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Digital Rock Analysis On Berea Sandstone And An Eor Study On Middle Bakken

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DIGITAL ROCK ANALYSIS ON BEREA SANDSTONE AND AN EOR STUDY ON MIDDLE BAKKEN

By

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This thesis, submitted by Barco Ngali Yolo in partial fulfillment of the requirements for the Degree of Master of Science in Petroleum Engineering from the University of North Dakota, has been read by the Faculty Advisory Committee under whom the work has been done and is hereby approved.

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To YHWH the Almighty, my mother Yvonne Risasi, my dad Jacques Yolo and my beloved Justine Kasay Ipoka for their incredible support.

ABSTRACT

Oil production from tight formations such as the Bakken Formation has experienced a boom in the last decade with recent breakthroughs in horizontal drilling and hydraulic fracturing. However, despite the technological progress, the oil recovery is still less than 10 percent, leaving a considerable amount of potentially recoverable oil. While miscible flooding is well understood in the conventional reservoir, it is not fully explored in unconventional reservoirs. Therefore, it is essential to evaluate different enhanced oil recovery techniques potential in tight shale plays.

In this thesis, the research studies CO_2 and ethane interactions with oil at reservoir conditions through laboratory experiments and examined their effects on the ultimate oil recovery. Due to the scarcity of CO_2, the study concentrates on the potential of using ethane as an alternative to CO_2 because the results showed CO_2 as a good candidate for EOR in the Bakken. Also, we have done an extensive digital rock analysis on a Berea sandstone in order to learn how to incorporate the process into EOR simulations. Several core flood experiments were run using CO_2 and ethane as the EOR agents and their results were compared. Next, Digital rock analysis and numerical simulation was employed to model the process.

In this work, the potential of different EOR processes was investigated, Digital rocks analysis and simulations were run to help better choose optimal EOR techniques and methodologies. It was observed that ethane was the best EOR agents for the Bakken and digital rock analysis can provide accurate reservoir characterisation of rock sample.

Keywords: oil production, DRA, CO_2, EOR, digital rock analysis, oil field, reservoir

CHAPTER 1

INTRODUCTION

Enhanced oil recovery (EOR) is the basic implementation of various techniques for increasing the amount of crude oil that can be extracted from an oil field. Enhanced oil recovery is also called tertiary oil recovery as following the primary and secondary recovery. According to the US Department of Energy, there are three fundamental techniques for EOR: Thermal recovery, Gas Injection, and chemical injection. Sometimes the term quaternary recovery is used to refer to more advanced, speculative, EOR techniques. The effectiveness of oil recovery from the oil-bearing formation using modern industrial method is considered unsatisfactory in all producing countries, while the consumptions of petroleum products are growing worldwide every year. Average ultimate oil recovery in different countries and region is ranging from 15 to 45 percent (Tzimas et al.,2005). For examples, 24-27 percent, in Latin America and southeast 16-17 percent in Iran, and 33-37 percent in the USA, Canada, and Saudi Arabia. Modern geological proven oil reserves in all known deposits in the world are reaching more than 500 billion tons, also, over 300 billion tons are classified as unrecoverable resources by many modern industrial methods of field development (Green et al., 1998). The remaining oil reserves removal rate range on average between 10-15 percent, which equals 30-40 billion tons. It may even be reached using enhanced oil recovery methods that are currently applied. Therefore, the remaining oil reserves in known deposits represent a significant source of supplies for increasing recoverable reserves and essential target for implementation of EOR methods.

Interest toward enhanced oil recovery method is increasing every year all over the world and researchers aimed at finding a scientific approach for choosing the most effective EOR are developing rapidly. To improve the economic efficiency of oil field development and to reduce direct capital investments for the entire period of the oil field is usually divided into three main stages

1. At the first stage of oil production (primary production), the natural energy of an oil field is used as much as possible (see figure 1). This driving force is mostly the elastic energy, the energy of the dissolved gas, the energy of the gas cap, and the potential energy of gravitational forces.
2. The second stage methods to maintain reservoir pressure by injecting water or gas are implemented. These means were called methods of secondary production.
3. At the third stage-enhanced oil recovery methods are used to improve the production efficiency. This stage is generally associated with the alleged tertiary production.

Figure 1. Wellhead from primary production

EOR Classification
Thermal recovery

This method is usually used for a reservoir with very high API such as reservoirs seen in Canada with tar sand and heavy oil. Amongst the thermal EOR methods use there are:

1. Steam Flooding
    a. Steam flooding is a method where heat is introduced to the reservoir by a continuous steam injection. A huge amount of hydrocarbon reserves worldwide is heavy oil. The drawback for this type of oil in production is that it has very has viscosity and therefore and bad mobility in-situ (Zhu et al., 2011). Using a continuous steam injection improve the mobility and further improve the production by cleaning the near-wellbore zone.
2. Cyclic steam stimulation
    a. Cyclic steam flooding is an EOR method is more favourable for massive oil extraction not only for heavy oil but for the naturally fractured reservoir as well as the heat introduced to the reservoir will reduce oil viscosity and improve recovery (Mollaei, Maini, & Jalilavi, 2007). This approach also was known as huff and puff consist of three phases: injection period, the soaking period and the return to production. The Huff and Puff method is currently also used for gas injection in the unconventional reservoir such as the Bakken North Dakota (Yu et al., 2014) (See Figure 2).

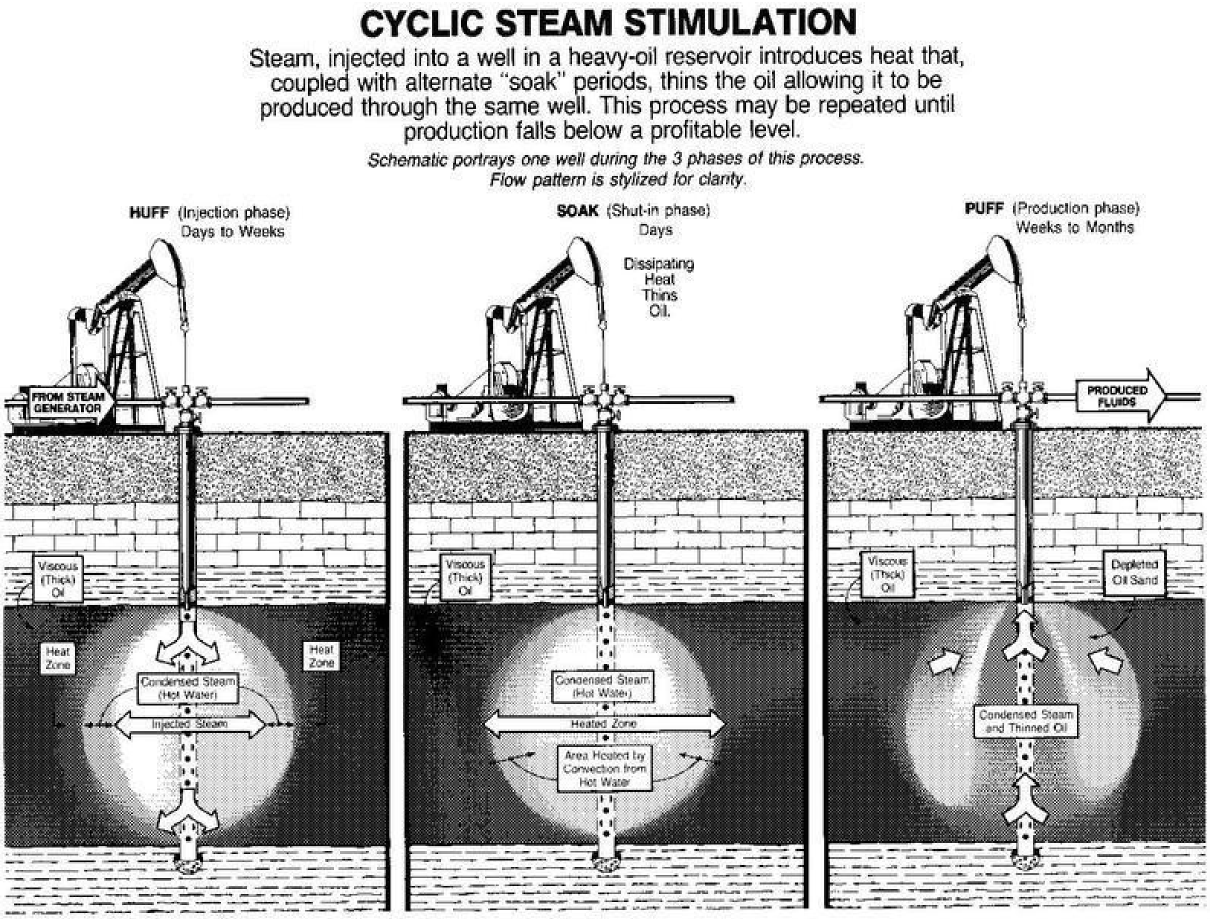


Figure 2. Cyclic stimulation (DOE.gov)

3. In-Situ Combustion

   a. In-situ combustion also called fire flooding had been used for more than 90 years successfully. However, it is considered a high-risk method due to its application to a weak candidate reservoir. It is called fire flooding because it reflects the movement of oil front burning in the basin. This method could be either forward or reverse as the combustion front can be moving toward or against the air flow. One of the main advantages of this methods is that it can be used in a wide range of reservoir which is pretty unique for a thermal EOR method (Wu et al.,1971).

4. Hot Water Flooding

Hot water flooding is the least expensive methods for thermal EOR. It works like a typical water flooding with the difference that it the water used is hot. The means are mostly used for heavy oil such as some types found in certain Canadian reservoirs (Torabi et al., 2012).

Gas Injection EOR

Air injection for Light hydrocarbons reservoirs. Air injection is an EOR method used to for light hydrocarbons reservoirs. It works by injecting air into the reservoir under pressure (Teramoto et al., 2006). The primary mechanism is the burning process caused by the mixture of the oxygen found in the injected air and the in-situ oil in place. This oxidation will start propagating through the reservoir.

Carbon dioxide injection. At the temperature above 31°C carbon dioxide is in a gaseous state under any pressure, if the temperature is below 31°C, it goes into the liquid state. However, under the pressure, less than 1044 psi carbon dioxide evaporates. The physical essence of the method is based on the excellent carbon dioxide miscibility in the reservoir fluids, providing volumetric expansion of oil in 1.5 ~1.7 times, miscibility with oil (elimination of capillary forces), oil viscosity reduction and consequently increasing the oil displacement coefficient for up to 0.95. However, the use of CO_2 as any other low viscosity agent associated with lower sweep efficiency (5~15 percent), that is why oil recovery factor can increase only by 7 to 11 percent. Nevertheless, there are cases where the recovery factor reaches 85 percent. Carbon dioxide can be injected in gaseous with full miscible pressure or liquid state combined with water flooding (see figure 3).

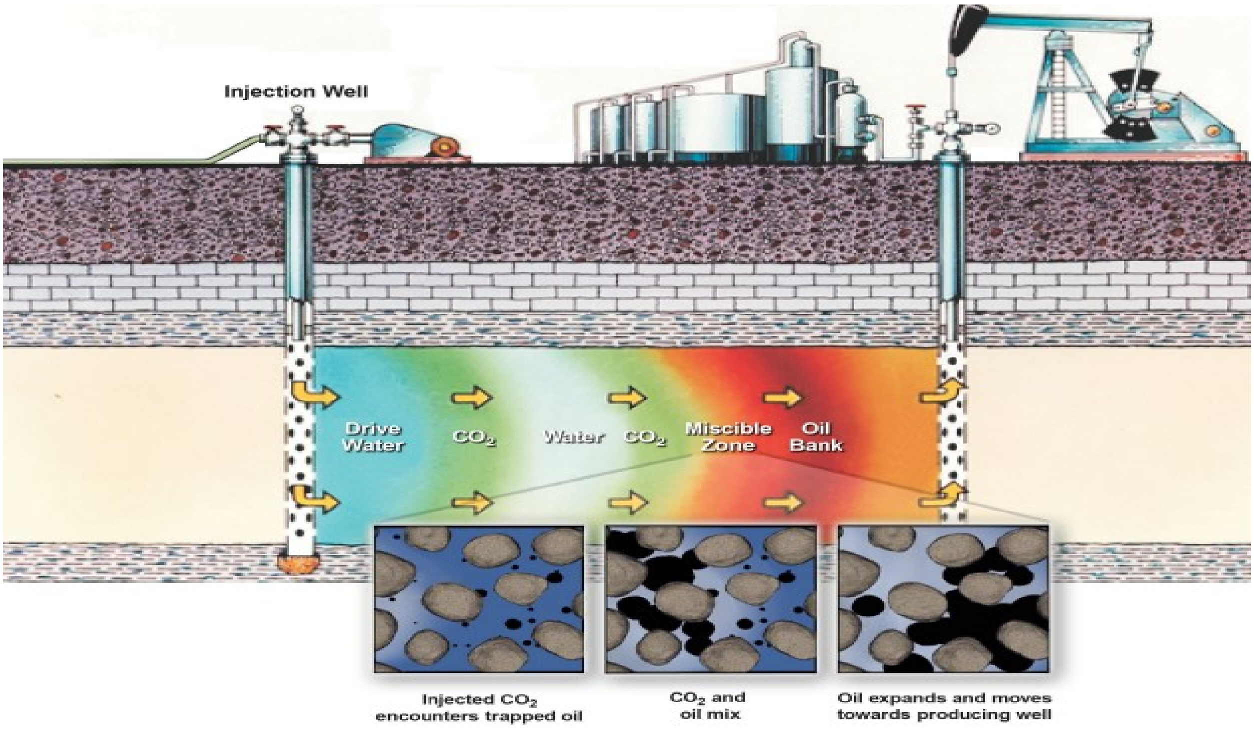


Figure 3. CO_2 EOR (DOE.gov)

Nitrogen and other natural gas injection. Nitrogen and additional natural gas injection could be a very viable EOR method for a specific reservoir candidate. Injections of natural gases (see figure 4) create a miscible front with the in-situ oil in place. It considered being a good candidate for a standard reservoir with a high content of ethane through hexane.

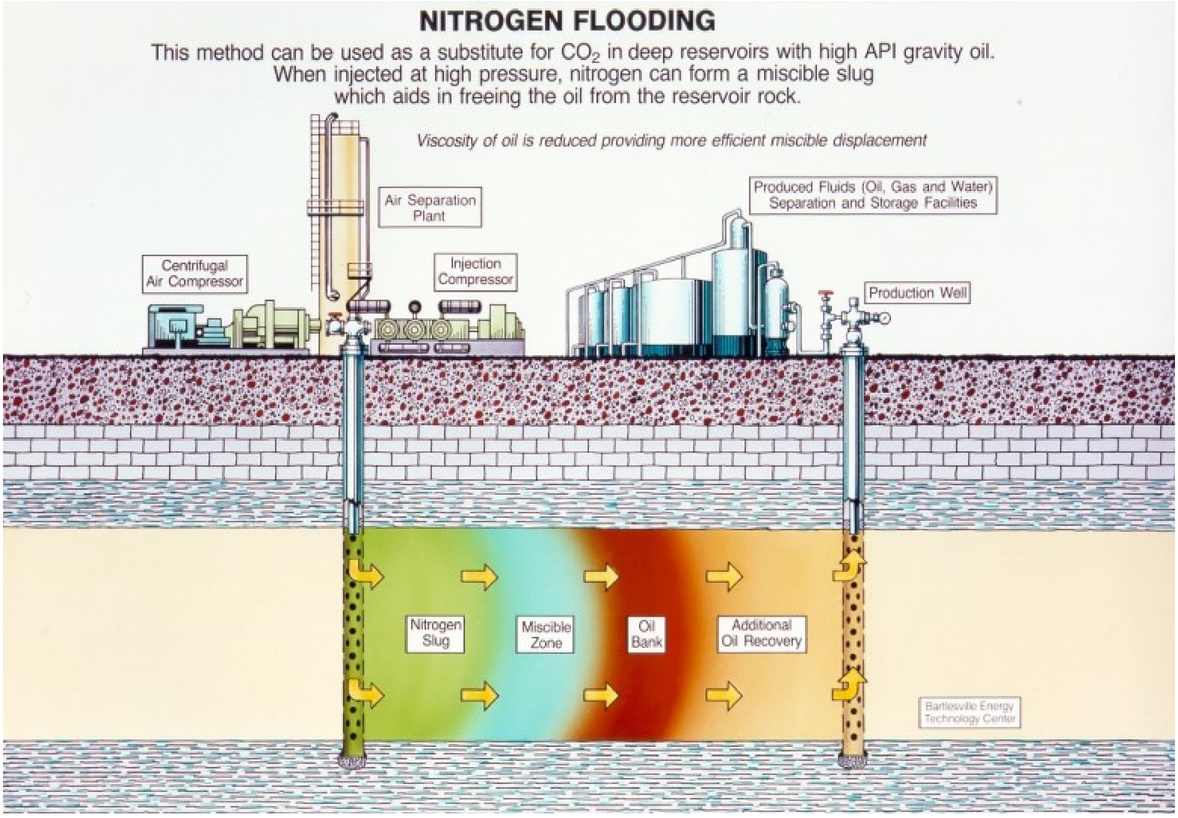


Figure 4. Nitrogen Flooding (DOE.gov)

Chemical Injection

Surfactant flooding (Foam Including). The method is based on the ability of the surfactant to reduce the interfacial tension at the boundary of oil and water, change oil-water-rock surface wettability and properties of adsorption layers that are formed at the boundary between oil-water and oil-rock surface. It uses dilute non-ionic surfactant solutions.

Polymer flooding. The method is based on the ability of the dissolved in water high chemicals polymers, even in small concentrations significantly increase water viscosity, reduce mobility and thereby improve sweep efficiency. When the concentration of water equals 0.01-0.1% its viscosity increases to 3-4 MPa. This led to a significant reduction of oil and water viscosity ratio in the reservoir and the suppression of liquid breakthrough.

Alkaline water flooding. The injection employs the term alkaline flooding into the reservoir of reagent, solvent, which are alkaline. The preferable concentration of the solution ranges from 0.05 to 5 percent, and in some cases can reach 25-30 percent. The most potent chemical reaction has a NaOH and Na_2SIO_3. These substances are recommended as essential reagents to enhanced oil recovery. They both actively interact with acidic components of oil, harden ions that water can contain (reservoir and injected) and the rock collector. Application of alkaline acting based on the interaction of alkaline liquids (reservoir and injected) and the rock fraction, which resulted in a change in the surface characteristics of the system oil-water-rock conditions and therefore oil displacement by water. The main factors that determine the oil recovery increase are to lessen the interfacial tension, oil emulsification, and reduction of rock wettability.

Acid displacement. The method of sulfuric acid injection is based on the formation of acid in the watered zone which in turn should be surfactant friendly and water-soluble. The primary mechanism is to reduce water permeability of washed areas, increase sweep efficiency, and reduce interfacial tension. The first process is to use sulfuric acid with a concentration of 90 percent, and the second corresponds to the use of acid of 80 percent concentration called alkylated sulfuric acid (ASA) (Griesinger et al.,1951).

Chemical reagent displacement (micellar-polymer flooding including). The micellar solution is an excellent dispersed colloidal system of hydrocarbon liquids (from LPG to light hydrocarbon), water, and a water-soluble surfactant which was stabilized by alcohol(isopropyl, butyl). Micellar flooding provides a reduction of interfacial tension in the reservoir for the optimal composition almost to zero (less than 0.001mN/m) (Green et al.,1998). According to some published data, micellar-polymer flooding can lead to a recovery of 80-90 percent (Green et al.,1998).

Microbiological treatment. This technique consists of injecting micro-organism inside the reservoir to produce surfactants which will help in oil production. The success of this method has been controversial and have not been applied in commercial scale yet.

Hydrodynamic EOR

Amongst the different hydrodynamic EOR there are:

- Integrated displacement technologies
- Development of by-pass oil reserves
- Barrier flooding
- Non-stationary flooding
- Accelerated production
- Stepwise thermal flooding

Combined EOR

In most cases where combined EOR methods are implemented there are different combinations of hydrodynamic and thermal, hydrodynamic and physico-thermal, thermal and physicochemical and other methods. Plasma-pulse technology (see figure 5) is the newest technique used in the USA as of 2013 (Patel et al.,2018). The technology originated in the Russian Federation at the St. Petersburg state mining university.

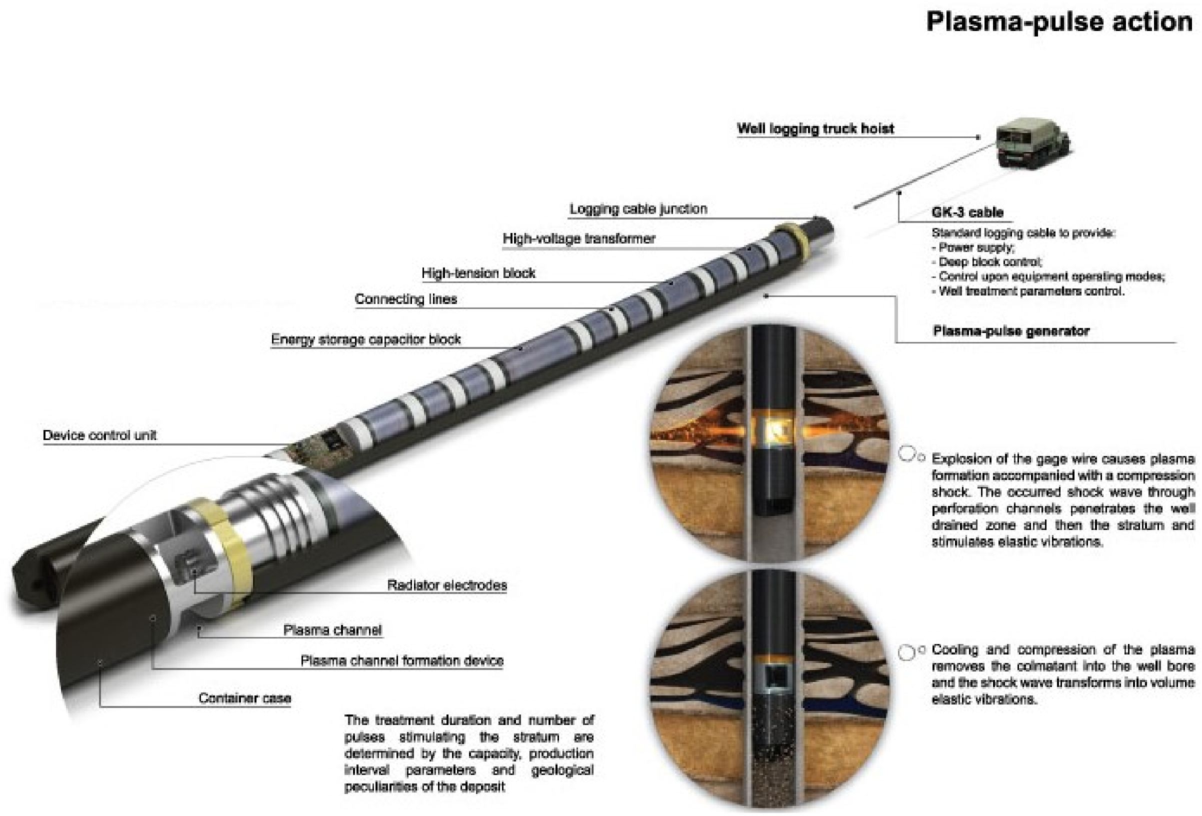


Figure 5. Plasma Pulse (Novas Energy)

Production Intensification

There are also some locally applied methods which are usually attributed to a particular group called oil production intensification methods. It would not be entirely correct to associate these methods with EOR methods. Since while increasing the recovery for some period it does not increase the ultimate oil recovery rate as EOR methods would. The mainly applied oil production intensification methods are as follows:

1. Hydraulic Fracturing and Horizontal Wells
    a. Hydraulic fracturing (see figure 6) is a technique used to bypass formation damage and stimulate the zone of interest. The method consists of fracturing the rock injecting a pressurized fluid. This method was developed a commercial scale since 1946 and has been since employed worldwide. (Coulter et al., 1976).

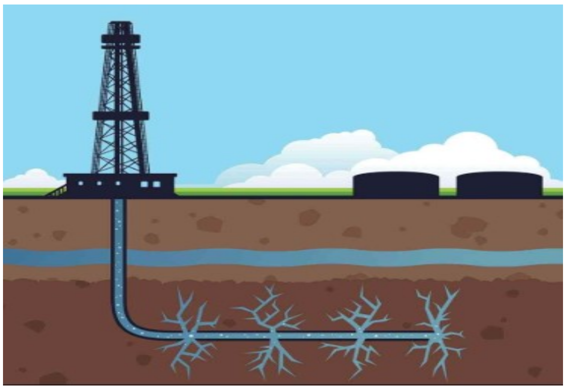


Figure 6. Hydraulic fracturing with horizontal well (motherearthnews.com)

Horizontal Wells

b. Drilling horizontal wells usually have more than 85 degrees; it improves the reservoir performance by having a more extended contact area with the reservoir. This method combined with hydraulic fracturing have allowed the industry to exploit formation that was non-economically exploitable (Prasad et al., 1990).

2. Wave Treatment

   a. This method consists of directing wave energy to the region of intersect in a hydrocarbon reservoir. (Jeon et al., 2015).

3. Acid stimulation

   a. Acid stimulation also called acid fracturing is the hydraulic fracturing method were the fluid used is acid instead of water. This type of treatment can be deployed in different stages (see figure 7) (Rafie et al., 2014).

Figure 7. Multi-stage hydraulic fracturing (Rafie et al., 2014)

The drilling and exploration method are critical to the successful production of oil. Besides, it determines whether an organization in the field will achieve its goals and mission. Consequently, it is imperative to review the nature of the oil field in question and select the most appropriate approach to use.

CHAPTER 2

RESERVOIR CHARACTERISATION OF BAKKEN

The Williston Basin is a critical intra-cratonic region made up of sedimentary deposit extending from the Southern parts of Dakota, all the way to North Dakota, Montana, and the Canadian provinces of Alberta, Manitoba, and Saskatchewan. Over the years, a lot of exploration work has been done in the region. However, since the mid-2000s the attention of explorers has been focused on the Bakken Formation (See figure 8). Shared by the U.S and Canada. It is located in North Dakota and Montana in the United States, and Saskatchewan and Manitoba share it on the Canadian territory (Sorensen et al.,2015). The Bakken petroleum system consists of Three Forks Formation, Lower, Middle, and the Upper Bakken Members (LeFever et al., 2011). The four members are known to be rich reservoirs of carbonates and mixed siliciclastic substances (Egenhoff et al, 2011). In recent years, they took place among the most important oil-producing regions. The development of these reservoirs started in 1953 with the discovery of the Antelope fields that extended from North Dakota.

Up to the 1970s, explorers limited their work to the Antelope filed because of the poor reservoir characteristics like low permeability and porosity in the Bakken Formations (LeFever et al., 1998). The development and exploration of the Bakken formation hit a higher gear with the completion of the first-ever horizontal well within North Dakota (Lindsay et al., 1988). The success of this particular well motivated the relevant stakeholders to look for new targets with the Bakken as well as the Three Forks Formations. Despite the poor reservoir characteristics, advances in well-drilling and completion methods resulted in the dramatic increase in exploration activities in the Bakken Formation in the mid-2000s.

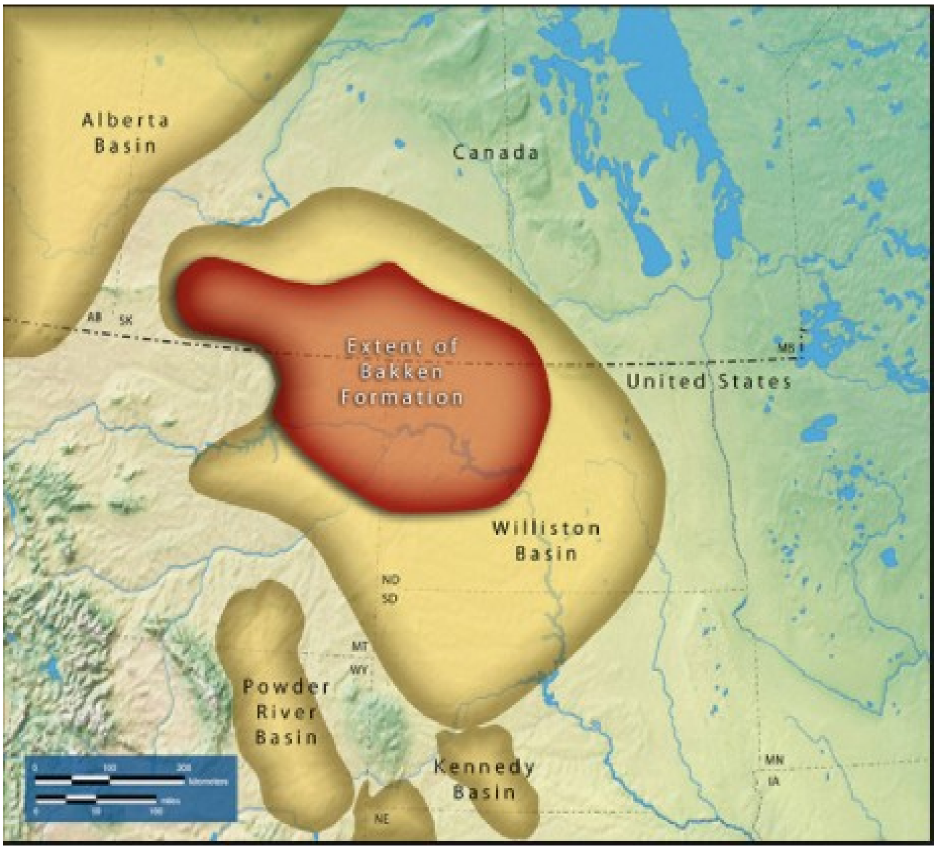


Figure 8.Bakken Map (EERC)

The Bakken Formation is regarded to be among the most productive regions of the Williston Basin and one of the richest low-permeability reservoirs found in North America (Nordeng & Helms, 2010; Pedersen & Christensen, 2007; Sorensen et al., 2015). Researchers contend that reservoir characterization has also helped in understanding the flow of oil in the matrix pores and fractures (see figure 9). Moreover, it was useful in conducting forecast modelling operations and the analysis of pressure depletion (Pedersen & Christensen, 2007). The lower and upper members of the Bakken Formation are made up of a mixture of massive and fissile organic-rich shale rocks (Nordeng & Helms, 2010). The shales act as an important source bed for the Bakken's Middle Member and other formations such as the Mission Canyon and Three Forks. It is also imperative to state that the lower and upper members are organic-rich regions with total organic carbon that range from about 12 to 26 percent of the total weight. Both of these formations have shales that are characterized by high Type II kerogen concentration. The Middle member is known to be poor in organic content with the total organic carbon ranging from about 0.1 to 0.3 percent of the weight. Despite this being the case, the member contains different substances and rocks like sandstone, dolostone, and shale that are critical to the production processes.

In 2015, 4.9 million barrels were produced in the U.S per day from unconventional reservoirs alone (Mansour et al., 2017). However, the OOIP of Bakken is estimated to be from 100 to 900 billion barrel (Sorensen et al., 2015) with a low recovery factor ranging from 3% to 7% (Sorensen et al.,2014; Mansour et al.,2017; Sorensen et al., 2015). Therefore, an increase of 1% of the recovery factor could lead to 1.6-9 billion barrels of additional oil (Yu et al., 2015). The reservoir has been used to produce millions of barrels every year in an attempt to meet the demands of the country and its citizens.

Most of the production target zone is in the non-shale Middle Bakken and the Three Forks zone (Jin et al., 2017). The Upper and Lower Bakken have shown from good logs to content an important oil content as they are the hydrocarbon source rocks with a Total Organic Carbon averaging 26.5% (Tran et al., 2011), but the transport phenomenon has yet to be well understood (Jin et al.,2017). On the other hand, the Middle Bakken is poorly organic with a TOC averaging 0.2wt% (Price,1999) which rock characteristics vary widely from classics (shale, silt, and sandstone) to carbonates (primarily dolomite) with five different lithofacies distinguished in North Dakota (Mansour et al.,2017).

The Bakken is overpressured with a pressure gradient that goes up to 0.73psi/ft (Meissner, 1978) with a matrix in shale made up of a combination of macropore bigger than 50 nm in diameter, mesopores varying from 2 to 50 nm in diameter and micropores with a diameter smaller than 2nm (Kuila et al.,2011). And such small pore sizes lead to high capillary pressure in the matrix and make the fluid flow harder to impossible (Jin et al.,2017). The average porosity of the middle Bakken is around 6% while its permeability ranges from 0.001

to 0.01 mD (Pu et al.,2015) with a water saturation which varies from 25 to 50% (Cherian et al.,2012). The Average gravity is around 42°API (Yu et al., 2014), gas/oil ratio varying from 507 to 1712 SCF/bbl. and the bubble point pressure ranges from 1617 to 3403 psi (Nojabaei et al.2013). With such complex properties, where the oil-wet kerogen surface increases the difficulty of EOR agent in sweeping oil molecules from it (Jin et al.,2017).

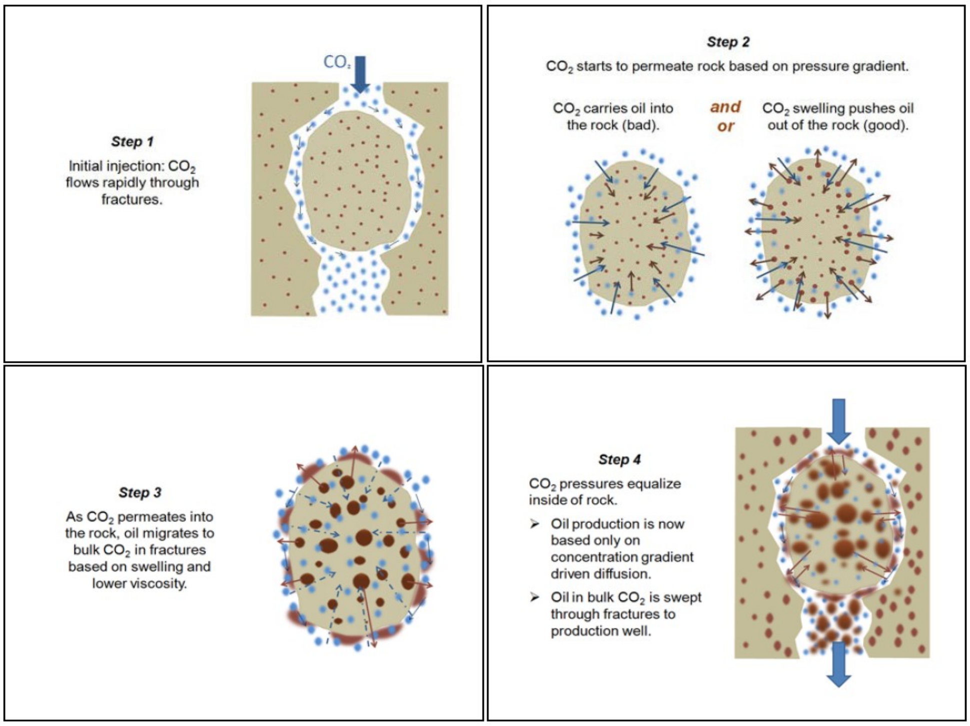


Figure 9.Conceptual steps for gas EOR in fracture networks (Hawthorn et al.,2013)

CHAPTER 3

DIGITAL ROCK ANALYSIS WITH PORE SPACE STUDY ON BEREA SANDSTONE

Introduction

Over the years, digital rock analysis (DRA) has evolved into a critical and powerful tool that can assist in the modeling of rock samples. DRA is applied to stone formations that are scanned using a wide range of methods that include X-ray computed tomography (see figure 8) and three-dimensional imaging approaches. It is also imperative to state that the digital rock analysis method allows for the characterization of simple and complex stone structures. The process entails looking at various properties such as the relative permeability, absolute permeability, pore network, porosity, and texture. Researchers and experts used DRA to save time and resources that could have otherwise been spent on other methods such as laboratory core tests. The digital rock technology method has been applied to simple rocks to predict and determine porosity, permeability, pore distribution, and conductivity. In other cases, advances in the imaging and computing approaches have allowed for the use of the technology to study the elastic properties and relative permeability of various types of rocks such as sandstone, shales, and carbonates. In these regards, DRA is a valuable tool that complements laboratory tests and assists in the understanding and visualization of rocks. In this work, we have run a throughout digital rock analysis using a Berea sandstone.

Even though digital rock technology is regarded as a promising tool, the application is still linked with specific challenges especially when it comes to the study of rock properties. The main limitation lies in the high cost of creating and modeling the high-resolution rock structures with high accuracy. Results from different types of models show that high-resolution images can capture detail rock structures. It is for this reason that experts and researchers always focus on creating and obtaining high-resolution images (see figure 12). There is a wide range of imaging techniques that are capable of scanning resolutions that range from hinders of micrometres to the desired nanometres. However, the costs of creating such images remain a challenge and a concern to experts and researchers. Although different imaging techniques have been developed and advanced over the years, it is only a few experts and researchers who can afford to buy and use the high-resolution imaging tools when conducting the digital rock analysis. In other instances, it takes a lot of time to prepare the samples (see figure 11) and scan the detailed structure of the sample with high resolution. Considering the small size of the sample, it would require running analysis on many samples to have a realist properties map of the region of interest. These challenges can complicate the process of conducting an accurate analysis. It is also imperative to state that even when high-resolution images have been developed, the simulations and analysis of large datasets can be challenging.

Figure 10. Micro-CT scan (Courtesy of NDSU)

Figure 11. Core sample prepared for CT scan

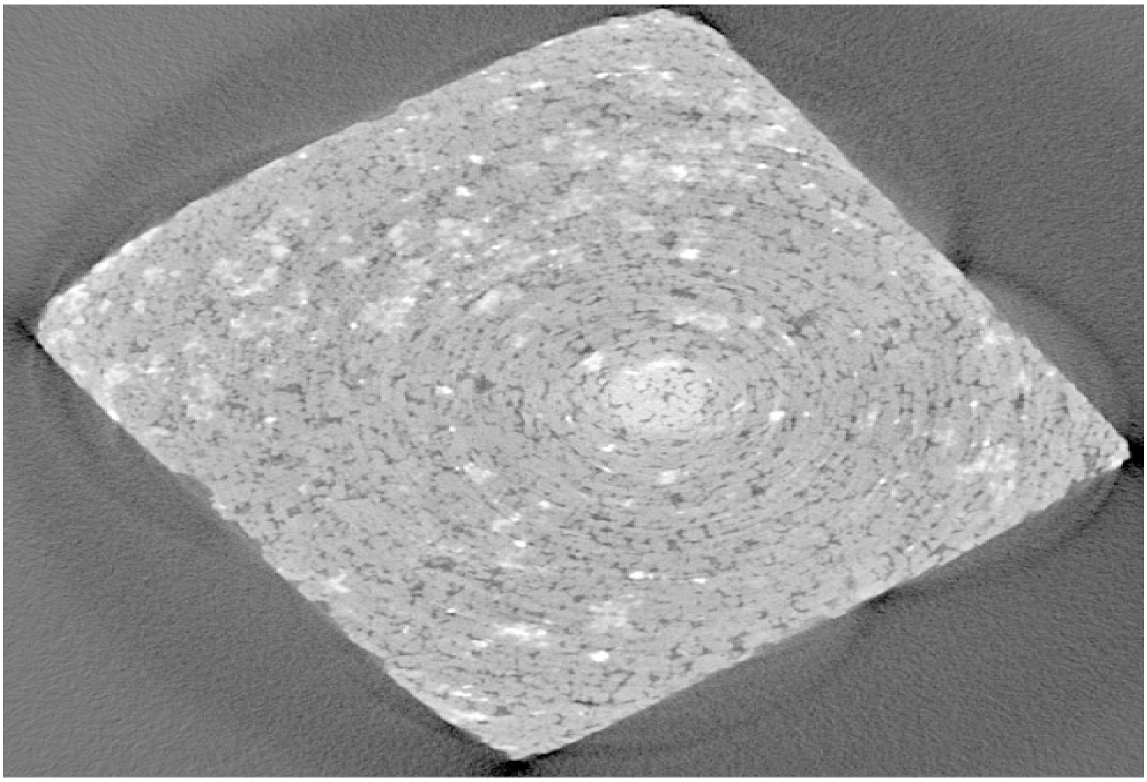


Figure 12. High-resolution image sample

In such instances, high central processing unit capacity and processing power are needed. These challenges notwithstanding, digital rock analysis remains a valuable and suitable tool for examining rock properties. Besides, it enables us to use high-resolution images to get an accurate picture of the nature of the rock samples and analyse its features. It is essential to make excellent decisions regarding both the sample size and the resolution to achieve accurate and acceptable analysis result within affordable costs. Previous tests and research have examined the manner in which resolution and sample size affected the outcomes of the analysis and revealed that they are critical to the process of digital rock modeling (see figure 12).

It is based on the investigations that suggestions have been made regarding the ideal representative element volume (REV) (Harris et al, 2015). It refers to the smallest sample volume over which the measurements give a representation of the macroscopic properties of the rock. The selection of the right REV coupled with the use of the appropriate degree of resolution will affect the outcomes of the analysis. Furthermore, the two variables affect the ability to examine a wide range of rock properties such as the voxel size and permeability. In addition, it helps in analysing how these features vary from one source to another.

The modeling was done in this thesis (see figure 13) showed that rock property analysis is a valuable method for understanding different characteristics. The tool helps in the determination of porosity, Pore Size Distribution, Mercury Injection Capillary Pressure, and permeability.

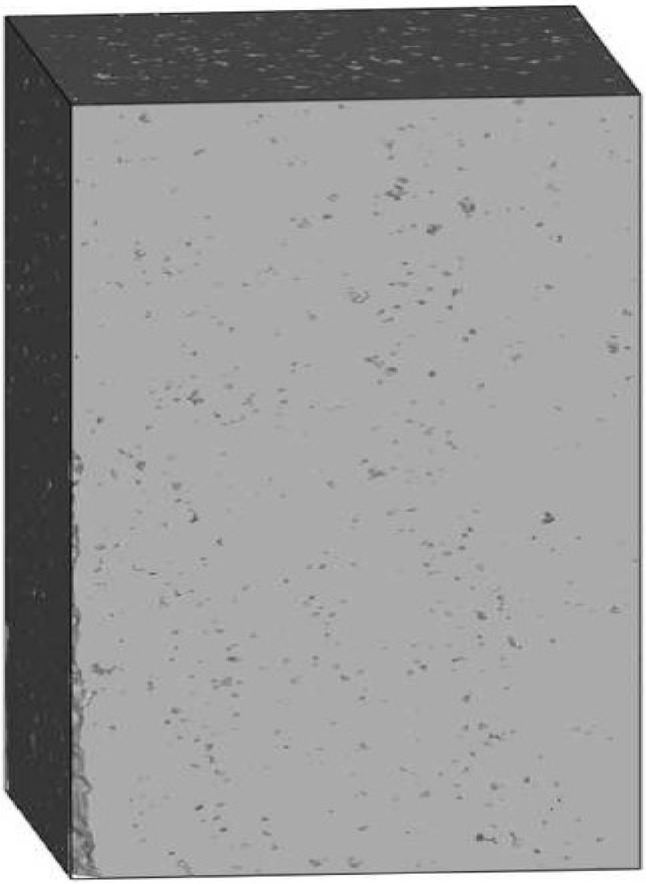


Figure 13. Visualization of digital rock

There are instances where these features are calculated through the conventional or laboratory methods. In some circumstances, it is done through indirect techniques such as the inversion of the seismic waves. In some instances, such as the current study, digital simulation and calculations are used to predict and determine the value of the rock properties. The digital images help in highlighting the desired rock properties at a microscale. Besides, it gives an avenue through which we can visualize the shape of the pores in the selected sample.

Results and discussions

Pore space analysis

One of the important parts of the digital rock analysis is that it helps us visualize the pore and grain space (see figure 14, 15). After acquiring CT-Scans images (see figure 12) and building a digital rock (see figure 13) with those images we have run some pore space analysis.

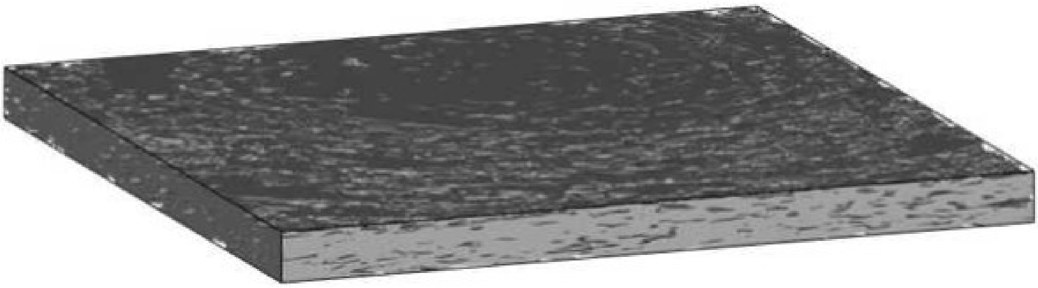


Figure 14. Visualization of grain space

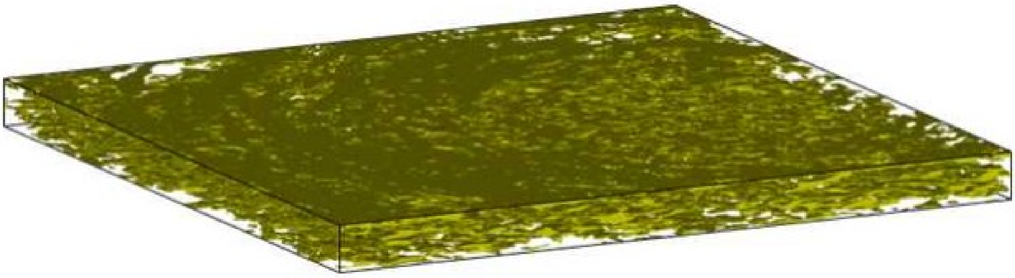


Figure 15. Visualization of the pore space

The pore space analysis is an area in which the digital rock technology has been employed to determine the pore spaces properties. In this case, a rigorous numerical analysis was done to measure and determine the critical throat radius, the total resolved porosity as well as the connected resolved porosity in the x, y and z direction. (See table 1). The approach complements the lab measurements and can be used to improve the capability of the geoscientists and petroleum engineer to characterize the pores and rocks under investigation. The trend is attributed to the fact that digital experiments can be done in real time and on small rock fragments like the drill cuttings which is not the case if we were to use a coreflood apparatus.

Table 1. Pore Space Properties

Total Resolved Porosity [%]	Connected Resolved Porosity [%]			Critical Throat Radius			
	X	Y	Z		X	Y	Z
19.3	18.6	18.6	18.6	[µm]	6.0	10.0	6.0
				[Voxel]	3.0	5.0	3.0

In the modern world, permeability and porosity are critical petrophysical features that help experts to carry out their work within the petroleum sector. At the moment, it is not easy to conduct and determine permeability distributions in-situ. Besides, various laboratory data analysis that has been done over the years have not yielded robust and universal details and standards related to features such as rock porosity and texture as petroleum reservoir specially shale's have a very high level of heterogeneity. The trend is linked to the significant variability in the pore space topology in many rocks and materials. Two primary factors cause the differences. The first variable is the deviations and variations in a deposition. The second case is the variations in the diagenesis. Therefore, the most reliable method of determining permeability and pore space is digital rock analysis. The modeling process involves using numerical and virtual experimental data to represent the pore spaces. Using this methodology allowed us to find the pore size distribution of the sample (see figures 16, 17).

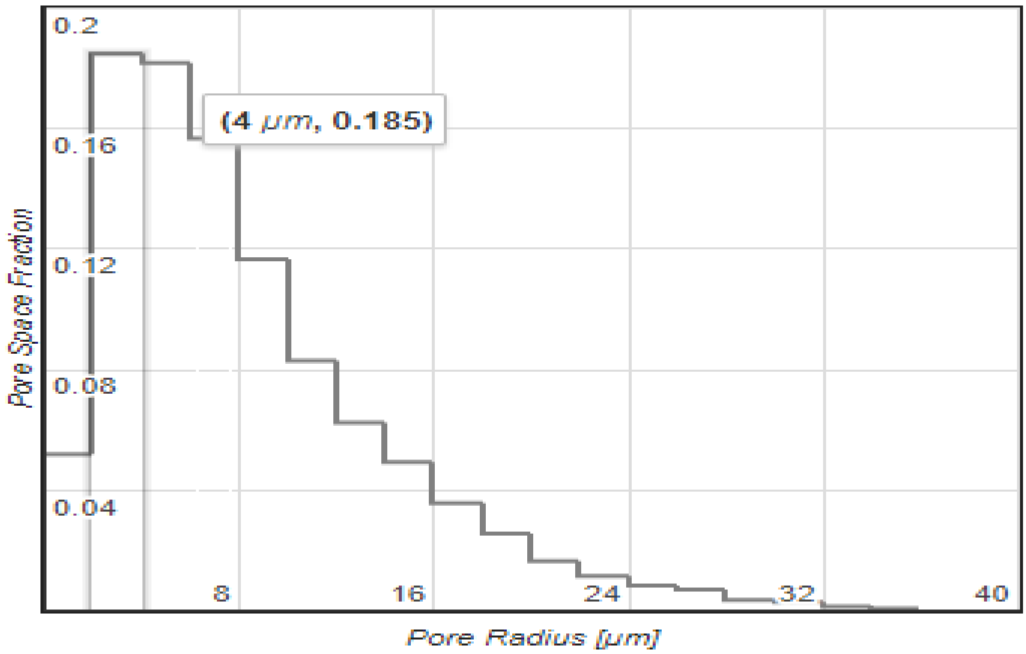


Figure 16.Pore Size Distribution in μm

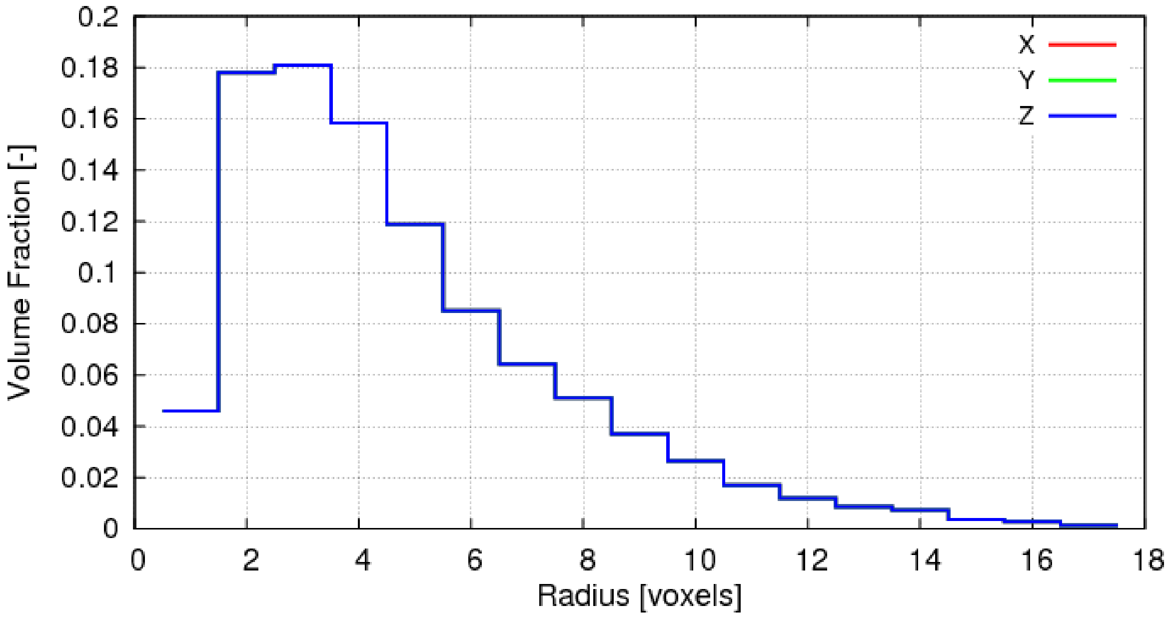


Figure 17. Pore size distribution in voxels

There are several advantages of using the digital rock analysis method to characterize the pore spaces. First, it is a non-destructive approach for conducting a physical examination on the rocks. In this case, the focus is on creating a three-dimensional representation of the samples and using them as the basis of understanding the features of the foundation under consideration. Second, the three-dimensional spaces can be reconstructed and analyses from the sidewall plug can be done which may not be applicable in the case of physical permeability measurement. Moreover, the numerical representation created through the digital analysis method helps in understanding the variations in sorting and diagenesis. In this regard, DRA provides an important avenue through which we can fully characterize rock samples and determine the size and distribution of pores. Another advantage of the digital rock analysis, it is that it provides resolved porosity profile throughout the sample (see figure 18) in the x, y and z direction.

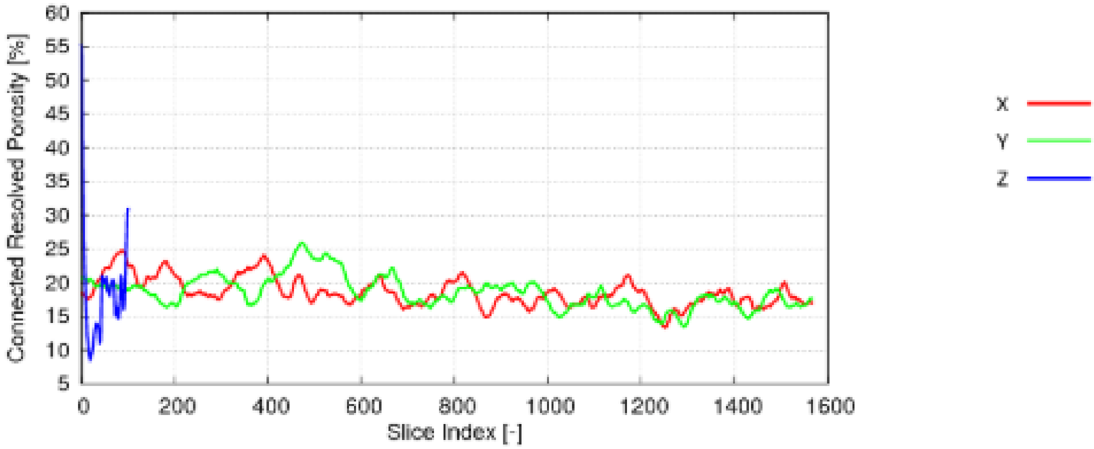


Figure 18. Resolved Porosity Profile

This type of data can be very hard to obtained using conventional physical laboratory analyses. However, this gives us a good insight into the variability of the properties throughout the rock sample. Using this tool can lead us to better understand uncertainties in shale reservoirs such as the Bakken. Furthermore, we can obtain a subdomain analysis giving us details about porosity change by size growing and space filling as seen in the figure below (see figure 19).

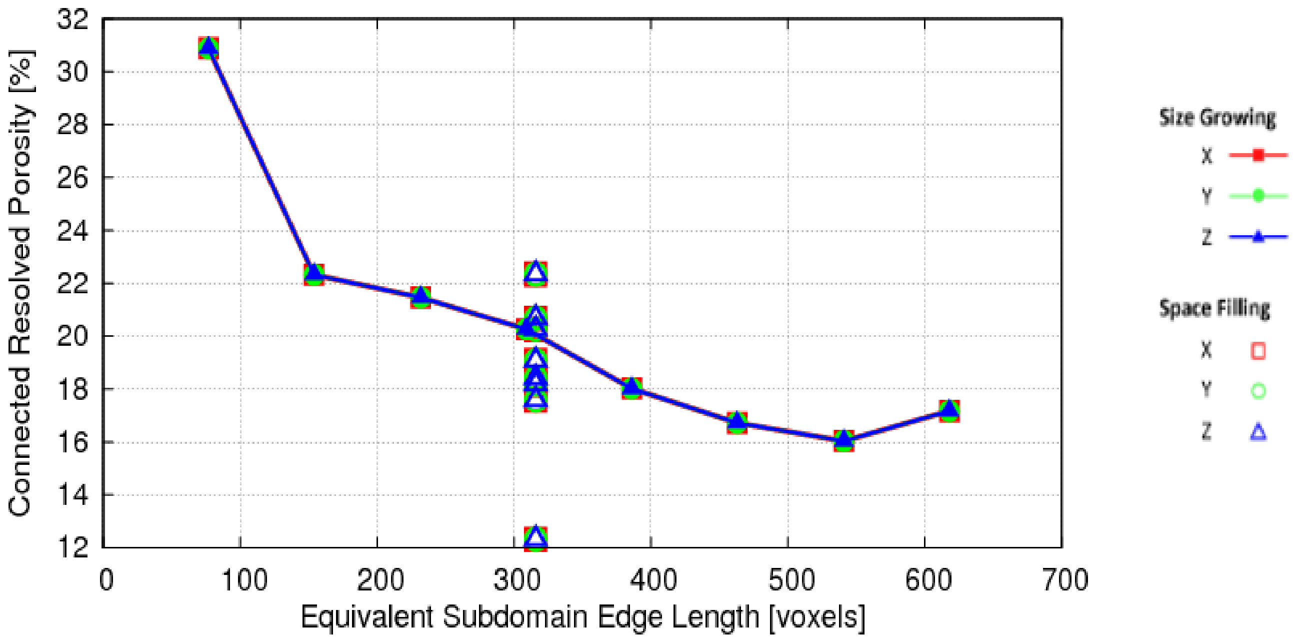


Figure 19. Subdomain analysis

To be better understand the later terms (see figure 20). The size growing and size filling in digital rock analysis means that for the size growing we analyse the digital rock sample properties from a small part of the sample, we usually start in the center of the sample and we start analysing larger samples until we have analysed the all sample (see figure 20 (a)). For the size filling, however, we divide the sample in the nth amount of part and we analyse each component separately (see figure 20 (b)). This make a huge difference especially for very heterogeneous samples, these capabilities make DRA even more valuable for reservoir such as the Bakken.

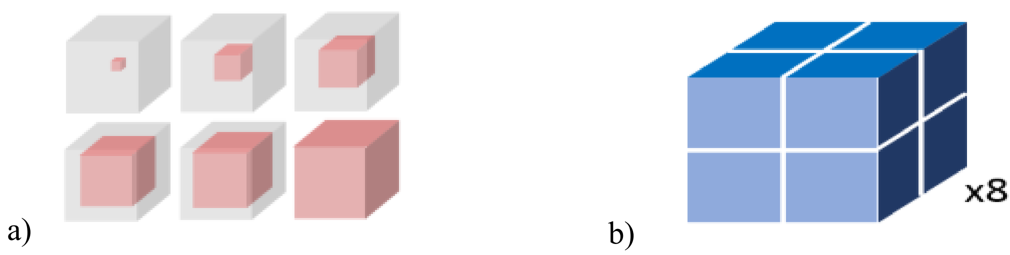


Figure 20. size growing and size filing

It is also important to mention that the hydraulic properties of rock formation are very critical when it comes to evaluating the economic viability of petroleum and gas reservoirs. The process entails examining and investigating factors such as flow mechanisms and porosity in the rocks. Digital rock analysis has proved to be an accurate and efficient method for evaluating porosity, permeability, as well as the matrix within conventional and unconventional reservoirs. We believe that it is an important and emerging technology within the oil and gas sector that can be used to solve and analyze problems that could not be tackled using traditional laboratory approaches. During our investigations, we have found that high-resolution data may be acquired from different samples such as shale, carbonates, and sandstone lithologies utilizing nano or micro computed tomography. In other cases, focused ion scanning/ beaming electron microscopes can be used as well to gather data needed to analyse the rocks. The extracted data can be analysed statistically through various tools such as digital rock workflow equipment. With this technique with have the ability to come up with a skeleton network of the pore throats, generate the distance map of the pore throat channels, and create values for the relevant pore surface areas. By comparing the statistical analysis outcomes for every lithology, significant differences may be noted and correlated to the reservoir characteristics.

Pore size analysis

Pore system analysis is critical because it generates important insights that can help in assessing flow and volume characteristics in various reservoirs. In some cases, the analysis creates lithologically distinct features that may be used in determining the representative elemental volumes. The process entails looking at the pore throat sizes both in 2D and 3D (see figures 21,22).and using curve fitting functions that are unique to the sample under consideration

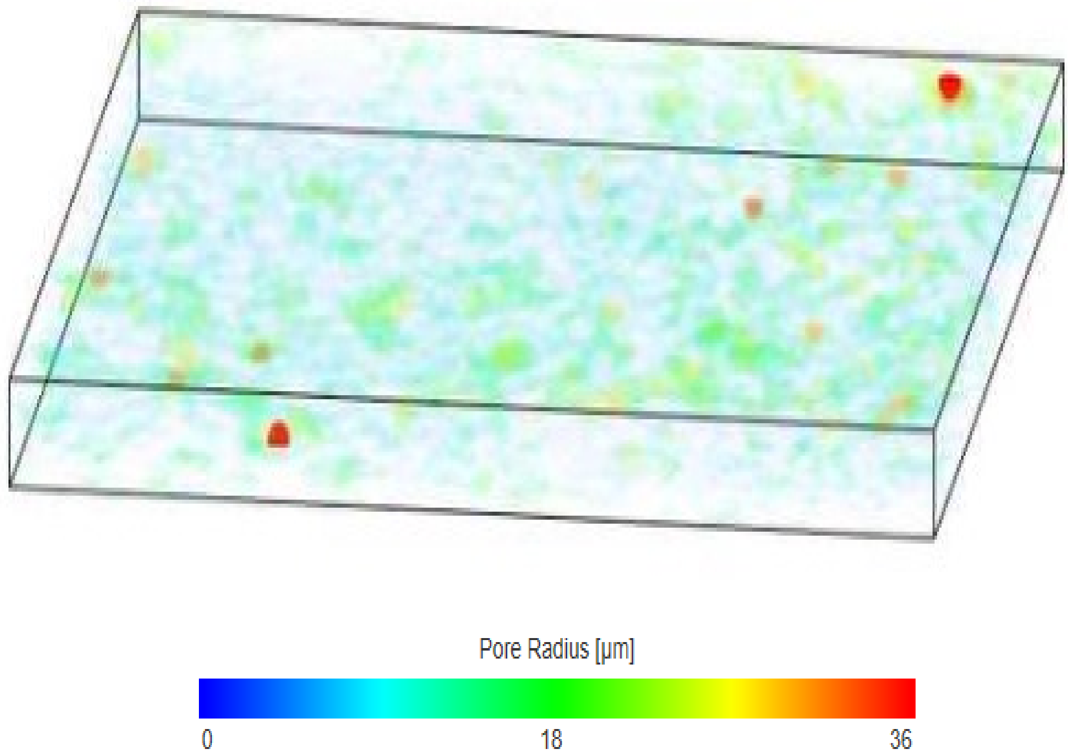


Figure 21.visualisation of the pore size

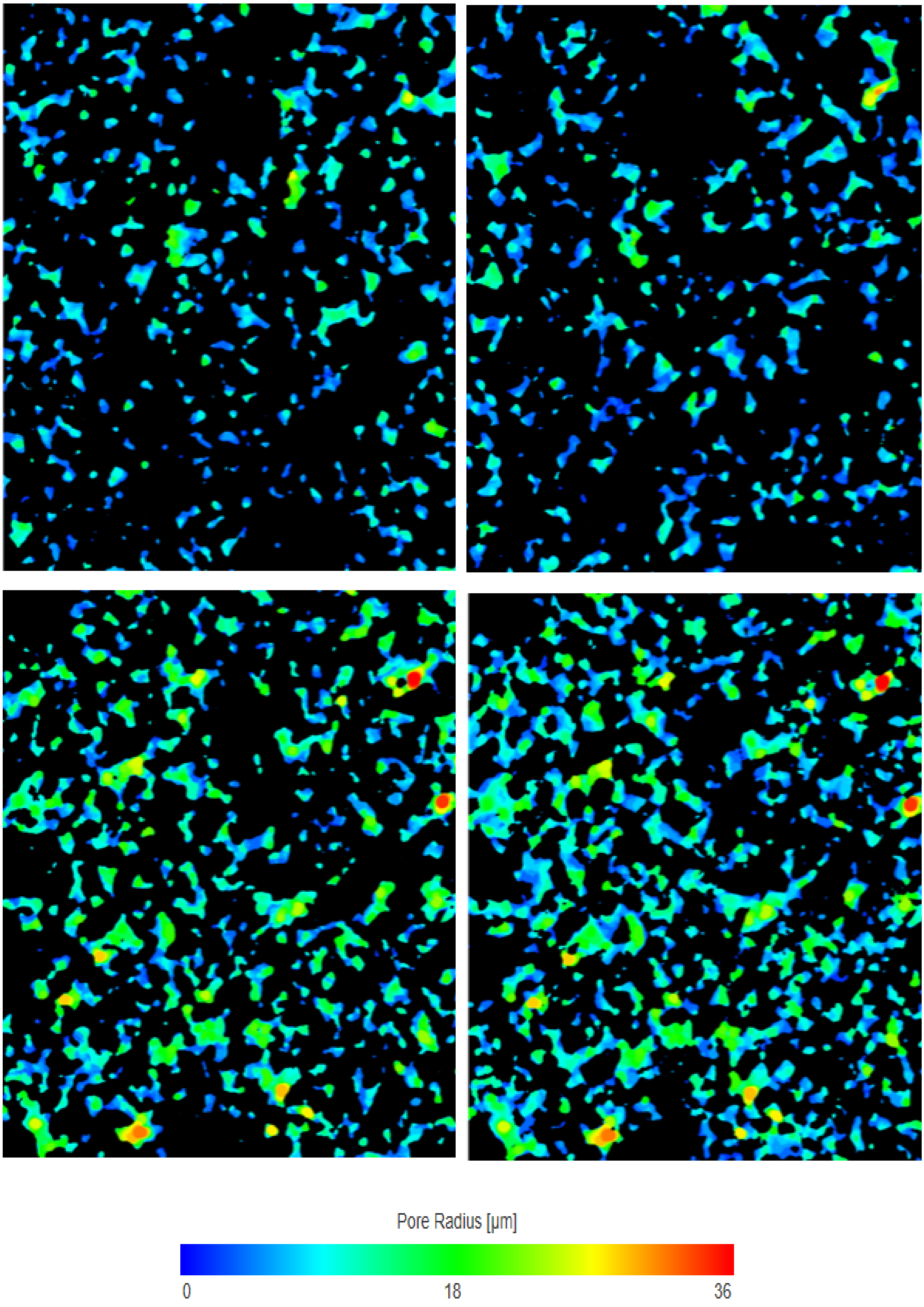


Figure 22. Pore size distribution plane view in z direction

The results are significant as they are distinct for every kind of lithology. Consequently, they can be used by explorers in determining the specific correlation between the parameter that is appropriate for every type of rock as well as the differences in the conventional and unconventional oil fields. Taking these factors into account, it is apparent that DRA is a critical technology that assists in conducting pore system analysis. Furthermore, it generates data regarding oil and gas volumes, flow capabilities as well as the reservoir formations. With such data in place, we are in a position to assess the economic viability of reservoirs formations and determine the best methods that should be used in the extraction process. Furthermore, the statistics generated from the process can be used to compare different reservoirs in a particular formation with the intention of coming up with appropriate plans for the development and extraction processes. The following subdomain profile was obtained after running a pore size analysis. (see figures 23,24).

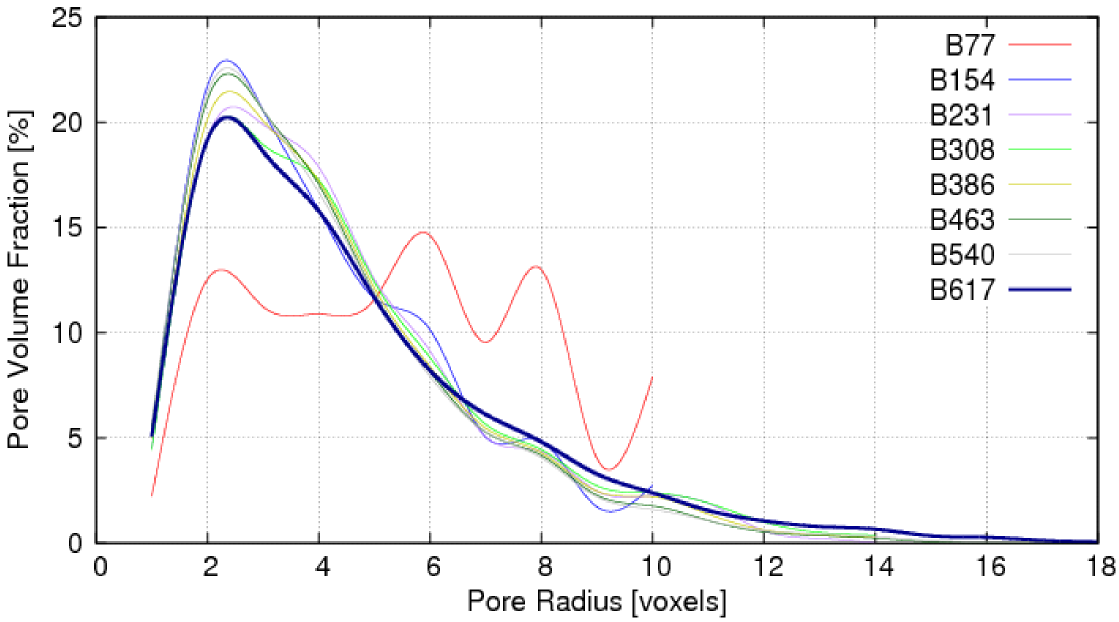


Figure 23. Subdomain analysis-size growing voxel

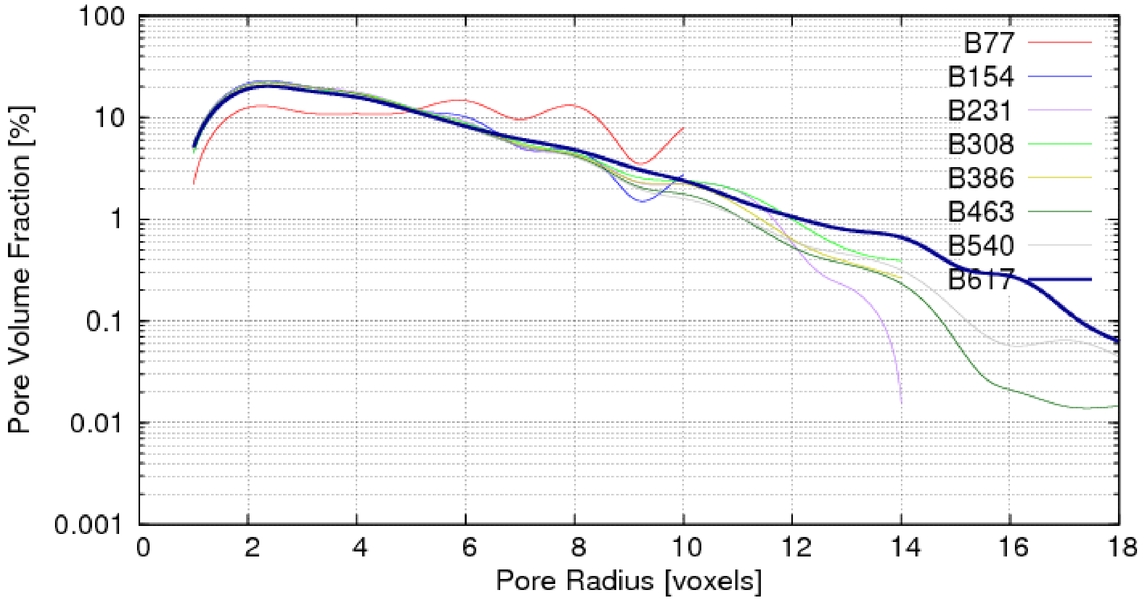


Figure 24. Subdomain analysis-size growing log

From the later analysis, we can see the variation in pore volume fraction as we analyse the different size of the same sample. We can note that the smallest sample B77 being the smallest box as we can recall previously (see figure 20) sample and B617 being the all sample. This is again another advantage of DRA which gives us a very good variation between the different effect of the size and pore volume. Running the same analysis using space filling (see figure 25) we can see another good variation and correlation of the pore volume fraction variation.

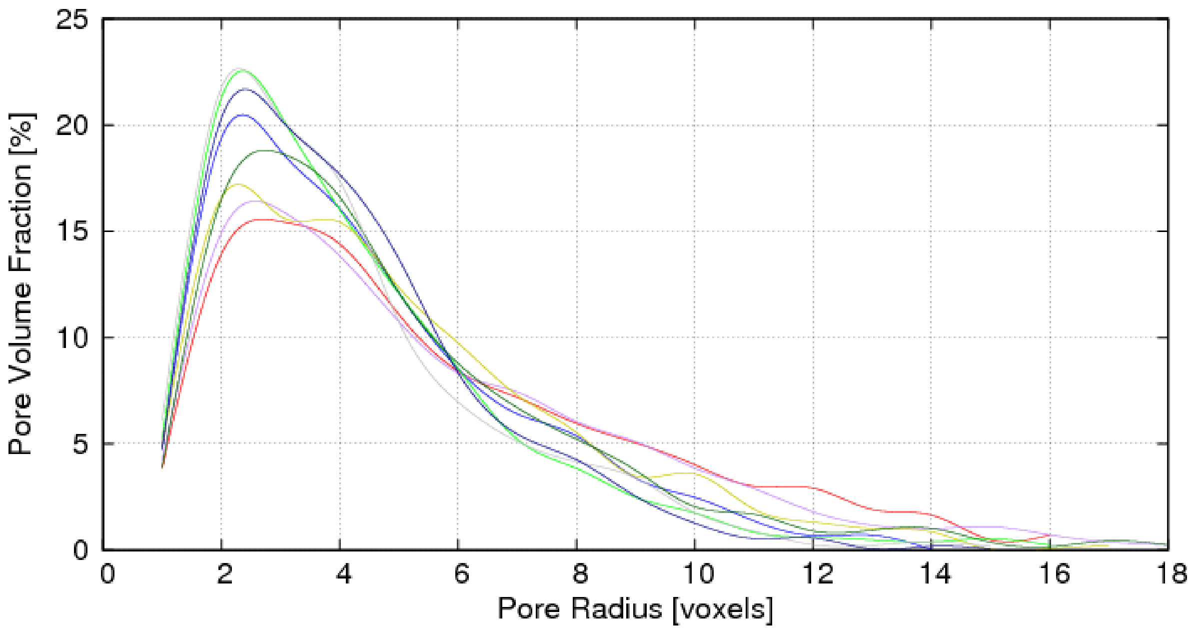


Figure 25. Subdomain analysis-space filling

Flow field

Digital rock analysis method has exhibited strong ability and potential in creating and visualizing flow fields (see figures 26,27,28) which allows us to run further analyses such as the permeability. The process entails coming up with geological microstructure images that help in understanding the transport systems and mechanisms in underground rocks, especially those obtained from unconventional resources like shale. The development of new technologies and methods that are capable of gathering high-resolution data has created new avenues for understanding flow fields and conducting DRA. While the advancements may require significant investments in equipment, they create high-quality data that are central to the oil and gas exploration processes and eventually implementing those data into a field scale model would allow us to understand and design better EOR processes. In some cases, we need to change the digital resolutions of the reconstructed digital sample and use micro-computed tomography (CT) scanned information to predict permeability and field flow for in field scale. In addition, the digital data gathered from the process helps in determining the representative element volume of the rocks, performing pore-scale modeling, and examining the critical sample sizes. These are processes that provide vital data on the field flow (see figure 26) and the features of the reservoirs.

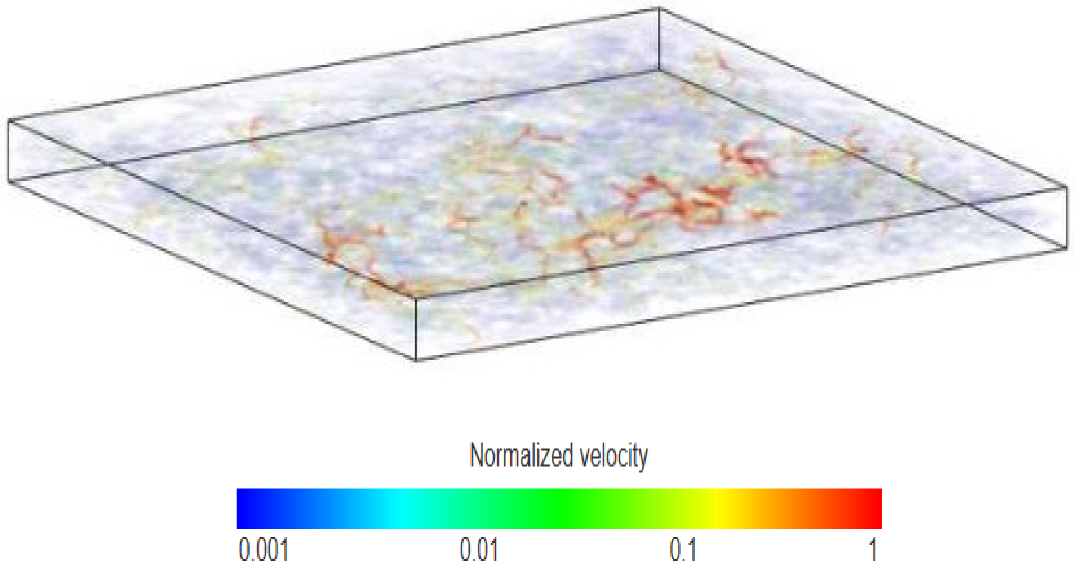


Figure 26. Velocity field visualization in z direction

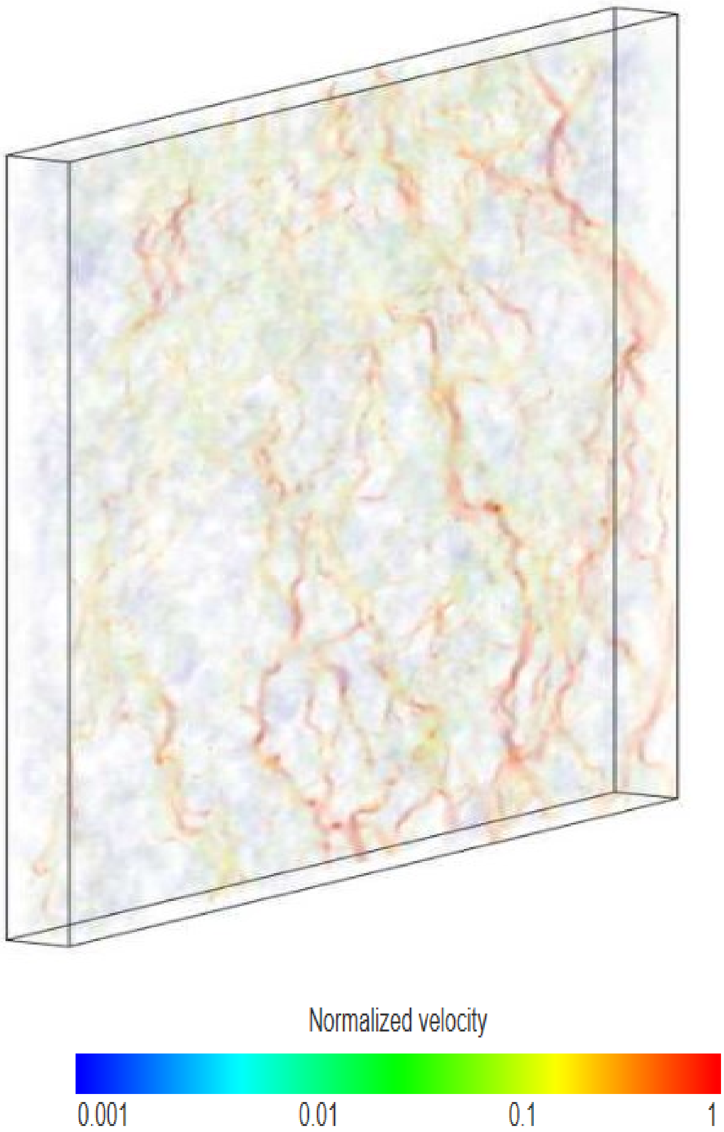


Figure 27. Velocity field visualization in x direction

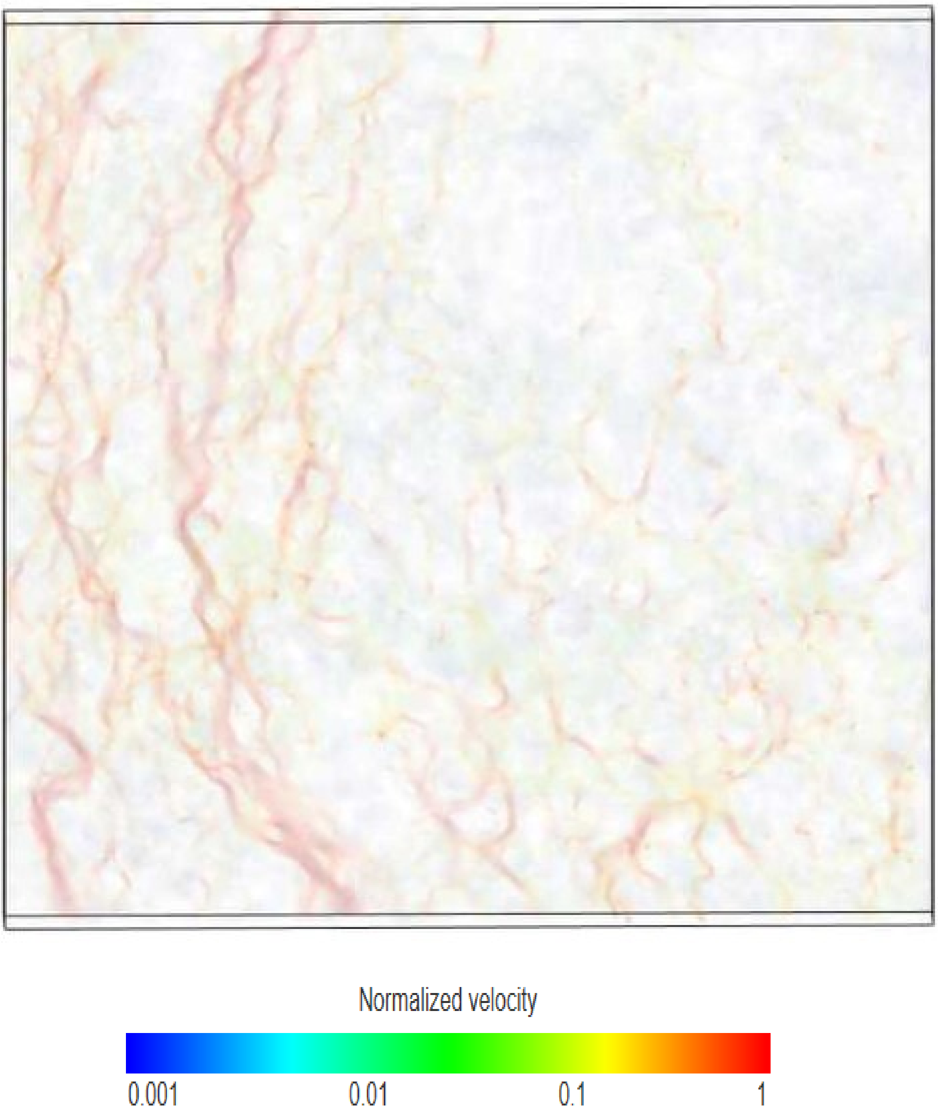


Figure 28. Velocity visualization in y direction

Space-filling analysis

DRA is a robust computation tool and method that is capable of tackling complex 3D space-filling analysis and examining velocity parameters. The operations can be done without changing the free parameter within the procedure. Using the statistical description of fluid flow phenomena. The technology creates a model of the sample in question. In our case, the analysis process shows that there is a very significant difference between the correlation of permeability and porosity in x, y, and z-direction but furthermore DRA allows us to quantify this relationship and such data would be very hard to obtained using conventional rock analysis (see figures 29,30,31).

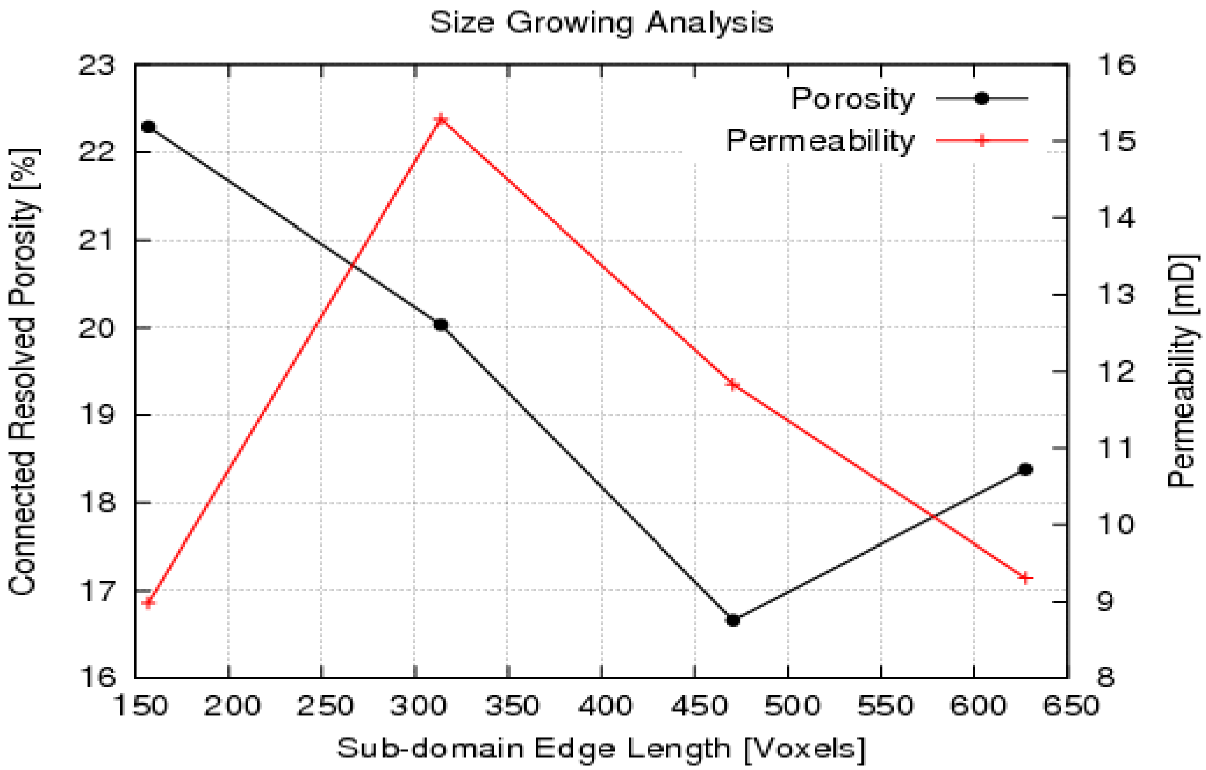


Figure 29. subdomain analysis in z-direction

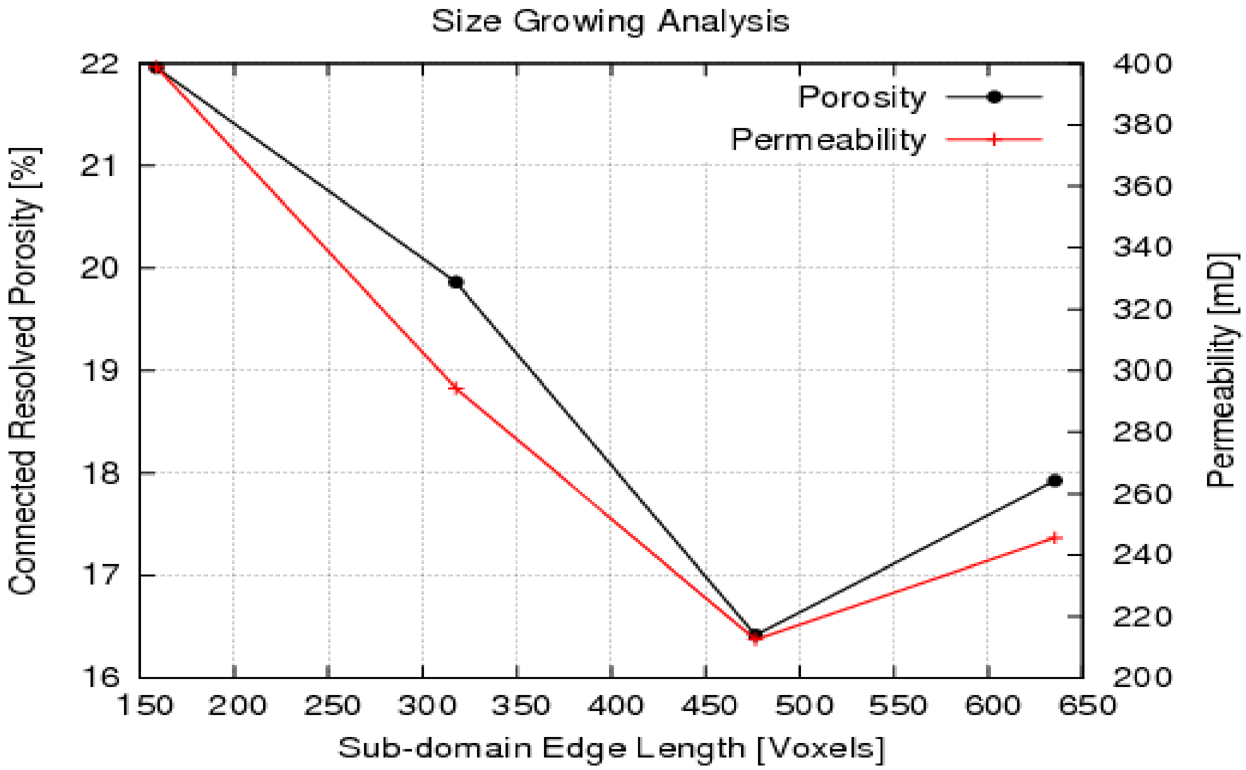


Figure 30. Subdomain analysis in x-direction

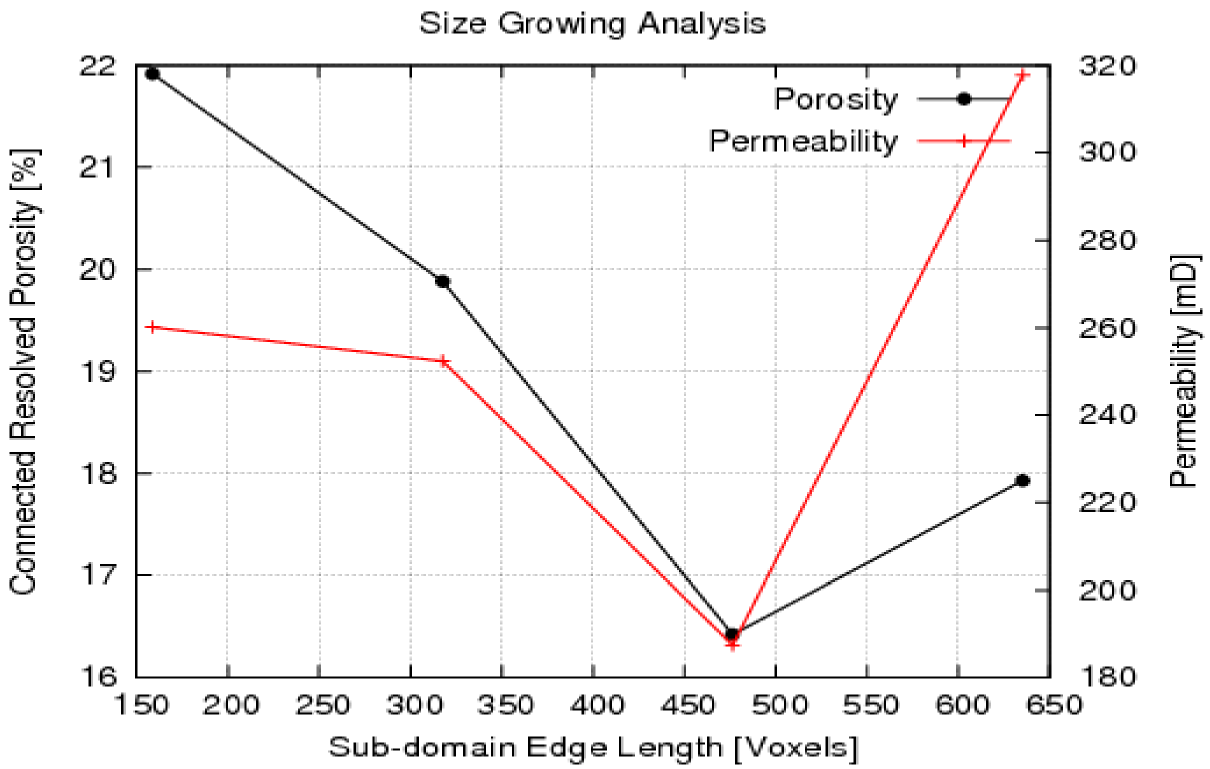


Figure 31. Subdomain analysis in y-direction

The trend is attributed to the small size of the individual particles making up the rocks as well as the large specific surface area. In addition, the pore spaces and filling capabilities of the samples contribute to the permeability. Information gathered from the analysis process also provide an avenue for performing cutting-based velocity estimations in situ. By comparing velocity data from different sources and samples, it is possible to understand the specific features of reservoirs and detect potential areas of divergence. This feature allows for the analysis and computation of permeability (see figures 32, 33, 34) in the x, y, and z-direction and to exploit the relationship between permeability and connect porosity. Eventually, DRA allows us not only to quantify the relationship between porosity and permeability but also to measure permeability and porosity in x, y and z-direction with will be time-consuming to obtained using conventional laboratory experiments. In our case, the permeability found in z-direction was 8.49 mD with a porosity of 18.26%, in y-direction was 302 mD with a porosity of 17.93% and in the x-direction was 242 mD with the same porosity of 17.93 percent.

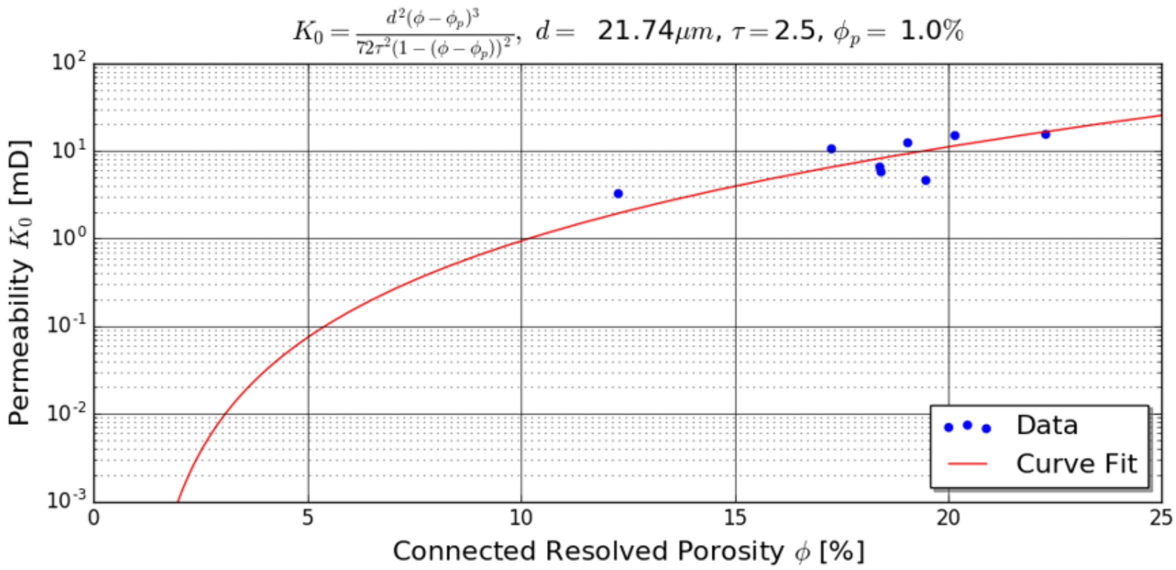


Figure 32. Subdomain analysis: space filling in z-direction

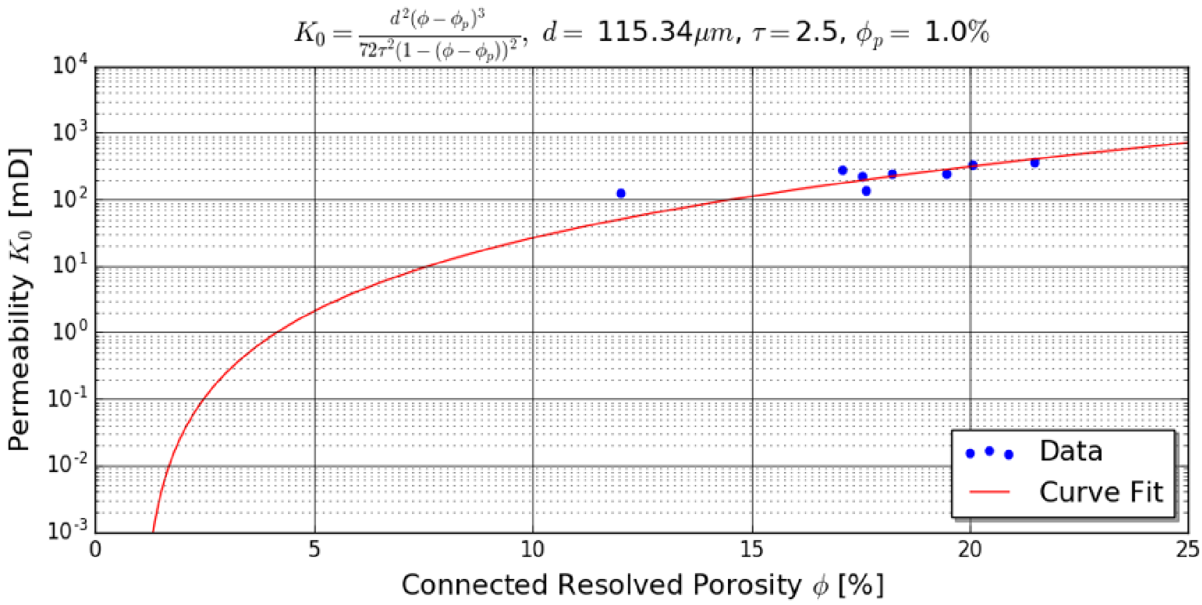


Figure 33. Subdomain analysis: space filling in x-direction

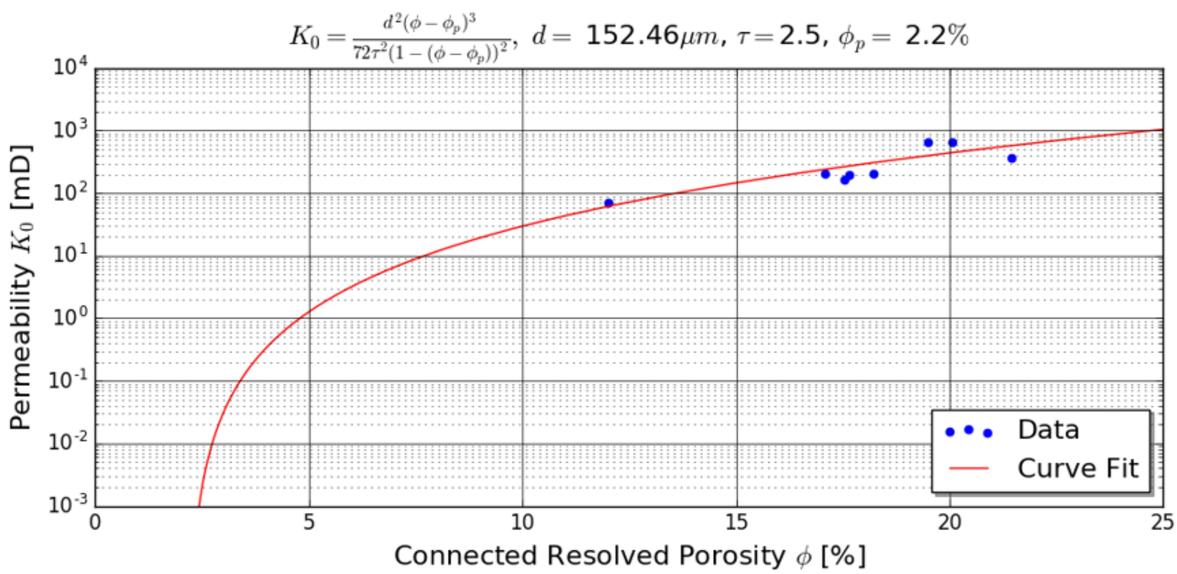


Figure 34. subdomain analysis: space filling in the y direction

There are other instances where the DRA technology has been combined with other high quality and powerful microscopy tools such as SEM to create avenues for analysing complex rock properties like porosity and velocity. The analysis is usually done from rock fragments, drill cuttings as well as the sidewall plugs. In addition, the methods can be utilized to create accurate images of the samples at the site and compared the relevant petrophysical measurements that are key to the exploration and reservoir development process.

The other method that has been used in analysing the digital features of rock samples is the mercury injection capillary pressure (MICP) tests (see figure 35). This approach has been used in conducting accurate investigations into the porosity, pore throat sizes, pore distribution, and the injection pressure of the samples. In addition, the tool assists in comparing the mercury saturation of different types of rocks in a reservoir setting.

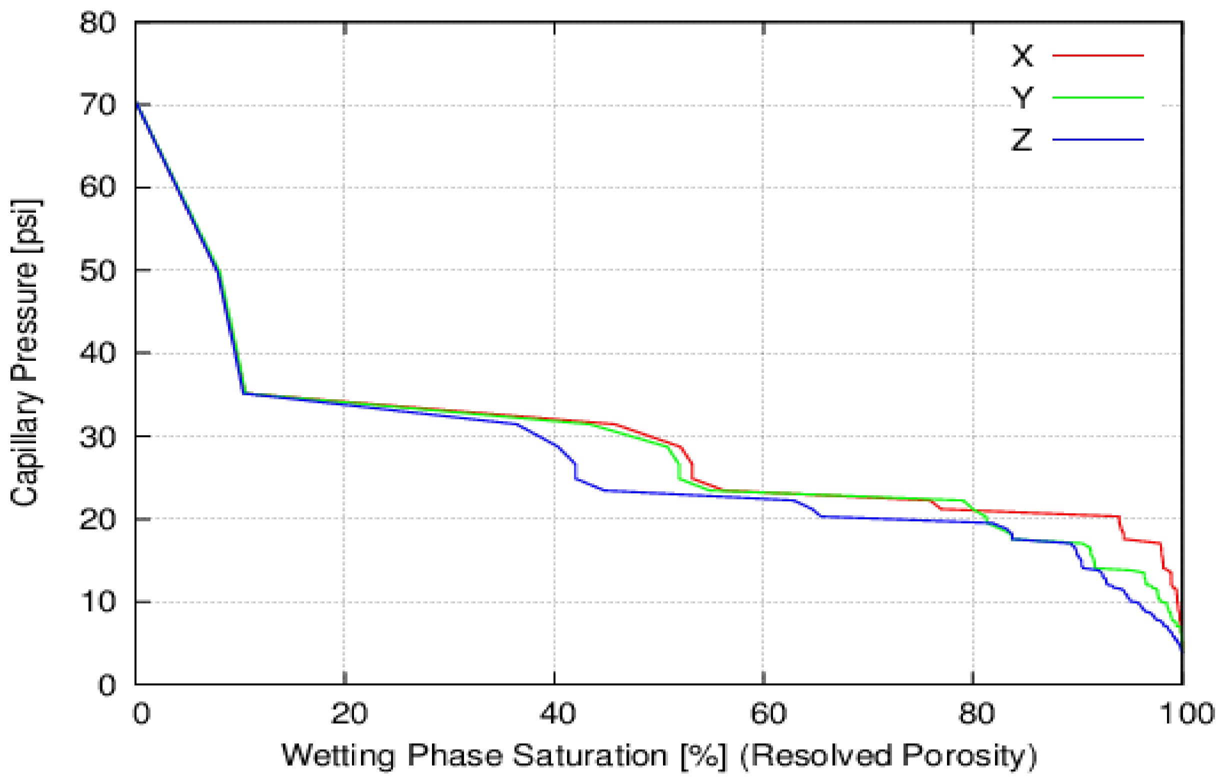


Figure 35. Mercury Injection Capillary Pressure (MICP)

Analysts and experts contend that the mercury capillary pressure tool was created to assist in determining the relationship between the saturation and capillary pressure in rock samples. The tests can only be done on samples that have been cleaned and dried. The core samples are often placed into an evacuated core chamber to allow for the measuring of differential pressure across the sides. The process continues until the injection pressure gets to the desired value. Based on the data collected, we were able to develop drainage curves and analyse the critical features of the rock sample (see figure 35). The primary advantage of the method is that it reduces the time spent determining the properties of the sample. Despite this being the case, the data obtained from the fully-wet and fully-non-wet phases may differ for the rock samples. Moreover, the permanent loss of the pore samples is a concern when using conventional laboratory analysis.

We can conclude by saying that digital analysis is a pioneer approached in characterizing rock properties. DRA if meshed and upscale accurately can be used to create more accurate geological model on a field scale and develop more efficient EOR method.

CHAPTER 4

ETHANE INJECTION AS AN ALTERNATIVE OF CO_2 INJECTION IN THE BAKKEN

Over the last few years, many studies have shown promising results from CO_2 injection in tight formations which may lead to a significant increase in the recovery factor. However, the disadvantages of CO_2 injection include equipment corrosion, reaction with formation of minerals, limited gas sources, and high costs. Ethane production in Bakken has drastically increased together with the massive oil production. It may become a viable enhanced oil recovery (EOR) solvent due to its advantage in miscibility, solubility, operation, and local supplies from the development of Bakken and other unconventional formations. Therefore, it is essential to study the feasibility of this cost-effective alternative EOR agent in the Bakken formation.

In this this thesis, we conducted core flooding experiments on a Middle Bakken and sandstone core samples, we injected the samples with both CO_2 and ethane separately. Oil recovery factors are recorded for each displacement experiment. A core scale simulation model was built up to mimic the injection process of the experiment. After that, we used the core properties to calibrate our simulation models to further evaluate the efficiency and behaviour of ethane versus CO_2 as EOR agents in the Bakken. Finally, we provide a brief economic evaluation of using both gases as injectants in the Bakken reservoir.

The results of our study show that ethane is a better choice than CO_2 as an EOR agent. Ethane injection achieved a higher recovery factor than CO_2 injection. Ethane minimum miscible pressure was lower than CO_2 with the Bakken in-situ oil. Ethane is more available in the Bakken than CO_2. The use of locally produced ethane is safer than CO_2 in terms of corrosion and management but will also help to reduce global warming caused by flaring.

This combined work of both experimentation and simulation provides a pioneer study in evaluating the performance of ethane injection in Bakken formation. The experiments give clear insight into the differences in recovery factors and recovery efficiency that we can expect from injecting CO_2 and ethane into the Bakken formation. Our experimental study provides details of oil composition change when injecting each gas. By laying the theoretical ground for ethane injection, this work offers data and proof for engineers and researchers to design more economically profitable EOR strategies.

Introduction

Since the 2000s, unconventional petroleum resources have seen a drastic growth in production with the emergence of multistage hydraulic fracturing and horizontal drilling (Zhang, 2016; Ostadhassan et al., 2018; Khatibi et al., 2018a, b). This breakthrough led the Bakken Formation in North Dakota (see figure 36) to become one of the major oil-producing plays in the US with average daily production growth from 175 bbl. of oil in December 1953 to 1,106,836 bbl. in March 2018 (DMR,2018). While the Oil Initially in Place (OIIP) for the Bakken is estimated to be around 900 billion barrels (Sorensen et al., 2015), the ultimate recovery factor is still approximately 7 percent (Mansour et al., 2017; Sorensen et al., 2014). It has been observed that many wells experience a 70 percent production decline within the first year and 50 percent more within the next two years before stabilizing (Jin et al., 2017) (see figure 37). This is due to the complexity of the Bakken Petroleum System (BPS) (Ding et al., 2014; Yolo et al., 2018).

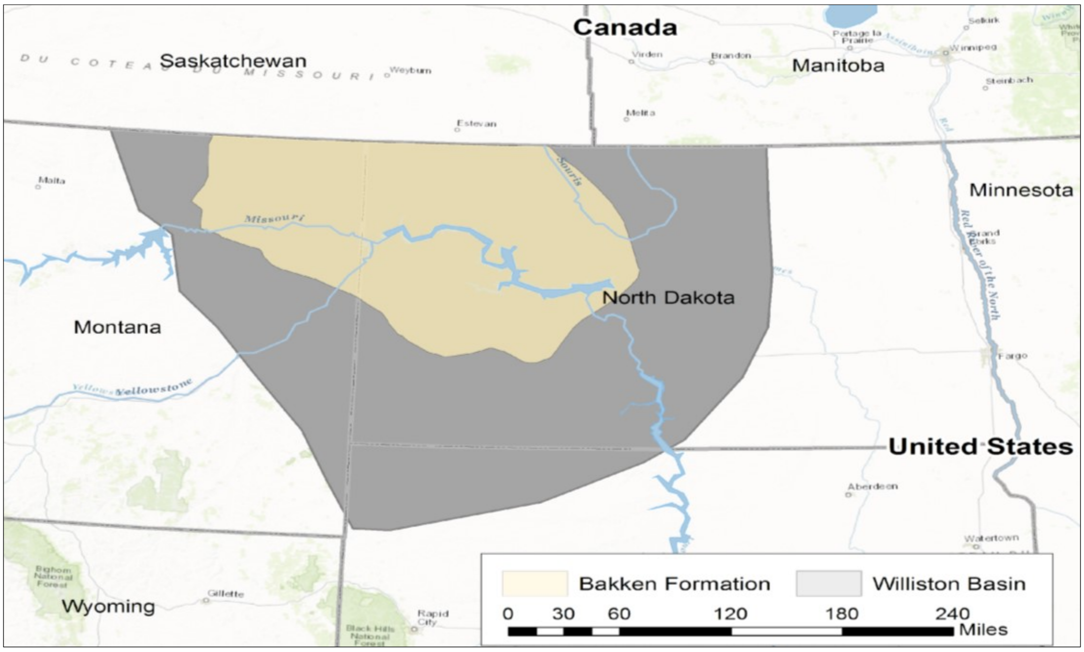


Figure 36. Bakken map (Khatibi et al., 2018c)

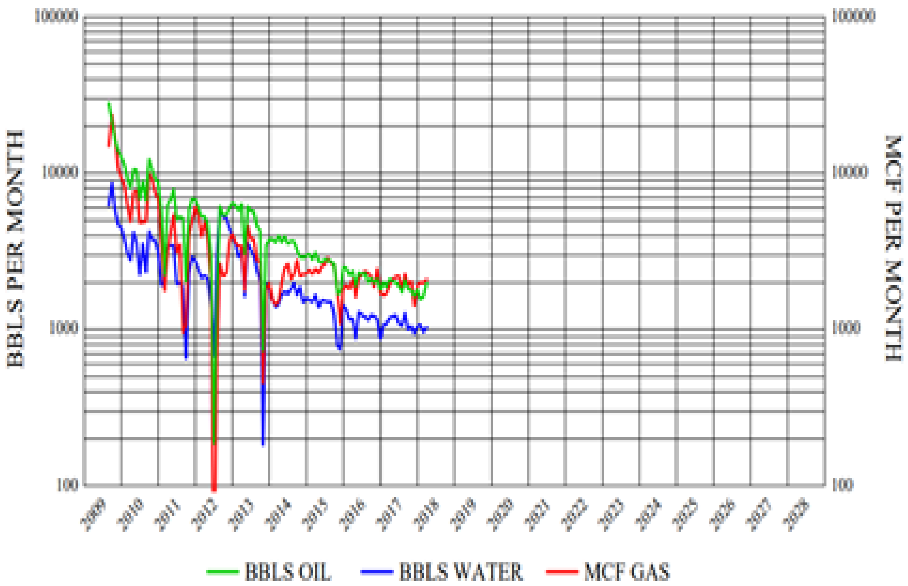


Figure 37. Typical Bakken well production

There are two known flow regimes in the Bakken petroleum system. In fracture networks with high permeability, the variation of velocity within the fluid called the viscous flow is the primary mechanism while diffusion dominates the flow in the low permeability matrix with permeability ranging from 0.0005 to 0.2md (Jin et al., 2017). Improving the recovery by even 1 percent could lead up to 9 billion barrels more (Yu et al., 2015). To enhance the recovery from unconventional plays, EOR methods can be employed. The ultra-low permeability of the Bakken is inadequate for waterflooding which requires a minimum of 1md threshold (Joslin et al., 2017; Jin et al., 2017). Studies have shown the efficiency of CO_2-EOR in unconventional reservoirs (Ding et al., 2014; Jin et al., 2017; Meyer, 2012). However, affordable CO_2 for EOR is not always available. Therefore, it becomes a challenge to use it on a field scale (McGuire et al., 2016). Increased production from unconventional reservoirs such as the Bakken has resulted in higher volumes of associated natural gas production, with ethane being the second most abundant component (Table 3). This, in turn, has led in more flaring at production sites in the Bakken where 300 million cubic feet of gas were flared in 2014 (EERC, 2015).

Table 3-Typical Bakken gas composition

COMPONENT	MOL %
H_2O (water)	0.02
N_2 (nitrogen)	5.21
CO_2 (carbon dioxide)	0.57
H_2S (hydrogen sulphide)	0.01
C_1 (methane)	57.67
C_2 (ethane)	19.94
C_3 (propane)	11.33
i-C_4 (isobutane)	0.97

n-C_4 (n-butane)	2.83
i-C_5 (n-pentane)	0.38
n-C_5 (n-pentane)	0.55
C_6 (hexane)	0.22
C_7	0.09
C_8	0.04
C_9	0.01
C_{10}^+	0.00

From a pricing point of view, the increase in gas production from unconventional reservoirs caused a drastic drop in the US ethane commodity price (see figure 38) and to be listed as fuel instead of petrochemical feedstock. (McGuire et al., 2016). The low cost and availability of ethane make it a good candidate as an EOR solvent. However, with a commodity price of 25c/gal, an MT of ethane is about $190 while pipelined CO_2 is reported to be in the $9-26/MT region. Even though low ethane price will still make it a viable EOR solvent, from a commodity price perspective ethane is several times more expensive than CO_2. Nevertheless, the oversupply of the local ethane production and the lack of infrastructures which makes it difficult for the locally produced ethane to reach the market led the amount of natural gas being flared in the Bakken shale to reached 222 million of cubic feet per day in June 2017(see figure 39) which is more than a billion dollars in loss of this valuable gas per year, and with the current near oil production record this number is expected to go much higher. Investing in local small-scale ethane processing plants with the capacity of turning the unwanted gas to liquid valuable end product will help monetize the flared gas while enhancing oil production. From an environmental standpoint flaring more than 222 million of cubic feet of gas with 57 percent of methane and 19 percent of ethane per day drastically contributes to the global warming, therefore, this shows the urge of using the Bakken produced gas as instead of flaring it.

The mechanisms of oil displacement using ethane include viscosity and interfacial tension reduction as well as oil swelling just as with CO_2 but also ethane solubility in water is poor compared to CO_2 since ethane doesn't exhibit significant polarity, whereas CO_2 does. Injectivity of ethane into the water-bearing area would be expected lower than CO_2, therefore the ethane's low solubility in water will lead it to be more available to oil than CO_2 as a considerable amount of CO_2 would dissolve into the water-bearing areas instead of the oil zones (Hamouda and Tabrizy, 2013).

Figure 38. Historical ethane price (King., 2015)

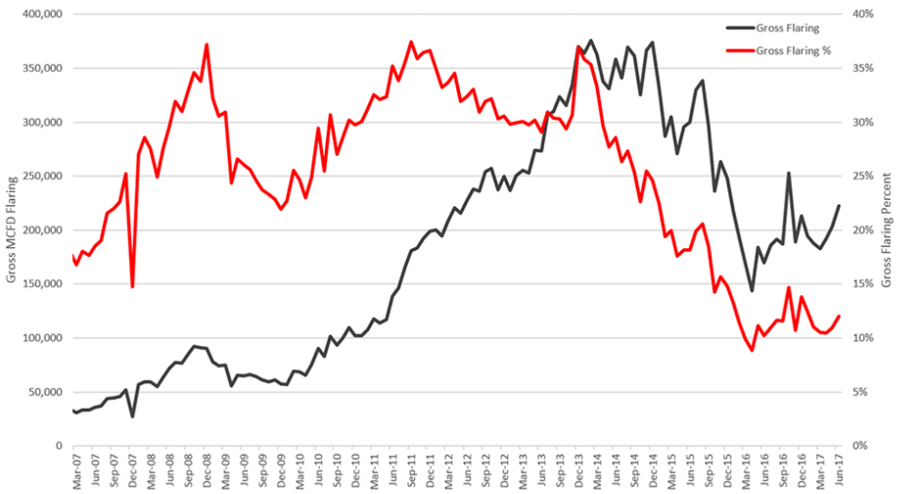


Figure 39. Bakken flaring (King., 2017)

Gas injection EOR has accounted for up to 2 percent of the US oil production (Dhuwe et al., 2016). Although CO_2 injection has been used since 1975 to help produce 1.4 billion barrels of oil (Hill et al., 2013), it is not the most efficient EOR solvent (Dhuwe et al., 2016). Most of the massive natural deposits of CO_2 have already been developed, with some 3500 miles of high-pressure CO_2 transport pipelines, finding additional CO_2 for EOR will become more challenging. Natural and industrial CO_2 sources will become insufficient (McGuire et al., 2016; Dhuwe et al., 2016; Meyer, 2012; Ning et al., 2018). Advanced Resources International (2012) report shows a demand of 25 billion tonnes of CO_2 for EOR and that the supply is short (see figure 40).

Reservoir Setting	Oil Recovery*** (Billion Barrels)		CO_2 Demand/Storage*** (Billion Metric Tons)	
	Technical	Economic**	Technical	Economic**
L-48 Onshore	104	60	32	17
L-48 Offshore/Alaska	15	7	6	3
Near-Miscible CO_2-EOR	1	*	1	*
ROZ (below fields)****	16	13	7	5
Sub-Total	**136**	**80**	**46**	**25**
Additional From ROZ "Fairways"	**40**	**20**	**16**	**8**

*The values for economically recoverable oil and economic CO_2 demand (storage) represent an update to the numbers in the NETL/ARI report "Improving Domestic Energy Security and Lowering CO_2 Emissions with "Next Generation" CO_2-Enhanced Oil Recovery (CO_2-EOR) (June 1, 2011).
**At $85 per barrel oil price and $40 per metric ton CO_2 market price with ROR of 20% (before tax).
***Includes 2.6 billion barrels already being produced or being developed with miscible CO_2-EOR and 2,300 million metric tons of CO_2 from natural sources and gas processing plants.
**** ROZ resources below existing oilfields in three basins; economics of ROZ resources are preliminary.

Figure 40. Next generation demand (Advanced Resources International, 2012)

Theory and Method

The success of an EOR method depends a lot on the availability of a low-price solvent (McGuire et al., 2016). With the drop in natural gas prices, ethane appears to be a good candidate. However, in a complex system like the Bakken, the fluid flow mechanism that we know from conventional reservoirs will not always apply. Sorensen et al. (2014) proposed a miscible EOR mechanism for unconventional reservoirs (see figure 41). The Bakken is a tight formation with a viscous flow in the fractures and diffusion-controlled flow in the matrix (Jin et al., 2017). The viscous flow wouldn't apply in the Bakken matrix due to its very low permeability and high heterogeneity (Ding et al., 2014). To explore diffusivity as a mechanism of oil recovery, the use of different solvents is a must for EOR investigation in unconventional plays (Kanfar et al., 2017).

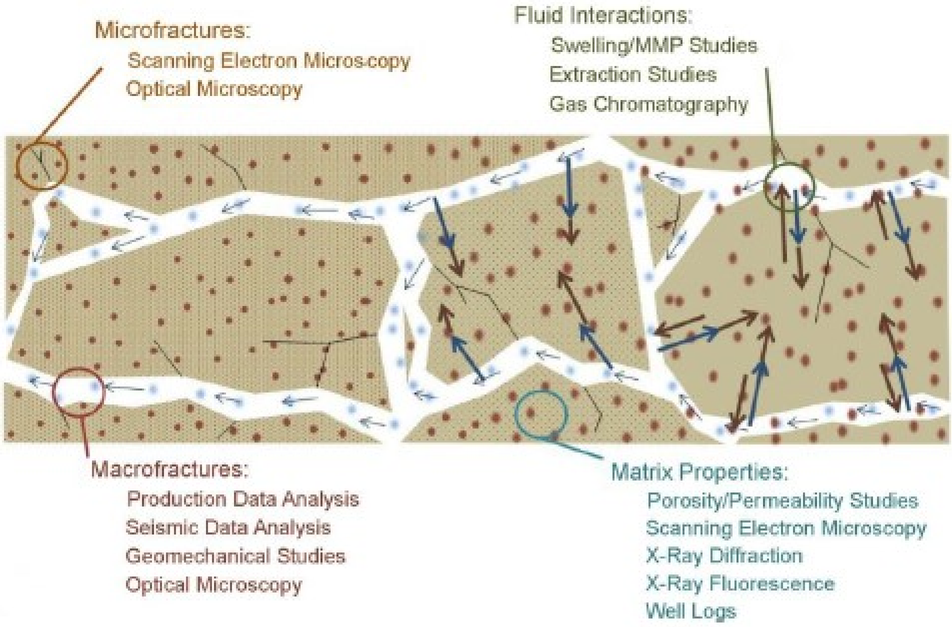


Figure 41. EOR Mechanism (Sorensen et al., 2014)

LABORATORY EXPERIMENT

Coreflood experiment

Due to the heterogeneity and low permeability of the matrix, most of the injected gas only moves fast through the fractures and not the matrix (Hawthorne et al., 2017; Yolo et al., 2018). To investigate the efficiency of CO_2 vs. ethane we have used a sandstone with a permeability of 44 md and porosity of 15 percent, and then used a core sample from the Middle Bakken with a permeability of 0.002 md and porosity of 8 percent to measure the recovery of CO_2 vs. ethane. For these experiments, we have first flooded our sandstone with both ethane and CO_2 and have measured the recovery then we have soaked our middle Bakken core sample with both ethane and CO_2 for 8 hours then we have measured the recovery. A detailed procedure of core-flood experiments (see figure 42) for both conventional and unconventional rock sample is described in our previous work (Yolo et al., 2018).

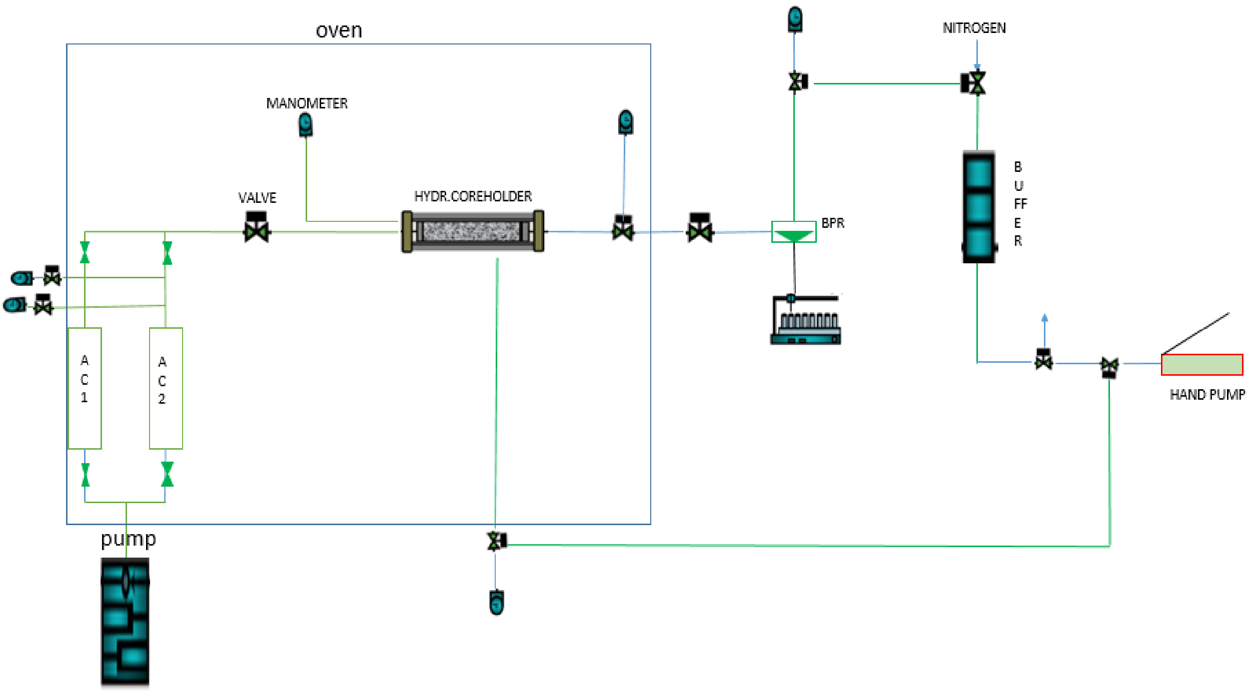


Figure 42. Coreflood apparatus (Yolo et al., 2018)

Core model description

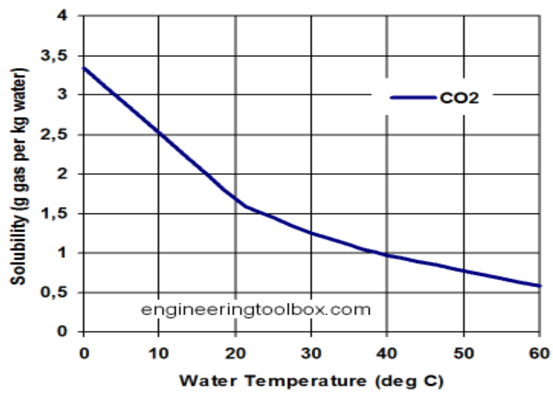
In this work, a dual-porosity compositional model (see figure 51) was created to characterize our 2.5-inch long and 1.5-inch diameter Bakken core plug to mimic core-flood experiments using both ethane and CO_2. We have populated our model with the core sample properties (Table 3) that we took from the file number 21884 at 11314.4 ft which are the depth at which our core sample was extracted. The different recoveries were then compared.

Table.3 Core properties

Property	Unit	Value
Permeability	millidarcies	0.003
Porosity	percent	5.6
Water Saturation	percent	38.5
Oil Saturation	percent	30.9
Total Saturation	percent	69.4

Results and Discussion

The first observation we make from our study using the online Engineering ToolBox is that CO_2 is more soluble than ethane in water (see figure 43). However, ethane is more soluble in oil than CO_2 (McGuire et al., 2016) and we know from reservoir properties (Table 3) that the water saturation of the Bakken is 38.5 percent which represents a significant amount of formation water considering that the Bakken has an estimated total reserve of 100 to 900 billion of Bbl. We also can see from (see figure 44) a significant amount of water being produced. This leads us to assume that ethane would outperform CO_2 in terms of solubility information water, as we would need to consider injecting more CO_2 than ethane because more CO_2 will dissolve in the formation water than ethane would



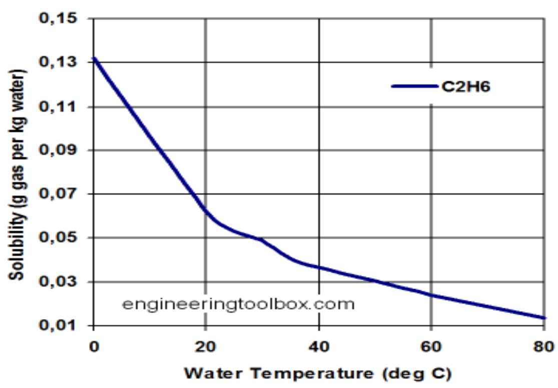


Figure 43. The solubility of CO2 and Ethane in water vs. temperature

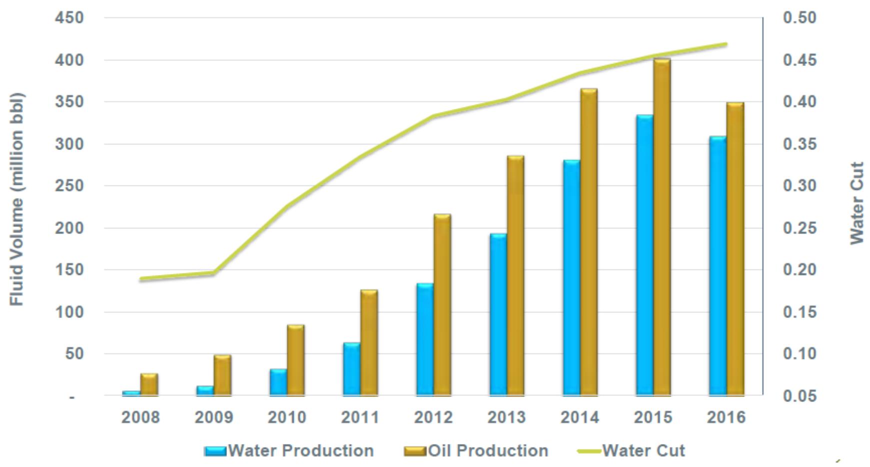


Figure 44. North Dakota Bakken Water and oil production in Bakken (EERC, May 2017)

The second mechanism that we learned from our experimental flooding of sandstone with ethane is that ethane injection would lead not only to a higher recovery than CO_2 (see figure 45) but will produce incremental oil with a higher proportion of lighter hydrocarbon fractions (see figure 46) than the CO_2 would which will make the produced oil more valuable on commodity markets because when transformed by an oil refinery it will generate more diesel and gasoline fuel.

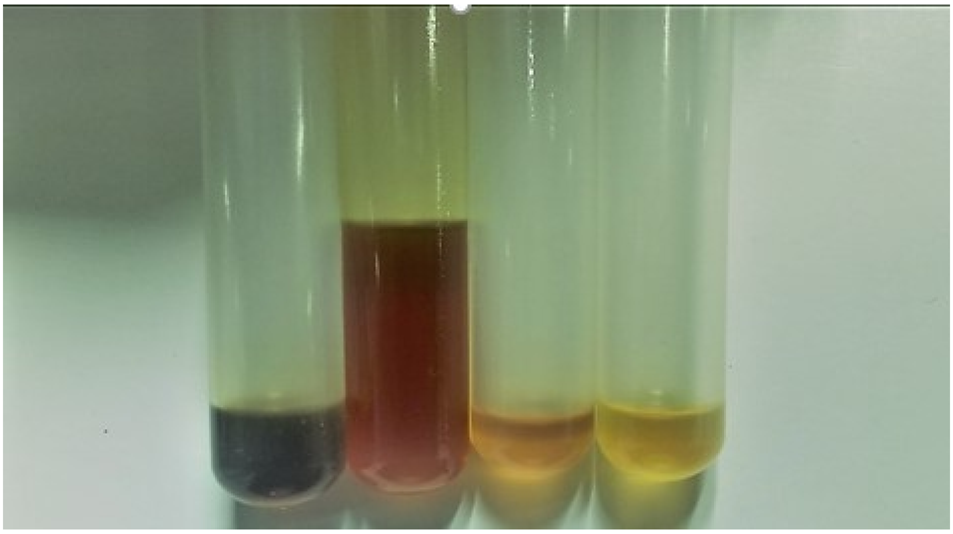


Figure 45. The proportion of light hydrocarbon fractions by ethane injection

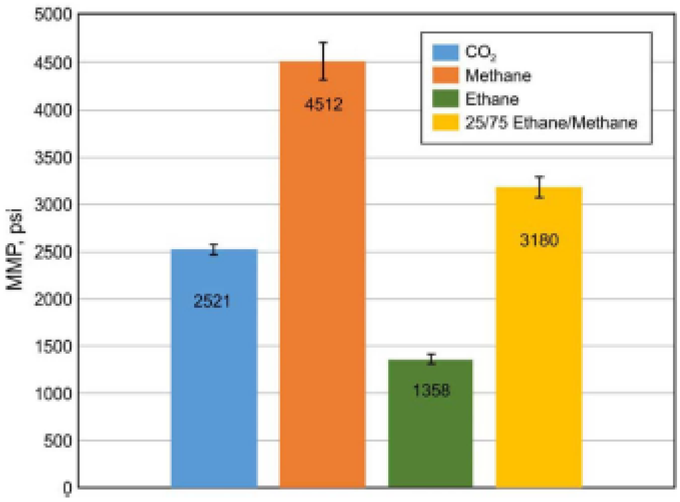


Figure 46. MMP value for a typical Bakken crude (Hawthorne et al., 2017)

From our core flood experiment on a sandstone sample, we have used the average Bakken reservoir pressure of 4,500 psi as our confining pressure and a 0ature of 220 F. We have then injected ethane through our core sample that we saturated with Bakken oil for 72 hours at 300 psi for both experiments. We have used a constant flow rate of 1 cc/minute to inject separately ethane and CO_2 in two different trials then measured the recovery for both experiments. We have cleaned our core sample after each experiment using a dean stark apparatus. The outperformance of ethane vs. CO_2 is evident, with ethane recovering 98.68 percent of oil while CO_2 recovered 80.68 percent (see figure 47). Knowing that most of the oil in the Bakken Petroleum System flows through the fractures where a viscous flow would apply and not the matrix we believe that ethane would outperform CO_2 as the fluid behaviour in the Bakken fractures will be similar to conventional reservoirs.

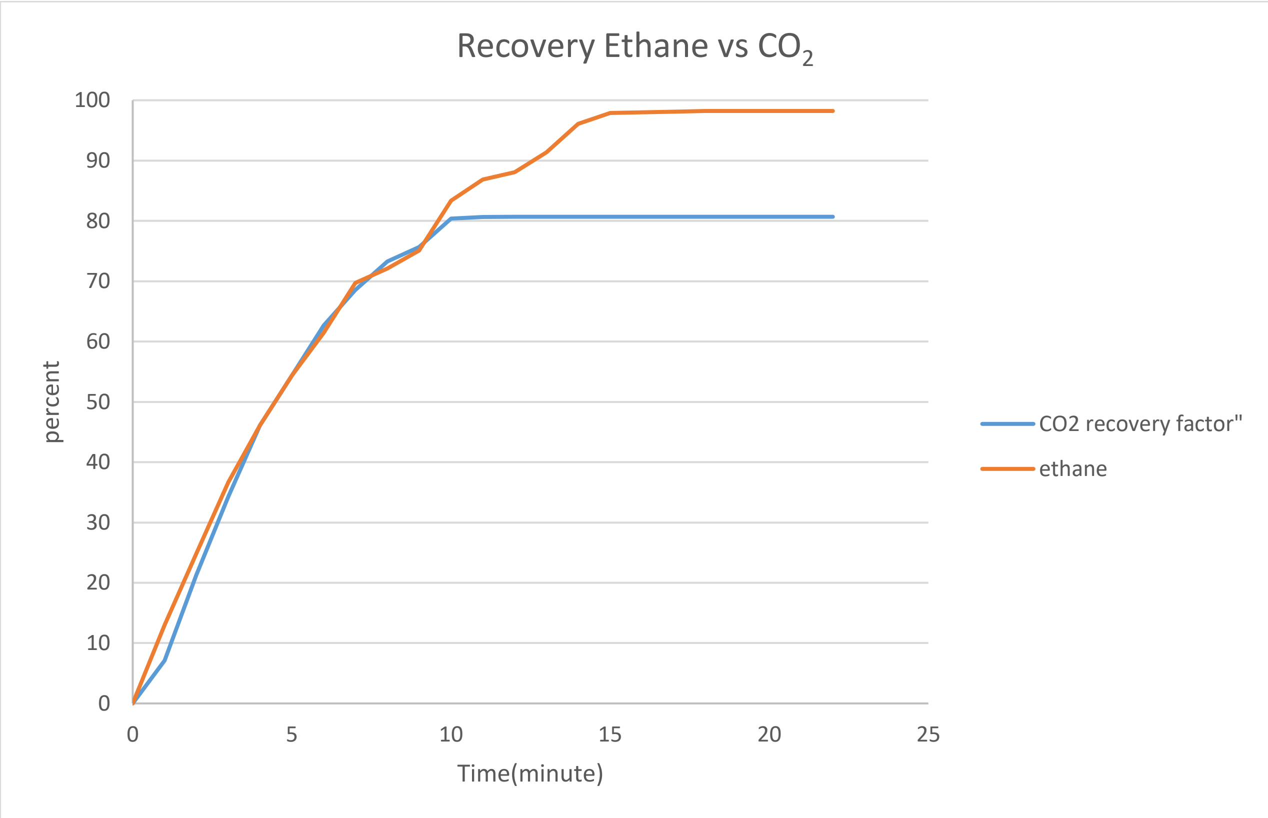
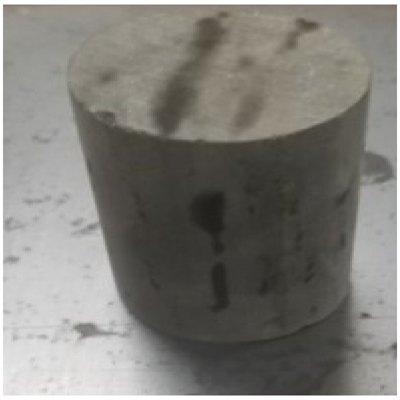


Figure 47. Comparison of oil recovery of ethane and CO_2 injection

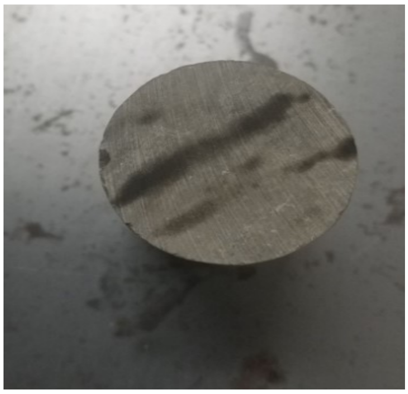
The following step was to perform a CO_2 vs. methane injection on a Middle Bakken core sample with a porosity of 5.6% and permeability of 0.003mD with fractures. After saturating the core sample for 2 weeks, we have seen that the fluid was not getting into the matrix but in the fractures, this confirmed what many researchers have mentioned, that in unconventional reservoir like the Bakken the fluid flows through the fracture and not the matrix

(Jin et al., 2017; Hawthorne et al., 2017). To study this phenomenon, we put a Middle Bakken core sample in an oil saturator for 2 weeks at 300 psi, and we retrieved it (see figure 48a). Following our 2weeks saturation process, we have polished and cut the rock to see if the matrix was indeed saturated. By looking at the core sample, we were able to see that the fluid was saturating only the fractures and proximal fractures zone of the rock (see figure 48b-f) and not the matrix itself. Doing so allowed us to study the recovery of hydrocarbons through the fractures and not the matrix as most of the oil in the Bakken Petroleum system flow through the fractures.

a) Bakken core sample after saturation before trimming

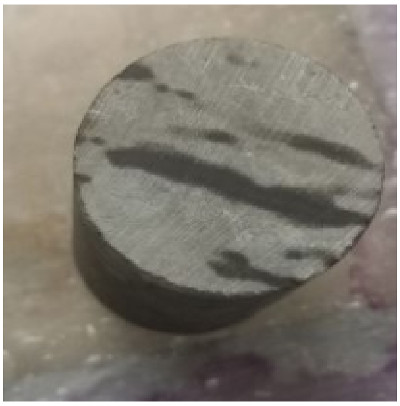


b) Bakken core sample after trimming

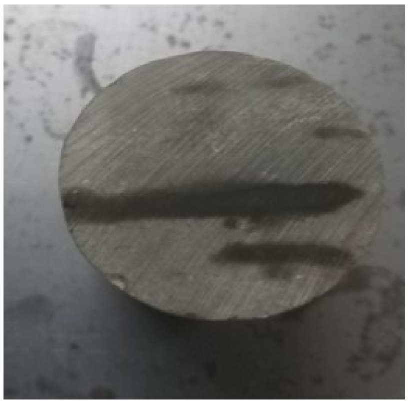


c) Bakken core sample after trimming

d) Bakken core sample after trimming



e) Bakken core sample after trimming



f) Bakken core sample after trimming

Figure 48. Core sample before and after trimming

After saturation, we had measured the weight of the sample which was 181.056g and compared it to the weight of the core sample before saturation which was 175.125 g, and the difference of weight obtained was 5.931g which was the weight of the oil inside our core sample. We have then put our core sample in a CO_2 bath inside our core holder (see figure 42) for 8 hours under 4500 psi to mimic a huff-and-puff on a core scale and then we have measured the ultimate recovery by measuring the weight of the sample which was 176.6g after the 8 hours experiment, the residual weight was thus 1.475g which was approximately 25 percent of residual oil and therefore 75 percent of recovered oil. The following step was to clean the core sample in a stark dean apparatus for 72 hours and measure the dry weight of the sample. The dried weight of our core sample after cleaning process was 175.010g, and we have used the same saturation process for the second experiment and the measured weight after saturation was 180.852g, the difference obtained between the two values representing the oil inside the core sample after saturation was 5.842g. We have then put our core sample in an ethane bath inside our core holder for 8 hours under 4500 psi and measured the weight of the sample after the experiment, and we obtained 175.846g, the residual weight was 0.746g which gives us around 13 percent of residual oil and 87 percent of the recovery. In experiments, we have used the same core sample to avoid the effect of a different sample property on our study. We finally compared the results recoveries, we were able to recover 75 percent for CO_2 and 87 percent for ethane after a soaking period of 8 hours (see figure 49).

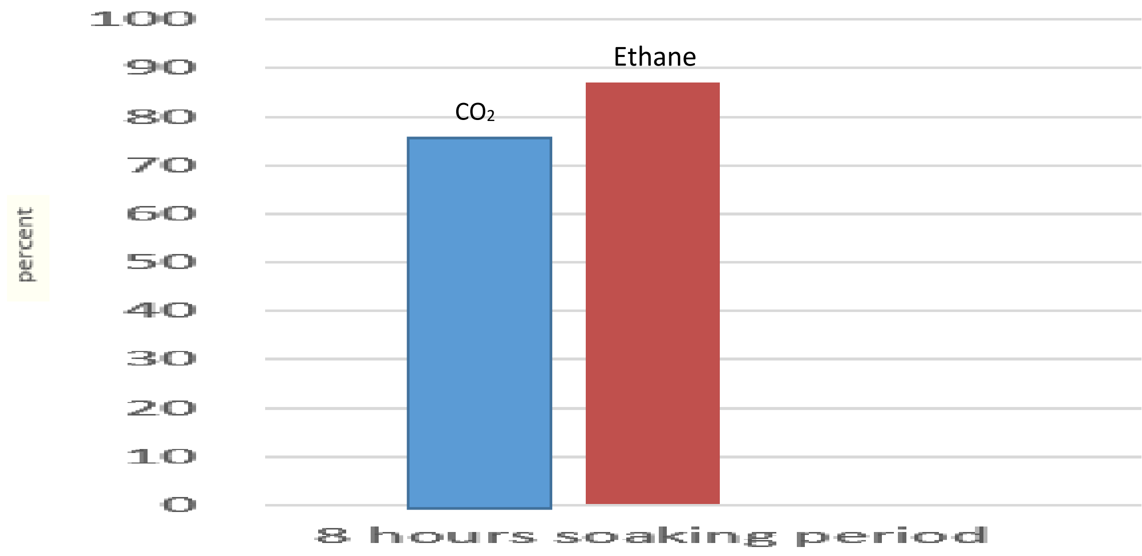


Figure 49. Recovery CO2 vs Ethane

Conclusions

A comparison study was performed to evaluate ethane and CO_2 as candidate EOR solvents in the Bakken Formation unconventional reservoir. What we can retain is: 1) Ethane is more available than CO_2 in the Bakken; 2) Ethane is much simpler to use than CO_2 in terms of infrastructure, minimum miscible pressure and production problems due to corrosion; 3) Ethane is less soluble in water than CO_2 which makes it more efficient in terms of volume needed for injection; 4) Ethane will diffuse less into the reservoir Nano-pore than CO_2 and will likely have more contact with the in-situ oil.5) Using produced Ethane will have a less global warming effect than flaring.

CHAPTER 5

RECOVERY OF CO_2 VS ETHANE FOR BAKKEN SAMPLE USING CORE SCALE MODELING

The goal of this chapter was to provide a validated core scale model of the laboratory experiment of our core. This, in turn, would be used to predict the laboratory outcome of different EOR experiment. This chapter explains the software used in the study and the model build for this study. The primary goal was of this chapter was not to do a sensitivity analysis on a full range but instead to evaluate the performance of CO_2 vs ethane if there were used as EOR injectant.

Core model description

We have built a model to mimic our experiment, to do so, we have used a GEM which is dedicated to unconventional reservoirs. We have developed a dual permeability/porosity compositional model (see figure 51) to characterize our 2.5-inch long and 1.5-inch diameter Bakken core plug to mimic core flood experiments using both ethane and CO_2. We have populated our model with the core sample properties shown in Table 3. We have also used the Diffusion Keyword to activate the diffusion mechanism as we have learned that one of the primary fluid flow mechanisms in the unconventional reservoir such as the Bakken is diffusion. Therefore, building a model without considering diffusion would not be correct. To mimic the experiment, we had to assign a maximum contact area between the EOR injecting gas and the core sample. What happened in the experimental part is that we bathed the core sample into the desired gas and let the gas soak inside the core for a certain amount of time, and then we allowed it flow back. Since this is a dual perm model which considers fractures, we have assigned to our model only 1 injection well and 1 production well to simulate a huff-n-puff using CO_2 and ethane as injectant. We have also used our core properties in this model (see Tables 4). For this study, we have only focused on the recovery achievable using CO_2 and ethane Huff-n-Puff which was discussed earlier.

Table 4. Model properties

properties	Unit	Value
Total Bulk Reservoir Volume,	RES FT3	4.06267E-04
Total Pore Volume	RES FT3	1.07877E-04
Total Hydrocarbon Pore Volume	RES FT3	9.49316E-05
Original Oil in Place, OOIP	STD BBL	1.04748E-05
Original Gas in Place, OGIP	STD FT3	8.93174E-03

Basic Reservoir Properties

The following reservoir properties we used: porosity, permeability, diffusion coefficient, relative permeability, capillary pressure, and surface tension were obtained from both literature and experiments. The PVT value used in our simulation were obtained from literature, except the fluid properties such as the viscosity, temperature, specific weight which were measured in the lab. Some interpolations were used for relative permeability and capillary pressure.

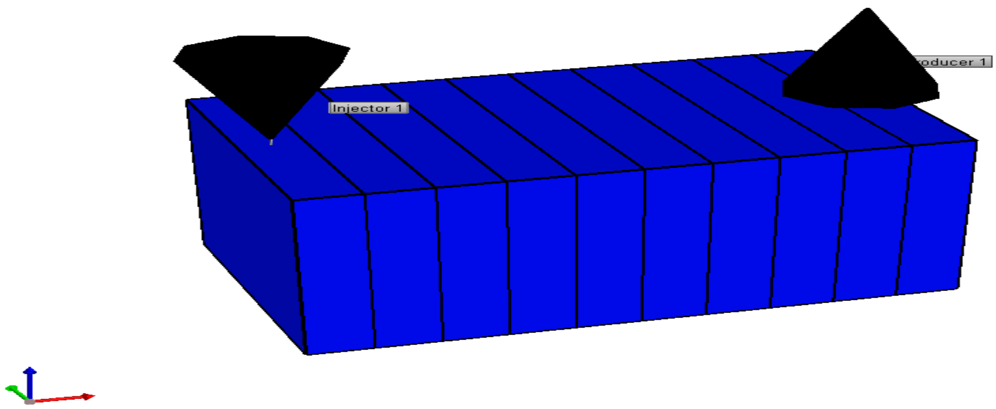


Figure 50. Core Scale Model

Huff and Puff Simulation

For our simulation, we have injected CO_2 and ethane from 1 injection well with the production well closed and allowed a soaking period of 8 hours for both ethane and CO_2. Next, after the 8 hours soaking period we have opened the production well allowing it to flow for a period of 45min in order to mimic our laboratory experiment from the chapter 4 of this thesis. We obtained a recovery factor of recovery of 79 percent from CO_2 injection and 93 percent from ethane injection which were close to our experimental investigation (see figure 51). This further prove that CO_2 Huff-n-Puff in a tight formation such as the Bakken could work on a field scale.

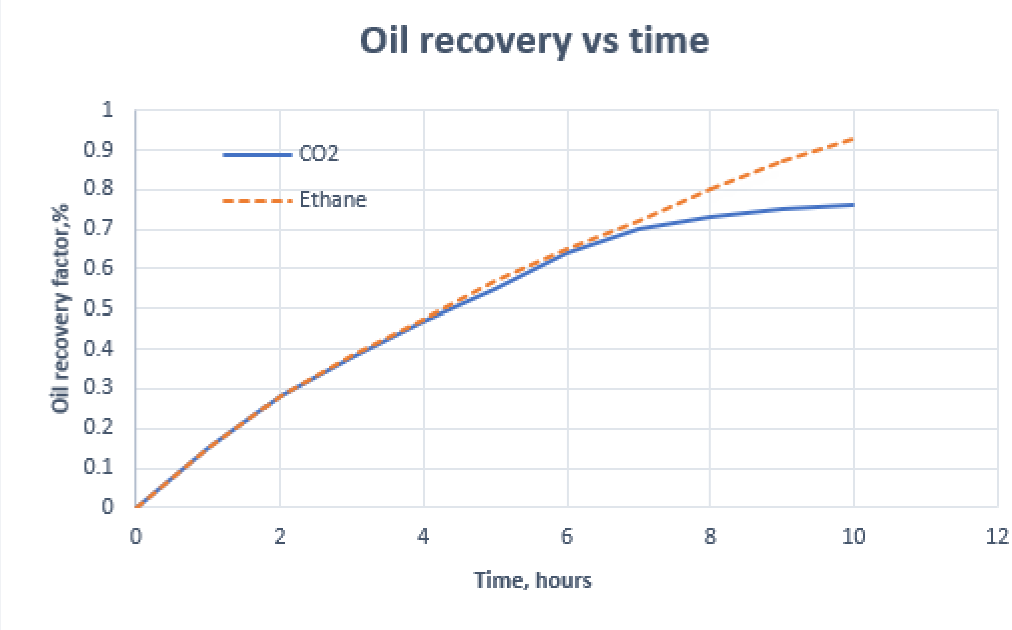


Figure 51. Recovery CO_2 vs Ethane

CHAPTER 6

CONCLUSION AND RECOMMENDATIONS

What we have learned from this study is that Huff-n-Puff could be the optimum EOR method for the unconventional reservoir. We have also agreed with previous others that unconventional is control by a Diffusion dominated flow with a “No fracture-No flow." A comparison study was performed to evaluate ethane, methane, nitrogen, and CO_2 as candidate EOR solvents in the Bakken Formation unconventional reservoir, while CO_2 outperformed methane and nitrogen, ethane exceeded CO_2. What we can retain is: 1) Ethane is more available than CO_2 in the Bakken; 2) Ethane is much simpler to use than CO_2 in terms of infrastructure, minimum miscible pressure and production problems due to corrosion; 3) Ethane is less soluble in water than CO_2 which makes it more efficient in terms of volume needed for injection; 4) Ethane will diffuse less into the reservoir Nano-pore than CO_2 and will likely have more contact with the in-situ oil. 5) Using produced ethane will have a less global warming effect than flaring. Due to the high organic content of the Bakken, we suggest studying the possibility of a mixed method surfactant-CO_2 Huff-n-Puff in Unconventional play. As for our digital rock analysis we retain that this tool would be optimum to study small sample such as drilling cutting which can be very hard to study using conventional laboratory. Digital rock analysis also gives us a very good insight of the variation of properties throughout the sample.

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