMG-GEM to perform a series of sensitivity studies to investigate the effects of operation parameters on oil recovery in shale oil cores, such as the number of injection cycles, molecular diffusion, soaking time, and operation schedule (Li & Sheng, 2017). The simulation results showed that incremental oil recovery in each of the subsequent cycles decreases as the number of injection cycles increases. The viscous displacement and relative permeability hysteresis mechanisms may have played a more important role than molecular diffusion as an EOR mechanism after the first five cycles. The larger core needs a longer soaking time to achieve the maximized oil recovery than a smaller core within a single cycle.

Ma et al. (2016) investigated the application of cyclic CO_2 injection as a primary oil recovery means to enhance the recovery of low-pressure light oil-tight formation field located in northwestern China under reservoir conditions. The reservoir original pressure was 954 psi, far below the MMP of 3,336 psi, and the reservoir temperature was 93 ^{o}F. They conducted 8 series of core floods, a total of 35 runs of cyclic gas injection in a composite core from a naturally fractured shale reservoir to evaluate the effect of major factors on the performance of mentioned EOR process. The operational factors evaluated in this study were gas injection rate, pressure depletion rate, maximum injection pressure and chasing gas (N_2), minimum termination pressure, and soaking time. And to mimic the reservoir heterogeneity, they used 21 core pieces from several wells with an average porosity of 19.1% and average permeability of 117 mD in a long composite cores sample of 38.7 inches in length and one inch in diameter. To prepare the cores, they flushed them with the brine and displaced it with crude oil from the same oilfield until no further water was produced out, establishing the connate water saturation (≈35%) and the original oil saturation (≈65%) and aged for one week. The experimental results showed that the first three cycles are the dominant contributors with a total recovery factor of 29% OOIP and chasing the CO_2 injection with N_2 would have the potential to improve the EOR efficiency while maintaining the performance at a favorable level. They conclude that an intermediate injection rate may produce more favorable results than a large injection rate, the recovery did not seem sensitive to the pressure depletion rate, oil production mainly occurs in the early production stage when the pressure is maintained higher than a certain level and an intermediate soaking time was more beneficial for the first cycle operations and the economy of the operation most.

Pu et al. (2016) conducted series of cyclic CO_2 injection experiments on core samples from a tight oil field located in western China to investigate the potential of applying the aforementioned

EOR process in enhancing oil recovery. The experiments tested different conditions such as operating pressure, soaking time, oil viscosity, differential production pressure, and multi-cyclic operation and performed on the fixed temperature of 167 ^{o}F and pressure ranging from 580 to 3,771 psi. The used cores' dimensions were 1.976 inches in length and 0.992 inches in diameter with an average porosity of 14.5% and 316 μd average permeability. The cores flooded with brine from the same oilfield to determine the pore volume and permeability followed by oil from the field until stop producing water to establish the average connate water saturation of 16.3% and average initial oil saturation of 83.7%. The experiments resulted in increasing the ultimate oil recovery to 41% OOIP (Pu et al., 2016a) at operating pressure of 2,320 psi, six hours soaking time, and four cycles. They found that the ultimate oil recovery increased with the operating pressure that is corresponding to the pressure depletion rate. Also, the recovery factor decreased with the cycle numbers which led them to suggest that the cyclic gas injection process should not be more than two cycles. They observed that extension soaking time would improve the oil recovery because the longer soaking time of CO_2 dissolution in the crude oil induces oil swelling and viscosity reduction. Also, the experiments showed that the oil recovery factor increased with the differential pressure and, the production differential pressure should be maximized for tight formations to allow the lighter oil to dissolve more CO_2. They concluded differential production pressure (dP) functioned as the dominant parameter in the cyclic CO_2 injection process for tight oil recovery enhancement, the injection pressure has a great impact on oil swelling and the EOR process should be designed at optimal operation to increase the efficiency of the gas utilization.

Jin et al., (2016) investigated the improvement of oil transportability in ultralow permeability formation in the Bakken field utilizing continuous CO_2 injection. They performed detailed core analysis to determine the petrographic and petrophysical properties for each of 21 core samples collected from two newly drilled wells from the system and used as they received. These core samples were 0.433-inch diameter and 1.57 inches long and had an average porosity of 6% and permeability ranges from 0.0006 to 0.2 md in Middle Bakken, from 0.001 to 2 md in Upper Three Forks, and less than 0.01 md for the Upper and Lower Bakken members. The experiments were performed at reservoir conditions (5,000 psi and 230^{o}F) and conducted as CO_2 bathing rather than a flow-through test to increase the understanding of the changes in microstructure and diffusion flowability within these tight geologic formations. The results showed that CO_2 can improve the recovery to a higher percentage (95%-99%) after 24 hours of exposure of CO_2 injection for Three Forks and Middle Bakken samples and 60%-68% for Upper and Lower Bakken samples (Jin et al., 2016). They concluded that the CO_2 greatly enhances the diffusion process to improve hydrocarbon transport in the ultra-tight matrix. CO_2 has greater areal contact in the reservoir enabling the diffusion process to expel hydrocarbon out of the matrix and the fracture network assists in alleviating potential injectivity challenges. Also, CO_2 could be injected into highly fractured tight reservoirs via fractures and extract oil from the matrix by diffusion mechanism. Jin et al. (2016) extended the work and conducted the above-mentioned EOR process on 13 samples using different gases like CO_2, N_2, CH_4, and C_2H_6 at the same reservoir conditions. The experiments demonstrated the improvement of oil recovery in all Bakken rocks and were able to extract up to 95% OOIP from Middle Bakken and 8% to 35% from Lower and Upper Bakken samples, respectively (Jin et al., 2016). The results also showed that CO_2 and C_2H_6 (the best) yielded better recovery efficiency than CH_4 and N_2 (the least). They conclude that CO_2 and hydrocarbon gas injection methods seem to be more feasible than others.

Li, L. et al. (2017) continued performing the cyclic gas injection experiments using the core samples from the Wolfcamp reservoir in Apache's Lin field and saturated them with dead oil from the same field to compare the enhanced oil recovery potential of different gases. The gases used in these experiments were N_2, CH_4) and CO_2 and injected at the same operating conditions: operating pressure of 2,000 psi and temperature of 104 ^oF. The core and dead oil properties were identical to the presented cores (Yu, Y. et al., 2016). The experiments showed that using CO_2 in the cyclic gas injection process to enhance oil recovery from Wolfcamp formation was the best, followed by N_2, then CH_{14} with the average oil recovery of 65%, 50%, and 35% after six cycles, respectively. The injection pressure above MMP of CO_2 Wolfcamp crude oil system which is estimated to be 1,620 psi at 104 ^oF can improve the oil recovery by 10% after seven cycles (Li, L. et al., 2017). However, when the injection pressure is higher than the MMP by more than 200 psi, the increase of the pressure is unable to enhance the oil recovery in shale cores significantly. This variation resulted from using dead oil to saturate the core samples which preferred to dissolve the CH_4 into the saturated oil or miscible CO_2 during the soaking period compared with N_2 that didn't dissolve or needed much higher miscible pressure. They determined that the oil recovery in the first injection cycles was larger compared with the subsequent cycles and CO_2 had a huge potential to produce more oil compared with other injectant. They concluded that the mechanism of cyclic gas injection includes operating pressures and gravity gradients, swelling, miscibility, and molecular diffusion lead to a lower hydrocarbon density, viscosity, and interfacial tension which resulted in enhancing unconventional oil recovery in shale or tight reservoirs.

CO_2 followed by enriched gas was found to be the most applicable improving oil recovery methods in unconventional reservoirs. CO_2 injection seems to be the most feasible and best technique among the reported improving oil recovery methods (Li, Sheng, et al., 2017) and (Alfarge et al., 2017), and the cyclic injection scheme or huff-n-puff injection process was the most effective and promising improving oil recovery solution in shale reservoirs (Yu et al., 2016) and

(Gamadi et al., 2013). Also, the first couple cycles of the cyclic injection process contributed with most production and the first cycle was the peak in production (Ma et al., 2016), (Li & Sheng, 2016) and (Li, Sheng, et al., 2017). Recovery factor from a single cycle increased with soaking time within a certain range (Yu et al., 2016) & (Yu & Sheng, 2015) and longer time has no noticeable impact. Also, the recovery factor increased with the pressure depletion time for each cycle (Yu & Sheng, 2015) and (Yu et al., 2016).

Table 2.3 gives a clear summary of the most significant studies conducted for using gas EOR methods to improve oil recovery from unconventional reservoirs.

Table 2. 3. Summary of the Reported Experimental Studies for Gas Injection EOR Techniques in Unconventional Reservoirs

Paper no.	**Authors**	**Year**	**EOR Method**	**Miscibility**	**EOR Mechanism**	**Best RF**
SPE 166334	Gamadi et al.	2013	N_2 HnP	Immiscible	Repressurization	73%
SPE 167200	Hawthrone et al.	2013	CO_2 CGI	Miscible	Extraction	90%
SPE 169142	Gamadi et al.	2014	CO_2 HnP	Near Miscible	Repressurization	85%
SPE 175034	Alharthy et al.	2015	Diff. Gases HnP	Miscible	Diffusion	95%
AlChE Conf.	Li et al.	2015	CH4 HnP	N/A	Repressurization	40.1%
SPE 178494 JUOGR 15	Yu & Sheng Yu et al.	2015 2016	N_2 HnP	Immiscible	Repressurization Fracturing	51%
SPE 179547	Yu & Sheng	2016	N_2 CGI	N/A	Repressurization	33.6%
Fuel 174	Ma et al.	2016	CO_2/N_2 HnP	Immiscible	Repressurization	29%
SPE 179533	Pu et al.	2016	CO_2 HnP	Miscible	Repressurization	40.9%
URTeC 2433692	Jin et al.	2016	CO_2 & Diff. Gases CGI	Miscible	Diffusion	>95%
SPE 185066	Li et al.	2017	Diff. Gases HnP	Miscible	Diffusion	65%

2.6.2. Simulation Modeling of Gas Injection EOR in Unconventional Resources

The reservoir simulation modeling is known as a useful tool in the hydrocarbon industry to exercise improving reservoir management. The simulation uses a numerical simulator like ECLIPSE, CMG, and other in-house simulators to develop various reservoir models and analyze their behaviors at different conditions over a period.

One of the earliest reservoir simulation modeling studies was conducted by Shoaib and Hoffman in 2009 for analyzing the impact of CO_2 flooding mechanism in the Elm Coulee Field in Montana State that is a tight oil reservoir (permeability: 0.01 – 0.04 md) with a very low primary recovery factor of 5 – 10%. They build two simulation models using ECLIPSE for a selected 2 x 2 miles sector consisting of six hydraulically fractured single-lateral horizontal wells: the black oil model represents the reservoir on primary recovery mechanism and the solvent model represents a miscible fluid injection process using CO2 as a solvent in different scenarios (Shoaib & Hoffman, 2009). This simulation study demonstrated that the continuous CO2 flooding of horizontal wells increases the production of the field over the primary recovery, more efficiently than vertical injection techniques and higher recovery compared with the single-well cyclic injection treatment. They recommended the best scenario to satisfy the production requirements was to drill new injectors along with converting existing producers to injection wells and to drill more producers such that having one injector between two producers. Shoaib and Hoffman (2009) concluded that this arrangement on horizontal injection increased the field recovery factor by 16% after eighteen years of injection of 0.2 PV of CO_2 at 6,000 psi.

A year later, researchers from Saskatchewan Research Council conducted a numerical simulation study evaluating the effectiveness and economy of CO_2 flooding potential for enhanced oil recovery an extremely tight formation with low porosity (5 – 15%) and low permeability (1 –

20 md) from Bakken field in Saskatchewan, Canada. Wang et al. (2010) created the reservoir model using the CMG -builder module and tuned the reservoir fluid model by the CMG-WinProp module and used the CMG-GEM model to simulate the gas injection process at five different factors. The 2 x 2-mile built model consisted of 13 hydraulically fractured horizontal wells completed in the Middle Bakken formation. They tested different strategies to compare the effects on oil recovery of injection well patterns, injection schemes, different solvents, different EOR schemes, and heterogeneity. The simulation study results showed that CO_2 flooding is presenting a technically promising method for recovering the vast Bakken oil and suggested using the reservoir fluid-injected gas PVT tests, MMP measurements, and core flood tests to perform a more realistic simulation study. They concluded that the good pattern can facilitate oil production (34%) and reduce the injected solvent and the mixture of CO_2 with enriched produced gas or enriched flue would have higher recovery performance (36%) compared with CO_2 alone as solvent. Also, the continuous CO_2 injection scheme had a higher production rate and better recovery factor compared with the cyclic CO_2 scheme (29%) and performed much more effectively if applied after primary oil recovery than continuous water flooding or secondary water flooding followed by tertiary CO_2 flooding (21%) (Wang et al., 2010).

Dong and Hoffman (2013) evaluated the performance of CO_2 injection for the Bakken interval in a sector of the Sanish Field. by building two (2 miles x 2 miles) numerical reservoir simulator models with three hydraulically fractured horizontal production wells using ECLIPSE. The Black Oil Model represented the primary recovery process which defines the reservoir properties, well details, and production rates. The solvent model observed and analyzed the CO_2 flooding to enhance oil recovery applications through different parameters: well type, numbers of well, injection operation, and injection type. They found that using the CO_2 injection method might increase oil recovery from 5% to 24%, the higher injection rate can yield a higher production rate and greater recovery factor, the oil increased to almost double the primary production while the impact of injection pressure is minute with more CO_2 required. They concluded that the continuous CO_2 injection resulted in four times more oil recovery compared to water flooding and the best scenario was to have an addition of four new horizontal injectors, which lead to the highest recovery factor of almost 30%.

In 2015, a compositional reservoir modeling was built via CMG GEM and performed to investigate the effectiveness of injecting CO_2 as a miscible gas injection into a hydraulically fractured long horizontal well and producing from an adjacent fracture that has an intersection with the same well to improve the oil recovery (Zhu, Balhoff, & Mohanty, 2015). The model consisted of two hydrofracking half-stage horizontal wells and was created in two base cases to represent the matrix permeabilities of 10 μD and 1 μD. Zhu e. al. investigated the effects of different reservoir properties and injection conditions on the recovery process by examining many parameters like injection pressure, reservoir heterogeneity, hydrofracking spacing, dispersion, and injectant compositions. The results from the model showed a 15.7% OOIP incremental recovery for the base model (primary recovery <10% OOIP for 500 days) with matrix permeability of 10 μD over 5,000 days of CO_2 injection at 7,000 psi and 12.5% OOIP for the model with matrix permeability of 1 μD, indicating that the gas injection scheme has the potential to vastly improve oil recovery in oil-rich shale formations (Zhu et al., 2015). The study concluded that increasing the injection pressure and reducing the hydrofracking spacing leads to higher production and faster recovery, heterogeneity and mechanical dispersion had insignificant or less effect on recovery; and injecting recycled HC gas improved the oil recovery and outperformed CO_2 since the recycled HC gas has lower viscosities.

Yu et al. (2015) studied the enhanced oil recovery by CO_2 as a cyclic gas injection process through modeling a sector from Bakken tight oil reservoirs by CMG GEM processor. The numerical simulation model dimensions were 340 ft. (length) x 1300 ft. (width) x 40 ft. (thickness) and the built-in grid block size was set to 20 ft. x 20 ft. x 40 ft. in x, y, z directions, respectively. They created four effective hydraulic fractures in the model with a half-length of 210 ft., the height of 40 ft., the conductivity of 50 md ft., and spacing of 80 ft. and set up the duration of the running time 30 years for all cases and scenarios. During the study, a comprehensive sensitivity was performed to investigate the effects of CO_2 molecular diffusion, the number of cycles, fracture half-length, permeability, and reservoir heterogeneity on the good performance of CO_2 huff-n-puff. The results showed that the CO_2 diffusion plays a significant role in improving oil recovery from tight oil reservoirs and the tight oil formation with lower permeability, longer fracture half-length, and more heterogeneity is more favorable for the CO_2 huff-n-puff process (W. Yu et al., 2015). They conclude that the oil recovery factor at 30 years of production for the case with CO_2 injection and diffusion was the highest while the recovery factor of the case with CO_2 injection while without CO_2 diffusion was the lowest.

A further study was conducted by Sanchez-Rivera et. al (2015) to optimize the cyclic CO_2 and hydrocarbon mixture injection operations in the Bakken shale. Their numerical reservoir model was created through the CMG GEM simulator to study various design components of the cyclic gas injection process and identify their impacts on recovery such as production pressure, the number of cycles, the length of injection, soaking, and production periods. Also, they examined the molecular diffusion and natural fractures' roles in the process. The single porosity model domain was 25 x 40 x 1 Cartesian grid with local grid refinement around the hydraulic fracture and a matrix permeability of 0.01 md. The single-stage horizontal hydraulic fracture well was modeled with dimensions of 320 ft. x 1,000 ft. x 10 ft. and 2 ft. wide. The base case scenario was run for 15 years at constant bottom hole pressure of 1,000 psi increased by a recovery factor of 15.1% OOIP. They found that increasing the injection time from 5 to 15 days yielded a 62% increment in the recovery which is the highest compared with other parameters that showed lower or negligible incremental recovery factors. The study concluded that shorter soaking periods are preferable over longer times, the cyclic gas injection process works best in reservoirs with highly conductive natural fracture networks, re-injecting CO_2-enriched hydrocarbon gases is technically and economically viable and improves the recovery over pure CO_2.

To better address the differences in flow mechanisms in unconventional reservoirs and optimize the improved oil recovery practice, Pu and Li (2016) introduced a new novel model that considered the capillarity and adsorption effects of the small pores for shale reservoirs using pore size distribution (PSD) directly from core measurements. The reservoir model was built in-house using a numerical simulator with different cases and run to study and evaluate both primary production and CO_2 enhance oil recovery (EOR) in both the Middle and Lower Bakken formations, respectively. The results showed that the highest primary recovery from both formations (Middle and lower Bakken) was about 12%OOIP and the ultimate incremental oil recovery of CO_2 flooding was about 26%OOIP and 39%OOIP for Middle and Lower Bakken, respectively (H. Pu & Li, 2016). The study concluded that understanding key production mechanisms of capillarity and adsorption would enable to differentiate production driving mechanisms in unconventional reservoirs, using the new compositional simulator model would simulate enhancing oil recovery by injecting CO_2 in unconventional reservoirs properly and considering the capillarity in the modeling process would predict higher oil recovery by CO_2 injection than the cases that did not include it.

Jiabei Han (2016) developed a geological (CMG Builder) and reservoir simulation (CMG GEM) model to evaluate enhancing oil recovery from a low-pressure tight oil reservoir segment (L=1,500 m, W=810 m, H=41.5m) in Ordos Basin, China. In the model, she used two hydraulically fractured production wells placed in the targeted layer and a stimulated reservoir volume (SRV) was defined around the transverse fractures with a permeability was twice that of the reservoir. To improve the recovery, a non-hydraulically fractured horizontal well was created in the model and placed between the above two horizontal producers to inject different fluids such as water, CH_4, CO_2, and separator gas and investigate the performance of the different cases. The obtained results from the study showed that primary recovery (maximum = 9%) of the abundant oil reservoir wasn't efficient in such a low-pressure reservoir and to improve the production, the water or gas should be injected. She compared the injection fluids impact over 20 years and found that the gas was more suitable for improving the oil recovery than the water (5.73% RF) and the CH_4 (8.08% RF) and separator gas (7.75% RF) were better than other investigated gases, mainly CO_2 (7.02% RF). In addition, Han studied the effects of heterogeneity over 20 years of injection through the reservoir simulator and found that the heterogeneity had an inverse relationship with the oil recovery. As the heterogeneity increases, the oil recovery decrease (Han, 2016).

In 2017, Zhang et al (2017) developed a numerical simulation model to investigate the cyclic CO_2 injection method with nanopore confinement application in the Bakken tight oil reservoir and handled the complex fracture geometries of the target field. In the study, they conducted phase equilibrium revision, evaluated the fluid properties with nanopore confinement, calculated MMP using the model, analyzed the good performance of CO_2-EOR, examined the impacts of matrix permeability, CO_2 molecular diffusion, and capillary pressure. They analyzed the performance of a field-scale horizontal well with non-planar fractures and natural fractures.

The cyclic injection simulation model was designed to inject CO_2 at 100 MMscf/day for one year after three years of production, shut-in for soaking for two months, and put on a production for one year. The model was performed to simulate the injection process considering different cases: without molecular diffusion and capillary pressure as a base case, with molecular diffusion only, with capillary pressure only, and with both CO_2 molecular diffusion and capillary pressure. The results revealed that the incremental oil recovery factor was 3.7% (17%OOIP) by applying the CO_2 molecular diffusion only, 1.4% (about 16%OOIP) by considering the capillary pressure only, and 5.1% (>18%OOIP) by combining the two parameters (CO_2 molecular diffusion and capillary pressure) over 20 years (Zhang et al., 2017). They concluded that both CO_2 molecular diffusion and capillary pressure were key parameters, had a positive influence on the CO_2 EOR applications, and were significant to capture real mechanisms during the injection process.

Phi and Schechter (2017) developed a full-field, dual-porosity, and structured grid model to improve a method to optimize different CO_2 EOR process in unconventional reservoirs of the Eagle Ford Shale field. After gathering the production data, geographic maps, geologic information, rock, and fluid properties from public resources and using them to build the robust model, they history matched the model through a CMG CMOST™ before applying the CO_2 EOR processes to the model. The 50 ft. × 50 ft. grid model built via CMG GEM with the domain of 5,000 ft. in I-direction, 1,800 ft. in J-direction, and thickness of 100 ft. In this study, several sensitivity analyses were conducted to investigate which parameters from the matrix and the natural fracture system would have a significant impact on the incremental oil recovery. The researchers found that among different CO_2 EOR methods tested, the huff-n-puff yielded the most promising outcome as compared to CGI and WAG methods in both oil production and economic performance in the volatile oil region of the Eagle Ford shale. Also, the huff-n-puff process didn't only recovers more oil after five years of EOR but also requires less CO_2 to be injected compared to the shut-in producer case from continuous CO_2 injection EOR scenario with the efficiency of one oil barrel to 18.48 Mscf (Phi & Schechter, 2017). With these encouraging results, the study demonstrated that the CO_2 huff-n-puff would be worth considering as the primary EOR method in unconventional liquid reservoirs in the future especially when the cost of injecting and operating CO_2 is lower, the oil price is higher, and the utilization of produced CO_2 is improved significantly as recycled.

To evaluate the performance of CO_2 cyclic injection in enhancing oil recovery from tight oil reservoirs, Lei et al. (2018) built a compositional reservoir simulation model with a hydraulic fracture network for a segment from Chang-7 tight Oil Reservoirs in Ordos Basin. The model was composed of two horizontal wells and hydraulic fractures with a height of 20 m which the thickness of the target layer, reservoir porosity of 13%, and permeability of 0.3 md. They performed a series of sensitivity studies via CMG CMOST simulator to quantify the impacts of reservoir properties, fracture features, and operation parameters such as injection rate, injection time, soaking time, number of cycles, and diffusivity to better understand the key parameters controlling the EOR process in tight oil formation. They found that the pressure gradient is the main driving force of CO_2 to the matrix-fracture interface and the optimum injection pressure is set around the MMP for CO_2 and the crude oil. The study concluded that the CO_2 injection rate is the most important parameter for the CO_2 cyclic gas injection process following by CO_2 injection time, number of cycles, and CO_2 diffusivity. At the end of 25 years, the best expected incremental oil recovery factor of the production from such tight formation was estimated to be 8.3% (Lei et al., 2018).

Table 2.4 gives an eminent summary of the most significant simulation studies conducted for using gas EOR methods to improve oil recovery from unconventional reservoirs.

Table 2. 4. Summary of Numerical Simulation Studies for Gas Injection EOR Techniques in Unconventional Reservoirs

Paper no.	Authors	Year	EOR Method	Miscibility	EOR Mechanism	Best RF
SPE 123176	Shoaib & Hoffman	2009	CO_2 CGI	Miscible	N/A	16%
SPE 137728	Wang et al.	2010	CO_2 CGI	Miscible	N/A	36%
SPE 168827	Dong & Hoffman	2013	CO_2 CGI	Miscible	N/A	30%
SPE 175131	Zhu et al.	2015	CO_2 CGI	Miscible	Diffusion	15%
Fuel 159	Yu et al.	2015	CO_2 HnP	N/A	Diffusion	27%
Fuel 147	Sanchez-Rivera et al.	2015	CO_2 HnP	N/A	N/A	62%
SPE 179533	Pu & Li	2016	CO_2 CGI	N/A	N/A	39%
SPE 180219	Li et al.	2016	CH_4 HnP	N/A	Represserization	31.5%
Thesis	Jiabei Han	2016	Diff. Gas CGI	N/A	N/A	8%
SPE 167200	Jin et al.	2017	Diff. Gas HnP	Miscible	Extraction	50%
SPE 187211	Zhang et al.	2017	CO_2 HnP	N/A	Diffusion & Capillary press.	18%
SPE 185034	Phi & Schechter	2017	CO_2 HnP and others	N/A	N/A	N/A
SPE 191873	Lei et al.	2018	CO_2 HnP	Near Miscible	Pressure Grad.	8.3%

2.6.3. Field Pilot Test Gas Injection EOR in Unconventional Resources

In contrast to the laboratory experiments and simulation modeling, the publishing of the field pilot tests of EOR methods in unconventional reservoirs is limited. As in the previous two sections where full reviews of laboratory work and numerical studies were introduced, this section presents the published results of the pilots conducted to investigate the applicability of different gaseous EOR methods in unconventional resources.

2.6.3.1. Bakken field

The initial gas injection pilot project in the Viewfield Bakken Field implemented in 2011 by Lightstream Resources Ltd., Canada was considered one of the first successful initiatives in-field application of gas injection EOR in unconventional resources. The project was designed with a one-mile horizontal injector (East-West direction) and 9 perpendicular horizontal producers (North-South direction) covering an area of 1,280 acres. The target formation net pay was 26 ft. thick, the porosity of 10 % and permeability ranged from 0.01 to 0.1 md. In this project, the solution gas (CH_4) was injected as an immiscible CGI tertiary recovery technique using the toe-heel pattern. The company expected primary recovery to be between 15% and 17% of the OOIP but within the first two years of EOR operations, the pilot project EUR has increased up to 19% (Schmidt & Sekar, 2014). The results have been encouraging and the production had increased from an initial rate of 135 bbl/d to a peak rate of 295 bbl/d in 12 months following the start of injection. The pilot project yielded significant positive production results and the average decline rate of pattern wells decreased from 20% before gas injection to approximately 15% post gas injection. They concluded that the gas EOR was the best injectant for the Bakken reservoir which would lead to continued success with gas injection and lead further expansion in developing unconventional resources.

After publishing the results of the field gas injection EOR pilot test in the Canadian Bakken field, four pilot tests were conducted independently in USA Bakken in North Dakota and Montana states. CO_2 as an injectant was used in three pilots while the fourth one injected enriched natural gas. Some tests were designed as CGI processes and other tests were designed as cyclic gas injection processes (Todd & Evans, 2016).

The process was performed in a horizontal lateral of 4,951 ft. long with a drainage area of 634 acres drilled in 33 ft. thick Bakken formation of 7.5% porosity (Alfarge, Alsaba, Wei, & Bai, 2018)(Alfarge et al., 2018). In the project, EOG operation was able to inject 30 MMSCF of CO_2 gas in the targeted formation easily without any problem at an injection rate of 1,000 Mscf/day for 30 days. After 11 days of the injection, CO_2 breakthrough was observed in an offset well which is located one mile west of the injector. There was no increased oil production at the first pilot well or any other offset wells.

In the second pilot test, the cyclic CO_2 injection scheme was conducted in 2009 at different Bakken parts in Elm Coulee Field in Montana by the different operators to evaluate the feasibility of the injection process in the Bakken reservoir. The test used a 1592 ft. hydrocally fractured horizontal well to inject a 45,000 Mcf of CO_2 at injection rate ranges of 1,500-2,000 Mscf/day for 45 days at a maximum injection pressure of 1,848. The well was shut-in for 64 days for soaking and then opened for production. The well started producing at a rate of 160 bbl/day in the first 8 days, then dropped to 20 bbl/day for 30 days, after that, the well was no longer naturally producing (Alfarge et al., 2018).

In the third pilot test, the cyclic CO_2 injection process was conducted in North Dakota in 2014 in a vertical well with 60 ft. of middle Bakken pay thickness. The CO_2 was injected at the rate of 300-500 Mscf/day in 20-30 days then the well was shut-in for 20 days. Then the well put on production. The operation was ceased after observation of CO_2 gas breakthrough in an offset well that was 900 ft. away which indicated for fracture in the vertical well which forces the operator to stop the operation.

In the fourth pilot test in North Dakota, the enriched natural gas composed mainly of 55% CH_4, 10% N_2, and 35% C_2H6^+ were continuously injected at 1,600 Mscf/day for 55 days and pressure of 3,500 psi in a horizontal injector well in the center sounded by four parallel horizontal wells in 2014. The producer wells were heel-to-toe offset from north 900 ft., south 1,200 ft., east 2,300 ft., and west 2,300 ft. As a result, all four offset wells had production increment in the months immediately after the gas injection which was approved to be a promising technique in these unconventional oil plays. The analysis of these pilots concluded that the injectivity does not appear to be a problem although the permeability is extremely low in these wells (Todd & Evans, 2016). The cyclic CO_2 injection did not prove any success which might give a clear indication that the proposed CO_2 diffusion mechanism is not existing in field conditions (Alfarge et al., 2017).

2.6.3.2. Eagle Ford Field

EOG resources announced in spring 2016 the great success in the cyclic gas injection project in Eagle Ford. The company reported a 30% to 70% increment in oil production from the wells under operations of huff-n-puff gas injection deployment. The detailed information wasn't published or shared with others as usual practice for the operator companies to protect their data from the other competitors. Hoffman, T. (2018) collected data for seven gas injection pilots from Texas Railroad Commission (TRC) conducted in three different locations in Eagle Ford Field. These 7 pilots which were performed by different operators over the last 5 years contain 49 wells and natural gases injected as a cyclic mode in all the pilots (Alfarge et al., 2018).

In the first pilot test, the lean gas (90%-95% CH_4 and 5%-10% C_2H_6) was injected as a cyclic scheme with 3 cycles performed in the north-eastern of Eagle Ford field. The pilot test started in late 2012 with a single well, additional four wells were added in 2013, and one well was added in 2015. The injection and soaking periods were about 4-6 weeks after which the well was put on stream till the production started to drop then another cycle was started. The injection rate was about 2-3 MMscf/day and the surface injection pressure was around 6,000 psi (Hoffman, 2018). The results of this pilot were encouraging because each cycle increased the production rate by about 50% of the initial rate.

The second pilot test was nearby the location of the first pilot test and the lease contained eight wells out of which four wells were injectors and the other are production wells. The average lease oil production rate since the injection starting in 2015 was 370 STB/day with a peak of 2,500

STB/day in the resuming of production. Like the first pilot, the results of this pilot were encouraging but only a 17% increment in the cumulative oil production was achieved over more than a 2 ½ year span after 1 ½ year of injected natural gas (Alfarge et al., 2018). The analysis indicated a positive outcome from the pilot, and as this is only about half of the wells in the lease, this is even more encouraging (Hoffman, 2018).

The third pilot test was conducted in the same location as previous pilots and designed as a toe-to-heel pattern containing 14 wells. The lease had eight horizontal producers run NW-SE, six cyclic natural gas injectors run perpendicular at the owe and heal of the original producers, and several monitor wells surrounding the test area. The average lease oil production rate since the injection starting in 2015 was 1,065 STB/day with a peak of 8,700 STB/day at the beginning of production (Hoffman, 2018). As in former tests, this pilot showed clear successful results where this pilot increased the cumulative production by 20% (over 550,000 STB) through injecting natural gas in only 2 ½ years (Alfarge et al., 2018).

The fourth pilot test was performed in the west part of Eagle Ford field in a location about 100 miles to the southwest of the other three previous pilots. This project contained four injectors in which the cyclic natural gas injection mode was implemented at the same time. In this test, the huff period was 6 months with an injection rate of 2-4 MMscf/day and the puff period was 2-3 months. A new cycle of huff-n-puff was performed when the production rate dropped below the minimum required rate and the process was repeated for 4 cycles. After that, the wells were subjected to a shorter injection/soak time of 4-6 weeks with a production period of 2 months. The reduced injection/soak period created a positive impact on the production profile of the wells. This pilot lasted for 3 years and doubled the incremental production for all the wells to 300 MSTB due to the injection process which is 1.3x more than predicted pre-injection cumulative production (Hoffman, 2018).

The fifth pilot test was conducted in the middle of the field in Atascosa County with a lease of a total of four wells: one injector and three producers. In this pilot, the injectant was richer than former tests with around 70% CH_4 and 30% $C_2H_6^+$ and injected in the cyclic mode at a rate of 2-2½ MMscf/day for one month (Hoffman, 2018). After a short soaking period, the well produces for around one month. The performance of this pilot was unclear due to the overwhelming ratio of the production wells to the injection wells in the reported lease data (Alfarge et al., 2018).

The sixth pilot test was conducted in a close location to the fifth pilot test with a lease of 61 wells from which the only one well was injector and the remaining are producers. In this project, the rich gas injectant composed of 70% CH_4 and 30% $C_2H_6^+$ was injected continuously for 30 days in a cyclic injection scheme at a rate of 2-2½ MMscf/day and put on a production for the same period after the short soaking time (Hoffman, 2018). Since there was only one injector among 60 producers in the lease, the results from the single cyclic gas injection pilot were not possible to be determined.

The seventh pilot test was an extension to the third pilot test with two additional offset leases on each side in 2016. This project contained a total of 41 wells of which 32 wells were injectors. Due to the success, additional wells (up to 10 wells) were added in 2017 to the project (Hoffman, 2018). Although the injection project had started recently, a clear increment in oil production was realized.

The pilot tests showed that the performance of natural gases exceeds the CO_2 performance in the field scale. There is a clear gap between experimental studies reports and pilot test performances for the applicability of CO_2 EOR in shale oil reservoirs. If the well or field conditions predict a low molar-diffusivity for the injected gases, the rich and lean gases would have better feasibility than CO_2 (Alfarge et al., 2018). The number of cycles has a negative impact on CO_2-EOR while it has a positive impact on NGs-EOR.

Table 2.5 summarizes the most significant field application of using gases as injectant in EOR methods to improve oil recovery from unconventional reservoirs.

Table 2. 5. Summary of Field Applications of Gas Injection Techniques in unconventional reservoirs

Paper no.	**Authors**	**Year**	**EOR Method**	**Miscibility**	**Field**	**Best RF**
WPC 21-2	Schmidt & Sekar	2014	CH_4 CGI	Immiscible	Bakken, Canada	19%
SPE 180270	Todd & Evans	2016	CO_2 HnP	N/A	Bakken, USA	Inj. Test
SPE 180270		2016	CO_2 HnP	N/A	Bakken, USA	Little
SPE 180270		2016	CO_2 HnP	N/A	Bakken, USA	Ceased
SPE 180270		2016	Nat. Gas HnP	N/A	Bakken, USA	Significant
SPE 189816	B. Todd Hoffman	2018	Lean Gas HnP	N/A	Eagle Ford, USA	50%
SPE 189816		2018	Nat. Gas HnP	N/A	Eagle Ford, USA	17%
SPE 189816		2018	Nat. Gas HnP	N/A	Eagle Ford, USA	20%
SPE 189816		2018	Nat. Gas HnP	N/A	Eagle Ford, USA	Doubled
SPE 189816		2018	Rich Gas HnP	N/A	Eagle Ford, USA	Unclear
SPE 189816		2018	Rich Gas HnP	N/A	Eagle Ford, USA	Not Determined
SPE 189816		2018	Nat. Gas HnP	N/A	Eagle Ford, USA	Not reported

Chapter 3. Methodology

The production from unconventional resources in the primary depletion stage is relatively new in field developments and the study of enhancing the recovery from the tight rock is not fully realized. The low primary depletion recovery emphasizes the need for a new technique to improve the efficiency of oil recovery from these resources. As seen in the literature review, the former experiment setups did not account for the gravity drainage impact on oil recovery. Furthermore, the natural or introduced fractures are not properly presented in these sets of experiments. In some experiments, the huge annular space between the core plugs and the container was used as the reservoir fracture which is massive in size compared to the small size of the core plug or ships. Moreover, another research was using very small chips or fragments to conduct the EOR experiment, which unfortunately represents a much larger SRV than the actual stimulated volume in the actual EOR process. Consequently, this research aimed to provide more insight into a new method of enhanced oil recovery from ultra-tight reservoirs.

This experimental study covered core preparation and the implementation of gas injection EOR experiments to improve oil production, in detail. This chapter demonstrated the experimental setup, the used materials, and the experimental procedures. The experimental setup included core cutting platforms, a core cleaning extractor, and the used core flooding and EOR apparatus. Section 3.2 is the materials section in which a description of the selected core samples and injected fluids in the porous media was provided. Section 3.3 elaborated on the performed steps to operate the prementioned devices and run the designed experiments.

3.1. Experimental Setup

3.1.1. Core Cutting

The planned core flooding & EOR experimental apparatus was designed and manufactured to handle core plugs of 1-inch or 2-inch diameter and lengths from 0 to 24 inches. A core cutting machine was refurbished and installed in LSU PETE E-lab to cut core plugs at the required diameter. The cutting platform is shown in Figure 3.1 made by Bluerock Tools with a related input power of 2,400 W, a maximum drilling diameter of 8 inches, and a no-load speed of 750 r/min.

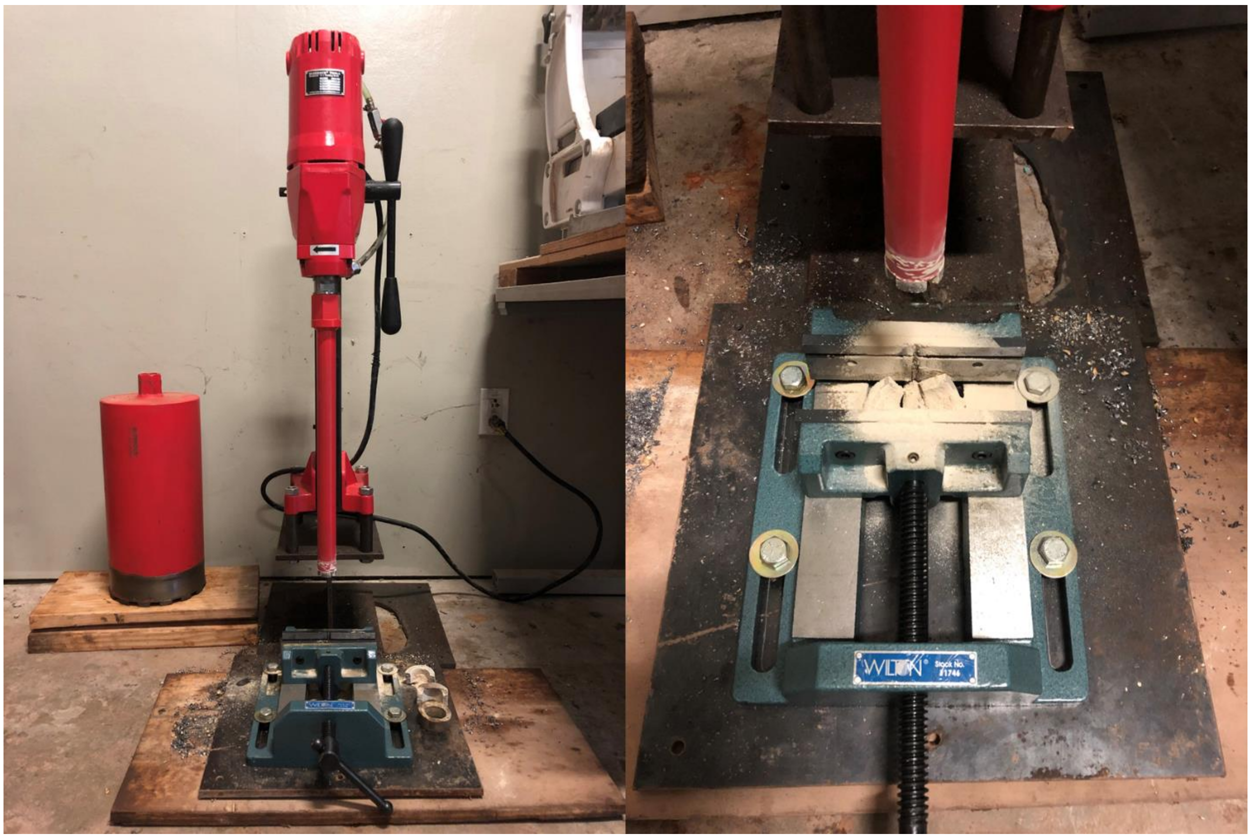


Figure 3. 1. Core Cutting Machine in LSU PETE E-lab Used to Cut Core Plugs and Samples

Another core cutting machine was used to cut a couple of shale plugs from TMS installed in the P.E.I. Drilling and Solids Control Laboratory in University of Louisiana at Lafayette (ULL). The cutting machine was made by Core Lab with a powerful motor to cut core plugs and samples up to 2-inch diameter and 3-inch long. The cutting platform in ULL is shown in Figure 3.2.

Figure 3. 2. Core Cutting Machine in ULL P.E.I lab Used to Cut Core Plugs up to 2-Inch Diameter

The rock cutting machine from Barranca Diamond in Figure 3.3 was installed in the LSU PETE RFI lab. This machine uses a PF10 Power Feed Saw to precisely cut and sharpen the two sides of the cut core plugs before taking measurements and proceeding to the next step.

Figure 3. 3. Rock-Cut and Sharp Edges Machine Installed in LSU PETE RFI Lab

3.1.2. Core Cleaning Extractor

To perform the cleaning process, a hot Soxhlet extractor installed in LSU PETE IFT lab as shown in Figure 3.4 was used to clean core plugs of 1-inch to 1.5-inch diameter with a maximum length of 8 inches. Another large Soxhlet extractor system was installed in the LSU PETE EOR lab to clean larger diameter core samples. This extractor can handle core diameters up to 4-inch and lengths up to 1-foot, Figure 3.5. In the cleaning process, both extractors were operated at a temperature range of 60-75℃ and recycling (83:17) Chloro-Methanol azeotrope as a cleaning chemical. The Marble 500G which contains Calcium Carbonate and Quartz that was used as boiling chips and the Silica Gel Sorbent of Grade 644 and mesh size 100-200 was filled in the ventilation end in both Soxhlet extractors.

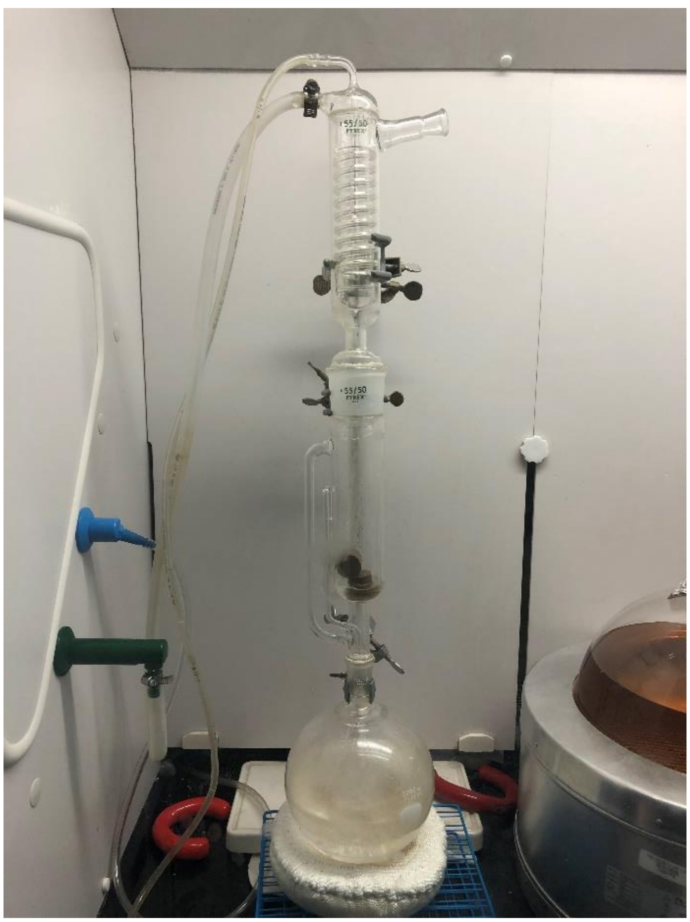


Figure 3. 4. Soxhlet Extractor Cleaning Plugs in LSU PETE IFT Lab

Figure 3. 5. Giant Soxhlet Extractor Cleaning Multiple Large Core Samples in LSU PETE EOR Lab

3.1.3. Heat Drying Oven

A heat oven from BLUE M was installed in the LSU PETE IFT lab, shown in Figure 3.6, was used to dry the cleaned core plugs and samples before proceeding to the measuring step. The oven was operated at 150-170 ̊F for several days to completely evaporate all the fluid contained in the cores.

Figure 3. 6. Heat Drying Oven in LSU PETE IFT Lab

3.1.4. Weight and Dimension Measurement Tools

Two scales were used to weigh the core samples and plugs immediately after drying, oil flooding, and gas injection processes. Figure 3.7 shows a 4-digit accurate scale (Model ACS 320-4) with a maximum weight of 320 grams made by KERN Company used to weight the small core plugs. The large core samples were weighed using the Sartorius CP4201 one-digit accuracy scale, shown in Figure 3.8.

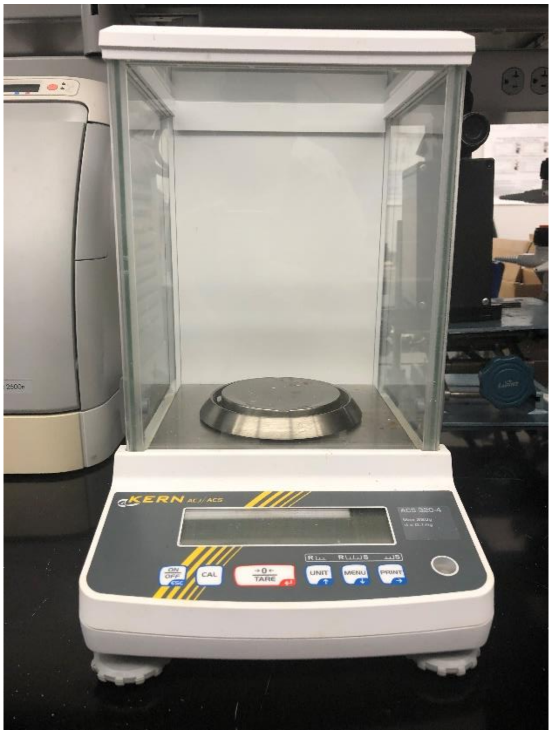


Figure 3. 7. A 4-Digit Accurate Scale Used to Determine the Core Plugs' Weights

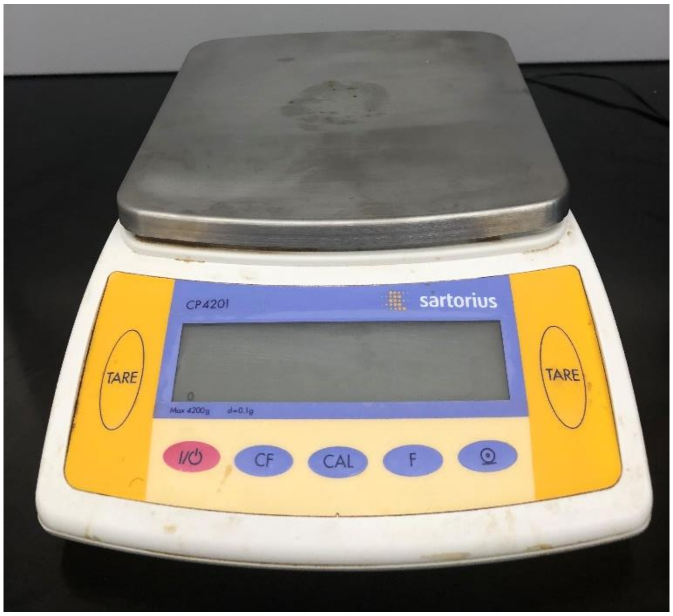


Figure 3. 8. A 1-Digit Accurate Scale Used to Determine the Large Core Samples' Weights

A 0.1 mm accurate reading caliper by Scinceware of Bel-Art Products was used to measure the dimension of the core plugs and samples with a maximum measurement of 150 mm. It can accurately measure the diameter and length of the used cores. The caliper is shown in Figure 3.9.

Figure 3. 9. A 0.1 mm Accurate Caliper Used to Determine the Core Plugs and Samples Dimensions

3.1.5. Core Holder

High pressure and high-temperature core flooding setup had been installed in the LSU PETE EOR lab. This setup had a core holder with 10,000 psi rated working pressure that can carry both 1-inch and 2-inch diameter core plugs and samples and lengths up to 2 feet as shown in Figure 3.10. This system was equipped with various accessories for both 1-inch and 2-inch set up including the sleeves, annular spacers, inner spacers, side ends, and end caps. Two slim tubes were used to centralize the 2-inch inner spacers inside the 2-inch sleeves. Two fluid distributors from each size were also included to complete the setup of inlet and outlet fluid flow compartments.

3.1.6. Pressure Acquisition System

Figure 3.11 represents the pressure acquisition system used to collect the pressure data during vacuuming, flooding, and EOR experiments. The system was composed of Omega data acquirer, two Omega pressure introducers, and WinWedge software developed by TALtech software company.

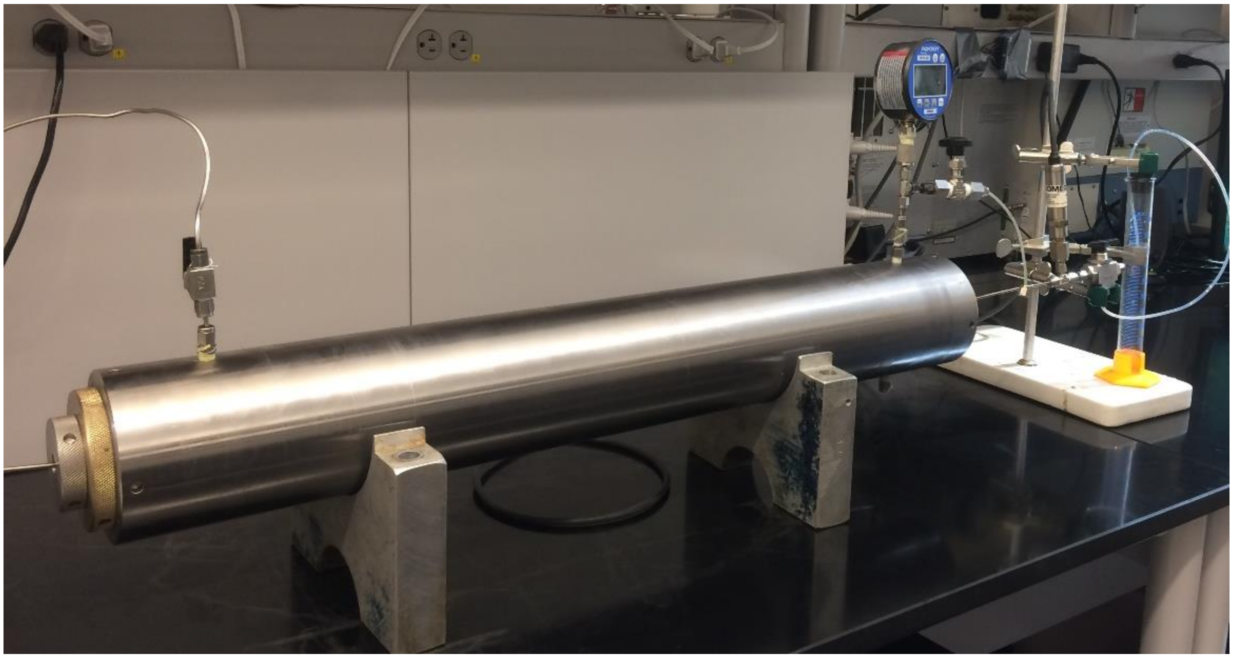


Figure 3. 10. A HPHT Core Holder Setup for Core Flooding and EOR Experiments

3.1.7. Flooding Injection System

In the fluid injection system, Figure 3.12 shows a TELEDYNE ISCO series D syringe pumps Model 100DM used to pump the deionized water from the storage Pyrex into the transfer vessel at a constant pumping rate or pressure. These pumps have a 5-digit ml/min flow rate accuracy.

A 500 ml liquid capacity transfer vessel shown in Figure 3.13 was used to hold the oil to flood the core plugs and sample the desired flooding rate or pressure. The vessel contains a piston that divides the inner chamber into two parts: the deionized water at the bottom side and the oil at the upper side. During the oil flooding process, the deionized water pumped by the syringe pump through the inlet port at the bottom of the transfer vessel and pushed the piston upward, which then displaced the oil through the outlet port to saturate the cores occupied in the core holder apparatus.

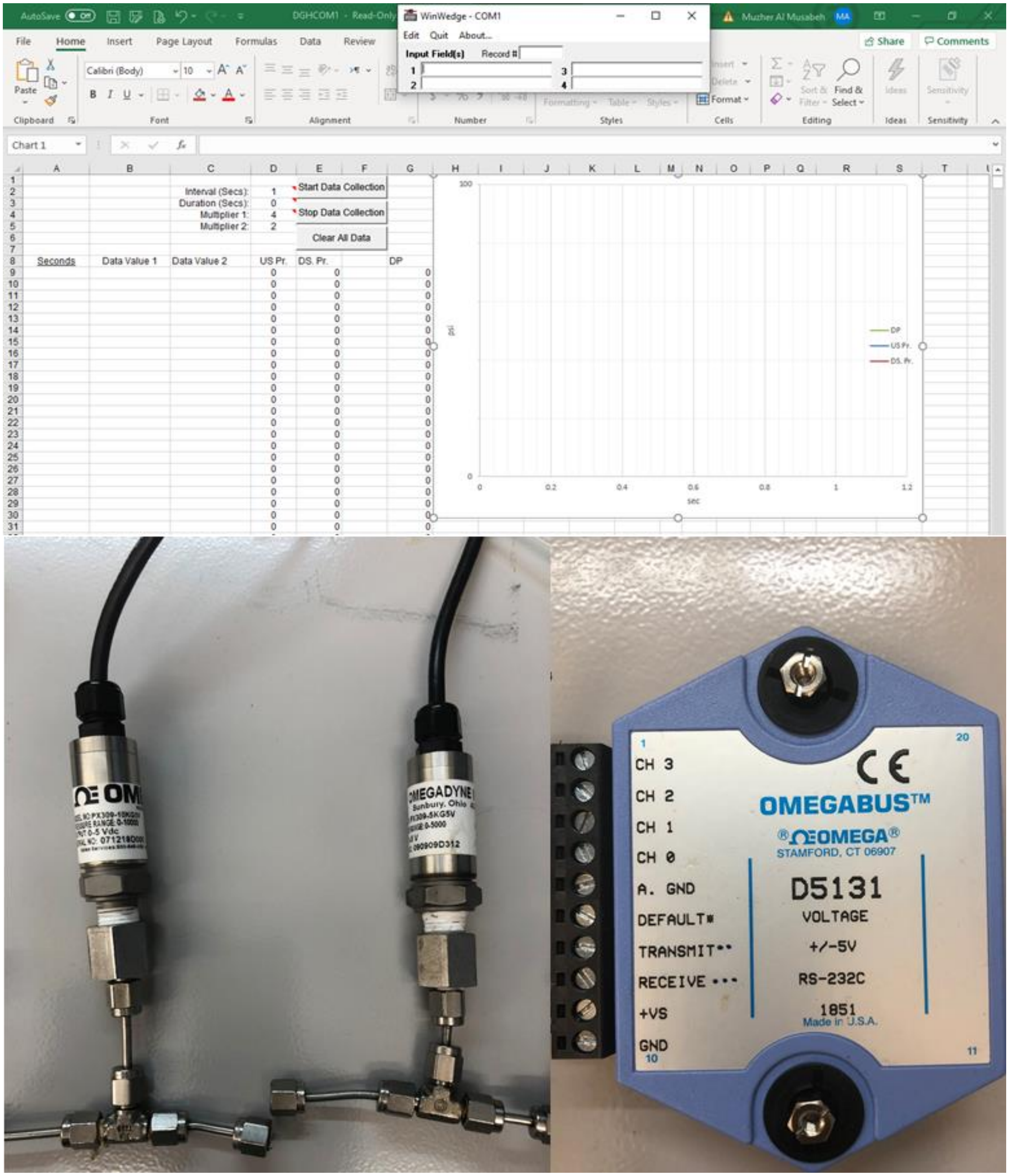


Figure 3. 11. Pressure Acquisition System Used to Read and Record the Obtained Pressures' Data for Core Flooding and EOR Experiments

Figure 3. 12. Teledyne ISCO Series D-syringe pump Used for Fluid Injection

Figure 3. 13. A 500 mL Capacity Fluid Injection Transfer Vessel Used to Flood the Cores with the Oil

3.1.8. Gas Injection System

In the gas injection system, the previously described syringe pumps were used to pump the deionized water from the storage Pyrex into the transfer vessel at a constant pumping rate or pressure. A 2,000 mL capacity transfer vessel was used to inject the required gas into the cores as shown in Figure 3.14. As the previous vessel, the deionized water pumped by the syringe pump through the inlet port at the bottom of the transfer vessel and pushed the piston upward, which then displaced the gas through the outlet port to displace the oil-saturated core samples or plugs.

Figure 3. 14. A 2,000 mL Capacity Gas Injection Transfer Vessel Used to Inject Gases into the Cores in EOR Experiments

Figure 3.15, two pressurized gas cylinders contained N_2 and CO_2 for use in the gas injection process in EOR experiments. The cylinders were secured firmly to the workbench using a clamp and a stretch band wrapped around the bodies. The gas flooded to the top part of the transfer vessel at a predetermined pressure before starting the injection process.

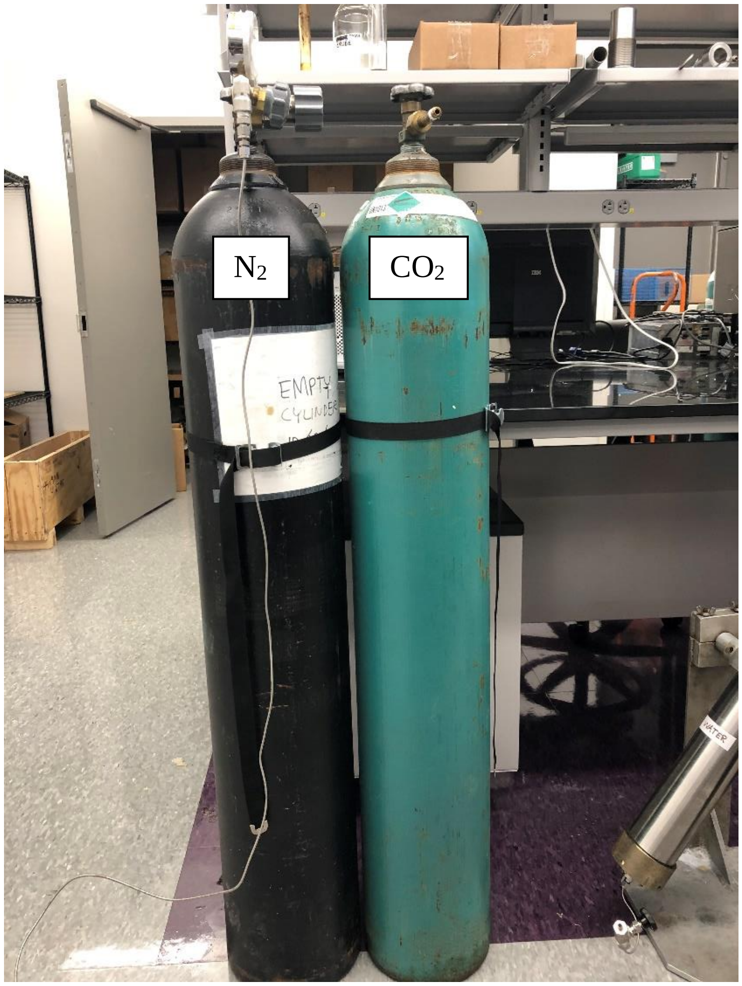


Figure 3. 15. Pressurized Cylinders Contained N_2 and CO_2 for Gas Injection Process

3.1.9. Fluid Production Equipment

The fluid production cylinder in Figures 3.16 was used to save the produced oil from the core flooding and EOR experiments. The cylinder is graduated at a 2-ml interval and can hold 250 ml of liquid. In these experiments, the cylinder was used as an oil storage tank. The other identical cylinder was used to remove the excess oil from the injection inlet parts before starting EOR experiments. The small Pyrex was used to save the hydraulic oil that displaced while depressurizing the core holder after each experiment.

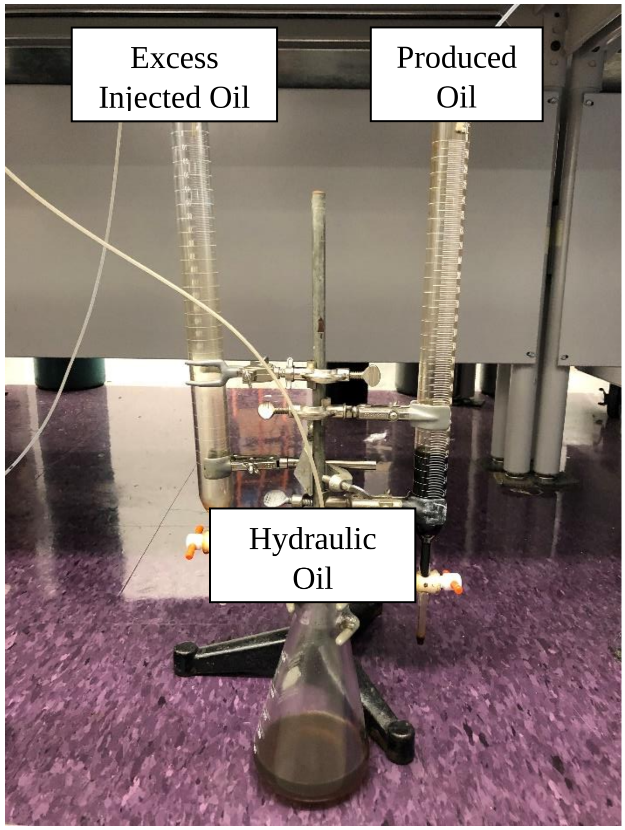


Figure 3. 16. Graduate Cylinders Used for Production Oil, Excess Oil, and Pyrex for Hydraulic Oil

3.2. The Materials

In the core flooding and EOR experiments, the oils used were from Tuscaloosa Marine Shale (TMS), LA, USA as saturated oil during core flooding and EOR experiments, deionized water as the pump flowing fluid to displace fluids in the transfer vessels, N_2 and CO_2 as the injectants. The core samples used for the experiments were extracted from Berea Sandstone (BSS), and Tuscaloosa Marine Shale (TMS). Further descriptions of the materials used are given below.

3.2.1. Reservoir Oil

The oil fluids were imported from two sources: TMS Well-A for BSS and TMS core plugs and samples' experiments. The key properties for these fluids were reported to this research from the source companies with the cooperation of a research group from the University of Louisiana at Lafayette (ULL), Lafayette, LA. The TMS Well A reservoir oil has a molecular weight (MW) of 186.94 and specific gravity (SG) of 0.834 at standard conditions with a 37.7 API gravity at 60 ℉. The reported viscosities are 9.62, 2.75, and 1.81 cp at 40, 100, and 140 ℉, respectively. Figure 3.17 showed the TMS Well-A viscosity profile as a function of temperature. From the figure, the estimated oil viscosity is 6 cp at an experiment design temperature of 70 ℉.

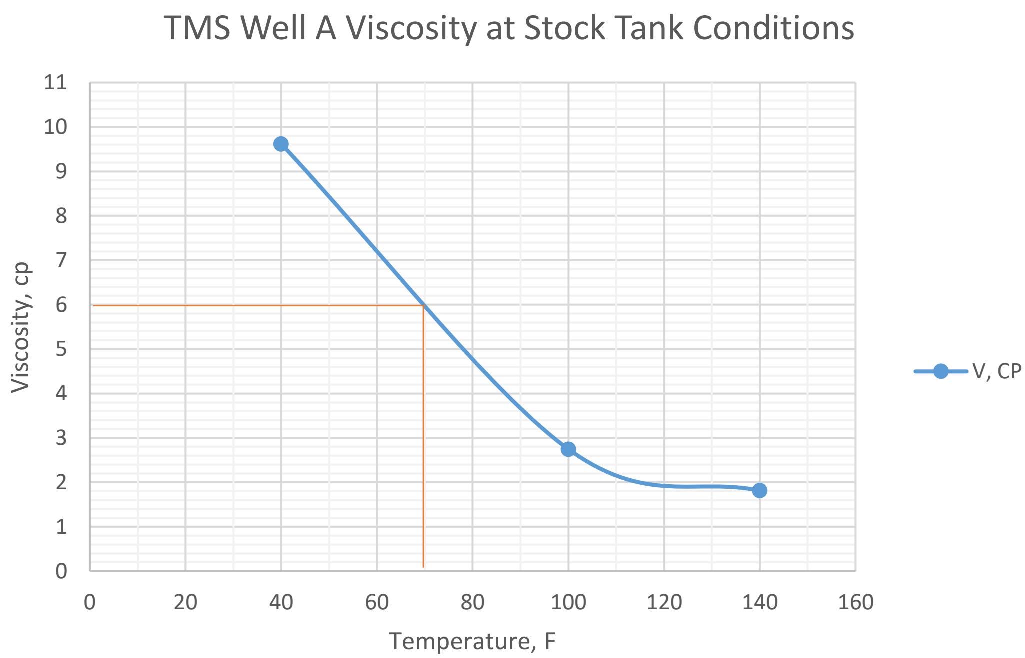


Figure 3. 17. TMS well-A Oil Viscosity Chart

3.2.2. Core Plugs and Samples

The core plugs and samples for the planned experiments were obtained from different resources; Berea sandstone (BSS) from the north USA, and TMS cores from Louisiana State, USA. These cores were selected to cover various tightness ranges on the reservoir quality charts of unconventional resources. The cores were cut in different configuration sizes with 1-inch or 2-inch diameters. The porosity and absolute permeability were determined for each plug and sample individually at standard conditions through core flooding processes before conduction the enhanced oil recovery experiments.

3.3. Experimental Procedures

The experimental work was carried out according to the procedures described in this section. The plan of experimental work was described first, followed by the procedures. These procedures included preparing the core plugs and samples, measuring cores' dimensions and weights, flooding the cores with the fluid, calculating the porosity, determining absolute permeability; and running EOR experiments.

3.3.1. Plan of Experimental Work

The experimental work was designed to perform gas injection EOR experiments for core plugs and samples extracted from unconventional resources. The plan included running CGI using N_2 as a base case before conducting GAGD experiments. The performed gas-injection EOR experiments started with the plugs from Berea sandstone cut parallel to the bed followed by a plug from the same source cut orthogonally. Then, a larger core sample from the same rock was cut and used to perform another EOR experiment. After that, a tighter core plug from TMS was used to represent ultra-tight and shale oil reservoirs.

3.3.2. Core Preparation

The core plugs and samples used in the core flooding and EOR experiments were cut in a cylindrical shape with a diameter of 1 inch or 2 inches. The core's length ranges between 1 and 5 inches. Before using them, each core side and ends were smoothed and sharpened to determine the core dimensions accurately. In a later stage, some cores were cut from the center longitude to create fractures that represent natural reservoirs or hydraulic fractures. After that, the cores entered the cleaning stage by the Soxhlet extractor, Figure 3.19, to remove oil and water as well as evaporated salts, mud filtrate, and other contaminants. The cleaning procedure process is as follow:

1. Prepared the Soxhlet extractor and filled it with about 1,000ml of a cleaning solvent mixture of 83% chloroform and 13% methanol and set the round bottom flask on a heater.
2. Placed the core in the thimble, which is fixed into a 2,000ml round bottom flask that was already filled with solvent mixture with boiling chips.
3. Connected the condenser to the thimble and the water supply was turned on so water can flow in and out of the condenser to cool and condense the boiling solvent vapor.
4. Completed the set-up and turned on the heater to start the cleaning process by immersing the core in the solvent and cleaning it inside the extractor for sufficient time.
5. Once the solvent started boiling, the vapor traveled upwards, cooled by the condenser, and condensed into liquid which drops into the thimble containing the core samples.
6. The process continued until the thimble is filled with the condensed solvent in which the core is completely immersed. The solvent drained back into the round bottom flask once it gets to a spill point on the thimble and the whole process started again.
7. Discontinued the cleaning process when the solvent looks too dirty and change it with a fresh mix of solvent and resumed the cleaning process.
8. When the core was completely cleaned, placed it in the oven for some time to dry and make it ready for the next step.

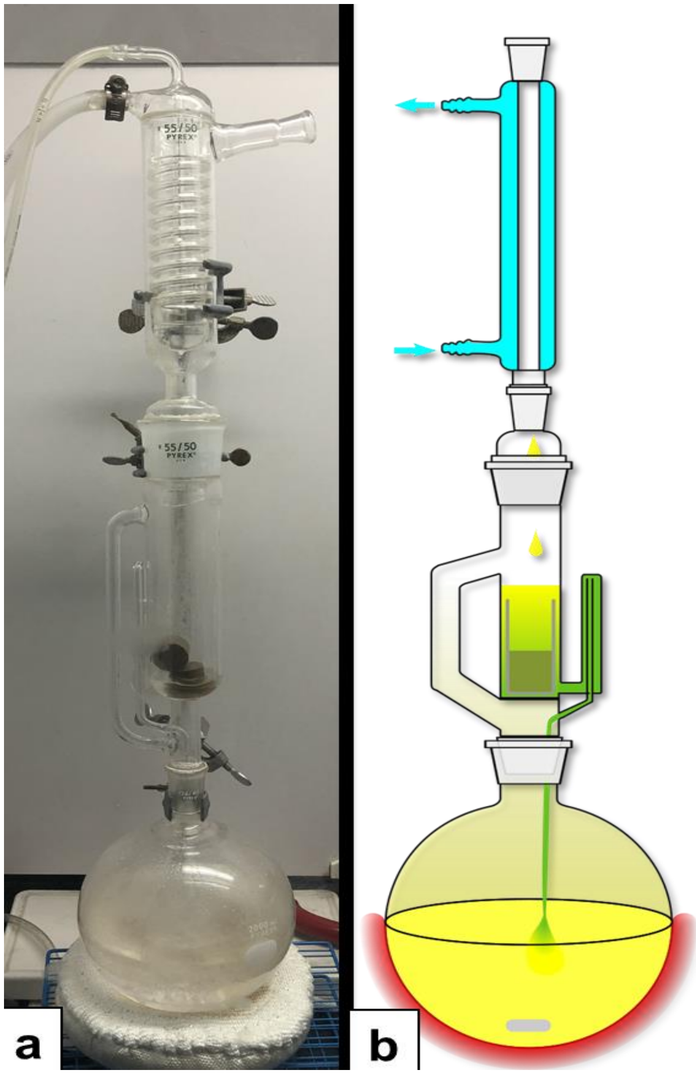


Figure 3. 18. (A) Soxhlet Extractor Set-Up in LSU PETE IFT lab. (b) Schematic of Operating Soxhlet Apparatus (McPhee et al., 2015)

3.3.3. Determine Core Dimensions and Petro-Physical Properties

After cleaning and drying the cores, the first action before performing any laboratory experiment was to weigh each core to determine its dry weight (W_{dry}) and measure all dimensions to calculate the bulk volume (BV). Then, the core was placed in a high-pressure core holder and vacuumed for a certain time before conducting any core flooding or EOR operation. The core flooding process was performed for all cores using the set-up apparatus as shown in Figure 3.20. Due to the low permeability, the core preparation and flooding process were conducted for a long time compared to the conventional core samples. After that, the oil was flooded at a predetermined pressure to fully flood the core. The flooded core was aged for some time to allow completely soaking of injected oil and represent reservoir conditions. The high pressure was maintained for the whole period of the oil saturation process. Then, the core was collected and weighed to determine the saturation weight (W_{sat}) and the saturated oil volume (V_{So}) can be calculated using the difference between both weights divided by the density of the used oil, equation no. 3.1, which is equal to core pore volume (PV). The percentage of pore volume to the bulk volume represents the porosity (ϕ), equation no. 3.2.

$$PV = V_{So} = \frac{W_{sat} - W_{dry}}{\rho_o} \qquad \text{Equation no. 3.1}$$

$$\phi = \frac{PV}{BV} \qquad \text{Equation no. 3.2}$$

Also, the permeability was determined by calculating the average slope of the different flooding rates (q's) and the corresponding staple pressure differences (ΔP's). The rates vs pressure differences were plotted in the cartesian chart and the slope (*m*) of the straight trend line was determined. The measured slope was manipulated in Darcy law and the absolute permeability (*k*) was calculated through equation no. 3.3.

$$k = \frac{q \cdot \mu \cdot L}{0.001127 \cdot A \cdot \Delta P} \qquad \text{Equation no. 3.3}$$

Where the injection rates (q's) in bbl/day, pressure differences (ΔP) in psi, viscosity (μ) in centipoise (cp), length in feet (ft), and area in feet square (ft^2). When using the slope, m, and converting the injection rate to laboratory measurement unit, cc/min or ml^3/min, for more convenience, then, the Darcy law becomes as in equation no. 3.4.

$$k = \frac{m \cdot \mu \cdot L}{0.12444 \cdot A} \qquad \text{Equation no. 3.4}$$

The procedure was repeated for each core individually before running the planned EOR experiments.

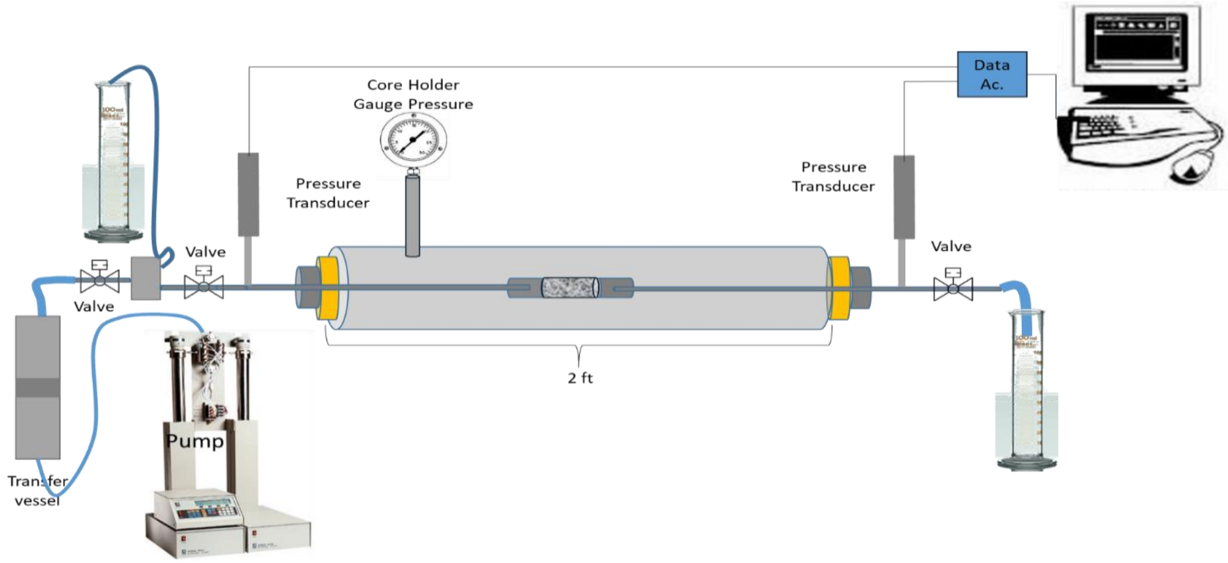


Figure 3. 19. Core holder Set Up Used for Core-Flooding Process

Note: For other unconsolidated shale cores, the sample was encapsulated with higher permeability sandstone end plugs and heat shrinkage tube (HST) before placing it into the core holder for flooding and EOR experiments, Figure 3.21. These shale cores are very fragile, and the plugs and the tube are used to protect the cores while loading and unloading from the core holder. The heat shrinkage tube is adding confining pressure which makes the core and the plugs compacted and handled as one piece.

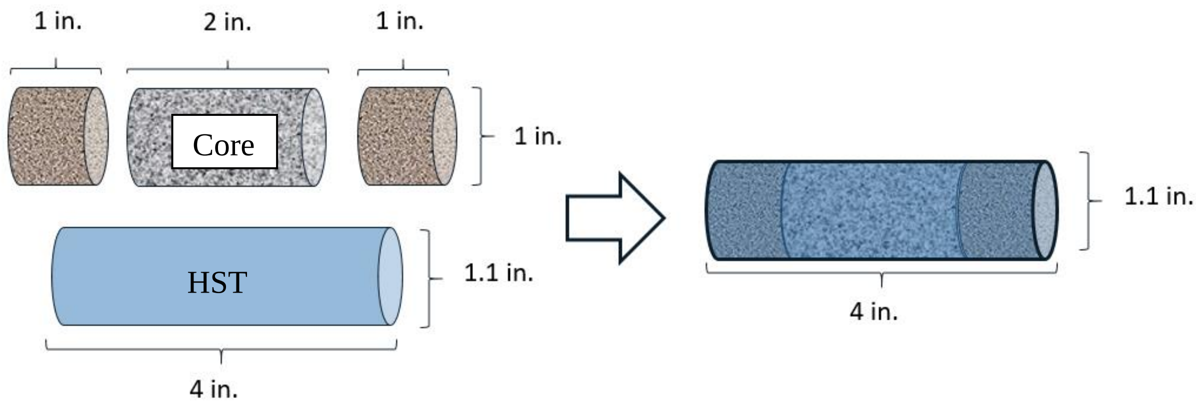


Figure 3. 20. Unconsolidated Shale Core with End Plugs and Heat Shrinkage Tube (HST)

3.3.4. Conducting Enhanced Oil Recovery (EOR) Experiments.

Figure 3.22 shows the two experimental apparatuses setup that was used to simulate the gas injection experiments in EOR processes in all injection scenarios. The saturated cores from the previous step will be placed in the core holder. The injection gases such as N_2 or CO_2 contained in the cylinders were filed in the accumulator, pressurized, and injected into the cores through the inlet connections and distributors of the core holder. At pre-defined pressure, the injection process held on and continued over time till inject the whole amount of gas or no further oil was produced. Then, the injection process stopped after the period and allowed the gas to continue displacing the saturated oil. For the CGI scheme, the gas was continually injected from one side and the oil was produced through the outlet connections on the other side of the core holder. For the GAGD process, the gas was injected from the top side after turning the core holder 90 ˚ and produced the oil from the bottom side. At the end of both schemes, the core sample was collected and weighed (W_{exp}).

The oil recovery after each EOR process was calculated by measuring the plug weight before and after the experiment relative to the difference in weight before and after core flooding as in equation no. 3.5. Thus, applying a certain injection pressure, multiple tests were performed on the same plug when studying the recovery history during the flooding process. The resulting data are analyzed and discussed to determine the best injection scheme, injected gas, operation factors, and optimized process.

$RF = \frac{W_{sat} - W_{exp}}{W_{sat} - W_{dry}} \times 100\%$ ……………………………………………………..Equation no. 3.5

Where (W_{sat}) is the weight of the core sample maximally saturated with oil, (W_{dry}) is the weight of the dried core sample, and (W_{exp}) is the weight of the core sample measured after the gas injection EOR test. It was noticed that the shale plugs used in this study had an ultra-low porosity (about 5%), which led to a small amount of oil (about or less than 2.5 g in weight) existing in the plug after full saturation, and less than 1 g of total oil was yielded at the end of the test. Therefore, it is impossible to monitor the oil production history conventionally by collecting data from a graduated cylinder or a scale that is placed at the outlet of the core holder.

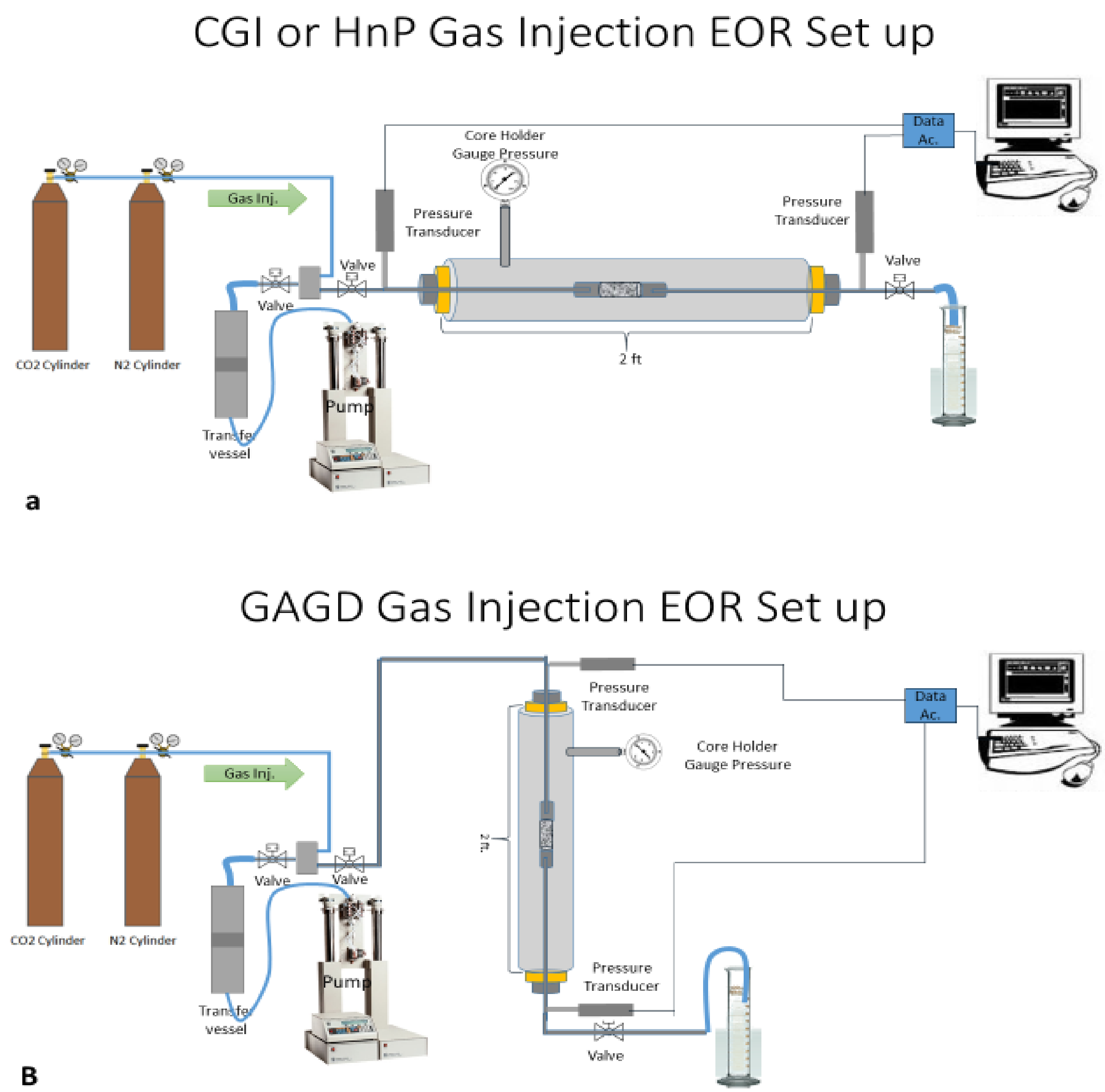


Figure 3. 21. Experimental Set-Up for (a) Continuous Gas Injection (CGI) and (b) Gas-Assisted Gravity Drainage (GAGD) Modes

Chapter 4. Results and Discussion

The results of this research work conducted in this study had been divided and discussed thoroughly in the following two main sections. The first section dealt with the core preparation and determination of rock properties. Different core samples from various reservoirs were used to examine the performance of the planned EOR experiments to accomplish the study's proposed goals. The effective porosities and absolute permeabilities were determined as aforementioned procedures in Chapter 3. The second section compared different EOR experimental results using the cores. A total of 33 gas-injection EOR experiments were presented, and detailed tables of the experimental operation parameters were provided in each sub-section. All cores were flooded with TMS well-A reservoir oil. The flooding processes were performed by injecting the oil horizontally, from left to right in this study at 1,000 psi and 70˚F temperature (overburden pressure set at 1,500 psi). Then, the core holder was set up to a designated position to perform the previously designed EOR experiments as follows: horizontal set up position for CGI or vertical for GAGD EOR experiments. An effort was made to discuss critical aspects of experimental and practical considerations of GAGD at different conditions to improve the EOR process in unconventional reservoirs.

4.1. Core Preparation and Property Determination

Unlike the conventional core samples, the cores from unconventional reservoirs required a specific treatment and cautious handling during the journey from the cutting stage to the storage after performing the flooding and EOR experiments. These cores are fragile in any stage particularly during cutting (Figure 4.1), after cleaning (Figure 4.2), and even though running oil flooding (Figure 4.3) or EOR experiments (Figure 4.4). Figure 4.5 displays the Berea Sandstone core sample no. 3 broken to 4 pieces after core flooding and EOR at reservoir pressure of 260 °F. In some rocks, only ONE core was cut perfectly without breaking or fragmenting out of a 3- or 4-feet rock column. Another type of unconventional core sample developed cracks after cleaning in the Soxhlet extractor. Also, the running time was much longer than conventional cores. It needs days instead of hours as will be explained in more detail in the following subsections.

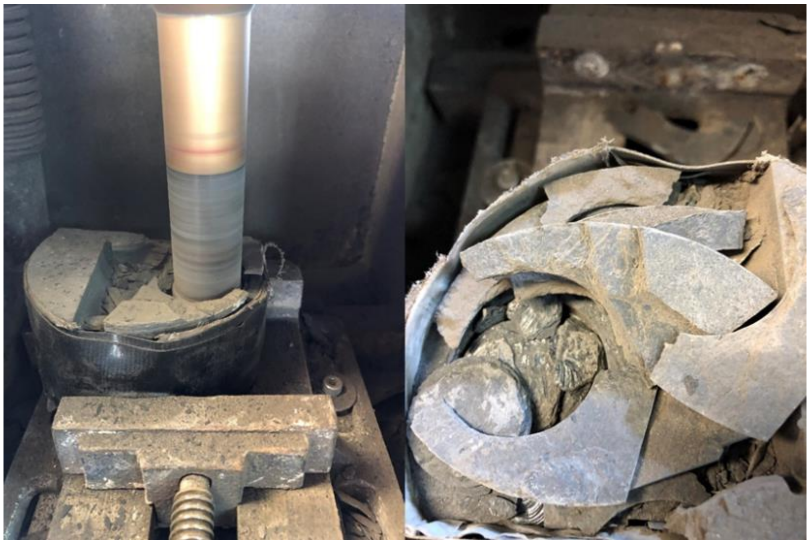


Figure 4.1. Unconventional Core Samples Fragile While Cutting

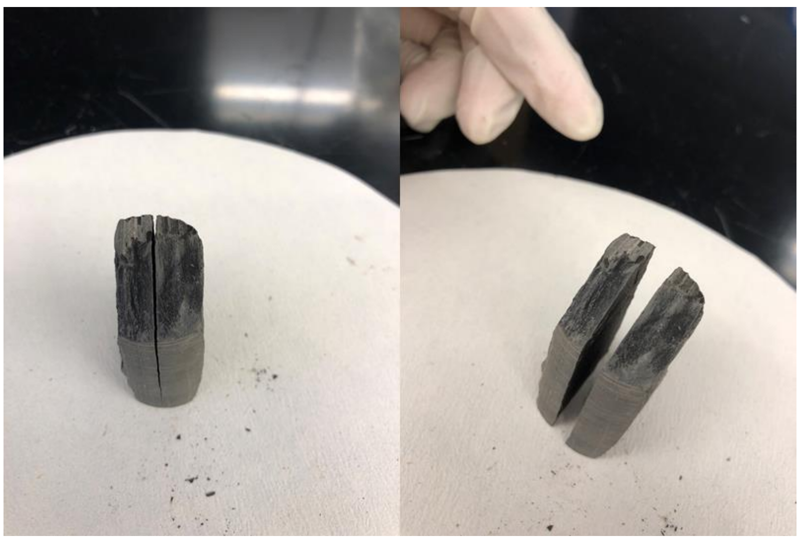


Figure 4. 2. Unconventional Core Samples Fragile After Cleaning in Soxhlet

Figure 4. 3. Unconventional Core Samples Fragile During Oil Flooding Experiment

Figure 4. 4. Unconventional Core Samples Fragile During Gas Injection Experiment

Figure 4. 5. Unconventional Core Samples Fragile After Core Flooding and Gas Injection Experiment at Reservoir Temperature (260 °F)

the study started displaying the results of oil flooding experiments to determine the effective porosity and absolute permeability for core plugs from Berea sandstone (BSS) first, followed by the core from Tuscaloosa Marine Shale (TMS).

4.1.1. Berea Sandstone Samples

Berea Sandstone outcrops are known for a wide range of rock properties including porosity and permeability. To test the proposed GAGD method in this type of rock, three plugs were cored from a very tight 2-inch diameter and 1-foot long core sample. Two plugs were cored horizontally parallel to the bedding plane and one plug cored orthogonally vertical to the bedding plane. The first plug was 1” in diameter and 0.8268” in length. The second plug was 1” in diameter and 1.43” in length. The third plug is a core sample with a diameter of 2 inches and a length of 4.09 inches. All plugs were cleaned in the Soxhlet extractor for several weeks after coring, dried in an oven for several days, and weighed on a Scale. The dry weights for both Berea sandstone core plugs and sample were 26.7586, 45.0982, and 521.3 grams, respectively. The Berea Sandstone plug no. 1 was used to determine the effective porosity, absolute horizontal permeability, and to examine the mechanism of enhanced oil recovery while the second plug was used to determine the absolute vertical permeability for the Berea sandstone. Tuscaloosa Marine Shale (TMS) oil from Well A is going to be used for all core flooding and EOR experiments. The TMS oil density is 0.8328 g/cm3 at standard conditions: a temperature of 20 °C and pressure of 0.101 MPa (68 °F &14.65 psi).

The core flooding process started by placing the plug in the core holder, pressurizing the apparatus to 2,600 psi using the hydraulic pump, running the vacuum pump to vacuum the plug from both sides, and monitoring the pressure on both sides utilizing WinWedge data acquisition software. Then, the plug was flooded with the TMS oil at a constant pressure of 2,500 psi. After making sure that the core is completely flooded with the oil, the stable different pressure, ΔP, was measured at three different flowing rates and used to determine the absolute permeability. To complete this stage, the core was collected and weighed after shutting down the pumps, relieving the pressures, and de-assembling the core holder. The flooded weight was found to be 27.2556 grams. The rock porosity and permeability were determined as follows: -

Saturation or pore volume calculation:

$$V_{So} = PV = \frac{W_{sat} - W_{dry}}{\rho_o}$$

$$V_{So} = PV = \frac{27.2556 - 26.7586}{0.8328} = 0.5968\ cm^3$$

Porosity calculation:

$$\phi = \frac{PV}{BV}$$

$$\phi = \frac{0.5968}{10.6409} = 0.0561 = 5.61\%$$

Permeability determination:

Table 4.1 lists the stable pressures at the corresponding flowing rates and plotted for all three cores used in the experiments. The straight lines are plotted in Figure 4.6 to determine their slopes and then calculate the absolute.

Table 4. 1. Injection Rates and Pressure Differences for Berea Sandstone Cores

Cores	**Flow Rate, q (cc/min)**	**Pressure Different, ΔP (psi)**
Core Plug 1	0.05, 0.075, 0.1	1574, 2124, 2462
Core Plug 2	0.05, 0.09, 0.1	108, 2200, 2350
Core Sample 3	0.05, 0.06, 0.07	1554, 1760, 2200

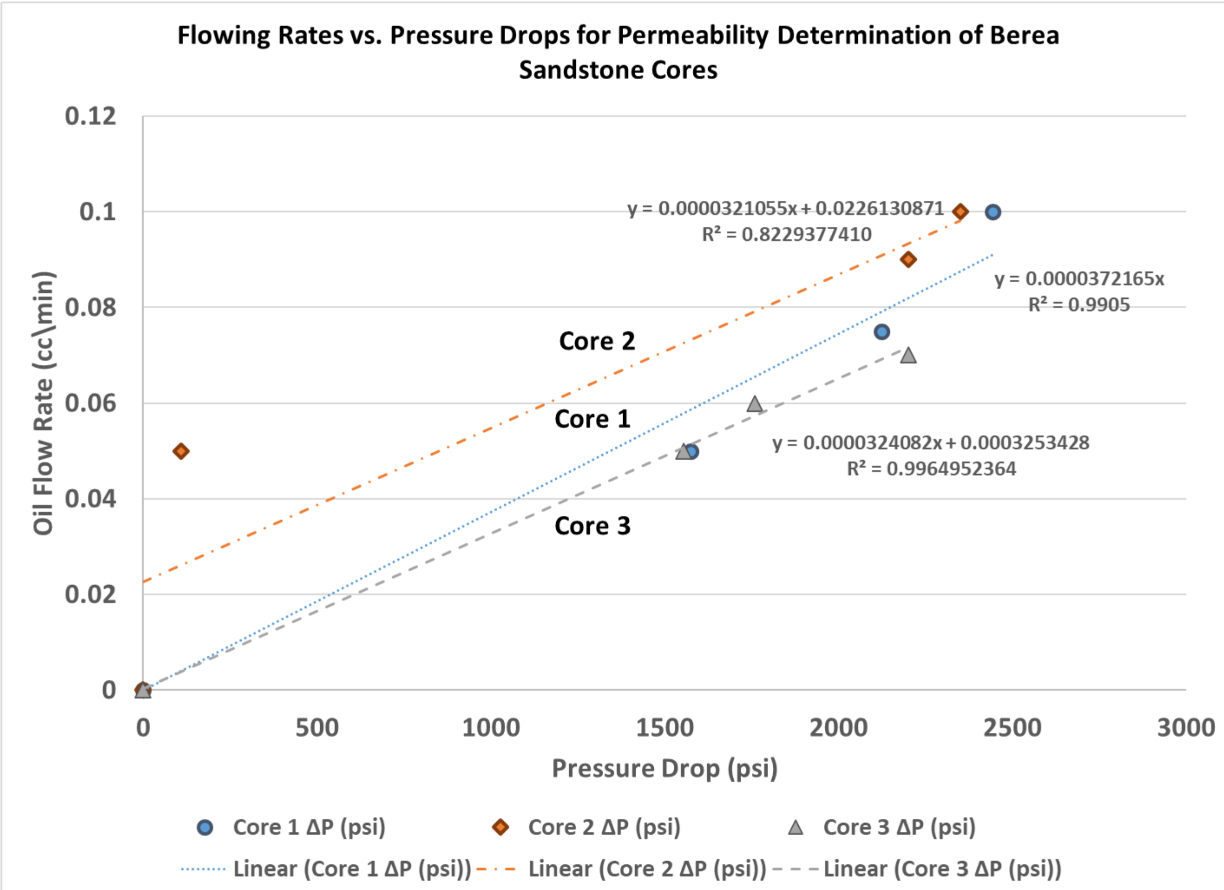


Figure 4. 6. Oil Flow Rate vs Pressure Different of Berea Sandstone Cores' Injection Tests

The absolute horizontal permeability, k_h, is calculated as per equation no. 3.2.4 is as follows:

$$k_h = \frac{m \cdot \mu \cdot L}{0.12444 \cdot A}$$

$$k_h = \frac{0.0000372165 \cdot 6 \cdot \left(\frac{0.8268}{12}\right)}{0.12444 \cdot \left(\frac{\pi \cdot 0.5^2}{144}\right)} = 0.02266771\ md\ or\ \mathbf{22.67}\ micro - darcy\ (\mu D).$$

The same calculation procedure was conducted on the Berea Sandstone Orthognal core plug no. 2 (BSS CPO#2) and the Berea Sandstone Horizontal core sample no. 3 (BSS

CPH#3) and presented in table 4.2. The aging stage started after determining the core properties before performing the EOR experiments.

Table 4. 2. Berea Sandstone Cores-Flooding Data Summary

Core Name	**Core 1**	**Core 2**	**Core 3**
Coring Direction	Horizontal	Vertical	Horizontal
Core Diameter	1-inch	1-inch	1.98 inch
Core Length	0.83-inch	1.43-inch	4.09 inch
Calculated Porosity	5.61%	6.20 %	5.09 %
Absolute Permeability	0.0227	0.0349 mD	0.0241 mD

4.1.2. Tuscaloosa Marine Shale Sample

The fourth sample was collected from the Tuscaloosa Marine Shale (TMS) reservoir which extends from southwestern Mississippi State through central Louisiana State to the eastern part of Texas State. The TMS reservoir is 250 to 800 ft thick (John et al., 1997) with mercury measured porosity less than 4% and calculated permeability ranges between 0.000001 to .0001 md (0.001 – 0.1 μd) (Lu et al., 2015). The used plug (Diameter = 1 inch & Length = 1.97 inches) is cored from 3.3 ft long rock extracted from Well-A in East Feliciana Parish at depth of 15,200 ft. The rock logged total porosity is 6.31 % and effective porosity is 3.7 %. The absolute permeability is 0.0017 md (1.7 μd) determined from the porosity-permeability correlation chart of Well-A, Figure 4.7. The summary of TMS core plug data was listed in Table 4.3.

Table 4. 3. TMS Plug no. 1 Core Data Summary

Core Name	**TMS Core Plug no. 1**
Core Diameter	1-inch
Core Length	1.97-inch
Core Effective Porosity	3.7 %
Core Determined Absolute Permeability	0.0017 mD

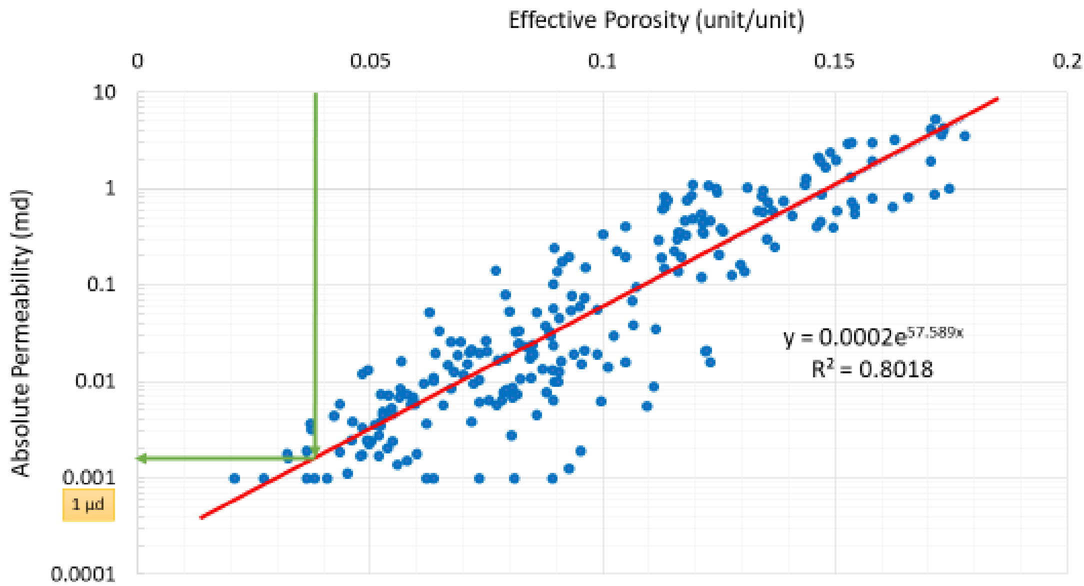
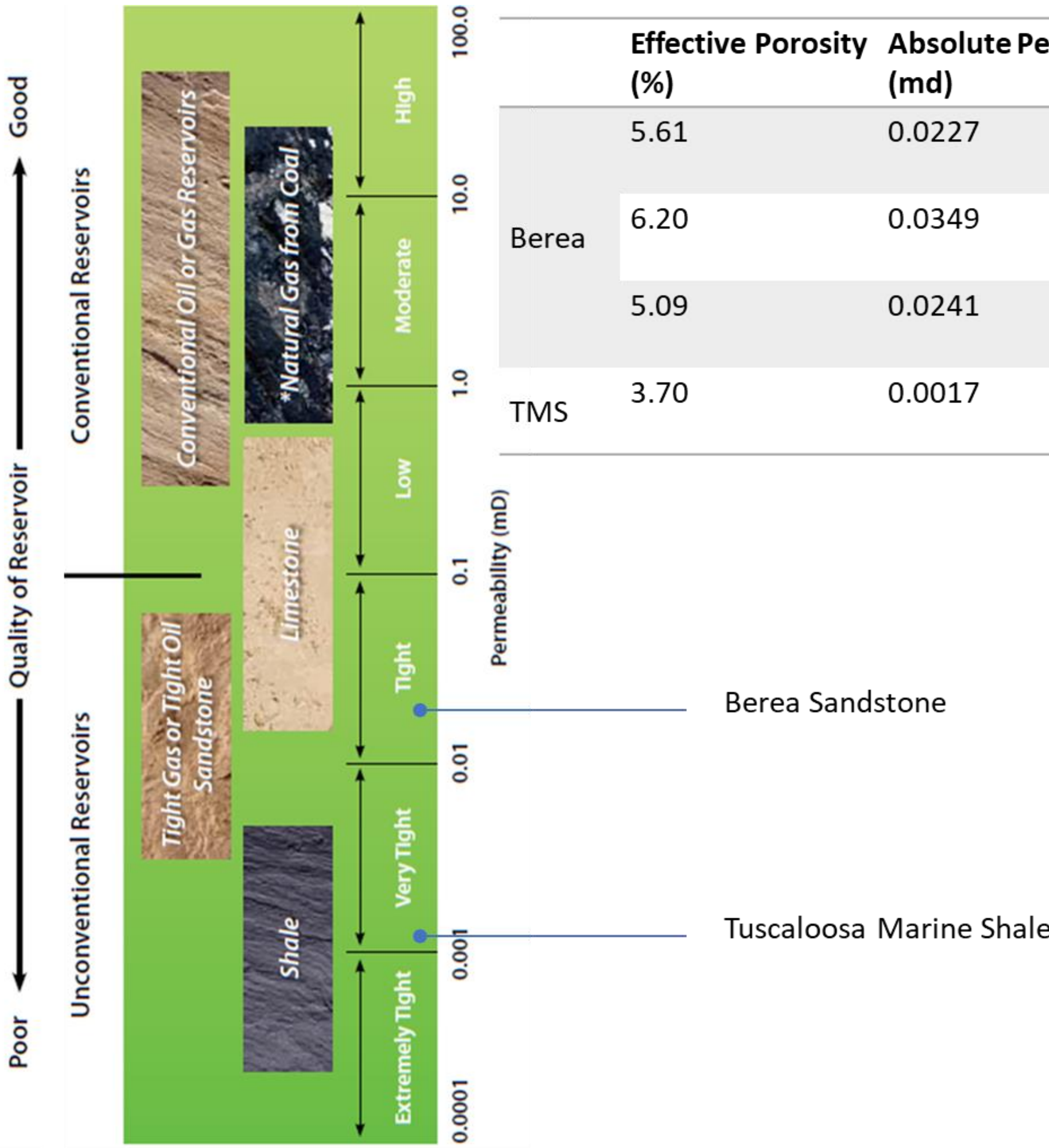


Figure 4. 7. East Feliciana Well-A Porosity-Permeability Correlation Chart

Petrophysical determined data was used to update the core plug and sample selection range of the hydrocarbon resources classification chart and represented the distribution in Figure 4.8. The Berea sandstone core plugs and sample were classified as tight oil sandstone while the Tuscaloosa Marine Shale plug was classified as Shale.



	Effective Porosity (%)	Absolute Permeability (md)
Berea	5.61	0.0227
	6.20	0.0349
	5.09	0.0241
TMS	3.70	0.0017

Figure 4. 8. Summary of Determined Petro-Physical Data and Distribution on the Hydrocarbon Resources Classification Chart (Resources, 2012)

4.2. Enhanced Oil Recovery Results and Discussion

After preparing core plugs and samples, determining their properties, and completely flooding with the reservoir oil, the cores were aged for some time to restore the oil-rock properties at high-pressure conditions. The aging time used in this research was a week which gave saturated oil enough time to interact with the rock (Haeri, 2018), before conducting EOR experiments. In the next subsections, the EOR experiments were discussed in detail for different types of cores collected from various unconventional reservoirs: Berea Sandstone tight plug and samples, and Tuscaloosa Marine Shale plug. The CGI mode had been performed for all cores to create a base case for comparison.

In the research project, several key topics were suggested to be discussed, including but not limited to:

- The implementation of the GAGD process to improve/enhance oil recovery from unconventional reservoirs.
- Comparison of enhancing oil recovery (EOR) technique between conventional CGI mechanism and GAGD process in unconventional reservoir cores.
- The optimization of the GAGD EOR process by determining several operational factors and their impact on the recovery from unconventional resources.

The results of enhanced oil recovery experiments presented in this section were discussed. The discussion was divided into nine parts including the effects of vertical injection, effects of introducing fracture, effects of injection/back pressures, effects of core cutting direction, effects of core size, effects of injection gas, effects of side-fractures, effects of low permeability, and effects of shale presence on enhanced oil recovery.

4.2.1. Berea Sandstone Core Plugs

The first objective of this study was to test the feasibility of enhancing oil recovery from unconventional resources using GAGD mode. To meet this goal, Berea Sandstone samples were used, and several experiments were conducted at different conditions. Due to its relatively small size and relatively good absolute permeability, the tight Berea Sandstone sample (≈0.023 md) yielded a shorter flooding time, which resulted in saving time in the core flooding and EOR experiments. On the other hand, the size of the core plug may lead to uncertainty during the calculations of oil-saturations in all stages including preparation, core-flooding, and EOR experiment. In this section, the results obtained from three Berea Sandstone core plugs were demonstrated: horizontal core (BSS CP1), orthogonal core (BSS CP2), and horizontal large core (BSS CS3). All experiments were performed in sufficient time after the core preparation stage, flooded with the TMS Well-A oil, and aged for a week at room temperature before injecting gas for enhanced oil recovery experiments. The oil recovery enhanced from this plug via the application of CGI, GAGD, and GAGD with fracture utilizing N_2 and CO_2 for all these modes. The applied procedure to run EOR experiments was identical to all core plugs and samples. The 30 performed EOR experiments using Berea Sandstone core plugs and samples were tabulated below. The details of each set of experiments were presented in the following corresponding subsections.

Table 4. 4. List of the Enhanced Oil Recovery Experimental Sets Conducted on Berea Sandstone Core Plugs and Sample

<table>
<tr><th>Experiment Set</th><th>No. of Experiments</th><th>Used Core</th><th>Injection Pressure</th><th>Temperature</th></tr>
<tr><td>Set no. 1</td><td>3</td><td rowspan="2">BSS CP1H</td><td>1,000 psi</td><td rowspan="6">70 ˚F</td></tr>
<tr><td>Set no. 2</td><td>3</td><td>2,000 psi</td></tr>
<tr><td>Set no. 3</td><td>3</td><td>BSS CP2O</td><td>1,000 psi</td></tr>
<tr><td>Set no. 4</td><td>15</td><td rowspan="3">BSS CS3HL</td><td>1,000-3,500 psi</td></tr>
<tr><td>Set no. 5</td><td>4</td><td>2,000 psi</td></tr>
<tr><td>Set no. 6</td><td>2</td><td>1,500 psi</td></tr>
<tr><td>Total</td><td>30 Experiments</td><td></td><td></td><td></td></tr>
</table>

4.2.1.1. Enhanced Oil Recovery Experiments Using Berea Sandston Horizontally Cored Plug (Plug No. 1)

The first plug was cored horizontally, parallel to the layered bedding, with a diameter of 1 inch and a length of 0.8268 inches. Three EOR experiments were conducted at 1,000 psi and another three experiments were performed at 2,000 psi as shown in Table 4.5. All EOR experiments were operated at room temperature and atmospheric outlet pressure with a confining pressure of 1,500 psi. The N_2 gas was used to conduct the three injection modes: CGI, GAGD, and GAGD with Fractures. N_2 is known as a noble gas (completely inert) and no interactions were expected to occur with saturated fluids at this pressure level.

Table 4. 5. List of the Enhanced Oil Recovery Experiments Conducted on Berea Sandstone Horizontal Core (BSS CP1)

Experiment No.	Mode	P_{in}, psi	T, ˚F	P_{out}, psi	P_{con}, psi
1	CGI	1,000	70	Atmospheric	1,500
2	GAGD				
3	GAGD w/Fracture				
4	CGI	2,000			
5	GAGD				
6	GAGD w/Fracture				

P_{in} Injection Pressure (psi)
T Operating Temperature (deg. Fahrenheit)
P_{out} Outlet Pressure (psi)
P_{con} Confining Pressure (psi)

4.2.1.1.1. Enhanced Oil Recovery Experiments of Berea Sandstone Horizontally Core (BSS CP1) at Injection Pressure of 1,000 psi and Operating Temperature of 70 ˚F

In the first EOR experiment on the Berea Sandstone plug (BSS CP1), the plug was flooded in the preparation stage and the saturated weight (W_{sat}) founded to be 27.2556 grams. The pump was set to inject N_2 into the plug in the CGI mode at a maximum pressure of 1,000 psi. The oil drops production was noticed at the injection upstream pressure and the injection of the gas was continued till no more oil was produced for a minimum time of 24 hours or complete the injection of 2,000 ml N_2 to confirm that the movable oil is already produced. The experiment was shut down and the plug was kept under the differential pressure overnight to get most of the differential pressure (dP) of oil recovery. After relieving all pressures, de-assemble the apparatus, the plug was collected and weighed. The after-EOR weight was 27.0244 grams which represented an oil recovery factor of 46.52% as illustrated in Figure 4.9.

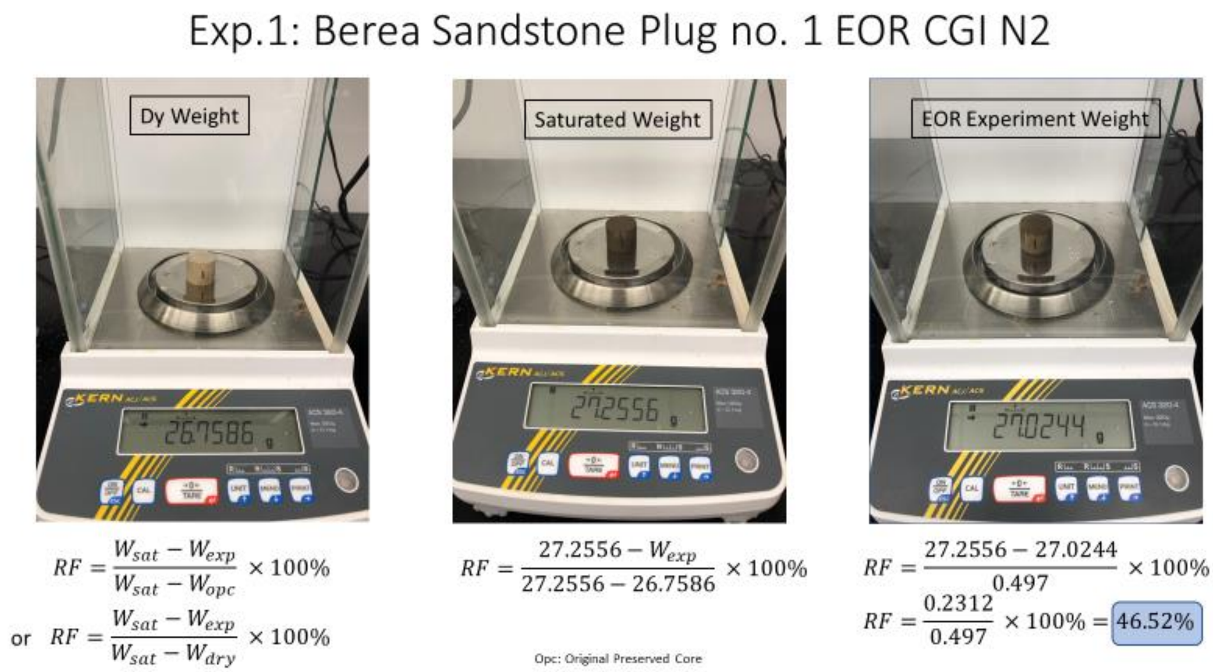


Figure 4. 9. Berea Sandstone Horizontal Core (BSS CP1) Oil Recovery Calculation for Continuous Gas Injection Using Nitrogen (N2-CGI) Mode at Injection Pressure of 1,000 psi and Operating Temperature of 70 ˚F

The GAGD process was applied to examine its impact on improving recovery from Berea Sandstone plug (BSS CP1). To proceed with the experiment, the plug was flooded with the TMS oil at a maximum pump operating pressure of 1,000 psi and kept under pressure overnight. The resultant saturated core weight was 27.2305 grams. Then, the core plug was returned to the core holder and pressurized up to 1,500 psi. The core holder apparatus was turned to a 90° angle and the oil accumulator was replaced by the gas accumulator. The N_2 was injected at a constant pressure of 1,000 psi for a sufficient time (24 hours or 2,000 ml) till no further oil drops were produced. The plug was collected after shutting down the experiment, relieving all pressures, and de-assembling the apparatus, then weighed. The after-experiment weight was found to be 26.9906 grams which resulted in a recovery factor of 50.84% as presented in Figure 4.10.

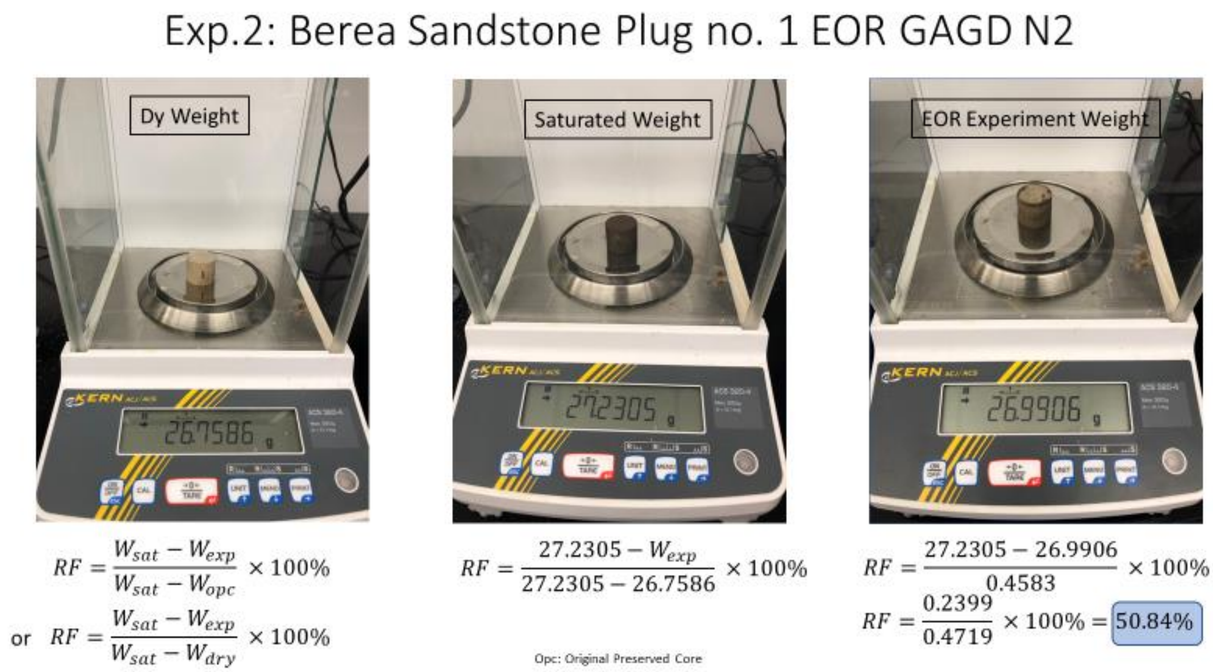


Figure 4. 10. Berea Sandstone Horizontal Core (BSS CP1) Oil Recovery Calculation for Gas-Assisted Gravity Drainage Using Nitrogen (N2-GAGD) Mode at Injection Pressure of 1,000 psi and Operating Temperature of 70 ˚F

To prepare for applying the proposed method, GAGD w/ Fracture, on Berea Sandstone plug (BSS CP1), two fractures with a depth of ¼ inch have been created from both ends with ¼ inch from the center. Then, the plug was cleaned in the Soxhlet for one day to remove the cutting dust and dried in the oven for another day as per the procedure in chapter no. 3. Before conducting the proposed method, the plug was weighed dry, and the weight was found to be 26.3605 grams. The plug was placed in the core holder, vacuumed till depressurized on both sides, and flooded with the TMS oil at a maximum pumping pressure of 1,000 psi. After the flooding process was completed, the plug was kept overnight under operating pressure. The flooded plug was weighed, and the saturated plug weight was 26.9048 grams. The N_2 gas was injected at 1,000 psi operating pressure and resulted in after EOR experiment weight of 26.6114 grams after the EOR experiment of GAGD w/ Fracture. The oil recovery factor from this experiment improved to 53.90% as illustrated in Figure 4.11.

Figure 4. 11. Berea Sandstone Horizontal Core (BSS CP1) Oil Recovery Calculation for Gas-Assisted Gravity Drainage With Fractures Using Nitrogen (N2-GAGD w/Fracture) Mode at Injection Pressure of 1,000 psi and Operating Temperature of 70 ˚F

The summary and comparison of EOR experiments on Berea Sandstone horizontal core (BSS CP1) using N_2 as injectant at an injection pressure of 1,000 psi and operating temperature of 70 ˚F were represented in Table 4.6. The proposed method, GAGD with introducing fractures to the side of core plug (GAGD w/Fracture) was superior to the other EOR experiments; CGI and GAGD with the improvement of 16% from CGI mode and 6% from GAGD. It is worth mentioning that the GAGD improved the recovery from the plug by 9.3% compared to the CGI mode (Base Case).

Table 4. 6. Summary of Berea Sandstone Horizontal Core (BSS CP1) Enhanced Oil Recovery Experiments Injected Nitrogen (N_2) at Pressure of 1,000 psi and Temperature of 70 ˚F

EOR Experiment	CGI	GAGD	GAGD w/ Fractures
Dry Weight, gram	26.7586		25.5491
Saturated Weight, gram	27.2556	27.2305	25.8932
Experimental Weight, gram	27.0244	26.9906	25.6962
Confining Pressure, psi	1,500		
Oil Flooding Pressure, psi	1,000		
Gas Injection Pressure, psi	1,000		
Operating Temperature, °F	70		
Recovery Factor, %	46.52	50.84	53.90
Improving Oil Recovery, %		9.3	15.9

4.2.1.1.2. Effects of Vertical Gas Injection and Introducing Fractures on Enhanced Oil Recovery Process at Injection Pressure of 1,000 psi and Operating Temperature of 70 ˚F Using Nitrogen (N_2) as Injectant

The effect of vertical gas injection in the GAGD process on oil recovery factor by injecting N_2 at a maximum injection pressure of 1,000 psi at an ambient temperature of 70 ˚F found out that the recovery factor was increased by 4.32% compared with injection in the horizontal direction and CGI mode. The result was not a total surprise as the vertical injection scheme ensures a gravity force assisted gas injection mechanism to enhance oil recovery from the reservoir. The experimental results from this experiment showed that GAGD injection mode could effectively improve the enhanced oil recovery up to 9.3% to produce up to 50.84 % OOIP from the reservoir as shown in Figure 4.12. The injected N_2 in GAGD mode from the top side of the apparatus (Core-holder) accumulated at the upper side of the core and displaced the oil down to the bottom side. With the help of gravity, more oil was produced compared to the injection mechanism at horizontal injection mode. From Figure 4.12 it is noted that the GAGD process recovers more oil from the horizontally cut core refers to the injection mechanism that allows the gas to invade each layer equally in stable oil/gas fronts, unlike the conventional CGI which suffers from gas separation near the injection and lets the gas flooding the upper layers mostly and leave the lower layers unswept. Both injection modes, CGI and GAGD, showed the effectiveness of gas injection to enhance the recovery at this kind of operating pressure and temperature by displacing the saturated fluid as piston force from one side to another (in CGI) and from top to bottom (in GAGD). This gravity segregation phenomena are a beneficial force to GAGD as it delayed the gas breakthrough to the producers and prevents the gas phase from competing for flow with the oil. The GAGD process was capable to eliminate the main problem faced with other conventional improving recovery methods: poor sweep and gas breakthrough which was reflected in higher oil recovery.

In the case of introducing fractures to the Berea Sandstone core plug, the oil recovery factor of the GAGD experiment at injection pressure 1,000 psi and ambient temperature of 70 ˚F increased by more than 3% and 7% compared to non-fractured CGI and GAGD experiments, respectively. Adding or introducing fractures to the Berea Sandstone core (or reservoir) increased the stimulated reservoir volume (SRV) which helped to elevate the performance of the enhanced oil recovery (EOR) process in improving oil recovery from sandstone cores (reservoirs). These added fractures to the core plug increased the gas/oil contact area which ease the gas invasion to the core and shorten the bath for the oil to flow in short distance to the production side in less production period. Changing the injection direction from conventional horizontal (from one side to the other side) to vertical injection (from top to bottom) and introducing fractures present evidence of GAGD process potential in tight sandstone reservoirs.

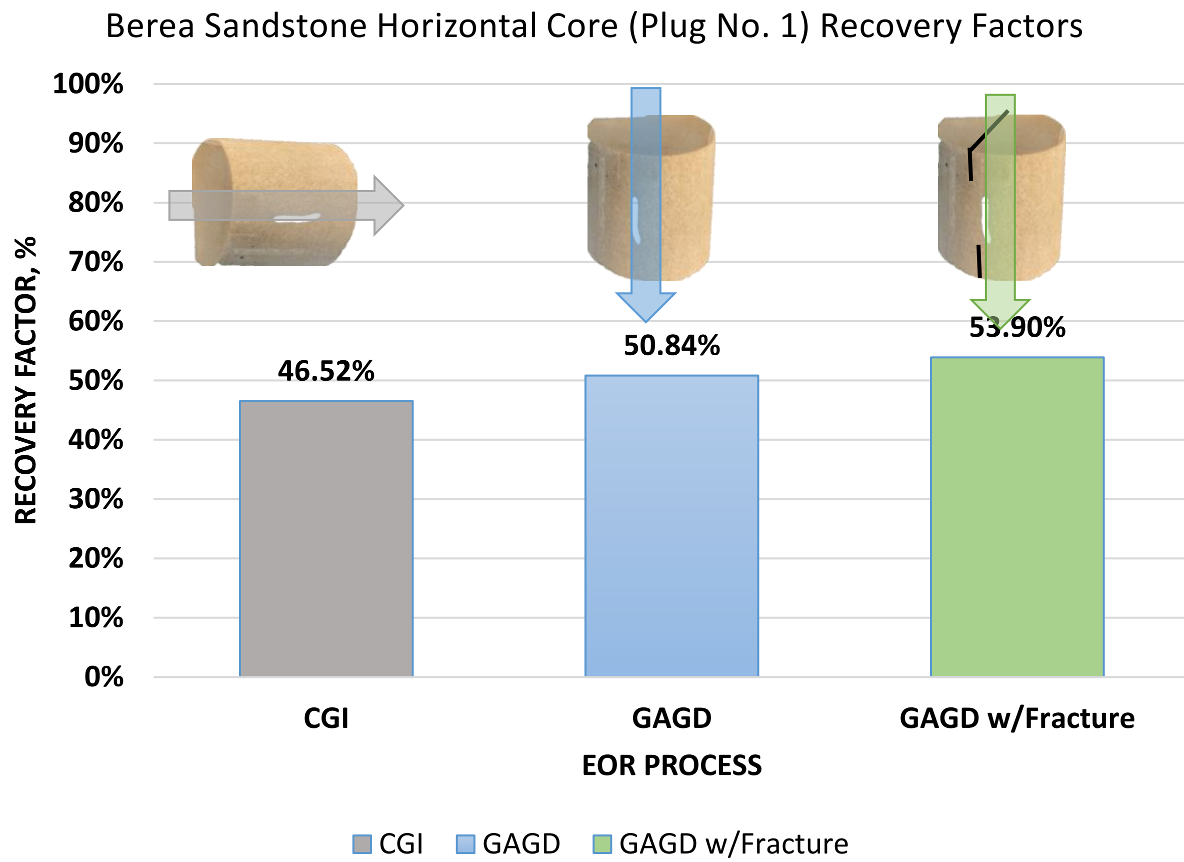


Figure 4. 12. Recovery Comparison of Berea Sandstone Horizontal Core (BSS CP1) Enhanced Oil Recovery Experiments by Injected Nitrogen (N2) at Pressure of 1,000 psi and Operating Temperature of 72 ˚F

4.2.1.1.3. Enhanced Oil Recovery Experiments of Berea Sandstone Horizontally Core (Plug No. 1) at an Injection pressure of 2,000 psi and Operating Temperature of 70 ˚F.

To study the impact of the injection process at higher pressure, the EOR experiments were performed at an operating pressure of 2,000 psi and a temperature of 70 ˚F. In all experiments, the TMS Well-A oil was flooded at 1,000 psi (Core holder confining pressure was 1,500 psi) and monitored the pressures using WinWedge software to confirm the plug is completely saturated for adequate time. After aging overnight, the plug was weighed, and the saturated weight was found to be 27.2169 grams. Figure 4.13 presents the core's weight after injecting N_2 at a maximum pressure of 2,000 psi for an adequate time as 27.0383 grams which represented an oil recovery factor of 38.97% OOIP.

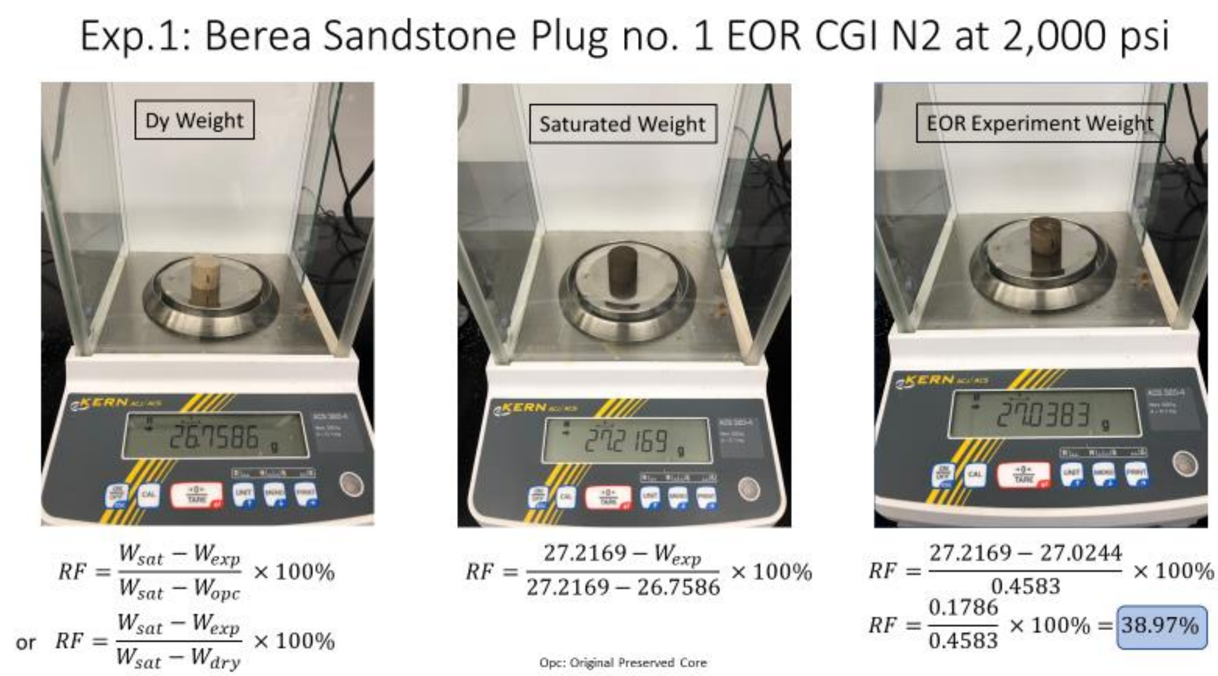


Figure 4. 13. Berea Sandstone Horizontal Core (BSS CP1) Oil Recovery Calculation for Continuous Gas Injection Using Nitrogen (N2-CGI) Mode at Injection Pressure of 2,000 psi and Operating Temperature of 70 ˚F

The GAGD experiment was conducted at the same operating conditions of room temperature, confining pressure of 2,500 psi, oil flooding at a pressure of 1,000 psi, and maximum gas injection pressure of 2,000 psi. The core saturated weight was 27.2329 grams and the after-EOR experiment weight was 26.9704 grams. Implementing these numbers in the recovery equation (Equation 3.5) resulted in obtaining a 55.34% oil recovery factor as shown in Figure 4.14.

Figure 4. 14. Berea Sandstone Horizontal Core (BSS CP1) Oil Recovery Calculation for Gas-Assisted Gravity Drainage Using Nitrogen (N2-GAGD) Mode at Injection Pressure of 2,000 psi and Operating Temperature of 70 ˚F

The proposed method, GAGD w/ Fractures was applied on the fractured Berea Sandstone core plug (BSS CP1) at an operating pressure of 2,000 psi. Before conducting the proposed method, the plug was weighed as dry, and the weight was found to be 25.5491 grams. The plug was placed in the core holder, vacuumed till depressurized on both sides, and flooded with the TMS oil at a maximum pumping pressure of 1,000 psi. After keeping the plug overnight under the operating pressure, the plug was weighed, and the saturated weight was 25.8932 grams. The N_2 gas was injected at a maximum pressure of 2,000 psi and an operating temperature of 70 ˚F. The EOR experiment resulted in a weight of 25.6962 grams after the EOR experiment of GAGD w/ Fracture. The oil recovery factor from this experiment improved to 57.25% OOIP as illustrated in Figure 4.15.

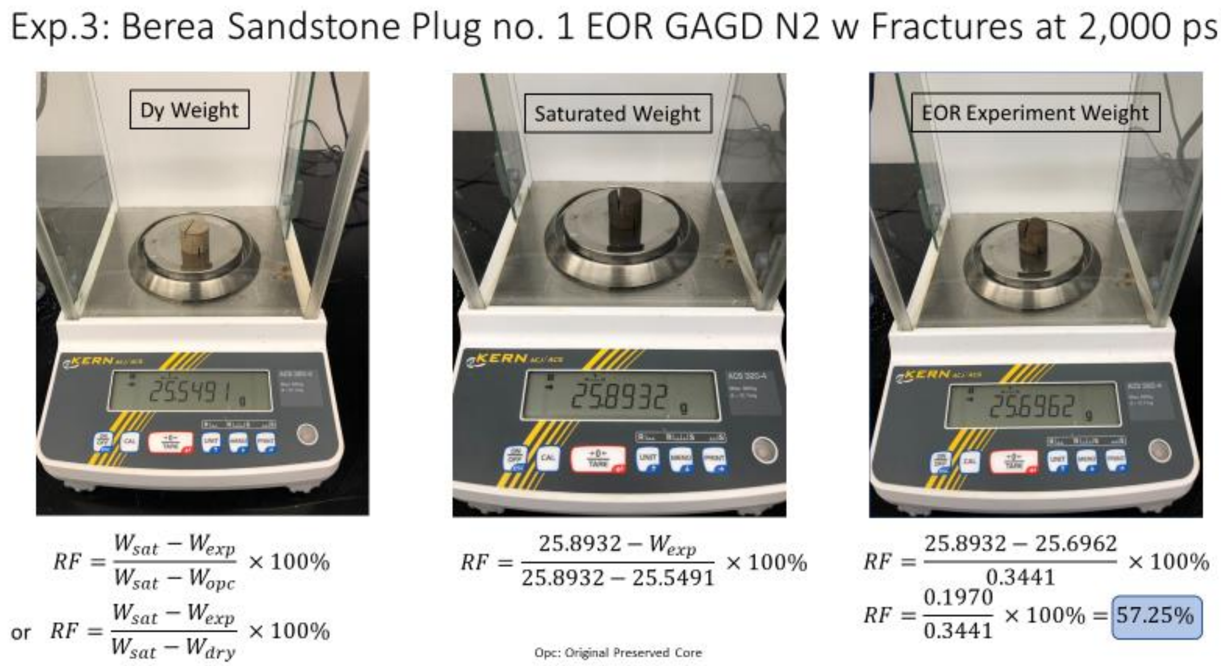


Figure 4. 15. Berea Sandstone Horizontal Core (BSS CP1) Oil Recovery Calculation for Gas-Assisted Gravity Drainage with Fractures Using Nitrogen (N2-GAGD w/Fracture) Mode at Injection Pressure of 2,000 psi and Operating Temperature of 70 ˚F

Summary and comparison of all conducted enhanced (EOR) experiments using gas of N_2 at 2,000 psi were represented in Table 4.7. Again, the proposed method, the GAGD with Fractures (GAGD w/ Fractures) process, showed superior results to other EOR mods: CGI and GAGD, with an improvement of 2.34% from the highest recovery (GAGD) mode and 43.2 % from the conventional CGI mode. Obviously, adding fractures to the core plug improves the recovery and that refers to the stimulated contact area created by fractures. It is worth mentioning that the GAGD improved the recovery from the plug by 40% compared to the CGI mode (Base Case).

Table 4. 7. Summary of Berea Sandstone Horizontal Core (BSS CP1) Enhanced Oil Recovery Experiments Injected Nitrogen (N2) at Pressure of 2,000 psi and Temperature of 70 ˚F

EOR Experiment	CGI	GAGD	GAGD w/ Fractures
Dry Weight, gram	26.7586		25.5491
Saturated Weight, gram	27.2169	27.2329	25.8932
Experimental Weight, gram	27.0383	26.9704	25.6962
Confining Pressure, psi		2,500	
Oil Flooding Pressure, psi		1,000	
Gas Injection Pressure, psi		2,000	
Operating Temperature, °F		70	
Recovery Factor, %	38.97	55.34	57.25
Improving Oil Recovery, %		40	43.2

4.2.1.1.4. Effects of High Gas Injection Pressure on Enhanced Oil Recovery Process at Injection Pressure of 2,000 psi and Operating Temperature of 70 ˚F using Nitrogen (N_2) as Injectant.

Figure 4.16 illustrated the effect of high injection gas pressure (P_{in}) on EOR mechanisms by injecting N_2 at a maximum injection pressure of 2,000 psi at an operating temperature of 70 ˚F. It was found out that high injection pressure can affect the conventional CGI process severely and result in lower oil recovery. In this study, the injection pressure of 2,000 psi lowered the oil recovery from Berea Sandstone Core (Plug no. 1) by about 7% OOIP in comparison with lower injection pressure (1,000 psi). Injecting gas at high pressure in the reservoir to improve the recovery may result in early breakthrough times and poor sweep efficiencies as observed from this experiment. On the other hand, the high injection pressure showed an improvement of recovery factors in both enhanced recovery experiments; the GAGD process and GAGD with Fractures (GAGD w/Fractures). The recovery factor was increased by 5.05% compared with injection at lower injection pressure in GAGD mode. Moreover, the same process and operating conditions showed 3% more improvement in the recovery from the fractured Berea Sandstone core plug. Combining all forces; gravity force (GAGD), stimulation volume (Fractures), and high injection pressure (Displacement) can result in magnificently and recovery of about 57.25% OOIP from tight sandstone samples. The obtained result was not surprising as a vertical injection scheme ensures assisted gas injection mechanism to enhance oil recovery from the reservoir. The injected N_2 in GAGD mode from the top side of the apparatus (Core-holder) accumulates at the upper side of the core and displaces the oil down to the bottom side. With the help of gravity, more oil was produced compared to the injection mechanism at horizontal injection mode. While the gas spread the top layers in CGI, it entered each layer equally in the GAGD process which was assessed to recover more oil from the core (reservoir). This set of experiments approved the conventional CGI process is suffered from gas separation near the injection and gas flooding at upper layers mostly which leaves the lower layers unswept. Even at higher injection pressure, the gravity segregation phenomena showed a benefits force in GAGD implementation as it delays the gas breakthrough, prevents the gas phase from competing for flow with the oil, and improved the oil recovery. The GAGD process, again, showed its capability to eliminate the main problem faced with other conventional improving recovery methods: poor sweep and gas breakthrough which was reflected in higher crude recovery. In this study, the fractures helped to elevate the performance of the EOR mechanism in improving oil recovery from tight sandstone core plugs (reservoirs) even at higher injection pressure.

4.2.1.2. Enhanced Oil Recovery Experiments Using Berea Sandston Core Plug (BSS CP1)

To examine the impact of the rock coring direction on the EOR mechanism, a 1 in diameter core plug was cut from the pre-mentioned 1 ft-long core Berea Sandstone sample. The plug was cored orthogonally, vertical to the bedding. The collected plug length is 1.43 inch and the dry weight after cleaning in the Soxhlet extractor and drying in the oven for sufficient time is 45.0982 grams. In the following sections, the results of three EOR experiments were shown: CGI, GAGD, and GAGD w/ Fractures, Table 4.8. All experiments were performed identical to each other and the horizontally cored Berea Sandstone plug no. 1. In all experiments, N2 was injected at 1,000 psi to enhance oil recovery from the plug at different injection modes.

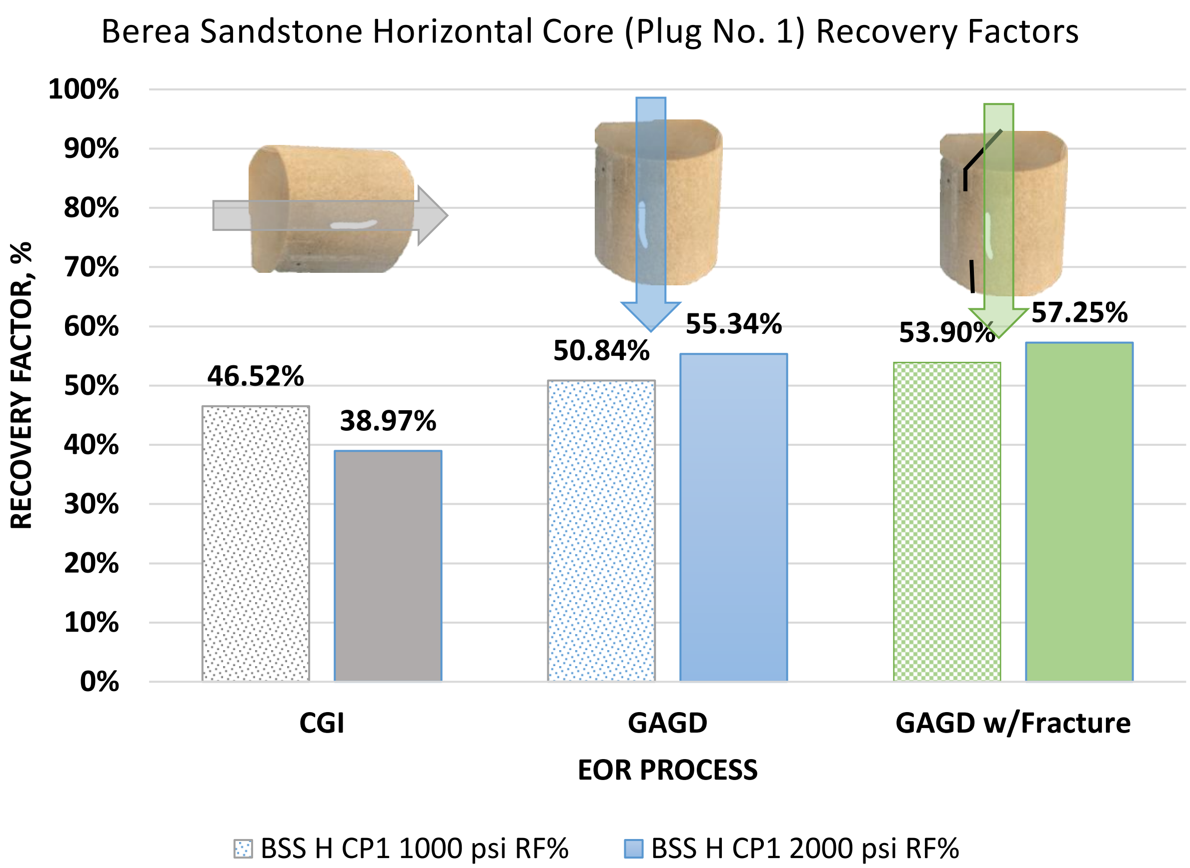


Figure 4. 16. Recovery Comparison of Berea Sandstone Horizontal Core (BSS CP1) Enhanced Oil Recovery Experiments by Injected Nitrogen (N2) at Pressure of 1,000 psi and Pressure of 2,000 psi at Operating Temperature of 72 ˚F

Table 4. 8. List of the Enhanced Oil Recovery Experiments Conducted on Berea Sandstone Orthogonal Core (BSS CP2)

Experiment No.	Mode	P_{in}, psi	T, ˚F	P_{out}, psi	P_{con}, psi
1	CGI				
2	GAGD	1,000	70	Atmospheric	1,500
3	GAGD w/Fracture				

P_{in} Injection Pressure (psi)
T Operating Temperature (deg. Fahrenheit)
P_{out} Outlet Pressure (psi)
P_{con} Confining Pressure (psi)

4.2.1.2.1. Enhanced Oil Recovery Experiments of Berea Sandstone Orthogonal Core (Plug No. 1) at Injection Pressure of 1,000 psi and Operating Temperature of 70 ˚F

In the first experiment of this series, the core was flooded with the TMS Well-A oil at 1,000 psi, aged for a week, and resulted in a core saturated weight of 45.9761 grams. After the gas of N_2 was injected at 1,000 psi in horizontal CGI to enhance the recovery of oil, the core was collected and weighed on the 4-digital scale. The after-EOR experiment weight was 45.5863 grams which is equivalent to 44.4% oil recovery factor (RF) as shown in Figure 4.17.

The GAGD was performed at the same condition and same procedure as the previous CGI experiment. The core was returned to the core holder, pressurized to 1,500 psi (confining pressure), flooded with TMS oil, and aged overnight. The core saturated weight was 45.9505 grams. Again, the core was returned to the core holder, pressurized to 1,500 psi, the core holder is turned vertically (90˚) and injected N_2 at 1,000 psi for sufficient time. The after-GAGD-EOR experiment weight was 45.5475 grams resulted in an oil recovery factor of 47.28% as presented in Figure 4.18.

To prepare for the proposed method, GAGD w/ Fractures; two fractures with a length of ¼ inch were introduced on both sides. Then, the core was cleaned for several days in the Soxhlet extractor and dried in the oven for enough time. The dry weight was 44.3326 grams before flooding with the oil and running the EOR experiment. The core plug was placed in the core holder, pressurized at 1,500 psi, flooded with TMS Well A oil at 1,000 psi, and aged for one week. The core saturated weight was recorded at 45.1690 grams. The core was returned to the core holder pressurized to 1,000 psi and N_2 gas was injected at 1,000 psi to enhance the core productivity. The core weight after the EOR experiment was 44.7217 grams which is equal to 53.48% RF as shown in Figure 4.19.

Exp.1-2: Berea Sandstone Plug no. 2 EOR CGI N2

$$RF = \frac{W_{sat} - W_{exp}}{W_{sat} - W_{opc}} \times 100\%$$

or $$RF = \frac{W_{sat} - W_{exp}}{W_{sat} - W_{dry}} \times 100\%$$

$$RF = \frac{45.9761 - W_{exp}}{45.9761 - 45.0982} \times 100\%$$

Opc: Original Preserved Core

$$RF = \frac{45.9761 - 45.5863}{0.8779} \times 100\%$$

$$RF = \frac{0.3898}{0.8779} \times 100\% = \boxed{44.40\%}$$

Figure 4. 17. Berea Sandstone Orthogonal Core (BSS CP2) Oil Recovery Calculation for Continuous Gas Injection Using Nitrogen (N2-CGI) Mode at Injection Pressure of 1,000 psi and Operating Temperature of 70 ˚F

Exp.2: Berea Sandstone Plug no. 2 EOR GAGD N2

$$RF = \frac{W_{sat} - W_{exp}}{W_{sat} - W_{opc}} \times 100\%$$

or $$RF = \frac{W_{sat} - W_{exp}}{W_{sat} - W_{dry}} \times 100\%$$

$$RF = \frac{45.9505 - W_{exp}}{45.9505 - 45.0982} \times 100\%$$

Opc: Original Preserved Core

$$RF = \frac{45.9505 - 45.5475}{0.8523} \times 100\%$$

$$RF = \frac{0.403}{0.8523} \times 100\% = \boxed{47.28\%}$$

Figure 4. 18. Berea Sandstone Orthogonal Core (BSS CP2) Oil Recovery Calculation for Gas-Assisted Gravity Drainage Using Nitrogen (N2-GAGD) Mode at Injection Pressure of 1,000 psi and Operating Temperature of 70 ˚F

Figure 4. 19. Berea Sandstone Orthogonal Core (BSS CP1) Oil Recovery Calculation for Gas-Assisted Gravity Drainage with Fractures Using Nitrogen (N2-GAGD w/Fracture) Mode at Injection Pressure of 1,000 psi and Operating Temperature of 70 ˚F

Table 4.9 summarized and compared the EOR experiments using N_2 at 1,000 psi and 70 ˚F temperature performed on the orthogonally cored plug (BSS CP2) from the Berea Sandstone sample. The proposed method, GAGD w/ Fractures, showed the best recovery results compared with the other EOR mods. Compared with the CGI mode as a base case, the GAGD mode improved the recovery by 3% and GAGD with the Fractures resulted in an improvement of 20.45. Obviously, adding fractures to the core plug improved the recovery by 13% compared with GAGD without fractures and the proposed method was superior to other studied EOR modes.

Table 4. 9. Summary of Berea Sandstone Orthogonal Core (BSS CP2) Enhanced Oil Recovery Experiments Injected Nitrogen (N2) at Pressure of 1,000 psi and Temperature of 70 ˚F

EOR Experiment	CGI	GAGD	GAGD w/ Fractures
Dry Weight, gram	45.0982		44.3326
Saturated Weight, gram	45.9761	45.9505	45.1690
Experimental Weight, gram	45.5863	45.5475	44.7217
Confining Pressure, psi		1,500	
Oil Flooding Pressure, psi		1,000	
Gas Injection Pressure, psi		1,000	
Operating Temperature, °F			70
Recovery Factor, %	44.4	47.28	53.48
Improving Oil Recovery, %		2.88	20.45

4.2.1.2.2. Effects of Core Cut Direction on Enhanced Oil Recovery Process at Injection Pressure of 1,000 psi and Operating Temperature of 70 ˚F Using Nitrogen (N_2) as Injectant

The effect of core cutting direction on EOR mechanisms by injecting N_2 at a maximum injection pressure of 1,000 psi and operating temperature of 70 ˚F showed a slight decrease in the oil recovery process as illustrated in Figure 4.20. Using an orthogonal cut core sample (BSS CP2) could reduce the recovery factors by an average of 4% compared with the horizontal cut core (BSSCP1) at the same operating conditions. In the conventional CGI process, using the orthogonal cut core recovered a 44.4% OOIP compared to 46.52% recovery by using the horizontal cut core plug (≈ 2% reduction). In the implementation of the GAGD process, the usage of an orthogonal core plug lowered the oil recovery from Berea Sandstone by about 7% OOIP in comparison with the horizontal cut core plug. By introducing the fractures to both cores, the reduction in the recovery factor from the orthogonal (53.48%OOIP) core was less than 1% when compared with the horizontal cut core (53.9%OOIP) plug via application of GAGD with fractures process. Unlike the application of EOR on the horizontal cut core, the injected gas in the EOR process into the orthogonal cut core plug entered the layers one after each other and displaced the oil from them, layer after layer. It was believed that the application of enhanced oil recovery processes through gas injecting at such low pressure in the reservoir might improve the recovery and have better sweep efficiencies using horizontal core plug as observed from this study. While using the horizontal cut core plug, the injected gas traveled from one side to another side displacing the reservoir oil without the need to crossflow between the layers. On the other hand, the crossflow between the layers was ought to displace the oil from each layer to another which might result in lowering the EOR process efficiency. Likewise, the result from the horizontal core plug, the effect of introducing fractures to the orthogonal cores improved the production recovery by 20.5% compared with the conventional CGI process and 6.5% compared with the GAGD process. Again, combining all forces on this type of reservoir; gravity force (GAGD), stimulation volume (Fractures), and injection pressure (Displacement) can result in excellent sweep efficiency and higher oil recovery factor (> 53% OOIP) from such tight sandstone samples. The obtained result from both Berea Sandstone core plugs proved that the proposed GAGD with Fracture process could assist gas injection mechanism and enhance oil recovery from the tight reservoir regardless of the bedding direction (Heterogeneity) contrasting to the other gas injection EOR modes. The proposed process (GAGD w/ Fracture) showed its capability to eliminate the bedding problem faced with other conventional EOR resulted in higher hydrocarbon recovery from the reservoir. In this study, the fractures helped to elevate the performance of the enhanced oil recovery (EOR) mechanism in improving oil recovery from tight sandstone core plugs even from the orthogonal bedding layers (layered reservoirs).

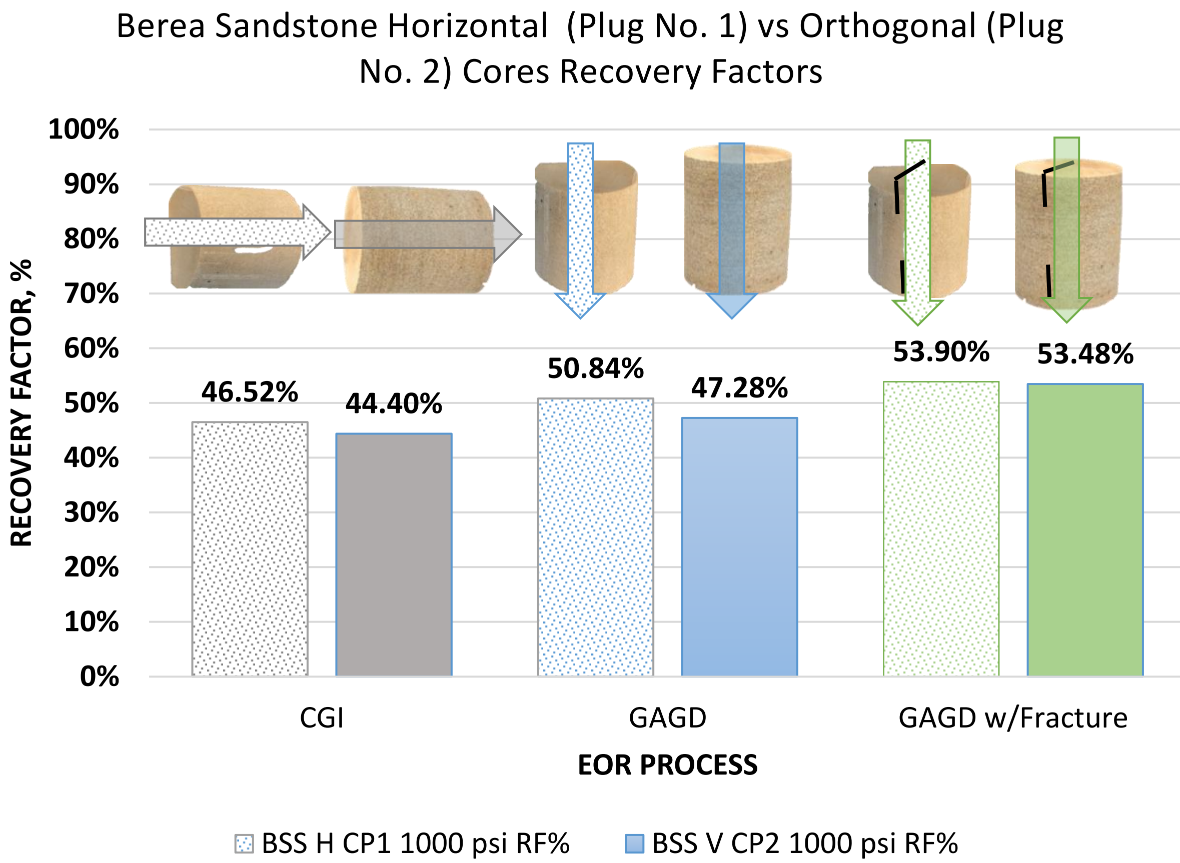


Figure 4. 20. Recovery Comparison of Berea Sandstone Horizontal (BSS CP1and Orthogonal (BSS CP2) Cores Enhanced Oil Recovery Experiments by Injected Nitrogen (N2) at Pressure of 1,000 psi and Operating Temperature of 70 ˚F

4.2.1.3. Enhanced Oil Recovery Experiments Using Large Berea Sandston Horizontally Cored Sample (BSS CS3)

The third Berea Sandstone sample (BSS CS3) was used to study the effect of the core size, injected gases, injection and back pressures, and the impact of having fractures on the EOR process. The BSS CS3 is cut from the same rock as the previous two core plugs (BSS CP1H and BSS CP2V) and has the same petrophysical properties. The BSS CS3 has a diameter of 1.98 inches (5.02 cm) with a length of 4.09 inches (10.385 cm). The bulk volume of the BSS CS3 is 50.17 cubic inches (205.54 cc) which is approximately 20x the bulk volume of BSS CP1. As listed in Table 4.10, five sets of gas injection EOR experiments (a total of 21 experiments) were performed.

First, the N_2 was injected in CGI mode. Second, the core holder was set vertically and N_2 was injected in GAGD mode. Third, the CO_2 was injected in GAGD mode. In these three sets, the experiments operated at an injection pressure range of 1,000 - 3,000 psi, and the core holder confining pressure was set at 3,500 psi. Fourth, different fracture configurations were conducted at the optimum injection pressure from the former three sets: upper-side, lower-side, and both sides' fractures. Backpressure was examined in the fifth set of EOR experiments.

Table 4. 10. List of the Enhanced Oil Recovery Experiments Conducted on Berea Sandstone Large Core Sample (BSS CS3)

<table>
<tr><th>Experiment No.</th><th>Injection Mode</th><th>Injectant</th><th>P_{in}, psi</th><th>T, ˚F</th><th>P_{out}, psi</th><th>P_{con}, psi</th></tr>
<tr><td>1</td><td rowspan="5">CGI</td><td rowspan="10">N2</td><td>1,000</td><td rowspan="21">70</td><td rowspan="19">Atmospheric</td><td rowspan="15">3,500</td></tr>
<tr><td>2</td><td>1,500</td></tr>
<tr><td>3</td><td>2,000</td></tr>
<tr><td>4</td><td>2,500</td></tr>
<tr><td>5</td><td>3,000</td></tr>
<tr><td>6</td><td rowspan="10">GAGD</td><td>1,000</td></tr>
<tr><td>7</td><td>1,500</td></tr>
<tr><td>8</td><td>2,000</td></tr>
<tr><td>9</td><td>2,500</td></tr>
<tr><td>10</td><td>3,000</td></tr>
<tr><td>11</td><td rowspan="11">CO2</td><td>1,000</td></tr>
<tr><td>12</td><td>1,500</td></tr>
<tr><td>13</td><td>2,000</td></tr>
<tr><td>14</td><td>2,500</td></tr>
<tr><td>15</td><td>3,000</td></tr>
<tr><td>16</td><td rowspan="3">GAGD w/ Fracture</td><td rowspan="4">2,000</td><td rowspan="4">2,500</td></tr>
<tr><td>17</td></tr>
<tr><td>18</td></tr>
<tr><td>19</td><td>CGI w/Fracture</td></tr>
<tr><td>20</td><td>CGI BP</td><td rowspan="2">1,500</td><td rowspan="2">500</td><td rowspan="2">3,000</td></tr>
<tr><td>21</td><td>GAGD BP</td></tr>
</table>

P_{in} Injection Pressure (psi)
T Operating Temperature (deg. Fahrenheit)
P_{out} Outlet Pressure (psi)
P_{con} Confining Pressure (psi)

4.2.1.3.1. Continuous Gas Injection (CGI) Enhanced Oil Recovery (EOR) Experiments of Large Berea Sandstone Horizontal Core (BSS CS3) By Injecting Nitrogen (N_2) at Pressures of 1,000-3,000 psi and Operating Temperature of 70 ˚F

As in all experiments, the CGI injection mode was used to create a base case for all gas injection EOR experiments. In the following 5 experiments, the gas of N_2 was injected at various pressures. The core dry weight was 521.3 grams. The core was flooded with the TMS Well A oil at 1,000 psi and the core holder pressure set at 1,500 psi for four days. Then, the core sample aged for a week before being collected and measured the saturated weight of 531.4 grams. The N_2 was injected at 1,000 psi for one whole day till no more oil was produced, the core collected and weighed, and the after-experiment weight was 527.8 grams. The recovery from the first EOR experiment was 35.64% as shown in Figure 4.21.

$$RF = \frac{W_{sat} - W_{exp}}{W_{sat} - W_{opc}} \times 100\%$$

or $$RF = \frac{W_{sat} - W_{exp}}{W_{sat} - W_{dry}} \times 100\%$$

$$RF = \frac{531.4 - W_{exp}}{531.4 - 521.3} \times 100\%$$

$$RF = \frac{531.4 - 527.8}{10.1} \times 100\%$$

$$RF = \frac{3.6}{10.1} \times 100\% = \boxed{35.64\%}$$

Figure 4. 21. Large Berea Sandstone Horizontal Core (BSS CS3) Oil Recovery Calculation for Continuous Gas Injection Using Nitrogen (N2-CGI) Mode at Injection Pressure of 1,000 psi and Operating Temperature of 70 ˚F

After completing the first experiment, the core was returned to the core holder, pressurized up to 1,500 psi, and flooded with the same oil at 1,000 psi. The core was kept overnight after being completely flooded and collected to determine the saturated weight. The W_{sat} was 531.0 grams. Gas of N_2 was injected at 1,500 psi for a whole day and the after-EOR experiment weight was 527.7 grams which resulted in a 34.02% oil recovery from the core sample as shown in Figure 4.22.

Exp.2: Berea Sandstone Sample no. 3 EOR CGI N2 (1500psi)

$$RF = \frac{W_{sat} - W_{exp}}{W_{sat} - W_{opc}} \times 100\%$$

or $$RF = \frac{W_{sat} - W_{exp}}{W_{sat} - W_{dry}} \times 100\%$$

$$RF = \frac{531.0 - W_{exp}}{531.0 - 521.3} \times 100\%$$

$$RF = \frac{531.0 - 527.7}{9.7} \times 100\%$$

$$RF = \frac{3.3}{9.7} \times 100\% = \boxed{34.02\%}$$

Figure 4. 22. Large Berea Sandstone Horizontal Core (BSS CS3) Oil Recovery Calculation for Continuous Gas Injection Using Nitrogen (N2-CGI) Mode at Injection Pressure of 1,500 psi and Operating Temperature of 70 ˚F

During running the third experiment, the core was cracked from the upper side (injection end). The broken core side was cut and cleaned the core in the Soxhlet extractor for three weeks. Then, the core was dried in the oven for a whole week before collecting the sample and measuring its dry weight. The new sample dry weight was 396.6 grams. After that, the core was flooded with the TMS oil at 1,000 psi (Core holder Pressure = 1,500 psi) for several days before aging for one week. After aging the core, it was placed on the scale and determined the saturated weight to be 403 grams. The core was returned to the core holder and pressurized to 3,500 psi and started injection N2 at a pressure of 2,000 psi for one whole day. The after-EOR experiment weight was 400.2 grams yielding a recovery factor of 43.7% as shown in Figure 4.23.

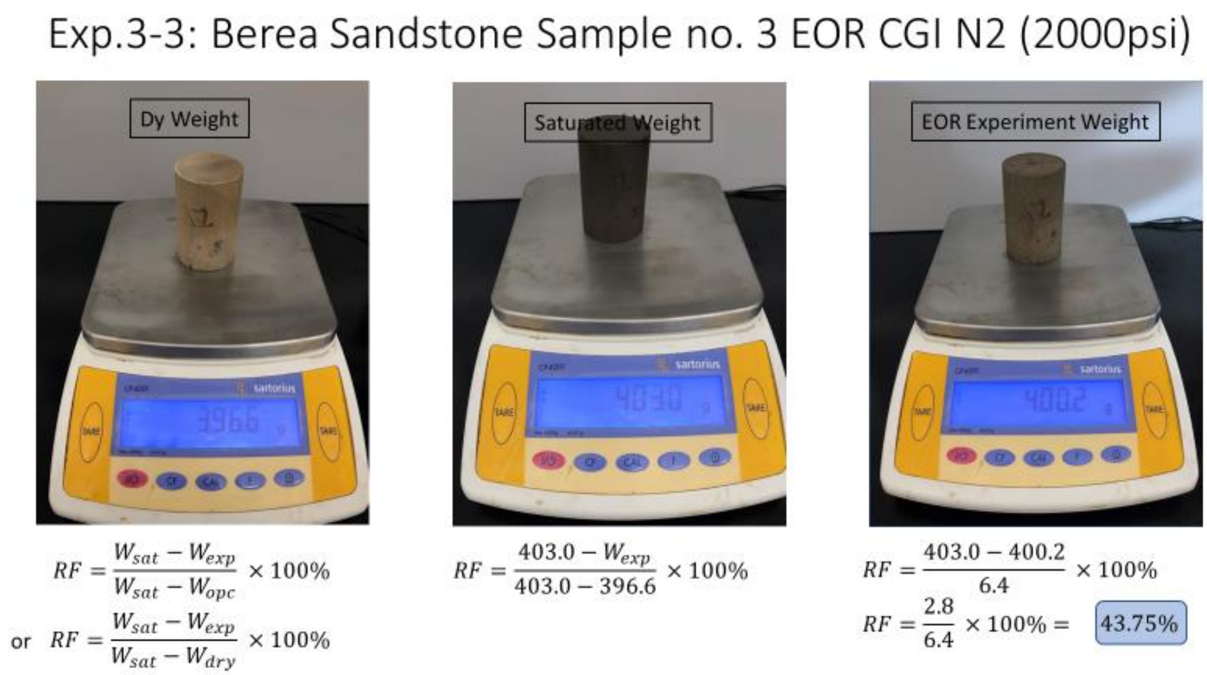


Figure 4. 23. Large Berea Sandstone Horizontal Core (BSS CS3) Oil Recovery Calculation for Continuous Gas Injection Using Nitrogen (N2-CGI) Mode at Injection Pressure of 2,000 psi and Operating Temperature of 70 ˚F

In the fourth experiment, the core was returned to the core holder and pressurized to 1,500 psi before flooding with oil at 1,000 psi for adequate time. Saturated core left aging overnight before collecting and weighting (Wsat = 403.5 gram). The N_2 was injected at 2,500 psi (core holder pressure 3,500) for a day till no further oil was produced and left overnight. After the experiment weight was 400.1 grams and the recovery factor increased to 49.28% as shown in Figure 4.24.

Exp.4: Berea Sandstone Sample no. 3 EOR CGI N2 (2500psi)

$$RF = \frac{W_{sat} - W_{exp}}{W_{sat} - W_{opc}} \times 100\%$$

or $$RF = \frac{W_{sat} - W_{exp}}{W_{sat} - W_{dry}} \times 100\%$$

$$RF = \frac{403.5 - W_{exp}}{403.5 - 396.6} \times 100\%$$

$$RF = \frac{403.5 - 400.1}{6.9} \times 100\%$$

$$RF = \frac{3.4}{6.9} \times 100\% = \boxed{49.28\%}$$

Figure 4. 24. Large Berea Sandstone Horizontal Core (BSS CS3) Oil Recovery Calculation for Continuous Gas Injection Using Nitrogen (N2-CGI) Mode at Injection Pressure of 2,500 psi and Operating Temperature of 70 ˚F

The last experiment in CGI series is to inject N_2 at higher pressure (3,000 psi). The core flooded with the TMS Well A oil for sufficient time and aged overnight resulted in a saturated weight of 403.3 grams. The gas of N_2 was injected at 3,000 psi (core holder pressure = 3,500 psi) till no further oil was produced in one whole day. Core after EOR experiment weight was 400.4 gram and recovery factor equaled 43.28%, Figure 4.25.

The CGI using N_2 has enhanced oil recovery from Berea Sandstone core sample no. 3 (BSS CS3) by increasing the injection pressure. Increasing the operating pressure resulted in improving the recovery by at least 17% with a maximum recovery factor of about 50% at 2,500 psi. The summary of the continuous N_2 injection experiments for BSS CS3 was listed in Table 4.11.

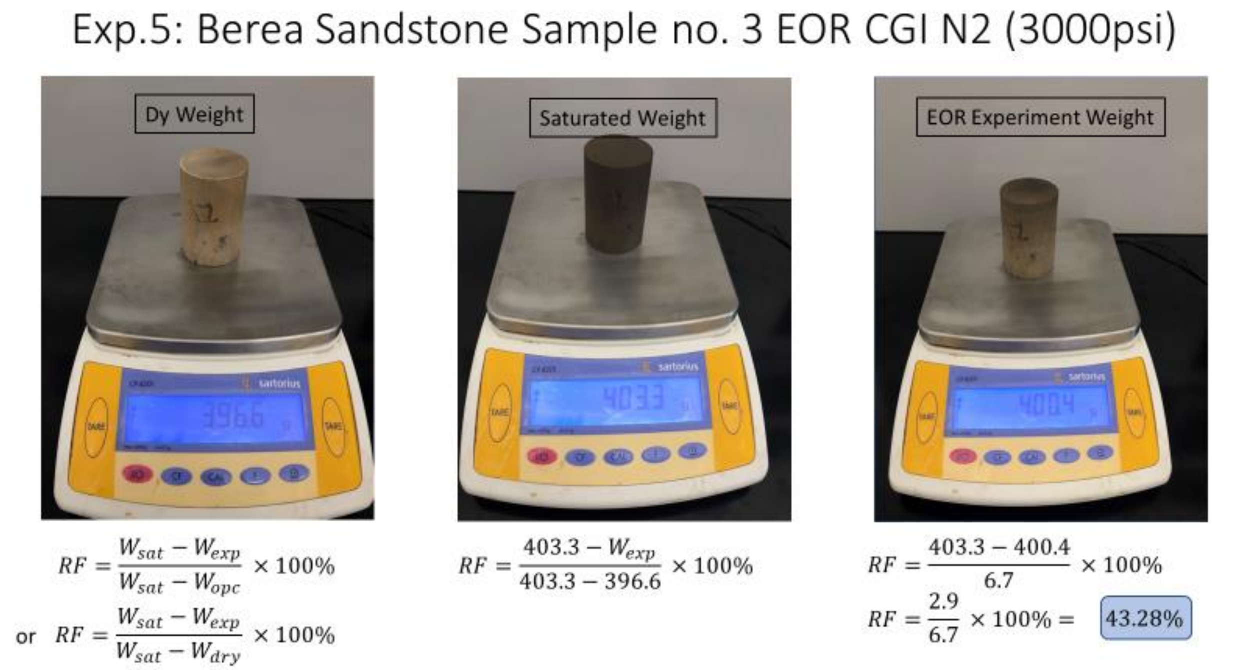


Figure 4. 25. Large Berea Sandstone Horizontal Core (BSS CS3) Oil Recovery Calculation for Continuous Gas Injection Using Nitrogen (N2-CGI) Mode at Injection Pressure of 1,500 psi and Operating Temperature of 70 ˚F

Table 4. 11. Summary of Large Berea Sandstone Horizontal Core (BSS CS3) Enhanced Oil Recovery Experiments by Injected Nitrogen (N_2) in Continuous Gas Injection (CGI) mode at Pressures of 1,000-3,000 psi and Temperature of 70 ˚F

EOR Experiment	**1,000**	**1,500**	**2,000**	**2,500**	**3,000**
Dry Weight, gram	521.3		396.6		
Saturated Weight, gram	531.4	531	403	403.5	403.3
Experimental Weight, gram	527.8	527.7	400.2	400.1	400.4
Confining Pressure, psi			3,500		
Oil Flooding Pressure, psi			1,000		
Gas Injection Pressure, psi	1,000	1,500	2,000	2,500	3,000
Operating Temperature, °F			70		
Recovery Factor, %	35.64	34.02	43.75	49.28	43.28
Improving Oil Recovery, %		-4.55	22.76	38.27	17.84

4.2.1.3.2 Gas-Assisted Gravity Drainage (GAGD) Enhanced Oil Recovery (EOR) Experiments of Large Berea Sandstone Horizontal Core (BSS CS3) By Injecting Nitrogen (N2) at Pressures of 1,000-3,000 psi and Operating Temperature of 70 ˚F

As in the previous section, the gas of N_2 was used to enhance the oil recovery from Berea sandstone. Five experiments were conducted at different operation pressures ranging from 1,000 psi to 3,000 psi. The difference in this section from the former one is that the core holder is set up vertically (90˚) which allows us to inject N_2 gas vertically. The injected gas displaces saturated oil from top to bottom as a piston movement. The same procedure and conditions were applied in all experiments: Oil flooding at 1,000 psi and core holder pressure1,500 psi, operating temperature is 72˚F, and the core holder pressure set at 3,500 psi for all gas injection experiments.

In the first experiment of this series, the core holder was set up horizontally and the Berea Sandstone core sample no. 3 (BSS CS3) was fully saturated with TMS oil for several days and aged overnight. The core saturated weight was 403.1 grams. After return, the core to the core holder and pressurized to 3,500 psi, the core holder turns 90˚ and the gas of nitrogen was injected vertically, from top to bottom at an injection pressure of 1,000 psi till no more oil produced or the 2,000 cylinders empty. The after EOR experiment weight was 400.4 grams and the recovery factor was 41.54% as shown in Figure 4.26.

After completing the first N_2 GAGD EOR experiment, the core holder was set horizontally and flooded the BSS CS3 with the oil at 1,000 psi for a couple of days and aged overnight. The core saturated weight was 403.3 grams. Then, the core returned to the core holder, pressurized to 3,500 psi, and turn vertically. The gas of nitrogen was injected at 1,500 psi resulted in after experiment weight of 400.2 grams and an improved recovery factor of 46.27%, Figure 4.27.

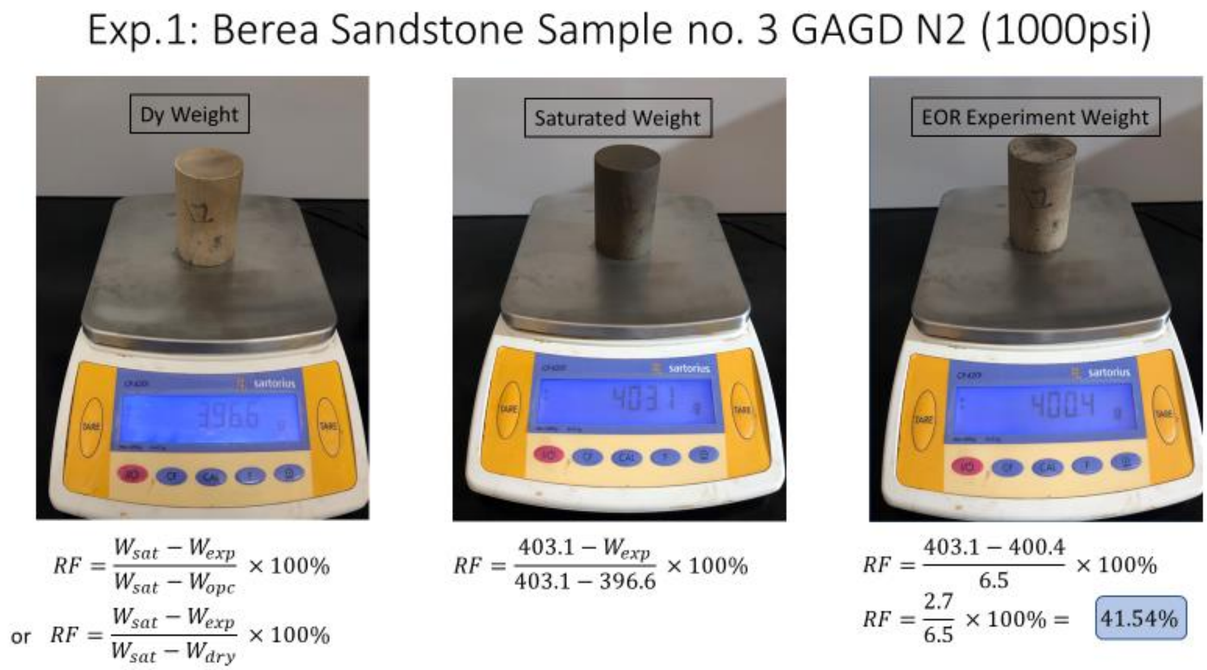


Figure 4. 26. Large Berea Sandstone Horizontal Core (BSS CS3) Oil Recovery Calculation for Gas-Assisted Gravity Drainage Using Nitrogen (N_2-GAGD) Mode at Injection Pressure of 1,000 psi and Operating Temperature of 70 ˚F

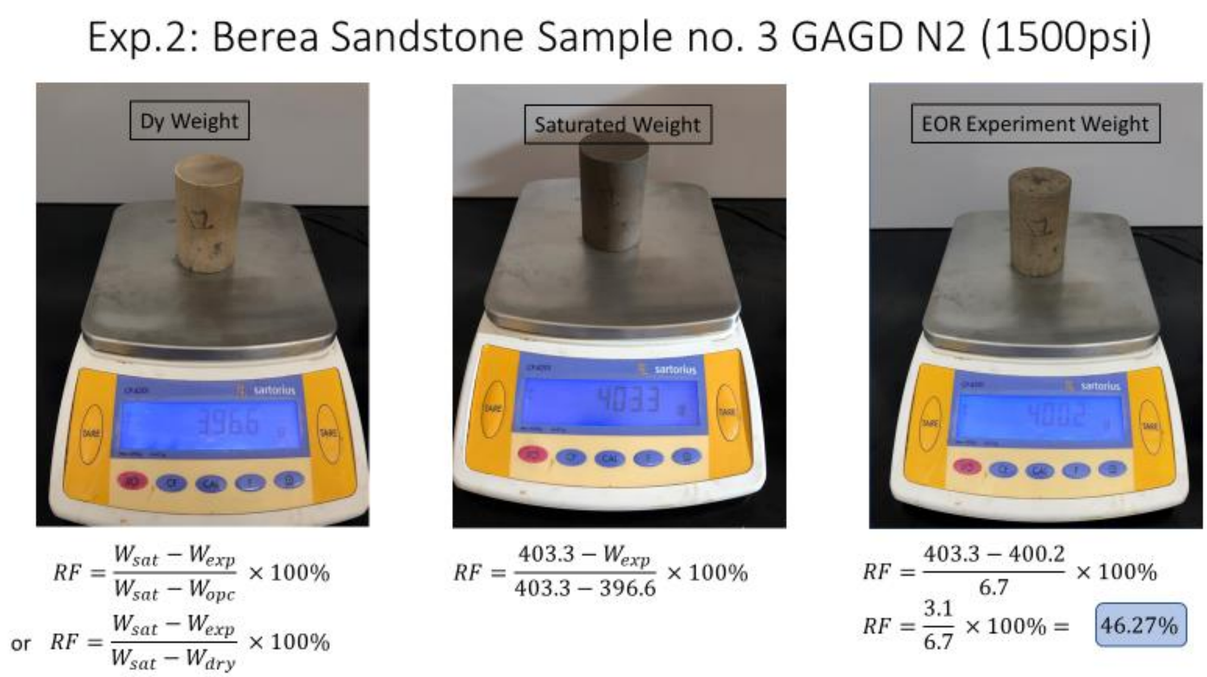


Figure 4. 27. Large Berea Sandstone Horizontal Core (BSS CS3) Oil Recovery Calculation for Gas-Assisted Gravity Drainage Using Nitrogen (N2-GAGD) Mode at Injection Pressure of 1,500 psi and Operating Temperature of 70 ˚F

Following the same procedure in previous experiments, the third experiment's oil-saturated weight was 403.1 grams. The nitrogen gas was injected at 2,000 psi and the weight after the EOR experiment was 400.1 grams. The oil recovery factor was calculated to be 46.15% as shown in Figure 4.28.

$$RF = \frac{W_{sat} - W_{exp}}{W_{sat} - W_{opc}} \times 100\%$$

or $$RF = \frac{W_{sat} - W_{exp}}{W_{sat} - W_{dry}} \times 100\%$$

$$RF = \frac{403.1 - W_{exp}}{403.1 - 396.6} \times 100\%$$

$$RF = \frac{403.1 - 400.1}{6.7} \times 100\%$$

$$RF = \frac{3.0}{6.5} \times 100\% = \boxed{46.15\%}$$

Figure 4. 28. Large Berea Sandstone Horizontal Core (BSS CS3) Oil Recovery Calculation for Gas-Assisted Gravity Drainage Using Nitrogen (N2-GAGD) Mode at Injection Pressure of 2,000 psi and Operating Temperature of 70 ˚F

Figure 4.29 shows the saturated and after EOR weight for the fourth experiment of Berea Sandstone core sample no. 3. The saturated weight was 403.1 grams and after injecting N_2 in GAGD mode at 2,500 psi was 400.0 grams. The oil recovery factor improved to 47.69%.

In the last N_2 GAGD experiment, the oil flooding operation resulted in a core saturated weight of 403.0 grams, and the gas of nitrogen was injected at 3,000 psi for a whole day. The after EOR experiment weight was 399.9 grams and oil recovery improved to 48.44% as illustrated in Figure 4.30.

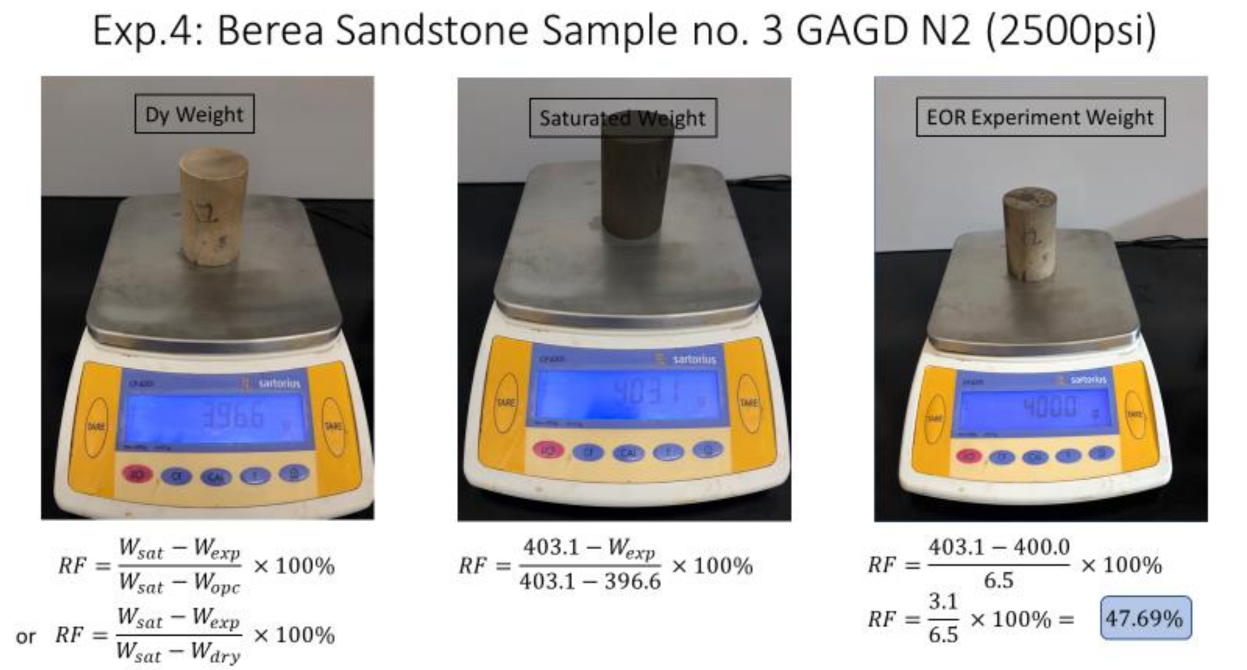


Figure 4. 29. Large Berea Sandstone Horizontal Core (BSS CS3) Oil Recovery Calculation for Gas-Assisted Gravity Drainage Using Nitrogen (N2-GAGD) Mode at Injection Pressure of 2,500 psi and Operating Temperature of 70 ˚F

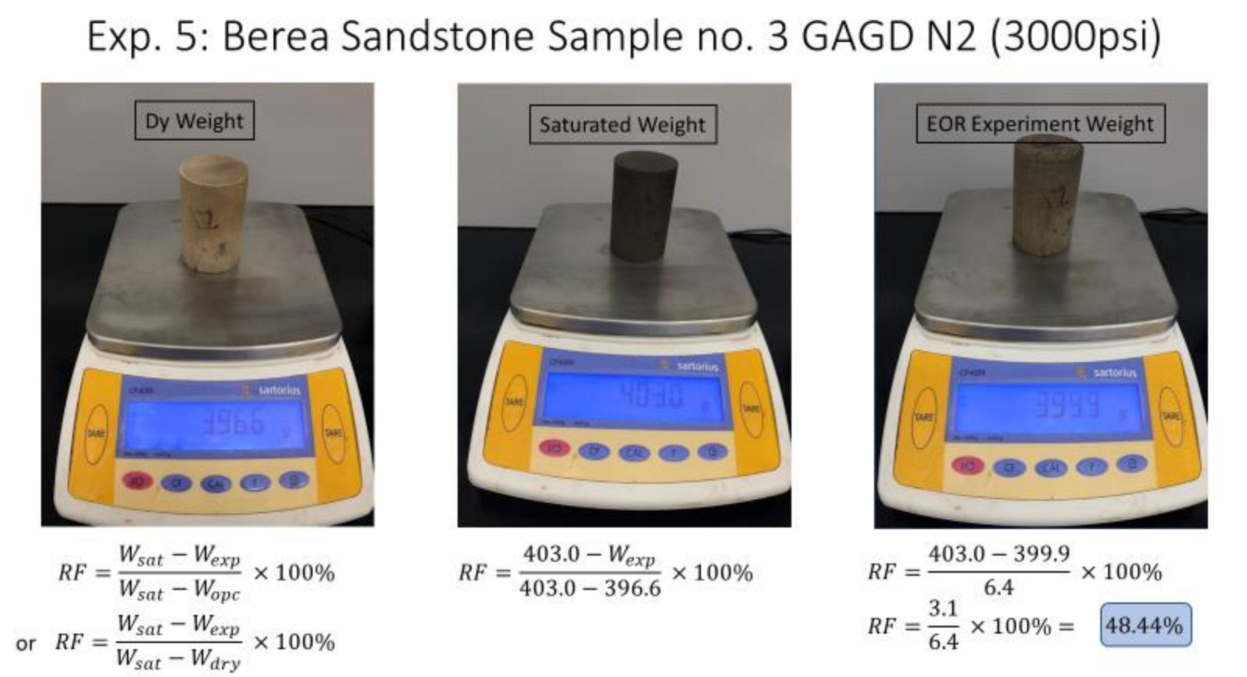


Figure 4. 30. Large Berea Sandstone Horizontal Core (BSS CS3) Oil Recovery Calculation for Gas-Assisted Gravity Drainage Using Nitrogen (N2-GAGD) Mode at Injection Pressure of 3,000 psi and Operating Temperature of 70 ˚F

Injected of N_2 vertically in GAGD mode enhanced oil recovery from Berea Sandstone core sample no. 3 (BSS CS3) by increasing injection pressure from 1,000 psi to 3,000 psi. This increment of operating pressure resulted in improving the recovery by at least 10% with a maximum recovery factor of about 49% at 3,000 psi. The summary of the GAGD N_2 injection experiments for BSS CS3 was listed in Table 4.12.

Table 4. 12. Summary of Large Berea Sandstone Horizontal Core (BSS CS3) Enhanced Oil Recovery Experiments by Injected Nitrogen (N_2) in Gas-Assisted Gravity Drainage (GAGD) Process at Pressures of 1,000-3,000 psi and Temperature of 70 ˚F

EOR Experiment	1,000	1,500	2,000	2,500	3,000
Dry Weight, gram			396.6		
Saturated Weight, gram	403.1	403.3	403.1	403.1	403.0
Experimental Weight, gram	400.4	400.2	400.1	400.0	399.9
Confining Pressure, psi			3,500		
Oil Flooding Pressure, psi			1,000		
Gas Injection Pressure, psi	1,000	1,500	2,000	2,500	3,000
Operating Temperature, °F			70		
Recovery Factor, %	41.54	46.27	46.15	47.69	48.44
Improving Oil Recovery, %		10.00	9.88	13.55	15.33

4.2.1.3.3. Effects of Core Size and Injection Pressure on Enhanced Oil Recovery Process Using Nitrogen (N_2) as Injectant at Operating Temperature of 70 ˚F

The effect of core sizes on the oil recovery process by injecting N_2 at injection pressures of 1,000 and 2,000 psi and an ambient temperature of 70 ˚F in both CGI mode and GAGD process found out that the recovery factors were showing a general decreasing trend for the obtained recovery factors (RFs) of large core size comparing with smaller one. The experimental results from this series of experiments showed that using a large Berea Sandstone core sample (BSS CS3) to examine CGI and GAGD enhanced oil recovery (EOR) mechanisms at 1,000 psi and 70 ˚F operating temperature lower oil recovery by approximately 10% RF and recovered 35.64 % OOIP and 41.54% OOIP by injecting Nitrogen (N_2) in CGI and GAGD modes, respectively. At injection pressure of 2,000 psi, the GAGD process followed the same trend and produced 46.15% OOIP (9

% < BSS CP1) while the recovery increased by 5% in CGI mode to produce 43.75% OOIP from the large BSS CS3 core. This increment in oil recovery refers to the early braked through of the injected gas in the smaller core plug at this operating condition (as seen earlier) while its delayed gas breakthrough by using a larger core sample. Implementation of the GAGD process in this large core showed about 3% to 6% OOIP recovery compared with conventional CGI mode using N_2 as injectant at same operating conditions. The general decrement recovery factors using large core referred to the fact that injected N_2 invaded most of the small core pores and displaces the oil effectively due to the core size which may not allow some reservoir phenomena to occur due to size limitation, e.g., gas segregation. This issue was solved by using the larger core sample for the same reservoir, Berea Sandstone. Unlike gas injection EOR experiments of BSS CP1, after each gas injection EOR experiment using BSS CS3 the injected gas swept the top layers of the core and left the bottom of the core not swept, as illustrated in Figure 4.31, due to the gas segregation which is more representative of this phenomenon in the real reservoir drive mechanism. Smaller core diameter with a shorter length ease oil displacement and flow which may not exist in the reservoir that making the usage of larger cores more reservoir representing and the results realistic.

In Figure 4.32, it is noted that the gas injection in the GAGD process recovered more oil compared with the CGI mode using N_2 from the Berea Sandstone large core sample in most of the performed gas injection EOR experiments at injection pressures of 1,000-3,000 psi with a 2.4% to 12.2% different in oil recovery. The result was not surprising as the vertical injection scheme ensures a gravity force assisted gas injection mechanism to enhance oil recovery from the reservoir which are unlike the conventional CGI mechanism that suffers from gas separation near the injection inlet and lets the gas flood the upper layers mostly and leave the lower layers unswept. Notably, higher injection pressure displaced more hydrocarbon and resulted in higher recovery compared with the lower pressure up to a level where increasing the pressure may not help to improve the recovery, but it may start work oppositely and disimprove hydrocarbon recoveries. In this study, the highest recovery was at 2,500 psi with RF of 49.28% OOIP in CGI mode and 48.44% OOIP in the GAGD process at 3,000 psi. The injection pressure after 2,000 psi showed a flat trend of oil recoveries with an average of 46% and 49% OOIP for CGI and GAGD, respectively. GAGD process eliminated major problems faced with other conventional CGI modes such as poor sweep and gas breakthrough which is reflected in higher crude recovery.

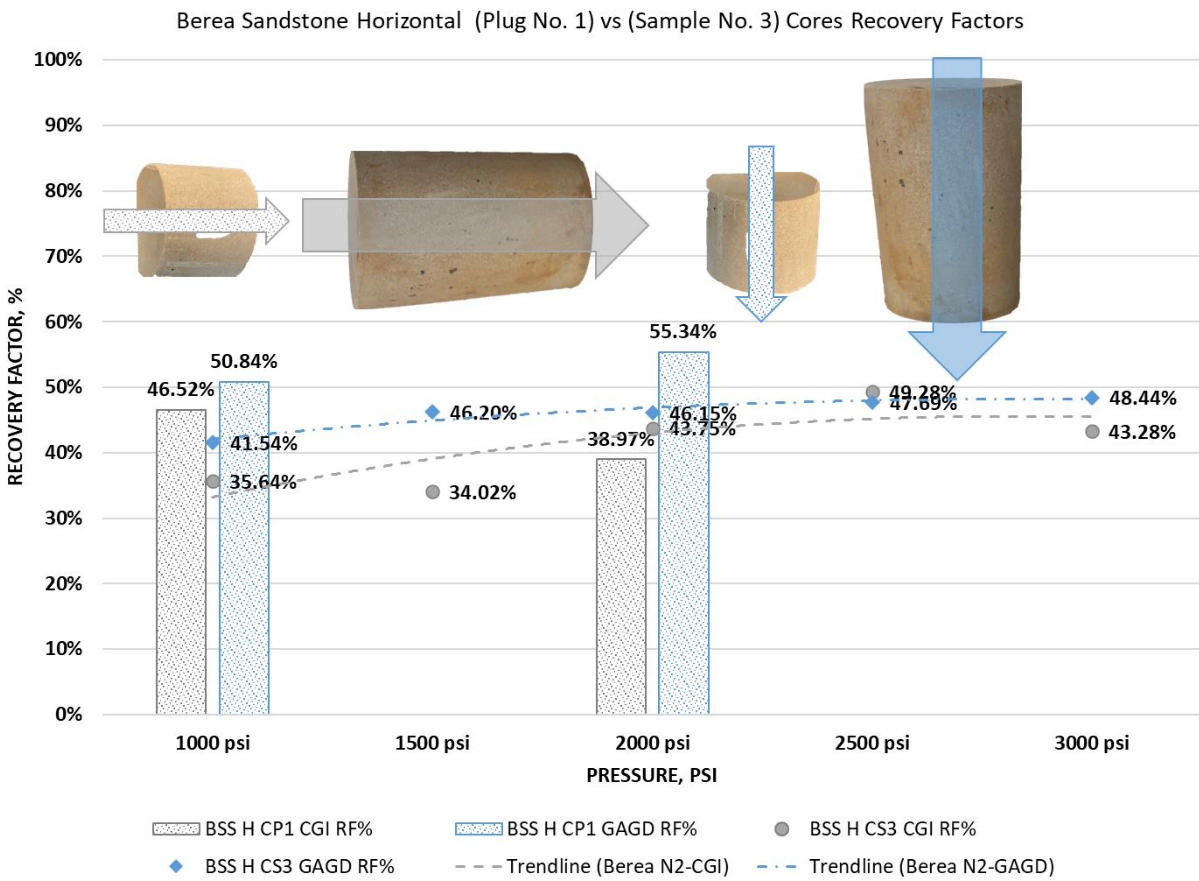


Figure 4. 31. Recovery Comparison of Berea Sandstone Horizontal (BSS CP1) and Large Berea Sandstone (BSS CS3) Cores Enhanced Oil Recovery Experiments by Injected Nitrogen (N2) at Injection Pressure of 1,000 psi and Operating Temperature 70℉

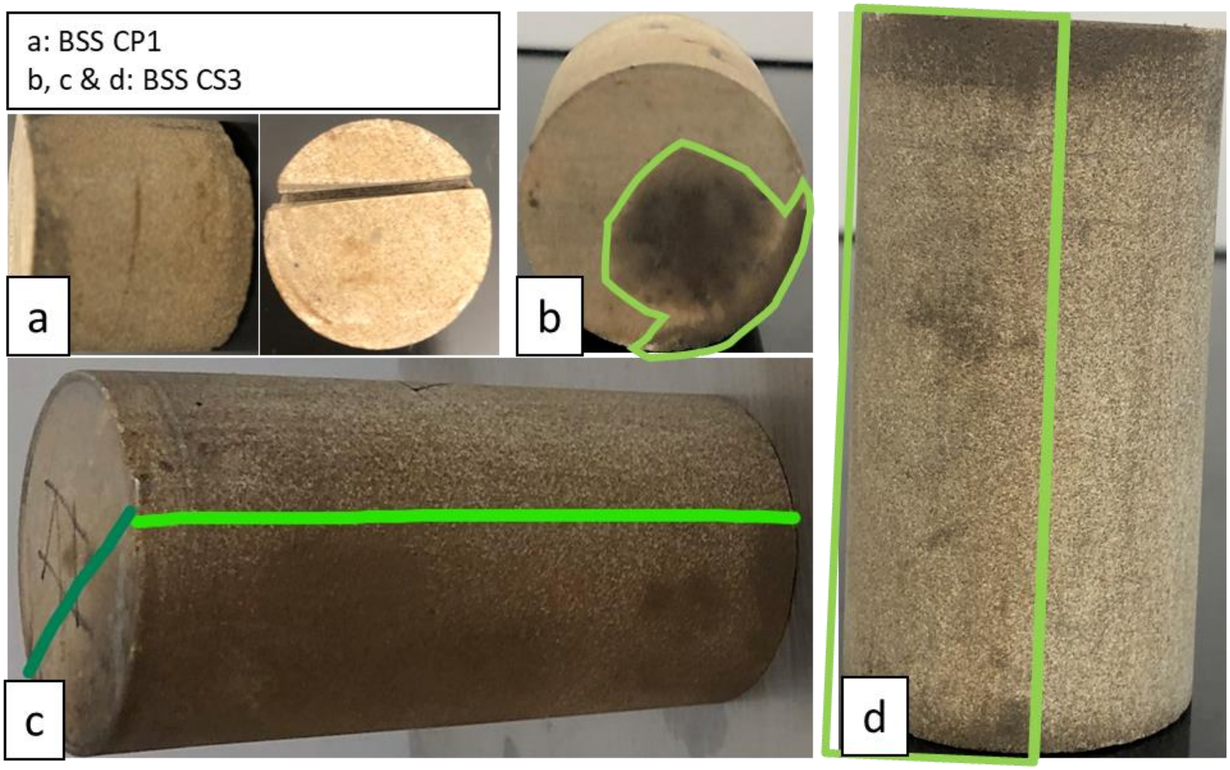


Figure 4. 32. Effects of Core Size of Recovery Mechanism on Berea Sandstone Horizontal Cut Core a) Small Plug (BSS CP1) and Large Core (BSS CS3) Enhanced Oil Recovery Experiments by Injected Nitrogen (N2) at Different Injection Pressures and Operating Temperature of 70℉

4.2.1.3.4 Gas-Assisted Gravity Drainage (GAGD) Enhanced Oil Recovery (EOR) Experiments of Large Berea Sandstone Horizontal Core (BSS CS3) By Injecting Carbon Dioxide (CO_2) at Pressures of 1,000-3,000 psi and Operating Temperature of 70 ˚F

In this set of experiments, the impact of using CO_2 to enhance oil recovery from non-conventional resources was examined. CO_2 is known as interactive gas in some conditions and is expected to improve the recovery from such reservoirs. In this section, the results of utilizing CO_2 as an injectant in GAGD mode at different operating pressures were presented. CO_2 was injected vertically at an injection pressure of 1,000 psi and the pressure was increased in consecutive experiments by 500 psi till reached 3,000 psi. The operating temperature was kept at 70˚F and the core holder pressure set up at 3,500 psi. The TMS Well-A oil is flooding in the core at 1,000 psi while the core holder is pressurized to 1,500 psi. The flooding processes were performed horizontally, and it lasts a couple of days before aging the flooded core overnights.

In the first CO_2 GAGD EOR experiment on Berea Sandstone Core Sample no. 3 (BSS CS3), the core holder was set up horizontally and pressurized to 1,500 psi. Then, the core flooded with the TMS oil at an injection pressure of 1,000 psi for several days and aged overnight. The core saturated weight (W_{sat}) was 403.1 grams. The core was returned to the core holder and set the confining pressure at 3,500 psi before turning the core holder 90˚ and started injecting CO_2 vertically at 1,000 psi. After completely injecting 2,000 ml (maximum vessel capacity) and no more oil was produced, the core was collected and weighed. Figure 2.33 showed the after-EOR experiment weight was 399.1 with a recovery factor of 61.54%.

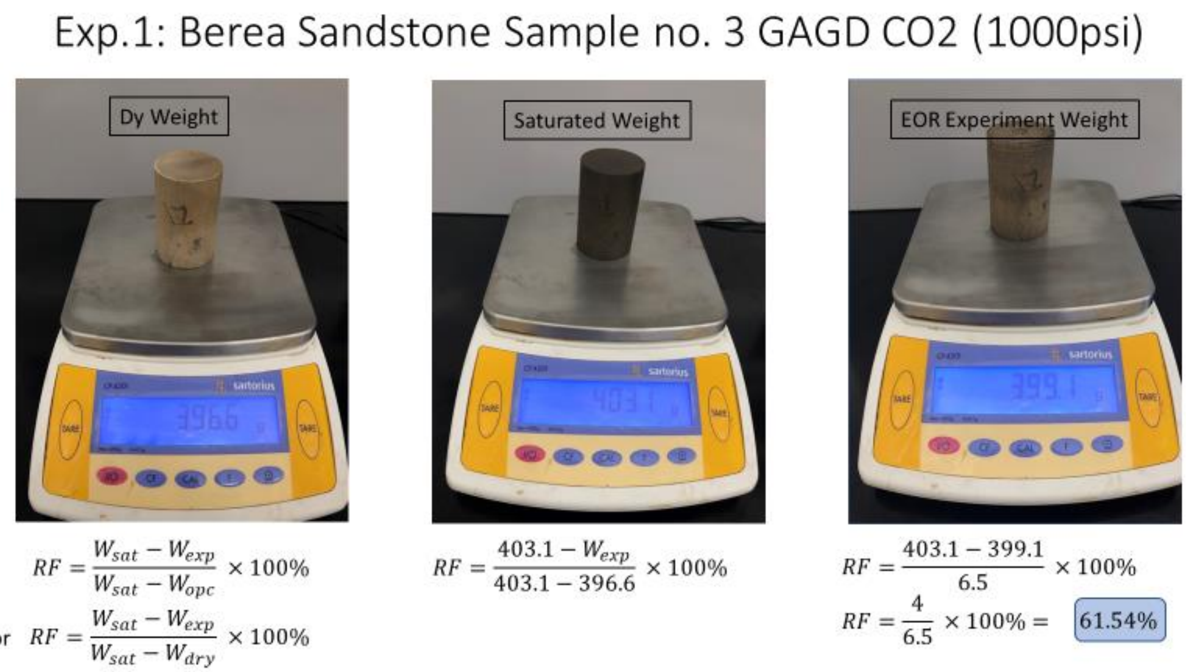


Figure 4. 33. Large Berea Sandstone Horizontal Core (BSS CS3) Oil Recovery Calculation for Gas-Assisted Gravity Drainage Using Carbon Dioxide (CO_2-GAGD) Mode at Injection Pressure of 1,000 psi and Operating Temperature of 70 ˚F

For the second experiment in this series (inject CO_2 at 1,500 psi), the setups of the flooding process and gas injection process were the same as the former experiment. The only difference was that the CO_2 was injected at 1,500 psi to enhance the recovery from the BSS CS3 sample. As shown in Figure 4.34, the core saturated weight was 403.0 grams, the after-EOR experiment weight was 398.1 grams and the recovery factor improved to 76.56%.

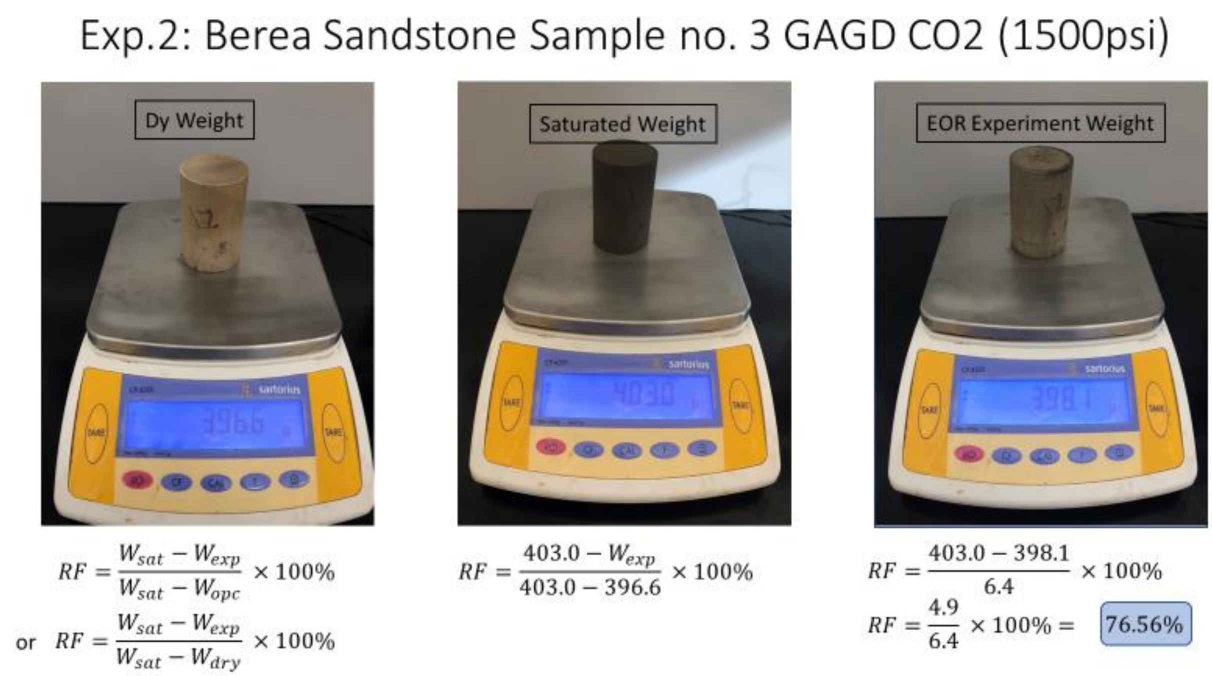


Figure 4. 34. Large Berea Sandstone Horizontal Core (BSS CS3) Oil Recovery Calculation for Gas-Assisted Gravity Drainage Using Carbon Dioxide (CO2-GAGD) Mode at Injection Pressure of 1,500 psi and Operating Temperature of 70 ˚F

In the third experiment, the BSS CS3 flooded with the oil and aged overnight which resulted in a saturated weight of 403.6 grams. The gas of CO_2 was injected vertically at 2,000 psi for adequate time till no further production. The core weight after the EOR experiment founded to be 398.1 grams and the calculated recovery factor was 78.57 % as shown in Figure 4.35.

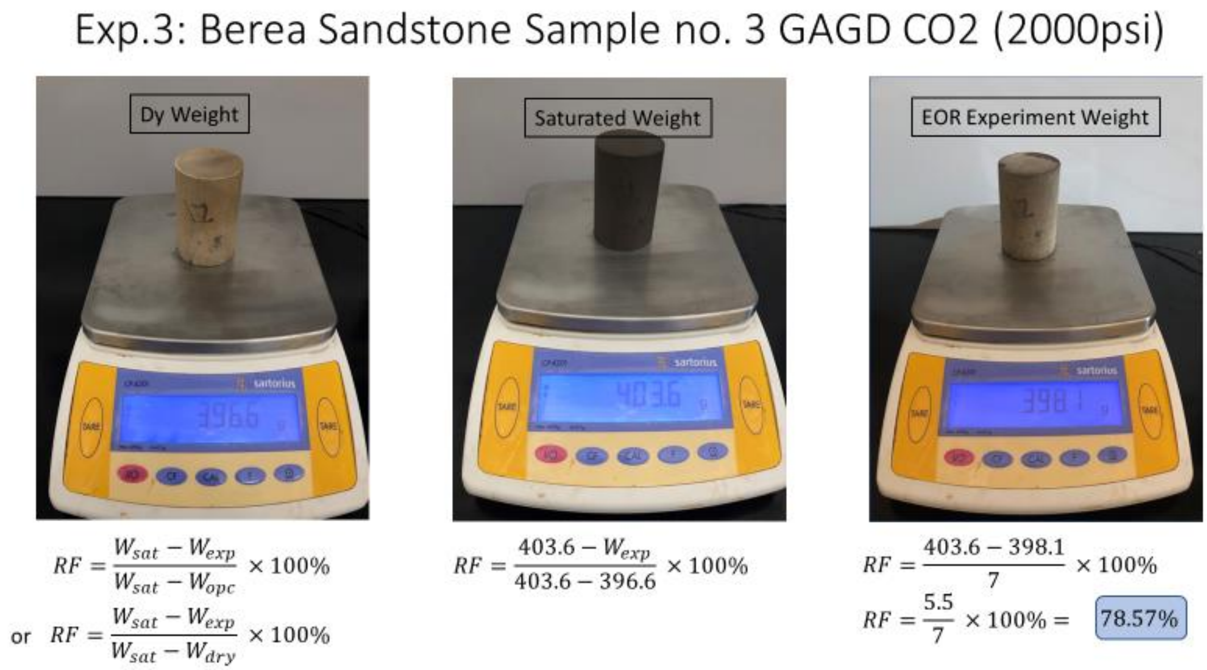


Figure 4. 35. Large Berea Sandstone Horizontal Core (BSS CS3) Oil Recovery Calculation for Gas-Assisted Gravity Drainage Using Carbon Dioxide (CO_2-GAGD) Mode at Injection Pressure of 2,000 psi and Operating Temperature of 70 ˚F

The core saturated weight for the fourth experiment was 403.5 grams after flooding with the oil for several days and aged overnight. The CO_2 gas was injected vertically at 2,500 psi for a whole day and stopped injection after no more oil was produced. The after-EOR experiment weight was 398.4 grams and the recovery factor was 73.91 %, Figure 4.36.

In the last experiment of this series of CO_2 GAGD, the saturated weight of BSS CS3 was 403.2 grams. The core holder turns vertically, and 2,000 ml of CO_2 is injected at 3,000 psi for a whole day. The after-EOR experiment weight was 398.1 grams resulted in a 72.73% recovery factor as shown in Figure 4.37.

Exp.4: Berea Sandstone Sample no. 3 GAGD CO2 (2500psi)

$$RF = \frac{W_{sat} - W_{exp}}{W_{sat} - W_{opc}} \times 100\%$$

or $$RF = \frac{W_{sat} - W_{exp}}{W_{sat} - W_{dry}} \times 100\%$$

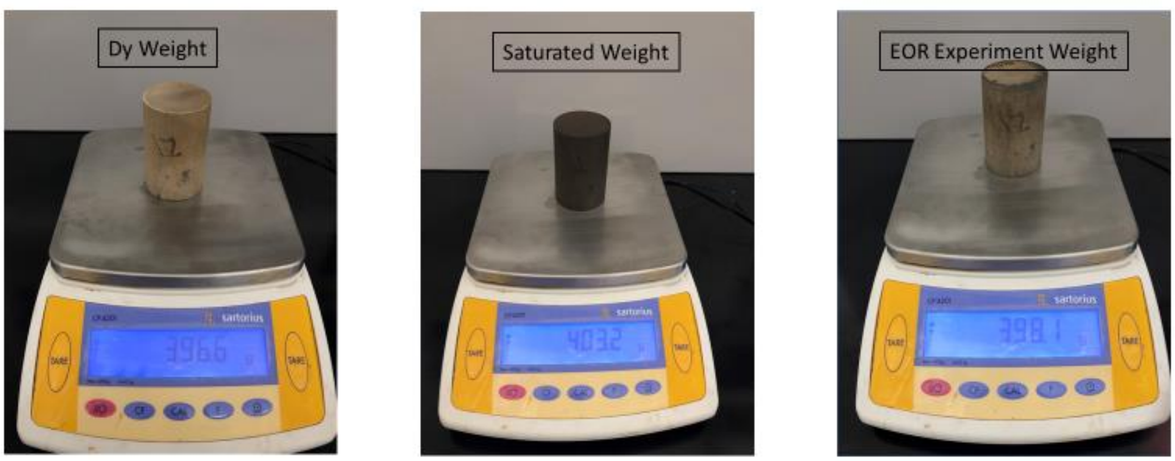
$$RF = \frac{403.5 - W_{exp}}{403.5 - 396.6} \times 100\%$$

$$RF = \frac{403.5 - 398.4}{6.9} \times 100\%$$

$$RF = \frac{5.1}{6.9} \times 100\% = \boxed{73.91\%}$$

Figure 4. 36. Large Berea Sandstone Horizontal Core (BSS CS3) Oil Recovery Calculation for Gas-Assisted Gravity Drainage Using Carbon Dioxide (CO_2-GAGD) Mode at Injection Pressure of 2,500 psi and Operating Temperature of 70 ˚F

Exp.5: Berea Sandstone Sample no. 3 GAGD CO2 (3000psi)



$$RF = \frac{W_{sat} - W_{exp}}{W_{sat} - W_{opc}} \times 100\%$$

or $$RF = \frac{W_{sat} - W_{exp}}{W_{sat} - W_{dry}} \times 100\%$$

$$RF = \frac{403.2 - W_{exp}}{403.2 - 396.6} \times 100\%$$

$$RF = \frac{403.2 - 398.1}{6.6} \times 100\%$$

$$RF = \frac{4.8}{6.6} \times 100\% = \boxed{72.73\%}$$

Figure 4. 37. Large Berea Sandstone Horizontal Core (BSS CS3) Oil Recovery Calculation for Gas-Assisted Gravity Drainage Using Carbon Dioxide (CO_2-GAGD) Mode at Injection Pressure of 3,000 psi and Operating Temperature of 70 ˚F

Replacing the gas of N_2 with the gas of CO_2 and injecting vertically in GAGD mode enhanced oil recovery from Berea Sandstone core sample no. 3 (BSS CS3) by at least 50% compared with former set (N_2 GAGD) experiments. Also, increasing CO_2 injection pressure from 1,000 psi to 3,000 psi resulted in improving recovery factor by 20%. The maximum oil recovery was about 79% at 2,000 psi. The summary of the GAGD CO_2 injection experiments for BSS CS3 was listed in Table 4.13.

Table 4. 13. Summary of Large Berea Sandstone Horizontal Core (BSS CS3) Enhanced Oil Recovery Experiments by Injected Carbon Dioxide (CO_2) in Gas-Assisted Gravity Drainage (GAGD) Process at Pressures of 1,000-3,000 psi and Temperature of 70 ˚F

EOR Experiment	1,000	1,500	2,000	2,500	3,000
Dry Weight, gram			396.6		
Saturated Weight, gram	403.1	403.0	403.6	403.5	403.2
Experimental Weight, gram	399.1	398.1	398.1	398.4	398.1
Confining Pressure, psi			3,500		
Oil Flooding Pressure, psi			1,000		
Gas Injection Pressure, psi	1,000	1,500	2,000	2,500	3,000
Operating Temperature, °F			70		
Recovery Factor, %	61.54	76.56	78.57	73.91	72.73
Improving Oil Recovery, %		24.41	27.67	20.25	18.18

4.2.1.3.5 Effects of Gas Injectant and Injection Pressure on Enhanced Oil Recovery Process Using Carbon Dioxide (CO_2) as Injectant at Operating Temperature of 70 ˚F

Figure 4.38 discussed the effect of different injections on the oil recovery process by injecting CO_2 at different injection pressures in the GAGD mode and compared the results with the impact of using N_2 as a base case. The injected at pressures of CO_2 gas ranged from 1,000 to 3,000 psi and the operating temperature is 70 ˚F. Overall, the usage of CO_2 as an injectant in GAGD mode improved the oil recovery from BSS CS3 by an average of 57.85%. At the lowest injection pressure, 1,000 psi, more than 61% OOIP was recovered by CO_2 injection compared to 41%OOIP recovered by the N_2 injection EOR process. As shown in the figure, the recovery factors using CO_2 as injectant were showing a general increasing trend for the obtained RFs to higher recoveries of oil in place (> 70%OOIP). CO_2 can enhance oil recovery by vaporizing the lighter hydrocarbons saturated in the core sample (Menzie & Nielsen, 1963) and (Rudyk et al., 2017) in addition to the immiscible and miscible displacements. The experimental results showed that injecting CO_2 would continue improving the recovery from the BSS CS3 showing strong agreement with the general trend of increasing total recovery as pressure increased in CO_2-EOR processes. The highest recovery (78.57%OOIP) was at an injection pressure of 2,000 psi which was 70% more than using N_2 as an injectant in the same operating conditions. After this injection pressure, the recovery started decreasing showing a little drop in the oil RFs. Notably, there was an optimum pressure (breakover point) after which the enhanced recovery process altered the direction and showed disimproving due to gas breakthrough at higher operating pressures. Rudyk et al. (2017) defined the breakover points in the hydrocarbon recovery curves that the pressure above which the recovery does not increase substantially as a minimum miscibility pressure when obtained in the slim tube tests. The increment in oil recovery by using CO_2 as an injectant to enhance oil recovery referred to the interaction of CO_2 with the reservoir fluid. The injected CO_2 invaded most of the small core pores displaced the oil effectively, eased oil displacement, and flowed at lower pressure. While in higher pressure, the injected of CO_2 may invade the pores and miscible with reservoir oil which results in oil's swallowing the injected gas, lowering its viscosity (μ), lowering the interfacial tension force (IFT), and then lowering the capillary pressure (Pc) in the reservoir as well as maintained reservoir pressure (Miri et al., 2014). All these parameters helped the CO_2 to diffuse the oil from these pores, create oil film flow, and drain the oil effectively to the production side. It was noted that the CO_2-GAGD process recovered more oil compared with the gas of N_2 from similar core samples in all conducted gas injection EOR experiments at injection pressures of 1,000-3,000 psi and room temperature. The aquired result was expected since the gas of CO_2 is reacting with the reservoir oil at some pressure levels and changes some oil properties while the gas of N_2 needs much higher pressure to be miscible with the same oil. In both types of EOR experiments, the vertical injection scheme ensures a gravity force assisted gas injection mechanism to enhance oil recovery from the reservoir compared with the conventional CGI. At lower pressure, the N_2 and CO_2 improved the oil recovery by displacing forces, but the later gas showed some interaction with reservoir fluid. At optimum pressure, the CO_2 was diffusing the hydrocarbon from the pores due to its interactive ability with the reservoir oil and enhanced the oil recovery at the most compared with the N_2.

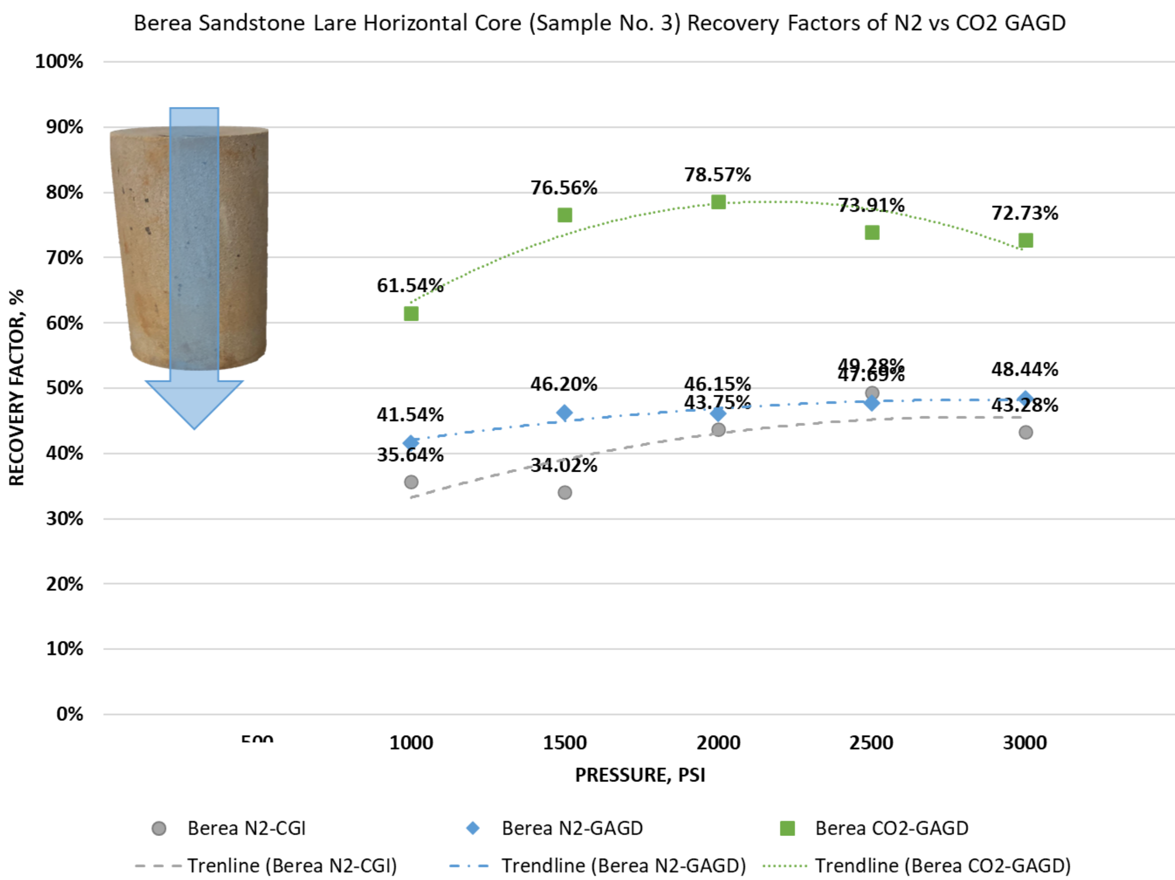


Figure 4. 38. Recovery Comparison of Different Gas Injection Impact on Large Berea Sandstone (BSS CS3) Core Enhanced Oil Recovery Experiments by Injected Carbon Dioxide (CO2) vs Nitrogen (N2) at Various Injection Pressures and Room Temperature of 70 ˚F

4.2.1.3.6 Gas Injection Enhanced Oil Recovery (EOR) Experiments of Fractured Large Berea Sandstone Horizontal Core (BSS CS3) By Carbon Dioxide (CO_2) at Injection Pressures of 2,000 psi and Operating Temperature of 70 ˚F

In the following set of experiments, the impact of introducing fractures to the core sample on enhancing the oil recovery was examined by using BSS CS3. Since the best results from the previous successful 15 EOR experiments were at an injection pressure of 2,000 psi and using CO_2 as an injectant. The following experiments were performed at an operating pressure of 2,000 psi and the core holder pressure set at 2,500 psi. For the first two experiments, one side fracture was created in the core sample. Then, the core was cleaned in the large Soxhlet extractor for three weeks and dried in the heated oven for one week. The core dry weight was measured to be 394.8 grams.

The core was placed in the core holder, set up confining pressure at 1,500 psi, and flooded with the TMS oil horizontally at 1,000 psi from the fracture side till completely saturated and aged for a week before collecting the core sample. The core saturated weight was 401.5 grams. After that, the core returned to the core holder and pressurized to 2,500 psi, turn the core holder to 90˚ before start injecting CO_2 vertically at 2,000 psi from the fracture side. The after-EOR experiment weight was 397.1 grams resulted in a recovery factor of 65.67% as shown in Figure 4.39.

The same experimental procedure was implemented in the core sample, but the core was turned to another side to perform the Lower Side Fractured EOR experiment. The oil was flooded horizontally into the fractured BSS CS3 from the non-fractured side at 1,000 psi and resulted in a core saturated weight of 401.7 grams. The CO_2 was injected vertically at 2,000 psi from the non-fractured side for the whole day. After the EOR experiment, the core collected and experimental weight (W_{exp}) was 397.5 and the recovery factor was 60.87%, Figure 4.40.

Exp.no.1 : Berea Sandstone Sample no. 3 GAGD CO2 (2000psi) w/ Upper Fracture

$$RF = \frac{W_{sat} - W_{exp}}{W_{sat} - W_{opc}} \times 100\%$$

or $$RF = \frac{W_{sat} - W_{exp}}{W_{sat} - W_{dry}} \times 100\%$$

$$RF = \frac{401.5 - W_{exp}}{401.5 - 394.8} \times 100\%$$

$$RF = \frac{401.5 - 397.1}{6.7} \times 100\%$$

$$RF = \frac{4.4}{6.7} \times 100\% = \boxed{65.67\%}$$

Figure 4. 39. Upper Fractured Large Berea Sandstone Horizontal Core (BSS CS3) Oil Recovery Calculation for Gas-Assisted Gravity Drainage Using Carbon Dioxide (CO2-GAGD) Mode at Injection Pressure of 2,000 psi and Operating Temperature of 70 ˚F

Exp. no.2: Berea Sandstone Sample no. 3 GAGD CO2 (2000psi) w/ Lower Fracture

$$RF = \frac{W_{sat} - W_{exp}}{W_{sat} - W_{opc}} \times 100\%$$

or $$RF = \frac{W_{sat} - W_{exp}}{W_{sat} - W_{dry}} \times 100\%$$

$$RF = \frac{401.7 - W_{exp}}{401.7 - 394.8} \times 100\%$$

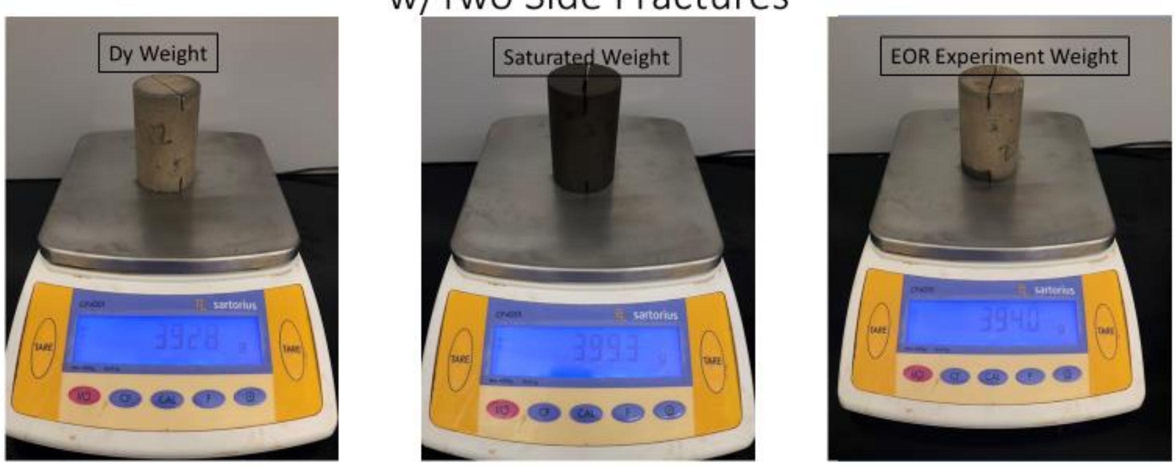
$$RF = \frac{401.7 - 397.5}{6.9} \times 100\%$$

$$RF = \frac{4.2}{6.9} \times 100\% = \boxed{60.87\%}$$

Figure 4. 40. Lower Fractured Large Berea Sandstone Horizontal Core (BSS CS3) Oil Recovery Calculation for Gas-Assisted Gravity Drainage Using Carbon Dioxide (CO2-GAGD) Mode at Injection Pressure of 2,000 psi and Operating Temperature of 70 ˚F

For the last experiments in this set, another fracture was created in the non-fracture side of the core and cleaned in the large Soxhlet extractor for three weeks. After heat drying the core in the oven for a week, the two-sided fractured Berea Sandstone core sample was collected and weighed. The dry weight (W_{dry}) of the core was 392.8 grams. As in previous experiments, the core placed in the core holder set core holder pressure at 1,500 psi and start flooding the core horizontally with the TMS oil at 1,000 psi for several days. The core saturated weight was 399.3 grams. After that, the core is returned to the core holder, pressurized to 2,500 psi, and turned 90˚ to prepare for CO_2 injection. The gas of CO_2 was injected vertically in GAGD mode for an adequate time resulted in the after-EOR experiment of 394.0 grams. The oil recovery factor was calculated to be 81.54% as demonstrated in Figure 4.41.

Exp. no.3 : Berea Sandstone Sample no. 3 GAGD CO2 (2000psi) w/Two Side Fractures



$$RF = \frac{W_{sat} - W_{exp}}{W_{sat} - W_{opc}} \times 100\%$$

or $$RF = \frac{W_{sat} - W_{exp}}{W_{sat} - W_{dry}} \times 100\%$$

$$RF = \frac{399.3 - W_{exp}}{399.3 - 392.8} \times 100\%$$

$$RF = \frac{399.3 - 394.0}{6.5} \times 100\%$$

$$RF = \frac{5.3}{6.5} \times 100\% = \boxed{81.54\%}$$

Figure 4. 41. Two-Sides Fractured Large Berea Sandstone Horizontal Core (BSS CS3) Oil Recovery Calculation for Gas-Assisted Gravity Drainage Using Carbon Dioxide (CO2-GAGD) Mode at Injection Pressure of 2,000 psi and Operating Temperature of 70 ˚F

The Carbon Dioxide was injected in CGI mode at the same injection pressure of 2,000 psi and the core holder pressure was set at 2,500 psi. The used BSS CS3 had a dry weight of 394.8 grams. The core was flooded with the TMS oil Well-A at flooding pressure of 1,000 psi and core holder confining pressure of 1,500 psi. The core saturated weight was 399.1 grams. The gas of CO_2 was injected continuously at a maximum injection pressure of 2,000 psi and a full cylinder volume of 2,000 ml. The after-EOR experiment weight was 392.8 grams, and the oil recovery factor was calculated to be 77.78% as shown in Figure 4.42.

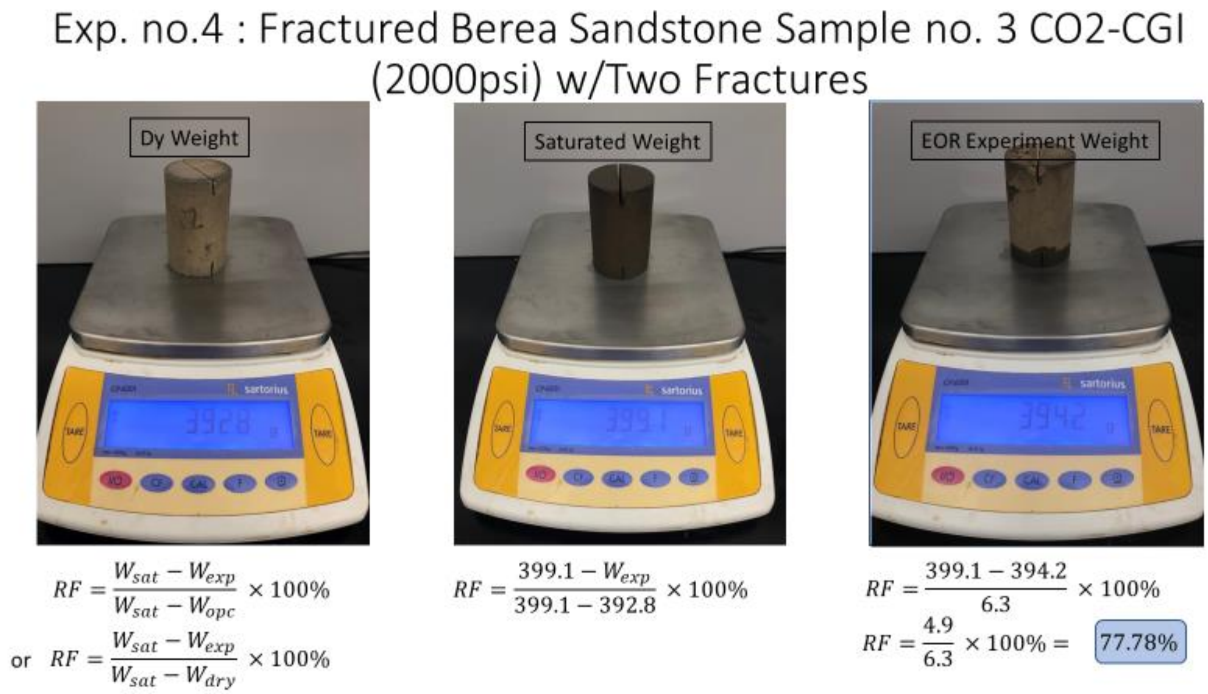


Figure 4. 42. Two-Sides Fractured Large Berea Sandstone Horizontal Core (BSS CS3) Oil Recovery Calculation for continuous Gas Injection Using Carbon Dioxide (CO2-CGI) Mode at Injection Pressure of 2,000 psi and Operating Temperature of 70 ˚F

Introducing the fractures to the Berea Sandstone core sample no. 3 (BSS CS3) had an impact on the recovery factor. The lower fracture was lowest comparing the upper fracture experiment. Among all experiments, the injection of CO_2 into Breas Sandston sample with two side fractures in the GAGD mode obtained the highest recovery from the core sample even with compare with CGI mode for the same core sample and experiment condition which was 81.54% at 2,000 psi and ambient temperature of 70 ˚F. The summary of the EOR through CO_2 injection experiments with fractures for Berea Sandstone Core Sample no. 3 (BSS CS3) was listed in Table 4.14.

Table 4. 14. Summary of Fractured Large Berea Sandstone Horizontal Core (BSS CS3) Enhanced Oil Recovery Experiments by Injected Carbon Dioxide (CO2) at Pressures of 2,000 psi and Operating Temperature of 70 ˚F

EOR Experiment	**Upper Fracture**	**Lower Fracture**	**2 Sides Fracture**	
	GAGD			CGI
Dry Weight, gram	394.8		392.8	
Saturated Weight, gram	401.5	401.7	399.3	399.1
Experimental Weight, gram	397.1	397.5	394.0	394.2
Confining Pressure, psi	2,500			
Oil Flooding Pressure, psi	1,000			
Gas Injection Pressure, psi	2,000			
Operating Temperature, °F	70			
Recovery Factor, %	65.67	60.87	81.54	77.78

4.2.1.3.7 Effects of Fracture Configuration on Gas Injection Enhanced Oil Recovery Process Using Carbon Dioxide (CO_2) as Injectant at Injection Pressure of 2,000 psi and Operating Temperature of 70 ˚F

The effect of fracture configuration on gas injection GAGD process on oil recovery factor by injecting CO_2 at a maximum injection pressure of 2,000 psi at an ambient temperature of 70 ˚F was discussed in this section. The EOR experimental results showed that about 61%OOIP can be recovered from the BSS CS3 when a lower fracture was created in the lower core side. It was found out that the recovery factor was increased by 7.9% when injecting CO_2 from the core upper side in GAGD mode resulted in more than 65% OOIP recovery. The results from adding another fracture to the unfractured side and having a 2 sided-fracture core were obtained from two gas injection EOR experiments: CGI and GAGD modes. The oil recovery increased to 77.78% OOIP from 2-sided fractured BSS CS3 by injecting the gas of CO_2 in conventional CGI mode. In comparison with the former three experiments, the vertical injection of CO_2 in the GAGD process resulted in about 82% OOIP recovery which was the highest oil RF from the core (BSS CS3) with an improvement in recovery factor of 34%, 24%, and ≈ 5% from lower, upper, and 2-side fractures EOR experiments. This high oil recovery was because of the vertical gas injection scheme with fracture introduction to the reservoir (core sample) which ensures that the gravity force assisted gas injection mechanism and allowed the gas to stimulate larger reservoir volume to enhance oil recovery from the reservoir as shown in Figure 4.43. Adding the fractures to the core sample improved the core flooding noticeably and saved time during oil flooding by half of the oil flooding periods that used to have for none fractured core. As in N_2 injection, the injected CO_2 in GAGD mode accumulated at the upper side of the core and displaced the oil down to the bottom side. With the help of gravity, more oil was produced compared to the injection mechanism at horizontal injection mode. Again, using CO_2 in the EOR process recovered more oil because it invades the pores from the top part and diffused the oil outward from each pore. It is noticed from the fluid coated the heat shrinkage tube (HST) and broken pieces that CO_2 was using diffusion force to produce the oil because of oil swallowing the injected gas, increased oil volume, lowering oil viscosity, lowering interfacial tension force, and lowering capillary pressure.

Unlike the conventional CGI, the GAGD process ensured an effective oil sweeping (from top to bottom) which results in higher oil recovery with the support of gravity and gas segregation forces. This gravity segregation phenomenon was a beneficial force to GAGD as it delayed the gas breakthrough to the producers and prevented the gas phase from competing for flow with the oil. The GAGD process was capable to eliminate the main problem faced with other conventional improving recovery methods: poor sweep and gas breakthrough which was reflected in higher crude recovery. Adding fractures to the Berea Sandstone core (or reservoir) increased the stimulated reservoir volume (SRV) which helped to elevate the performance of the enhanced oil recovery (EOR) process in improving oil recovery from tight sandstone cores (reservoirs). These added fractures increased the gas/oil contact area which ease the gas invasion to the core and shorten the bath for the oil to flow in short distance to the upstream side in less production period. Changing the injection direction from conventional horizontal (from one side to the other side) to vertical injection (from top to bottom) and introducing fractures present evidence of GAGD process potential in tight sandstone reservoirs.

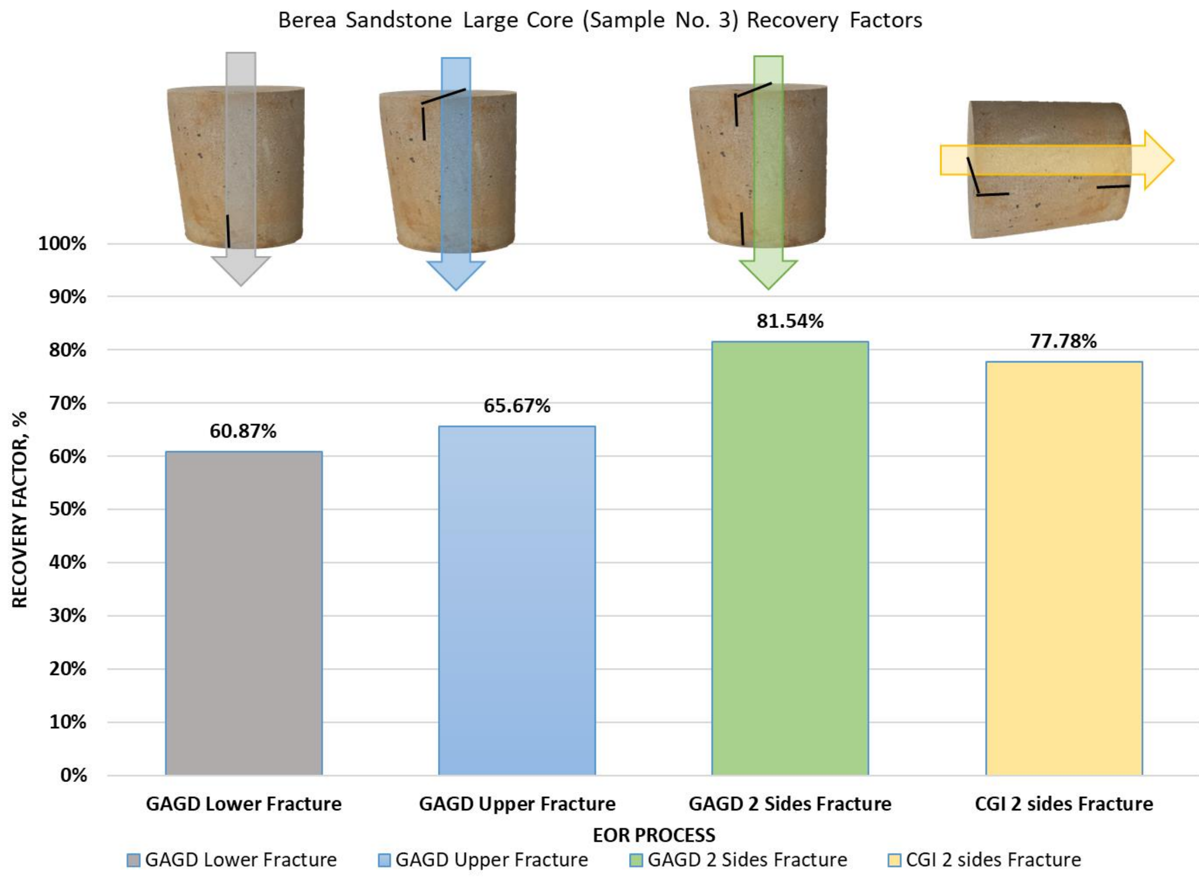


Figure 4. 43. Recovery Comparison of Different Fracture Configuration on Gas Injection Impact on Large Berea Sandstone (BSS CS3) Core Enhanced Oil Recovery Experiments by Injected Carbon Dioxide (CO2) at Injection Pressures of 2,000 psi and Operating Temperature of 70 ˚F

Overall, this study showed the GAGD process improved the oil recovery over the CGI in all conducted experiments on tight Berea Sandstone cores because of gravity force. Both examined EOR methods displayed a little decrease in oil recovery while applied on the orthogonal cut core sample due to the heterogeneity. The larger core volume showed lower oil recovery compared with the smaller core volume because of stimulated volume variations. In this study, the injection pressure showed a noticeable effect on oil recovery due to fluid displacement and gas breakthrough phenomena. The injection of CO_2 showed a significant effect on obtained oil recovery compared with the N_2 in the GAGD process because of miscibility, lower viscosity, interfacial tension, and capillary pressure at optimum injection pressure. Adding fracture to the core eased the fluid flow, shortened the flowing bath, and stimulated more reservoir volume because of increasing gas/oil contact area. Two side-fractured cores demonstrated the highest oil recovery (82%OIIP) by injecting CO_2 in GAGD mode at an optimum injection pressure of 2,000 psi and operating temperature of 70 ˚F. This obtained high recovery resulted from combining the effects of all mentioned forces and parameters to determine the best-operating conditions and EOR experiment's design.

4.2.1.3.8 Gas Injection Enhanced Oil Recovery (EOR) Experiments of Fractured Large Berea Sandstone Horizontal Core (BSS CS3) By Carbon Dioxide (CO_2) at Injection Pressures of 1,500 psi, Backpressure of 500 psi and Operating Temperature of 70 ˚F

In the following set of experiments, the backpressure (BP) impact on enhancing oil production from the fractured Berea sandstone core samples (BSS CS3) was examined. The following two experiments were performed using CO_2 as an injectant for CGI and GAGD injection modes as follows: CO_2-CGI and CO_2-GAGD with BP of 500 psi and at T of 70 ˚F. To examine the impact of having a back pressure on EOR experiments, a pressurized back pressure regulator was connected to the production line. The confining pressure was increased by 500 psi to 3,000 psi as a result of having a back pressure of 500 psi. The gas of CO_2 was injected at 1,500 psi in both EOR modes. After flooding the core with TMS oil, the measured saturated weight was 398.6 grams. 2,000 ml of CO_2 was injected in conventional CGI mode and the after-EOR experiment weight was 394.6 grams that led to a recovery factor of 68.97% as presented in Figure 4.44.

$$RF = \frac{W_{sat} - W_{exp}}{W_{sat} - W_{opc}} \times 100\%$$

or $$RF = \frac{W_{sat} - W_{exp}}{W_{sat} - W_{dry}} \times 100\%$$

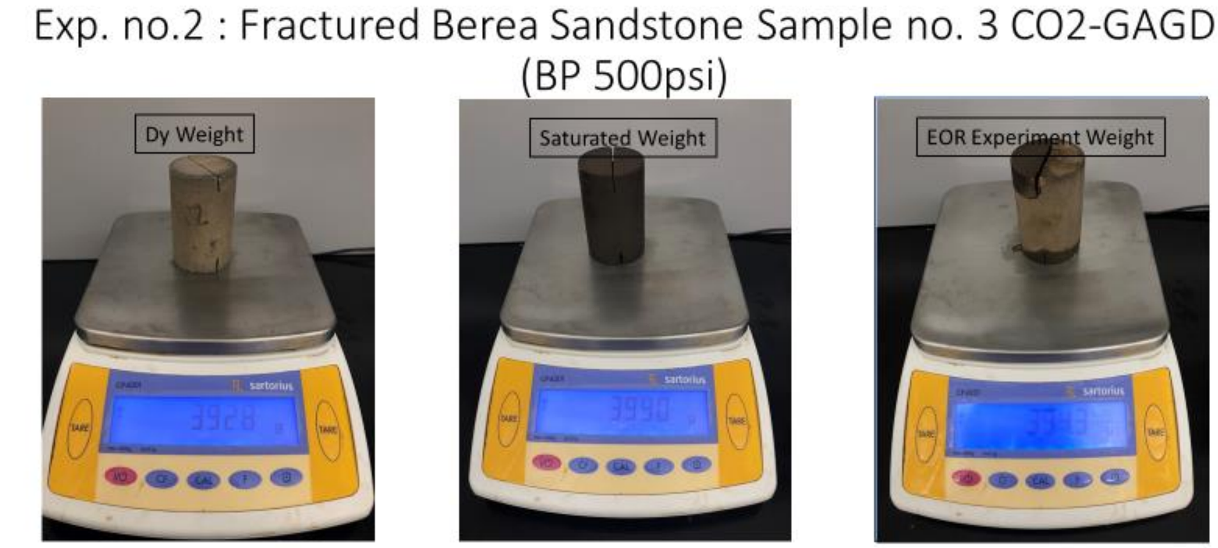
$$RF = \frac{398.6 - W_{exp}}{398.6 - 392.8} \times 100\%$$

$$RF = \frac{398.6 - 394.6}{5.8} \times 100\%$$

$$RF = \frac{4.0}{5.8} \times 100\% = \boxed{68.97\%}$$

Figure 4. 44. Large Berea Sandstone Horizontal Core (BSS CS3) Oil Recovery Calculation for Continuous Gas Injection Using Carbon Dioxide (CO2-CGI) Mode at Injection Pressure of 1,500 psi, Back Pressure of 500 psi, and Operating Temperature of 70 ˚F

To prepare the same core for conducting the GAGD process, the TMS oil was flooded at 1,000 psi and the core saturated weight was 399.0 grams. The final weight measured after CO_2 injection at 1,500 psi at room temperature was 394.3 grams resulted in a 75.81% OOIP recovery, Figure 4.45.



$$RF = \frac{W_{sat} - W_{exp}}{W_{sat} - W_{opc}} \times 100\%$$

or $$RF = \frac{W_{sat} - W_{exp}}{W_{sat} - W_{dry}} \times 100\%$$

$$RF = \frac{399.0 - W_{exp}}{399.0 - 392.8} \times 100\%$$

$$RF = \frac{399.0 - 394.3}{6.2} \times 100\%$$

$$RF = \frac{4.7}{6.2} \times 100\% = \boxed{75.81\%}$$

Figure 4. 45. Large Berea Sandstone Horizontal Core (BSS CS3) Oil Recovery Calculation for Gas-Assisted Gravity Drainage Process Using Carbon Dioxide (CO2-GAGD) Mode at Injection Pressure of 1,500 psi, Back Pressure of 500 psi, and Operating Temperature of 70 ˚F

The summary and comparison of EOR experiments on fractured large Berea Sandstone horizontal core (Sample no. 3) using CO_2 as injectant at an injection pressure of 1,500 psi, the backpressure of 500 psi, and operating at room temperature were represented in Table 4.15. The proposed method, GAGD w/Fracture, improved the oil recovery by 10% compared with conventional CGI mode even with a back pressure of 500 psi. Again, the GAGD process showed superiority in enhancing oil recovery over CGI (Base Case) at immiscible conditions of injection pressure 1,500 psi and operating temperature 70 ̊F.

Table 4. 15. Summary of Fractured large Berea Sandstone Horizontal Core (BSS CS3) Enhanced Oil Recovery Experiments by Injecting Carbon Dioxide (CO_2) at Pressure of 1,500 psi, Backpressure of 500 psi, and Temperature of 70 ˚F

EOR Experiment	CGI	GAGD
Dry Weight, gram	392.8	
Saturated Weight, gram	398.6	399.0
Experimental Weight, gram	394.6	394.3
Confining Pressure, psi	2,000	
Oil Flooding Pressure, psi	1,000	
Gas Injection Pressure, psi	1,500	
Back Pressure, psi	500	
Operating Temperature, °F	70	
Recovery Factor, %	68.97	75.80
Improving Oil Recovery, %		9.9

4.2.1.3.9. Effects of Back Pressure (500 psi) on Enhanced Oil Recovery Process at Injection Pressure of 1,500 psi and Operating Temperature of 70 ˚F using Carbon Dioxide (CO_2) as Injectant.

Figure 4.46 illustrated the effect of back pressure (P_{out}) of 500 psi on enhanced oil recovery (EOR) mechanisms by injecting CO_2 at a maximum injection pressure of 1,500 psi at an operating temperature of 70 ˚F. The backpressure affected both examined EOR mechanisms. The experimental results showed that the conventional CO_2-CGI process can produce up to 69% OOIP from the fracture BSS CS3 while the CO_2-GAGD improved the oil recovery by10% more than the CGI to produce up to76% OOIP. Both processes showed great sweep efficiencies as observed from these experiments. Combining all forces; gravity force (GAGD), stimulation volume (Fractures), and high injection pressure (Displacement/Diffusion) resulted in immense recovery and proves the superiority of the GAGD process over the CGI mode in enhancing the productivity from such type of unconventional resources. The obtained result was not unexpected as a vertical injection scheme ensured assisted gas injection mechanism to enhance oil recovery from the reservoir even with exist of backpressure which implied a force works counter to the EOR drive forces. In this study, the production backpressure helped to expose the performance of the GAGD process as an efficient EOR mechanism in improving oil recovery from tight sandstone core samples (reservoirs) even at the existence of backpressure from the production/trunk lines or processing plants.

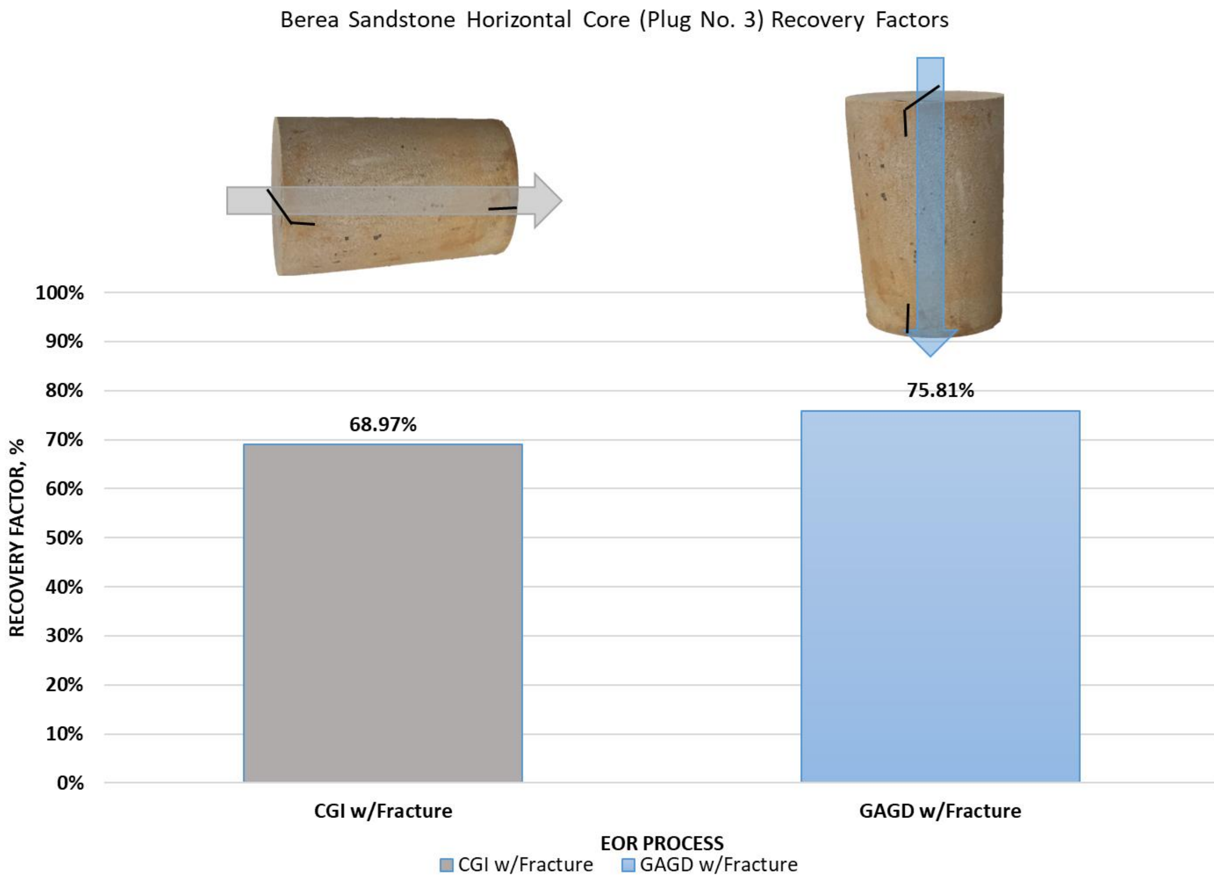


Figure 4. 46. Recovery Comparison of Backpressure (500 psi) Impact on Large Berea Sandstone (BSS CS3) Core Enhanced Oil Recovery Experiments by Injected Carbon Dioxide ($CO2$) at Injection Pressures of 1,500 psi and Operating Temperature of 70 ˚F

4.2.2. Tuscaloosa Marine Shale Core Plug

An ultra-tight core plug was extracted from Tuscaloosa Marine Shale Plug (TMS) was used to test the possibility of applying the proposed method in extremely low permeabilities rocks and reservoirs. 1-inch diameter and the 1.97-inch plug was cored from a 3 ft. long rock column pulled out from a well drilled in an East Feliciana Parish, central State of Louisiana to conduct three experiments as per Table 4.16. The determined effective porosity and absolute permeability for the TMS plug were 3.7% and 0.0017 md, respectively.

Table 4. 16. List of gas Injection Enhanced Oil Recovery Experiments Conducted on Tuscaloosa marine Shale core Plug

Experiment No.	**Mode**	**P_{in}, psi**	**T, ˚F**	**P_{out}, psi**	**P_{con}, psi**
1	CGI				
2	GAGD	1,000	70	Atmospheric	1,500
3	GAGD w/Fracture				

P_{in} Injection Pressure (psi)
T Operating Temperature (deg. Fahrenheit)
P_{out} Outlet Pressure (psi)
P_{con} Confining Pressure (psi)

The TMS core plug was easily brittle and every time we used it small portions would break and remove from the core. For that, we used the core saturated weight (Wsat) to estimate the core dry weight (Wdry) as in Equation 4.1:

$W_{dry} = W_{sat} - PV * \rho_o$ ………………………………………………….....…Equation no. 4.1

The pore volume (PV) was calculated using Equation no. 3.2 as

$$PV = BV * \emptyset$$

And the bulk volume (BV) is calculated as.

$$BV = \pi * \frac{D^2}{4} * L$$

Where:

- D is the core diameter and
- L is the core length.

To avoid severe damage to the TMS core plug, the plug was caped in each oil flooding or gas injection experiment with higher permeability rock caps (Berea Sandstone) and covered with a heat shrinkage tube. Figure 4.47 is showing the TMS core preparation for the core flooding and EOR experiments.

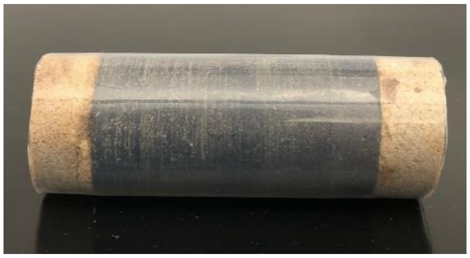


Figure 4. 47. TMS Core Preparation for Oil flooding or Gas Injection Experiment

4.2.3.1. Enhanced Oil Recovery Experiments Using Tuscaloosa marine Shale core Plug (TMS CP1)

In the first EOR experiment conducted on the TMS, the core plug was used to inject CO_2 in CGI mode to create a base for comparison with other injection modes as what has been done with other core plugs and samples. The core was placed in the core holder, pressurized to 1,500 psi, and flooded with the TMS oil for 12 continuous operating days. After aging the core for a week, the core was collected and weighed on a 4-digit scale to determine the saturated weight. The core saturated weight (Wsat) founded to be 64.7852 grams and the dry weight (Wdry) was estimated to be 63.26662 grams. The gas of CO_2 was horizontally injected in CGI at 1,000 psi for two days. The after-EOR experiment weight was determined to be 64.7400 grams and the recovery factor was 2.98% as shown in Figure 4.48.

Exp.1: TMS Core Plug no. 1 CO2-CGI (1,000psi)

Calculated Dy Weight

Total Porosity=	0.0737	or
Diameter=	2.51	cm
Hight=	5	cm
Bulk Volume=	24.74043	cc
Pore Volume=	1.82337	cc
Oil density:	0.832843	g/cc
Saturated Weight=	64.7852	g
Calculate dry Weight=	63.26662	g

$$RF = \frac{W_{sat} - W_{exp}}{W_{sat} - W_{opc}} \times 100\%$$

or $$RF = \frac{W_{sat} - W_{exp}}{W_{sat} - W_{dry}} \times 100\%$$

$$RF = \frac{64.7852 - W_{exp}}{64.7852 - 63.26662} \times 100\%$$

$$RF = \frac{64.7852 - 64.7400}{1.5186} \times 100\%$$

$$RF = \frac{0.0452}{1.5186} \times 100\% = \boxed{2.98\%}$$

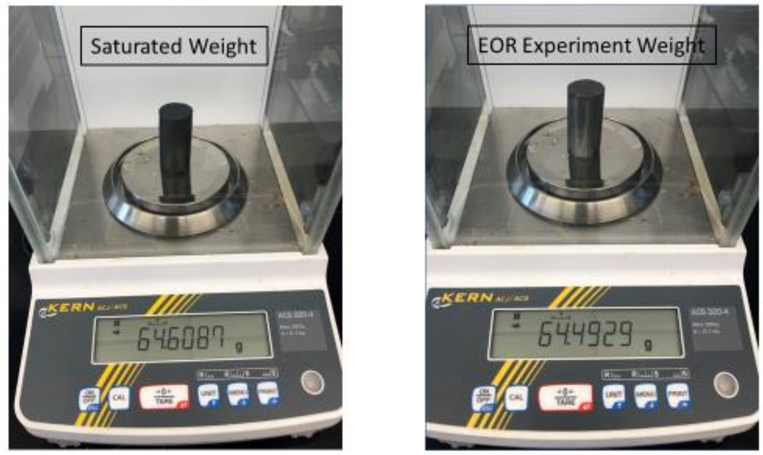
Figure 4. 48. Tuscaloosa Marine Shale Core Plug Oil Recovery Calculation for Continuous Gas Injection Using Carbon Dioxide (CO2 -CGI) Mode at Injection Pressure of 1,000 psi and Operating Temperature of 70 ˚F

In the GAGD EOR experiment, the core was flooded with the oil for 16 continuous operating days and aged for a week before collecting and weighing it. The core saturated weight was 64.6087 grams, and the estimated dry weight was 63.09012 grams. The saturated TMS core plug was returned to the core holder, pressurized to 1,500 psi, and turned vertically to start injecting CO_2 in GAGD mode. The gas of CO_2 was injected vertically for 2 complete days. The core after-EOR experiment weight was 64.4929 grams, and the oil recovery factor was calculated to be 7.63% as presented in Figure 4.49.

Exp.2: TMS Core Plug no. 1 CO2-GAGD (1,000psi)

Calculated Dy Weight

Total Porosity=	0.0737	or
Diameter=	2.51	cm
Hight=	5	cm
Bulk Volume=	24.74043	cc
Pore Volume=	1.82337	cc
Oil density:	0.832843	g/cc
Saturated Weight=	64.6087	g
Calculate dry Weight	63.09012	g



$$RF = \frac{W_{sat} - W_{exp}}{W_{sat} - W_{opc}} \times 100\%$$

or $$RF = \frac{W_{sat} - W_{exp}}{W_{sat} - W_{dry}} \times 100\%$$

$$RF = \frac{64.6087 - W_{exp}}{64.6087 - 63.09012} \times 100\%$$

$$RF = \frac{64.6087 - 64.4929}{1.5186} \times 100\%$$

$$RF = \frac{0.1158}{1.5186} \times 100\% \boxed{= 7.63\%}$$

Figure 4. 49. Tuscaloosa Marine Shale Core Plug Oil Recovery Calculation for Gas-Assisted Gravity Drainage Injection Using Carbon Dioxide (CO2 -GAGD) Mode at Injection Pressure of 1,000 psi and Operating Temperature of 70 ˚F

In the last experiment of the series (CO_2-GAGD w/Fractures), the core flooded with the TMS oil for 10 days and aged for a week before determining the saturated weight. The core saturated weight was 64.2301 grams, and the calculated dry weight was 62.71152 grams. The fracture was created in the core, cap rocks were assembled with it. The fractured core with caps rock was covered with a heat shrinkage tube before placing it in the core holder and setting the confining pressure at 1,500 psi. The weight after-EOR experiment was 64.1603 grams resulted in a recovery factor of 4.6% as shown in Figure 4.50.

Even on ultra-tight core plugs, the GAGD process proves the possibility to improve the oil recovery by doubled compared with the conventional CGI mode. Introducing the fractures to the Tuscaloosa Marine Shale plug had impacted the recovery factor by 54% compared with CGI and by -39.7% compared with GAGD without fracture. The summary of the CO2-EOR injection experiments for the TMS core plug was listed in Table 4.17.

$$RF = \frac{W_{sat} - W_{exp}}{W_{sat} - W_{opc}} \times 100\%$$

or $$RF = \frac{W_{sat} - W_{exp}}{W_{sat} - W_{dry}} \times 100\%$$

$$RF = \frac{64.2301 - W_{exp}}{64.2301 - 62.71152} \times 100\%$$

$$RF = \frac{64.2301 - 64.1603}{1.5186} \times 100\%$$

$$RF = \frac{0..0698}{1.5186} \times 100\% \boxed{=4.60\%}$$

Figure 4. 50. Fractured Tuscaloosa Marine Shale Core Plug Oil Recovery Calculation for Gas-Assisted Gravity Drainage Injection Using Carbon Dioxide (CO2 -GAGD) Mode at Injection Pressure of 1,000 psi and Operating Temperature of 70 ˚F

Table 4. 17. Summary of Tuscaloosa Marine Shale Core Plug Enhanced Oil Recovery Experiments Injected Carbon Dioxide (CO2) at Pressure of 1,000 psi and Temperature of 70 ˚F

EOR Experiment	CGI	GAGD	GAGD w/ Fracture
Estimated Dry Weight, gram	63.26662	63.09012	62.71152
Saturated Weight, gram	64.7852	64.6087	64.2301
Experimental Weight, gram	64.7400	64.4929	64.1603
Confining Pressure, psi	1,500		
Oil Flooding Pressure, psi	1,000		
Gas Injection Pressure, psi	1,000		
Operating Temperature, °F	70		
Recovery Factor, %	2.98	7.63	4.6
Oil Recovery Improvement, %		156	54

4.2.3.2. Effects of Ultra Tight Shale Core (Supper Low Permeability) on Enhanced Oil Recovery Process Using Carbon Dioxide (CO_2) as Injectant at Injection Pressure of 1,000 psi and Operating Temperature of 70 ˚F

The results of the completed CO_2 EOR experiments on the ultra-tight rock showed that injecting CO_2 into a low-permeability TMS core plug could recover about 3% OOIP by the conventional CGI method as a base case. Figure 4.51 shows that injecting the CO_2 in the GAGD process could double the oil recovery from the core plug and produced about 8% OOIP while implementing the process on the fractured core plug improved the recovery by 55% only compared with the base case. The result of GAGD on the TMS core presented an excellent agreement with the obtained result from previous core plugs and samples. GAGD process by injecting CO_2 at a maximum injection pressure of 1,000 psi at an ambient temperature of 70 ˚F proved the ability of the gravity force to assist gas injection mechanism and enhanced oil recovery even from the ultra-tight reservoirs. The injected gas in the GAGD process accumulated at the upper side of the core and displaced the oil down toward the production outlet. With the help of gravity, more oil was produced compared to the injection mechanism at horizontal injection mode. The gas of CO_2 as an injectant showed the ability to enhance oil recovery by vaporizing the lighter hydrocarbons and other saturation fluids in the core plug even at such operating conditions. The forces gravity force (GAGD) and vertical injection pressure (Displacement) on this type of unconventional resource, resulted in excellent sweep efficiency and higher oil recovery factor. Although adding fracture to the TMS core plug (core long fracture) did not help to improve the oil recovery in the GAGD experiment because the injected gas flowed in the fracture easily compared with the nano-sized pores, it still improved the oil recovery compared with the conventional CGI by 3.03% OOIP.

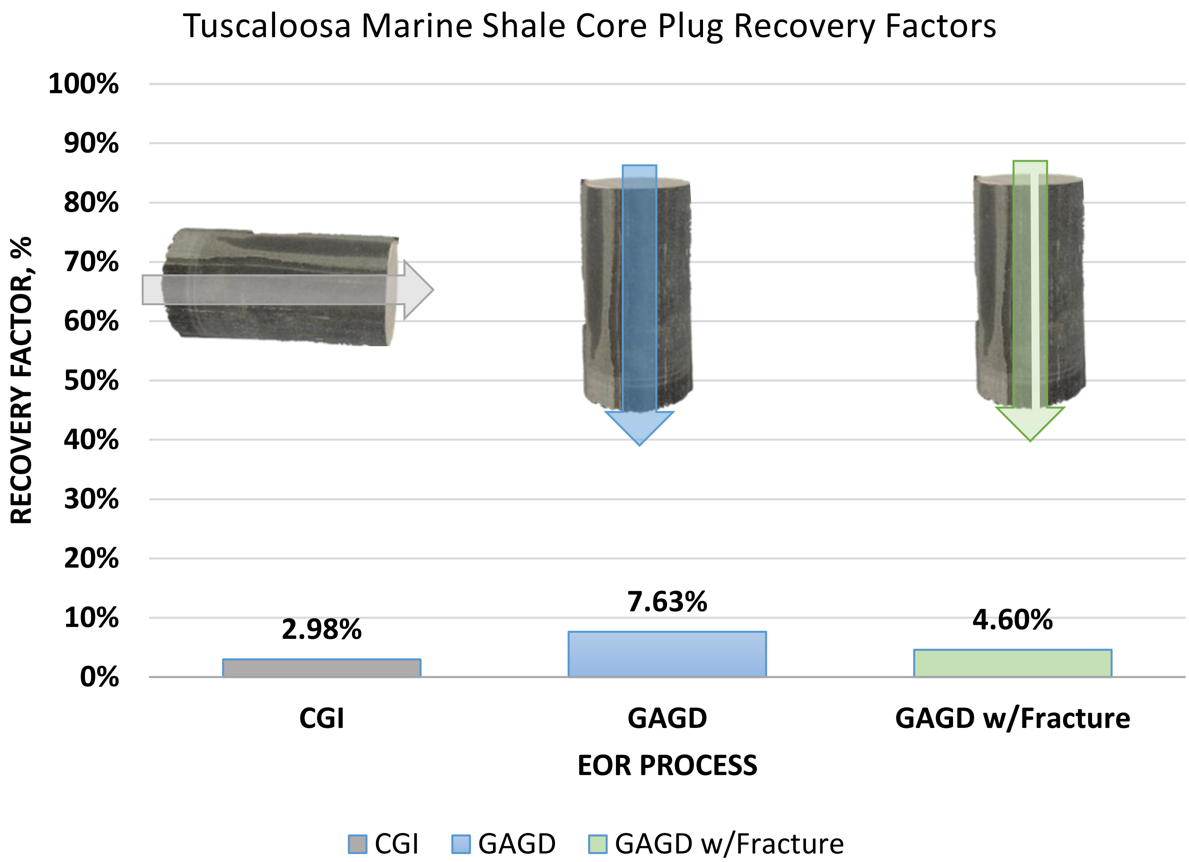


Figure 4. 51. Recovery Comparison of Tuscaloosa Marine Shale Formation Core Enhanced Oil Recovery Experiments by Injected Carbon Dioxide (CO2) at Pressure of 1,000 psi and Operating Temperature of 70 ˚F

4.3. Discussion Summary

New insights into the enhanced oil recovery mechanisms from unconventional resources presented with concrete scientific evidence into the context of the GAGD process and the GAGD with fracture implementation to improve reservoir productivities. In this study, the gas injection EOR experiments by the gases of N_2 and CO_2 investigation were conducted through an experimental approach on different cores' sizes, cut directions, and rock types at different operating parameters. The used core plugs and samples were extracted from Berea Sandstone, and Tuscaloosa Marine Shale (TMS). In this section, the effects of injection direction, injection pressure, core cut direction, core size, injectant, fracture, and back pressures were discussed in the view of the proposed GAGD application in EOR and the importance of gas selection, fractures, and operating conditions. The parameters measured at different times were the core dry weight, saturated weight, and after-EOR experimental weight that were manipulated together in Equation 3.5 and used to calculate the oil recovery for each experiment for all core plugs and samples.

The recovery factors obtained from vertical injection N_2-GAGD EOR experiments at room temperature and a wide range of injection pressures on Berea Sandstone cores showed an average increment of 6% compared with N_2-CGI which indicated that the GAGD process had a promising potential in these sorts of reservoirs in terms of porosity and permeability. While injecting N_2 at conventional CGI mode recovered between 34% to 42.2% OOIP, the vertical injection in the GAGD process showed the possibility to produce 42% up to 55.94% OOIP from the same reservoir. These results showed a concrete agreement with previous works that proved the GAGD process is active even for conditions of immiscible inert gas injection (Miri et al., 2014) like the gas of Nitrogen. It was also observed that injection of N_2 at a higher pressure in relatively small core size plugs caused a reduction in the recovered oil by approx. 5% in CGI mode while it improves the oil recovery by more than 5% compared with lower pressure or 16% OOIP compared with CGI at the same high injection pressure. These results accentuated the importance of injecting the gas at an optimum injection pressure otherwise the EOR process might suffer and face a major issue at the reservoir due to gas breakthrough as the effect of gas segregation and viscous fingering in CGI mode which was not seen in the GAGD process due to the stable of gas front displacement as an effect of injection from top to bottom in the reservoir. In the GAGD process, the pressure maintenance, horizontal and vertical displacement of oil by gas, vaporization of the liquid components from the oil phase, and oil swelling were the main physical mechanisms to support enhancing hydrocarbon recovery (Miri et al., 2014). Overall, the finding results proved that vertical injection is the potential mechanism for oil displacement in low-permeability reservoirs.

Reservoir bedding had a non-negligible impact on hydrocarbon recovery, the EOR experiments displayed lower OIP recoveries in both N_2-CGI and N_2-GAGD modes. Using orthogonal core in EOR experiments cut about 4% to 7%, respectively, from the OOIP recovery obtained from horizontal-cut cores from the same reservoir at the same conditions. In the orthogonal-cut core, the injected gas displayed the oil from the layer to one after or below while in parallel to the bedding core the oil displaced in the same layer. Also, core size was an important parameter in EOR experiments, and its effects were tested at two different pressures. In general, using small core plugs resulted in higher recovery (approx. 9% OOIP) in both CGI and GAGD using N_2 as an injectant at low injection pressure. On the other hand, the high injection pressure reduced the recovery from smaller core plugs in CGI mode due to gas early breakthrough. Applying back pressure in EOR experiments had similar effects and could reduce the hydrocarbon RF's by >11% in CGI mode and less percentage in the GAGD process (7%). As discussed earlier, the findings in this study showed that high injection pressure or backpressure might result in lowering the production from small core plugs in conventional CGI, but it had a revered impact or less effect on the GAGD process which indicated the technical feasibility and the potential of the GAGD process to avoid operating and reservoir problems that may be faced and suffered in conventional EOR methods.

The results of using CO_2 as an injectant to improve hydrocarbon recovery were astounding and showed off a strong agreement with the widespread thought of using it to enhance oil recovery in the U.S. and worldwide. It improved the RF of Berea Sandstone in the range of 46.5% to 70.25% and was able to produce up to 78.6% OOIP at an optimum injection pressure in the CO_2-GAGD process. In the shaly or shale core samples, the process was able to recover 0.7 to 1.6x times the oil recovery obtained by conventional CO_2-CGI mode. Besides the displacement force of CO_2 when injected into the reservoir, it reduced the oil viscosity, interfacial tension, and capillary pressure. More light and intermediate hydrocarbon components were vaporized from the oil phase into the injected CO_2 and produced (Miri et al., 2014). At or near breakover point (MMP), the oil production reached the maximum level as most hydrocarbon components were produced and oil/gas IFT and capillary pressure become negligible or eliminated. It was recommended to perform a minimum miscible pressure determination experiment from the viewpoint of miscibility mechanisms using Slim Tube (ST), Raising Bubble (RB) apparatus, or Vanishing Interfacial tension (VIT) technique (Ayirala, 2005; Mu et al., 2019) to reduce the uncertainty associated with the miscibility conditions of EOR experiments presented herein. Nevertheless, these findings clearly showed the potential of CO_2-GAGD as a drive mechanism to enhance the recovery from the tight and low-permeability reservoir.

In all experiments involving fracture configuration, it was shown that the oil recovery can be improved by 2.3% - 13% using small core plugs by injecting the gas of N_2 vertically in the GAGD process at pressure ranges between 1,000 to 2,000 psi at room temperature. The impact of introducing the fracture to the core sample on the EOR mechanism was configured by injecting CO_2 in a large Berea Sandstone sample at the pressure of 2,000 psi (the optimum injection pressure of CO_2-GAGD EOR experiments). Fracture at the production end in the GAGD process displayed the lowest recovery factor (61%OOIP) while introducing the fracture at the injection side improves the oil recovery by 8% or 5%OOIP. The core sample with two sides fractured demonstrated the larger improvement in oil recovery when injecting CO_2 in both examined EOR modes. While conducting the CGI mode, the introduction of fractures resulted in a high oil recovery factor

(77.78%OOIP) and the vertical injection in the GAGD process with a fracture in both ends showed the highest recovery from the core (81.54%OOIP) with more than 4% productivity improvement. This study, therefore, showed that introducing fractures into the reservoirs and using CO_2 as an injectant at optimum pressure could significantly increase the stimulated reservoir volume and result in boosting the hydrocarbon recovery by more than 0.5x to 1x times in comparison with injecting N_2 and non-fracture reservoirs.

Overall, the obtained results from this intensive work provided a fundamental basis for applying tertiary recovery mechanisms in the field-scale recovery increments of unconventional resources as well as laboratory-scale. This study demonstrated the potential of the GAGD process with fractures to recover additional oil from such reservoirs and lower the carbon emissions (Okwen et al., 2010) by capturing, recycling, and using it to enhance the oil productivity from matured conventional reservoirs and unconventional resources as well. The scientific significance and broad engineering implications of findings in this study ensured the continuous contribution of scientific research and academics in the improvement of the oil industry and reduction of atmospheric emissions of CO_2 and thereby mitigating global climate change. Reusing and recycling the CO_2 as an injectant in the EOR mechanisms restores the human-earth balance and harmonizes the carbon cycle which is in line with the global circular carbon economy initiative.

Chapter 5. Conclusions and Recommendations

5.1. Conclusions

The Gas-Assisted Gravity Drainage (GAGD) process as an enhanced oil recovery (EOR) mechanism from unconventional resources was studied through an experimental approach and compared with the conventional Continuous Gas Injection (CGI). When the experiments were performed, the gases of Nitrogen (N_2) or Carbon Dioxide (CO_2) were injected into various cores saturated with oil extracted from unconventional reservoirs. After implementation of the experimental work, the oil recovery factors (RF) were calculated by using Original Oil-In-Place (OOIP) for all experiments consistently. Based on the experiments at different conditions, the following conclusions can be drawn:

- The objective of the core flooding and EOR is to investigate the feasibility of enhanced oil recovery from unconventional resources by the implementation of the GAGD process, compare with conventional CGI mode and expand the scientific and engineering understanding of Gas-Injection GAGD EOR mechanism was successfully met. From the EOR experiments,
    - The gas injection enhanced oil recovery investigations in unconventional resources performed at room temperature and injection pressure of 1,000 psig (as reference conditions) by injecting N_2 into core plugs and samples extracted from Berea Sandstone reservoir showed that the GAGD process can effectively improve the oil recovery by maintaining the pressure as a reservoir energy source, providing a gravity stable front to displace (injection) and drain the oil (gravity force) to the production side.

- Inject CO_2 into core plugs and samples extracted from Berea Sandstone, and Tuscaloosa Marine Shale (TMS) reservoir showed that the GAGD process can effectively improve the oil recovery by maintaining the pressure as a reservoir energy source, providing a gravity stable front to displace (injection) and drain the oil (gravity force) to the production side. The injected CO_2 dissolved in the saturated oil, swells its volume, reduces its viscosity, interfacial tension force, and capillary pressure, and flows through the bath ways (film flow) leading to better volumetric sweep efficiency and higher ultimate oil recovery.
- In the Berea Sandstone horizontal cut core plug (BSS CP1) and sample (BSS CS3), the vertical injection of N_2 in cores with low permeability (23 – 24 μ-darcy) at reference conditions (P = 1,000psig, T = 70˚F) improved the oil recovery factors by 4% to 6% OOIP, respectively, comparing with injection in the conventional horizontal direction Continuous Gas Injection (CGI) mode. This improvement in the recovery by the GAGD process achieved as a result of invading each layer equally in stable oil/gas fronts and supporting of gravity force as a driving mechanism which cannot be said for the conventional CGI mode that suffers from gas separation near the injection side and flooding mostly in the upper layers leaving the lower layers unswept and early gas breakthrough.
- In Tuscaloosa Marine Shale horizontal cut core plug (TMS CP1), the vertical injection of CO_2 in ultra-tight core with poor absolute permeability of 1.7 μ-darcy at an injection pressure of 1,000 psig and room temperature as reference conditions improved the oil recovery by 4.65% OOIP to recover a total of 7.63% OOIP from TMS core sample compared with the 2.98% total recovery from the implementation

of conventional Continuous Gas Injection (CGI) mode. This excellent results from the CO_2-GAGD experiment implementation in TMS indicate that the process has promising potential to recover a significant amount of reserved oil in shale reservoirs even at immiscible conditions which are relatively impossible to accomplish by the conventional CGI mode.

- The objective of the core flooding and EOR is to investigate the reservoir (cores) and operating conditions in enhanced oil recovery from unconventional resources including strata beddings, core size, injection pressure, injected gases, and backpressure via implementation of the GAGD process and compare with conventional CGI mode was successfully fulfilled. From the EOR experiments,
    - Investigating the effect of gas injection enhanced oil recovery on unconventional resources performed at room temperature and injection pressure of 1,000 psig (as reference conditions) by injecting N_2 into horizontal and orthogonal core plugs extracted from Berea Sandstone showed that the GAGD process can effectively improve the oil recovery by maintaining the pressure as a reservoir energy source, providing a gravity stable front. The injected N_2 provides better volumetric sweep efficiency in the GAGD process and increased the oil recoveries by 4.32% and 2.88% OOIP from the horizontal and orthogonal cut cores, respectively, compared to CGI.
    - Investigating the effect of core size on EOR performance in unconventional resources at room temperature and injection pressure of 1,000 psig (as reference conditions) by injecting N_2 into two different sizes (1 PV to 20 PV) horizontal core plugs extracted from Berea Sandstone showed that the GAGD process can

successfully improve the oil recovery and provide better volumetric sweep efficiency in the GAGD process and increased the oil recoveries by 4% to 7% OOIP comparing with CGI. The phenomena of gravity segregation and poor sweep efficiency in CGI mode were observed in the large core sample as the larger diameter and bigger core size provide a wider range for the injected gas to segregate which cannot be seen in shorter radius core plugs. The usage of smaller core size plugs showed better performance on EOR experiments compared with the larger core samples but with little uncertainty in determining the oil recovery factors.

- Investigations of the effect of injection pressure on EOR performance in unconventional resources conducted at room temperature and injection pressure of 1,000 psig (as reference conditions) and 2,000 psig by injecting N_2 into a horizontal Berea Sandstone core plug exposed the important role played by this factor. In the GAGD process, higher injection pressure improved the productivity of the core plug and produced about 5% OOIP more oil recovery than at reference pressure while it demonstrated counterproductive to the EOR process and decrease the oil RF by 16% OOIP as the small plug suffered from the gas early breakthrough and fingering. Higher injection pressure showed great potential for enhancing oil recovery in large Berea Sandstone sample through increasing the N_2 or CO_2 injection gradually from 1,000 psig to 3,000 psig all examined CGI and GAGD injection modes. Results from the EOR experiments conducted at room temperature showed that the higher injection pressure influenced the sweep efficiency such that can increase the oil recoveries up to 18 % OOIP compared with reference pressure (1,000 psig). Such a trend continues improving the oil recovery until the system reach threshold pressure above which the recovered oil becomes less because of gas breakthrough and fingering. Increasing injection pressure can only result in a good recovery performance at immiscible conditions and when the injection pressure is above the miscibility, showed that a further increase in the pressure could not result in a better or significant increase in oil recovery factor.

  - Investigation of the effect of injected gas (injectant) on EOR performance in unconventional resources performed at room temperature and different injection pressures by injecting N_2 or CO_2 into to core plugs extracted from Berea Sandstone, and TMS showed that the CO_2 can significantly improve the oil recovery though providing a better volumetric sweep efficiency and interacting with saturated oil in the GAGD process and increased the oil recoveries by at least 47% compared with using the gas of N_2 as injectant to enhance oil recovery in the GAGD process.
  - The back pressure investigations on enhanced oil recovery in unconventional resources performed at room temperature and backpressure of 500 psig by injecting CO_2 into fractured large Berea Sandstone core sample at 1,500 psig showed that the higher backpressure can decrease the oil recovery factors by 7% to 11% in CGI and GAGD, respectively. The backpressure applied a reverse force that opposite the flow direction and decreases oil flow through the production outlet.

- The objective of the core flooding and EOR to understand the predominant recovery mechanisms in enhanced oil recovery from unconventional resources by analyzing the results and studying the observation of EOR implementation was successfully achieved.
  - The EOR experiments showed that the gas of N_2 is economic and eco-friendly and displace oil mostly through an immiscible displacement approach due to its high

minimum miscibility pressure (MMP) while the gas of CO_2 in continuous flooding mode in CGI and GAGD improves the macroscopic sweeping efficiency and enhances the microscopic displacement efficiency via diffusivity of saturated oil. Injected CO_2 in shale reservoirs not only could be permanently sequestered within the small pores in an adsorbed state, but also could participate in enhancing recovery of oil or natural gas through maintaining pressure, miscible displacement, molecular diffusion, or evaporate light components. The gas of CO_2 can diffuse into rock pores of shale plugs causing the oil swelling and making the solution gas drive seems to be an effective production mechanism.

- The objective of the study is the impact of natural or introduced hydraulic fractures on enhanced oil recovery from unconventional resources by the implementation of the EOR experiments on partial or completely fractured cores and compare with unfractured cores or different fracture configurations in the Gas-Injection EOR mechanism was accomplished. From the EOR experiments,
    - The observed impacts of natural or hydraulic fractures on enhanced oil recovery mechanisms are directly linked to stimulated reservoir volume (SRV) observed at the conducted EOR experiments. Introducing hydraulic fractures to the core plug and samples effectively increased the stimulated volume by increasing the gas/oil contact area, which is in turn effectively increased by increasing the stimulated pores and reducing the fluid bath from one side to another.
    - In the Berea Sandstone horizontal cut core plug (BSS CP1), the injection of N_2 in partially fractured core (both sides) in the GAGD process at ambient temperature and pressure of 1,000 psig and 2,000 psig improved the oil recovery factors by 2%

to 3%, respectively, as the stimulated pores increased and displaced the oil in a shorter bath to the production side. These were achieved as a result of increased the stimulated reservoir volume and display more efficient to invade each layer equally in the EOR driving mechanism which cannot be said for non-fractured cores.

- Comparing with the impact of introducing fractures to the orthogonal cut Berea Sandstone core plug (BSS CP2) by injecting N_2 at reference conditions, the improvement in the oil recovery by the GAGD process with fracture was remarkable with about 13% OOIP recovery more than the implementation of the process without fractures. Introducing the fractures in both sides of such types of vertical cut core plugs creates a bath to the injected gas to reach more layers, deeply stimulate layer after layer, enhance the productivity via a shorter fluid bath, and reach higher oil recovery as well as horizontal cut core plugs.
- The impact of fracture configuration on enhanced oil recovery mechanism in large Berea Sandstone sample (BSS CS3) by injected CO_2 at an optimum injection pressure of 2,000 psig and room temperature showed that introducing the fracture from the injection side may improve the oil recovery by 8% compared with the fracture from the production side in the GAGD process, at least. On the other hand, introducing partial fractures to both sides display excellent results compared with a one-sided fracture core sample. Injecting gas of CO_2 can enhance the productivity via prementioned forces and both side fractures and boost up the recovery factors to 77.78% and 81.54% OOIP in CGI modes and GAGD process, respectively. Resultantly, the CO_2-GAGD process with fractures enhanced the productivity from the reservoirs (cores) and showed the superiority of EOR mechanisms compared

with the usage of N_2 as injectant, CGI mode, non-fractured, or one-side fractured cores.

- In the Tuscaloosa Marine Shale core plug (TMS CP1), the injection of CO_2 in a completely fractured core in the GAGD process at room temperature and pressure of 1,000 psig showed a decrease in the oil recovery factors by 3% OOIP compared with CO_2-GAGD implementation on non-fractured TMS core plug. By using intensive horizontal drilling and hydraulic fracturing techniques in shale resources, the saturated oil and injected gas may escape from the ultra-tight matrix of shale toward the hydraulic fractures as the fractures ease the fluid flow compared with the rock matrix. Unlike partial fractures, complete fractures may result in low recovery from such types of resources and to introduce partial or short fractures to the shale resources is recommended and expect to increase the stimulated reservoir volume and allow injected gas to interact with the saturated oil to enhance the reservoir productivity.

5.2. Recommendations:

In this research, the enhanced oil recovery potential of the gas-injection GAGD process was systematically studied in conjunction with using N_2 and CO_2 gases as injectant at EOR experiments and introducing the hydraulic fractures to the core plugs and samples for potential application in unconventional resources such as ultra-tight and shale oil reservoirs. Different reservoir (core) and operating conditions such as core cut direction (bedding), core size, injection, and back pressure, and injected gases were studied in view of improving the cores' productivity and enhancing the oil recovery from such types of reservoirs and compared the proposed process with the conventional CGI injection mode. Core flooding experiments were conducted before EOR experiments on each used core to determine the petrophysical properties; effective porosity and absolute permeability to rank the selected cores on the quality of reservoir scale.

Regardless of the complete examination, investigations, and significant observation which prompted a commitment of important and relevant information in petroleum engineering, certain gaps and limitations were not addressed. Accordingly, this examination has cleared the way for ensuing research which can be perfumed to extend the current assortment of studies in the area of gas-infusion GAGD EOR for unconventional resources. Therefore, the following suggestion is raised, in view of future research:

- This work investigated the gas-injection GAGD EOR and the effects of various factors on enhanced oil recovery mechanism using core flooding and EOR apparatus at ambient conditions of room temperature and designed operating pressures. A more comprehensive study on the impact of pressure and temperature is recommended to expand the understating of the performance of gas-injection EOR mechanisms at typical reservoir subsurface conditions. Performing the EOR experiments at reservoir conditions will further reveal the contribution of enhanced oil recovery to improve the reservoir productivity and in turn oil recovery factors.
- The effect of oil displacement mechanisms on gas-injection EOR in unconventional resources such as diffusivity and miscibility can be studied to extend current scientific understanding and further strengthen the field applications. It is recommended to perform a minimum miscible pressure (MMP) determination experiment from the viewpoint of miscibility mechanisms using miscibility test techniques. The MMP determination will reduce the uncertainty associated with the miscibility conditions of EOR experiments and

help to identify a reference pressure to optimize the CO_2-EOR experiments and provide a further understanding of the fluid displacement mechanism in the pore to core scale.

- In this study, the core flooding and EOR experiments were performed on relatively small plugs and core samples (20 PV) that create a certain range of uncertainty related to the core sizes. It is recommended to conduct the gas-injection EOR experiments using a bigger core sample and higher pore volumes to reduce the uncertainty percentages and produce solid EOR recovery results.
- The gas-injection GAGD EOR process was investigated in this study through an experimental approach in the absence of water saturation due to the extensive time needed to flood these tight cores with the reservoir brine. To mimic the reservoir fluid saturations and understand the impact of drainage and imbibition paths in fluids flow through the porous media, a more comprehensive study in the presence of brine on relative permeability and capillary pressure to include hysteresis effects is recommended.
- The success of this study proves that the gas-injection GAGD EOR process can significantly enhance the productivity of the core and improve the oil recovery factors compared with the conventional CGI mechanism in core scales. It is recommended to go further step in this investigation process and perform a well-scale or small sector field application of the proposed process. The well-test will provide a better standing of the proposed process and ensure its capability to clear up the application's difficulties and open a new window for further research and development of the GAGD process.
- In this study, the proposed gas-injection GAGD and conventional CGI EOR mechanism were performed in continuous injection mode but that is not the limit for the current EOR research. It is recommended to perform the GAGD in cyclic gas injection mode and study

the effect of vertical gas injection on the EOR mechanism and compare it with the conventional cyclic injection mode and cyclic-GAGD process. This will bring another successful implementation of gas-injection GAGD in the EOR process and further potential in enhanced oil recovery in different unconventional resources where other EOR methods are not capable to work.

- To perform the experimental laboratory core flooding and EOR experiments in this study, the procedure of pressurizing and de-pressurizing, assembling and de- assembling the core holder apparatus and collecting the core for weight, and determining the recovery factors. It is recommended to implement the X-ray CT-Scanning technology in the core flooding and EOR to determine the core weights and calculate the recovery factors after each experiment. The application CT-Scanning will eliminate the pressurizing and assembling procedures, avoid the effects of depressurization on the core body, reduce the operational steps and provide more accurate measurement of the core's saturation through the CT number which reflects the core lithology properties, especially the core density and the change in the core density at the condition of dry and oil-saturated data.
- This study was performed at the laboratory core-scale level to reveal the potential of the gas-injection GAGD EOR process to enhance the productivity of unconventional resources. A full field application through numerical simulation modeling using Petrel, CMG, and other platforms is recommended to study the proposed process capabilities in field-scale. This study will uncover further understanding and unlock more potential for GAGD applications in unconventional resources.

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Vita

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