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Abstract

For over a century, waterflooding of oil reservoirs have been performed to improve oil recovery for two reasons: to provide pressure support to the reservoir and to displace the oil entrapped in the pores of the rock. Researchers discovered that the wetting properties of the reservoir played a critical role in the efficiency of the waterflood. The backdrop for which numerous researches have been conducted is the significant improvement of the general understanding of the wetting properties of oil reservoirs, with the objective to optimize oil recovery. Apart from the gravity, viscous and capillary forces that are responsible for oil recovery in waterflooding experiments, several other factors influence oil recovery. Factors such as temperature, porosity and permeability of the rock system, formation water, mineralogy of the rock, acidic and basic components in oil among other factors influence oil recovery.

In this study, the effects of injection rate and oil viscosity in waterflooding of sandstones were examined. The main focus was to investigate the influence of capillary forces in mobilization of oil during waterflooding experiments. Two set of outcrop cores, Bandera brown and Leopard, were used for this study. Oils used in this study were synthetic oils which were prepared in the laboratory by mixing Marcol oil and n-heptane at different volume ratios. Two synthetic oils, one with a viscosity of 3cP (MO3) and the other with a viscosity of 11cP (MO11), were used for this study. Spontaneous imbibition experiments were carried out on the cores, with formation water being the imbibing brine. Subsequently, viscous flooding experiments were conducted on the cores at a high (4PV/day) and low injection rate (1PV/day).

Oil recovery during the spontaneous imbibition experiments of the cores yielded a significant amount of OOIP, which was an indication of the cores' strong water wetness. Spontaneous imbibition is a capillary driven phenomena hence the driving force that is responsible for oil recovery are capillary forces, thus capillary forces contributes immensely in oil recovery.

It was drawn from this research that injection rate seem not to significantly affect oil recovery during waterflooding as observed with all the cores used in this study. Viscous flooding performed on the cores at high and low injection rate showed that oil viscosity and injection rate do not significantly affect oil recovery, confirming that capillary forces is important in the recovery process in water wet cores.

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Nomenclature

BB	Bandera brown core
cP	Centipoise
dFw	Diluted formation water
dP	Pressure drop
EOR	Enhanced oil recovery
FW	Formation water
IFT	Interfacial Tension
LP	Leopard core
MO	Mineral oil
OOIP	Oil originally in place
Ppm	Parts per million
PV	Pore volume
SI	Spontaneous imbibition
S_{wi}	Initial water saturation
VF	Viscous flooding
W_{sat}	Saturated weight
W_{target}	Target weight

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1 Introduction

1.1 Background

About 50% of all petroleum reservoirs are sandstones (Bjorlykke, 2010) ,which means sandstones encompass a considerable amount of the world’s hydrocarbon reserves. For decades, breakthroughs and efforts have been made to determine the best possible, low environmental impact and cost efficient method of recovering as much hydrocarbons as possible from reservoirs (Zitha et al., 2011).

The sandstone system is a unique system due to its mineralogical composition and their behaviour owing to the fact that sandstone reservoirs are normally composed of stable minerals like quartz, feldspar and rock fragments, accessory minerals and pores saturated with fluids (Weimer and Tillman, 1982). Ultimate recovery of sandstones are typically low under the natural drive or primary recovery mechanisms. This means that a major portion of the producible reserves remain trapped in the reservoirs and that makes them a candidate for enhanced oil recovery (EOR) processes.

Injection of fluids into the reservoir to enhance oil production has been implemented for several years, a typical example of such being water injection (waterflooding).

The goal of any waterflooding process is to act as pressure support to prevent the dissolved gas from boiling out of the oil, and additionally to displace the oil by water (water in – oil out). Some of the waterflooding methods improve oil recovery by wettability alteration.

In a waterflooding process, the proficiency with which the oil is displaced by water in reservoirs varies from less than 10% to as much as 80%.This variability of the effectiveness of waterflooding is a consequence of the fluid properties and the nature of the pore system of the rock (Wardlaw and Cassan, 1979).

Viscous, capillary, and gravity forces control oil recovery during water injection. In fractured and low permeable reservoir formations and at low flow rates the major driving forces in a porous media are capillary forces controlling the efficiency of oil transport (Karpyn et al., 2009). Wettability is a major factor controlling the location, flow, and distribution of fluids in a reservoir. The wettability of a core will affect almost all types of core analyses, including capillary pressure, relative permeability, waterflood behaviour, electrical properties, and simulated tertiary recovery (Anderson, 1986).

The wetting properties of a rock influences the success of a waterflooding process hence the initial wetting properties of sandstones has a major stake in oil recovery. The initial wettability of rocks is established by the chemical equilibrium between the brine, oil and the mineral surface (Cuiec, 1984).

Most sandstones reservoirs are initially water-wet due to their composition, thus waterflooding experiments are relatively efficient in sandstones than in carbonates which has unfavourable mixed to oil-wet tendencies (Al-Lawati and Saleh, 1996).

Apart from the wetting properties, Thomas et al. (1989) highlighted that reservoir geometry, fluid properties, reservoir depth, lithology and rock properties, fluid saturations, reservoir uniformity and pay continuity, primary reservoir driving mechanisms are all equally important factors worthy of consideration in waterflooding at reservoir scale. This is also largely true for laboratory parametric studies using outcrop sandstone cores. Viscosity of oil which is a fluid property, as well as the rate of injection of the displacing fluid play key roles in waterflooding processes in laboratory studies.

Conventional waterflood recoveries have been seen to be low for oils with high viscosity due to conflicting mobility ratio between oil and the injected water. However, in light of this potential inefficiency, waterflooding is still applied in many heavy oil fields since it is relatively cost efficient and field operators have years of experience designing and controlling waterflood (Mai and Kantzas, 2009).

The impact of oil viscosity in waterflooding was emphasized by Torabi et al. (2010) in an experiment to study the effect of oil viscosity on waterflooding, immiscible CO_2 injection and water alternating CO_2, concluded that oil viscosity has a profound effect on the recovery factor in a waterflooding process.

Similarly, injection rates contribute immensely to the waterflooding process. At a reservoir scale, injection rate is an important economic variable that is considered in waterflooding processes. The rate at which fluid can be injected and produced affects the waterflood project and the economic benefits. Estimating the injection rate is also important for the proper sizing of injection equipment and pumps (Ahmed, 2018).

Several research has gone into finding the optimal injection rate for a waterflooding process. Liu et al. (2012) asserts setting proper water injection rate is key to operate a waterflood efficiently, and further highlighting that the success of employing an optimal injection rate could reduce water cycling at field, section and pattern levels, improve water/oil ratio (WOR) and areal sweep efficiency and improve oil production and recovery by directing water injection to specific zones and areas. The roles of oil viscosity and injection rate cannot be overemphasized in waterflooding at reservoir scale as well as in laboratory studies.

1.2 Problem Statement

The viscosity of the oil to be displaced in a waterflooding process is an important factor for consideration, as it can impact oil recovery. That property of the oil can alter the overall crude-brine-rock interaction established for a sandstone reservoir system. Very low to very high viscous oils have their peculiar effects on oil recovery. In a waterflooding process, the displacing fluid displaces oil at a rate, which is the injection rate. The potential to recover as much as oil there is to recover could be dependent on the injection rate. It is expected that different rates of injection would have an effect on oil recovery. It is therefore necessary to conduct an experimental investigation to determine the impact of viscosity of oil and injection rate in oil recovery in sandstone and serve as further knowledge to existing literature.

1.3 Objectives

This thesis will seek to investigate the effects that injection rates and oil viscosity has on oil recovery in a waterflooding experiment using sandstone outcrop cores. These parameters to be investigated are components of capillary forces in a waterflooding setup, hence this project will seek to examine how capillary forces interplay in oil recovery by critically analysing the effects of viscosity and injection rate in oil recovery. In determining the impact of these factors on oil recovery, spontaneous imbibition and viscous flooding experiments will be conducted on the outcrop cores. This research will seek to find out, that at what injection rates will optimal oil recovery be observed? Furthermore, given a system where there is no wettability alteration i.e. at constant wettability, what influences oil mobilization in a waterflooding experiment?

This thesis opens with some of the theories of the research area in which foundational concepts requisite to understand the subject matter is presented. Principal among them are the subject of wettability and understanding the sandstone reservoir system, which will then be followed by the various experimental processes. Discussion and conclusions on the results will be presented in later chapters.

2 Fundamentals

This chapter focuses on the foundational concepts of oil recovery. It is widely accepted that the resultant hydrocarbon of the thermal alteration of organic matter are recovered by different methods depending on the pressure level of the reservoir, the viscosity of the hydrocarbon among other factors. It is vital to comprehensively understand some of the fundamentals and terms associated with oil recovery and more importantly, enhanced oil recovery.

2.1 Oil Recovery Mechanisms

Hydrocarbons in the reservoir may undergo basically three types of oil recovery namely primary recovery, secondary recovery and tertiary recovery. The conditions of the oil reservoir at any point in the lifespan of the reservoir will determine which type of oil recovery would be implemented.

2.1.1 Primary Recovery

This refers to the type of recovery where hydrocarbons are produced due to the natural energy initially stored in the reservoir. Basically, the hydrocarbons are produced by natural depletion of the reservoir. Primary recovery results from the use of natural energy present in a reservoir as the main source of energy for the displacement of oil to producing wells. These natural energy sources are solution gas drive, gas-cap drive, natural waterdrive, fluid and rock expansion, and gravity drainage (Green and Willhite, 1998). In the absence of external forces, the primary depletion inefficiently produces only 10 to 30 percent of the original oil in place (Shah, 1981).

2.1.2 Secondary Recovery

This recovery method involves injecting fluids to pressurize the reservoir after the natural driving forces have diminished. Secondary recovery refers to techniques such as gas or water injection (waterflooding) that have the main purpose of boosting or maintaining reservoir pressure(Lake et al., 2014). Waterflooding is the more common of the two secondary methods. The recovery factor after the secondary stage is usually 30-50 % of OOIP (Castor et al., 1981).

2.1.3 Tertiary Recovery

This method of recovery is implemented when the options of primary and secondary methods have been exhausted and uneconomical. Tertiary recovery involves the injection of gases or liquid chemicals and/or the use of thermal energy (Green and Willhite, 1998).The expected result of a tertiary method is to improve the total displacement efficiency by altering the properties of the oil and reduction of the residual oil. Oil recovery from reservoirs do not necessarily go through the primary-secondary-tertiary order. Since oil recovery do not follow that order, the term enhanced oil recovery is often used instead of tertiary oil recovery. Some reservoirs may require EOR methods at the onset of oil production

2.2 Enhanced Oil Recovery (EOR)

Enhanced oil recovery refers to reservoir processes that seeks to recover residual oil which were not produced by secondary processes. Primary recovery uses the natural energy of the reservoir to produce oil or gas. Secondary recovery uses injectants to re-pressurize the reservoir and to displace oil to producers. Enhanced oil recovery processes target what is left. They focus on the rock/oil/injectant system and on the interplay of capillary and viscous forces (Stosur, 2003).

The term EOR encompasses all methods that involves injecting a fluid into a reservoir to maximize production of hydrocarbons. EOR implies a reduction in oil saturation below the residual oil saturation (S_{or}). Recovery of oils retained due to capillary forces (after a waterflood in light oil reservoirs), and oils that are immobile or nearly immobile due to high viscosity (heavy oils and tar sands) can be achieved only by lowering the oil saturation below S_{or} (Thomas, 2008). Taber et al. (1997) highlights that EOR processes are classified into four different categories namely: thermal methods, gas injection, chemical flooding and emerging processes. Selecting an EOR process is dependent on particular reservoir conditions. The petrophysical properties, chemical as well as fluid properties of a reservoir must be considered in implementing an EOR process.

2.3 Reservoir Displacement forces

In waterflooding processes, there are forces interaction between the porous media and the fluid present. Viscous, capillary, and gravity forces control oil recovery during water injection (Aghaeifar et al., 2019).

2.3.1 Fluid flow in porous media

The transport or flow of fluids in a porous media is principal in oil recovery processes. A major principle that describes flow through porous media is the Darcy's law. It describes the relationship between the fluid viscosity, the flow rate throughout the porous media and the pressure drop over a given distance. Equation 2.1 presents the Darcy's law;

$$u = -\frac{k}{\mu}\frac{dP}{dx} \qquad (2.1)$$

Where:

u -Flow rate (m^3/s)

k - Permeability (m^2)

μ - Fluid viscosity (Pa.s)

dP/dx - Pressure gradient

2.3.2 Capillary forces

Forces of capillary is an important displacement force in oil recovery and depending on rock framework, these forces can act in favour or against oil recovery. They are an outcome of the interaction between the dimensions and geometry of pores, the interfacial and surface tensions by the fluid phases and the rock, as well as wettability. Trapping of the greater portion of the non-wetting fluid within the interstices of the rock is the responsibility of capillary forces Bentsen and Anli (1976). Laplace equation established for capillary across a curved surface considering the radius of curvature is given by;

$$\mathrm{P}_c = \mathrm{P}_o - \mathrm{P}_w = \frac{2\sigma_{ow}\cos\Theta}{r} \tag{2.2}$$

Where:

P_c - Capillary pressure

P_o - Oil-phase pressure at a point just above the oil-water interface

P_w - Water-phase pressure just below the interface

r - Radius of cylindrical pore channel

σ_{ow} - Interfacial tension between oil and water

Θ - Contact angle measured through the wetting phase (water)

2.3.3 Viscous Forces

Viscous forces are experienced in a porous medium by the pressure drop that occurs as a result of flow of a fluid through the medium(Green and Willhite, 1998).There is a resistance of fluid flow in a porous medium when flow is in place, and that resistance is the action of viscous forces. The magnitude of the viscous forces can be determined by simply having the channels of the reservoir as a cluster of capillary tubes in parallel.

Assuming a laminar flow through the tubes, Poiseuille's law for laminar flow is used in calculating the pressure drop.

$$\Delta\mathrm{P} = \frac{8\mu L v}{r^2\, g_c} \tag{2.3}$$

Where:

$\Delta\mathrm{P}$ - Pressure difference across capillary tube

μ - Viscosity

L - Length of tube

v - Average flow velocity in tube

r - Tube radius

g_c - Conversion factor

2.3.4 Gravity forces

Phases of fluids in the reservoir are segregated by gravity which are influenced by their densities in the porous medium. Water, having the largest density among oil and gas, stays at the bottom of the reservoir. Chen et al. (2001) in their work asserted that gravity forces is of major concern when the density differences between the oil and water are large but are also important at low oil-water IFT conditions. Gravity forces could also lead to inept recoveries through overriding and underriding of the displacement setting. The hydrostatic pressure difference over the oil-water interface due to gravity is described as follows:

$$\Delta P_g = \Delta\rho \cdot \mathrm{g} \cdot \mathrm{H} \qquad (2.4)$$

Where:

ΔP_g – Pressure difference over the oil-water interface due to gravity (Pa)

$\Delta\rho$ – Difference in density of the two phases (kg/m^3)

g – Gravitational acceleration constant, 9.8m/s

H – Height of column

2.4 Wettability

Wettability is defined as the tendency of one fluid to spread on or adhere to a solid surface in the presence of other immiscible fluids. In a reservoir, the flow, location and distribution of fluids is greatly influenced by wettability. It is a property of a rock, thus in a crude oil/brine/rock (COBR) system, it is an estimate of the rock's preference for either water or oil. The wetting properties of a rock and the potential alteration of these properties has been found to affect capillary pressure, relative permeability, waterflooding behaviour, dispersion of tracers, simulated tertiary recovery, residual oil saturation ,irreducible water saturation and electrical properties (Anderson, 1986).

2.4.1 Classification of Wettability

The pore surfaces of reservoir rocks have inclination towards oil, water or elements suspended and dissolved in the fluids. This affinity for which type of fluid presents a phenomenon which informed Erle (2008) to highlight four general states of wettability namely ;

- Water wet
- Fractional wettability
- Mixed wet
- Oil wet

A water/oil/rock system is considered to be water wet when more than 50% of its surface is wet by water. The smaller pores are occupied by water while oil occupies the larger pores as droplets settled on a sheet of water. Water exists as the continuous phase while oil exist as the non-wetting phase in the porous medium. When a water wet core is saturated with oil, water will imbibe spontaneously into the rock displacing oil.

Fractionally wet describes a phenomenon where wetting is distributed randomly in the rock due to the heterogeneity of pore surface. So a part of the rock can be preferentially water wet or oil wet. There is no continuous phase in a fractionally wet setting (Brown and Fatt, 1956).

Salathiel (1973) defined mixed wettability as a phenomenon where the small pores in the rocks are water wet thus saturated with water and contain no oil, while the larger pores are oil wet and contains all the oil thereby forming a continuous track. When the pore surface of the rocks has affinity for oil components, then an oil wet system is in place. Oil will usually be in the smaller pores while water occupies in the larger pores. In a preferentially oil wet system, when the rock is saturated with water in the presence oil, oil will imbibe into the rock hence displacing the water phase until a state of equilibrium is attained.

2.4.2 Wettability Measurements

2.4.2.1 Wettability measurements on smooth surfaces

In order to study the fundamental principles of wettability, the simplest systems are the ones that involves smooth surfaces. They provide several advantages as fast wettability estimations, high reproducibility, and straightforward comparisons of significantly different systems.

A number of methods are employed in the industry to measure wettability of rocks. With these methods, both quantitative and qualitative measurements of wettability can be estimated. The methods include but are not limited to contact angle, Amott water index ,United States Bureau of Mines(USBM) ,chromatographic wettability and spontaneous imbibition (Strand et al., 2006).

Contact angle

The wettability of the system can be evaluated by measuring the contact angle between the solid, in this case a rock, and the two immiscible fluids. The individual adhesive attraction of the fluids to the rock goes into equilibrium with the interfacial tensions of the two fluids and that equilibrium is reflected by the contact angle (θ). The water phase serves as the medium through which the contact angle is measured.

Contact angle measurements are used as a primary approach to evaluate the wetting state of a rock surface (Yuan and Lee 2013), Figure 2.1.

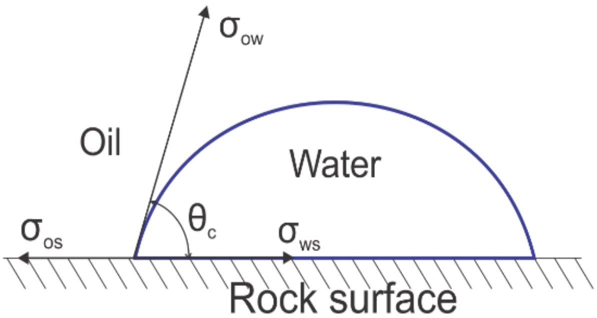


Figure 2.1. Static contact angle measurements, θ_c.

It is the most common of several quantitative methods used to evaluate the wettability of pure fluids on plain surfaces (Anderson, 1986; Morrow, 1990) typically Iceland spar crystals representing calcite or limestone surfaces, or and mica or glass representing different type silicate minerals linked to sandstone systems. Besides, it has often been suggested used as a reservoir wettability measurement (Treiber and Owens, 1972).

In a static equilibrated Oil – Water – Solid system; the degree of wettability is expressed as function of the angle measured through the denser phase as seen in Figure 2.1.

The static equilibrium can be defined by Young's equation, Equation 2.5, which was developed on a thermodynamic basis stated by Gibbs (Berg, 1993).

$$\sigma_{os} = \sigma_{ws} + \sigma_{ow} \cos\theta \qquad (2.5)$$

Where the main parameters of the equation are the interfacial tensions, σ_{os}, σ_{ow} and σ_{ws}, which are in mechanic equilibrium:

- θ_c Contact angle measured through the denser phase
- σ_{os} Oil – Solid interfacial tension
- σ_{ow} Oil – Water interfacial tension
- σ_{ws} Water – Solid interfacial tension

A general classification of the wettability in function of the contact angle measurement is described in Table 2.1.

Table 2.1. Wettability classification as function of contact angles

Contact angle (°)	Wettability
0 – 30	Strongly water–wet
30 – 90	Water–wet
90	Neutral–wet
90 – 150	Preferentially oil–wet
150 – 180	Strongly oil–wet

The main problem with contact angle measurements is that it represents homogeneous wettability on smooth surfaces. The surfaces need to be prepared in front of the experiments which could affect the surface wetting. Contact angle measurements could not be performed in typical pore spaces of porous rocks due to large droplet sizes (microliter) which will not fit into pores with nano or a few micrometer diameters. Nor is it possible to picture fluid droplets in representative micron sized pores, even by use of micro–CT with typical voxel resolutions down to 3 μm.

2.4.2.2 Wettability in porous media

A proper estimation of reservoir wettability is fundamental for the success of a waterflooding operation. However, contact angle measurements are not representative of porous media due to the complex geometry of pores structure. Nevertheless, different experimental techniques have been proposed, and the most widespread in the scientific community are: Amott (Amott, 1959), Amott Harvey, USBM, Cryo–ESEM (Boassen et al., 2006) or Methylene blue adsorption. Some of these methods are destructive, time consuming, and involves a large number of experimental operations reducing the reproducibility and the value of the measurements. It is also difficult to perform most of these experiments at elevated and realistic temperatures for reservoir systems.

Spontaneous imbibition

Spontaneous imbibition is a practical way to approach and quantify the degree of water wetness established in porous rocks restored with initial water saturation of FW and an oil phase like a crude oil (Anderson 1986).A sketch of an Amott cell is seen in Figure 2.2.

A spontaneous imbibition experiment is performed by placing the restored core in the Amott cell surrounded by FW. If the core behaves water wet, positive capillary forces will promote imbibition of the FW into water wet pores, mobilizing oil which will be expelled from the core as seen in Figure 2.2.In the spontaneous imbibition experiment, monitoring both the rate of imbibition and the ultimate recovery dictates how the core behaves. This is a useful measure because the driving force of the rate is proportional to the imbibition capillary pressure (Morrow, 1990). To perform an adequate interpretation, it is important to count with reference results that are near to the initial wettability of the cores (Denekas et al., 1959; Ma et al., 1999). Furthermore, this test can provide information about dynamic IFT and other wetting processes that could be of interest for reservoir engineers but are not explicitly exposed in the

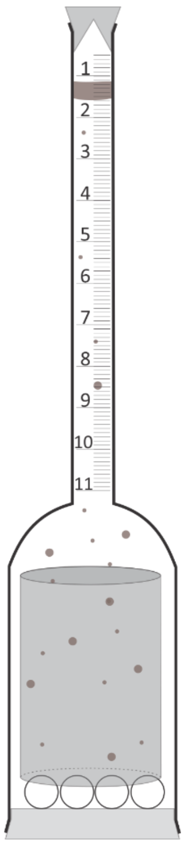


Figure 2.2. Spontaneous Imbibition cell.

Amott or USBM method. For instance, in some cases imbibition capillary pressure can be near to zero but the imbibition process can continue at a very slow pace (Morrow, 1990).

However, in order to discriminate well the wettability of systems in which the spontaneous imbibition is not occurring in significant quantities, other methods like USBM could be employed (Cuiec, 1984; Donaldson et al., 1969).

2.5 Sandstones

Sandstone is a clastic sedimentary rock formed through transportation ,deposition, compaction and cementation of different mineral composition of sand grains (Haldar and Tišljar, 2014).The composition of sandstone is influenced by the character of sedimentary provenance, the nature of the sedimentary process within the depositional basin and the kind of dispersal paths that link provenance to basin (Dickinson and Suczek, 1979).

2.5.1 Mineralogy of Sandstone

The mineralogy of oil reservoirs is important since it influences the wetting nature of the rock and has an impact on oil recovery. Due to the presence of silicate minerals in sandstones, they are also known as siliciclastic sedimentary rocks. Sandstones are composed of materials like quartz, feldspar, mica and clay minerals.

2.5.1.1 Quartz

Any type of mineral can be present in sand grains, but quartz grains are the most abundant type of sand grains (Prothero and Schwab, 2004) .Quartz are hard crystalline minerals bearing silica and often referred chemically as Silicon oxide (SiO_2).Quartz is a common constituent of gneiss, schist, quartzite and other metamorphic rocks (Klein and Hurlbut Jr, 1985).Rocks having high content of quartz is thought to be mature considering the rework and the weathering process the rock has gone through with quartz being the primary mineral present (Boggs Jr, 2014).

2.5.1.2 Feldspar

Feldspars originate from magma as crystals in both intrusive and extrusive igneous rocks. Decomposition of feldspars comes easy compared to quartz, due to their relatively soft nature of their grains. They are present in many types of sedimentary rocks as well. The feldspar mineral are aluminosilicates whose structure are composed of corner-sharing AlO_4 and SiO_4 tetrahedra linked in an infinite three dimensional array (Ribbe, 2018). A sandstone with high presence of feldspar contains information about the source area climate and topography. There are three endmembers of feldspars;

- Potassium of K-feldspar endmember $KAlSiO_8$
- Albite endmember $NaAlSiO_8$
- Anorthite endmember $CaAl_2Si_2O_8$

Solid solutions between K-feldspar and albite are called alkali feldspar. Solid solutions between albite and anorthite are called plagioclase. Albite is considered both a plagioclase and alkali feldspar. Figure 2.3 illustrates the composition triangle of feldspars.

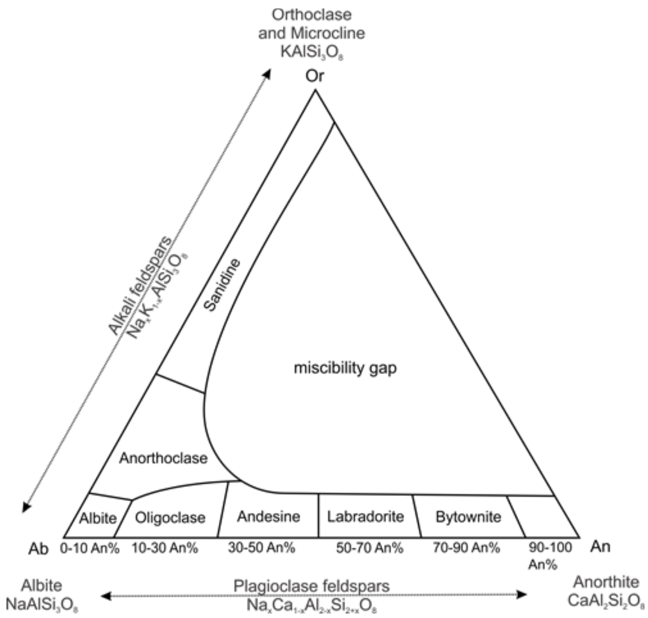


Figure 2.3 Feldspar ternary diagram (Redrawn after Chemistry of Elements (1998) - p. 357.)

2.5.1.3 Clay

Clay minerals are products of weathering and more particularly formed by the partial decomposition of minerals like feldspar. They are heavily present in sedimentary rocks like mud rocks. Clays are transported as clasts and can be considered as fine to very fine textured detrital particles. Clay minerals have large surface area coupled with high reactivity in the reservoir. The grains size of clay particles have diameters less than 2µm.They have a cation exchange capacity (CEC) hence they act as cation exchangers. The relative affinity of cations towards the clay surface is $Li^+ < Na^+ < K^+ < Mg^{2+} < Ca^{2+} < H^+$ (Civan, 2015).

Clay minerals are composed of tetrahedral silicate and octahedral hydroxide sheets which are layered according to a ratio of these sheets thereby resulting in different structures for different clay minerals. The following groups constitute clay minerals:

- Kaolin group which has minerals like kaolinite, dickite, and nacrite
- Smectite group with minerals like montmorillonite and nontrinite
- Illite group with clay micas
- Chlorite group

2.5.2 Outcrop sandstone materials

In laboratory studies of rock and wettability, outcrop materials are usually used to represent the reservoir rock. The main reason why outcrop materials are used is because they are cheap and readily available unlike real reservoir samples (Puntervold, 2008). Much attention should be paid to which type of outcrop material to be used since they may have similar lithology but may behave differently (Strand et al., 2007). Outcrop sandstones containing silicate minerals of quartz, feldspars and clays can influence wettability and strength of the rock.

2.5.3 Heterogeneity of sandstone systems

The pore size (pore throat radius) distributions and permeabilities of sandstone rocks are controlled by the grain sizes and the amount of the individual matrix minerals. Mercury injection (MICP) into rock samples gives a clear indication of the pore heterogeneity of porous sandstone rocks. In Figure 2.4 it can be observed that the tested outcrop T rock material consisted of a substantial amount of macropores (>2 mm), in addition to some meso (>0.5 mm – <2mm) and micro (<0.5 mm) pores accounting for 17 % of the total pore volume (PV).

The pore throat radii vary by three orders of magnitude, from $10 \cdot 10^{-9}$ m (nm) to $20 \cdot 10^{-6}$ m (μm) confirming heterogeneous pore size distribution, which need to be accounted for and which could affect the displacement efficiency during waterflooding of reservoirs or core experiments in the laboratory. Large pores are more easily displaced than smaller pores, and stronger capillary forces or displacement forces are needed to displace oil from the smallest pores.

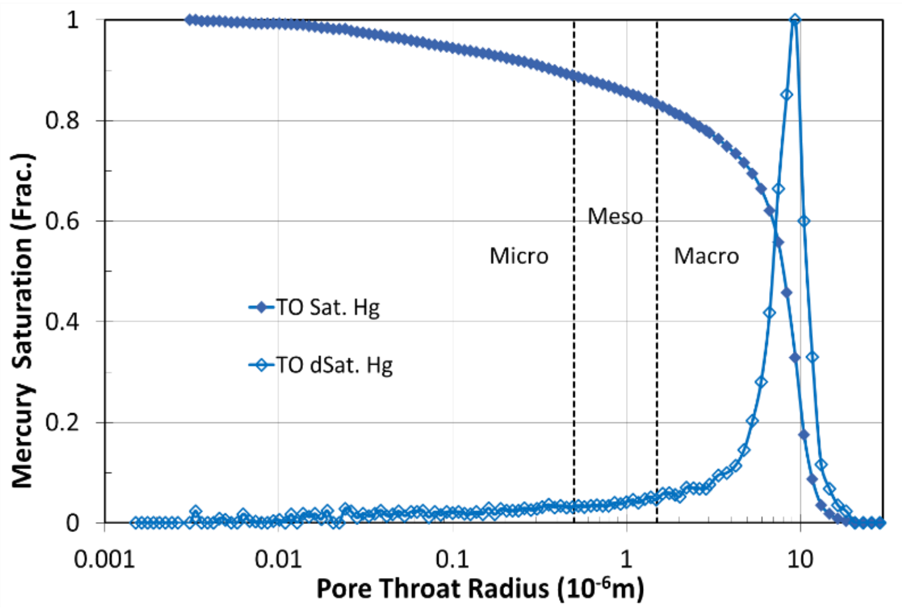


Figure 2.4 Mercury injection (MICP) for pore throat radius distribution of porous outcrop T sandstone rock. (TO) samples

In Figure 2.5, results from a typical oil recovery experiment demonstrating tertiary Smart Water EOR effects in a sandstone core are shown. Both produced oil (%OOIP) and pressure drop (DP) at constant injection rate of 4PV/D are monitored when first flooding formation water (FW) followed by Smart Water, which in this case is a low salinity (LS) 1000 ppm NaCl brine.

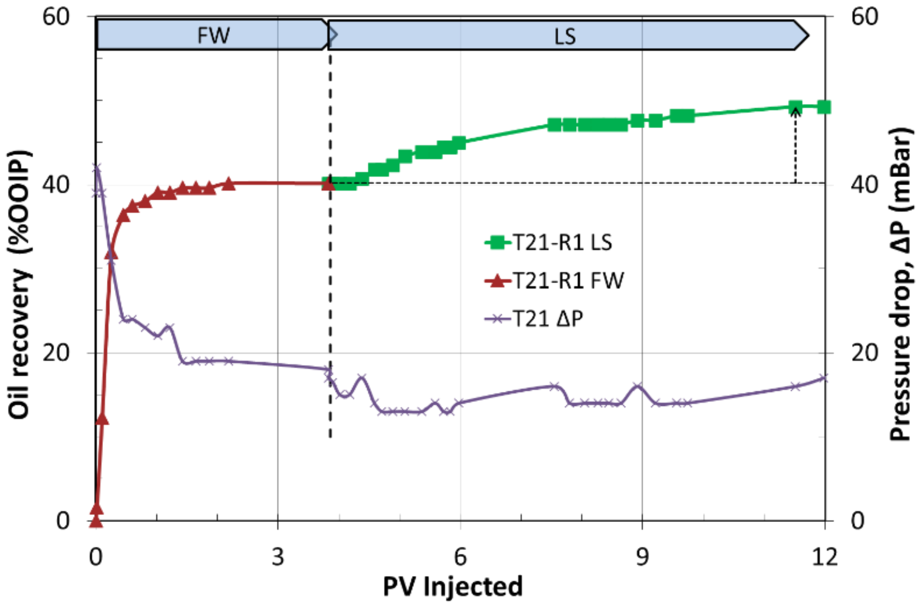


Figure 2.5 Oil recovery test from a sandstone core restored with S_{wi} = 20% and crude oil. The core was successively flooded with FW – LS at a rate of 4 PV/day at 60 °C. Oil recovery (%OOIP) and pressure drop (DP) are monitored during brine flooding (Torrijos, 2017).

A recovery plateau by FW injection was reached at 40 %OOIP, while a significant increase in oil recovery of 25% was observed during LS injection, ending with an ultimate recovery plateau of 50 %OOIP. There was no increased pressure drop accompanying the extra oil recovered during LS injection. The observation in Figure 2.5, confirmed in other studies (Webb et al., 2005), questions the explanations of improved mobility control (IFT variations) (McGuire et al., 2005), clay swelling (Tang and Morrow, 1999) , fines migration (Tang and Morrow, 1999) and diverted flow (Skauge et al., 2010) , proposed for the mobilization of immobile oil in the tertiary oil recovery process. It seems that increased pressure drop during the waterflood experiments is not a requirement for observing enhanced oil recovery by low salinity or Smart Water brines.

2.5.4 Wettability and wettability alteration

Capillary forces are one of the main oil recovery mechanisms in porous media. When the core wettability is on the water wet side, positive capillary forces will contribute in the mobilization of oil especially from smaller pores.

An outcrop T core was restored and spontaneous imbibed with FW_T to evaluate the initial core wettability. By introducing LS as imbibing brine in tertiary mode, we could evaluate if the LS brine could induce a chemical wettability alteration process towards more water wet conditions. The results are presented in Figure 2.6.

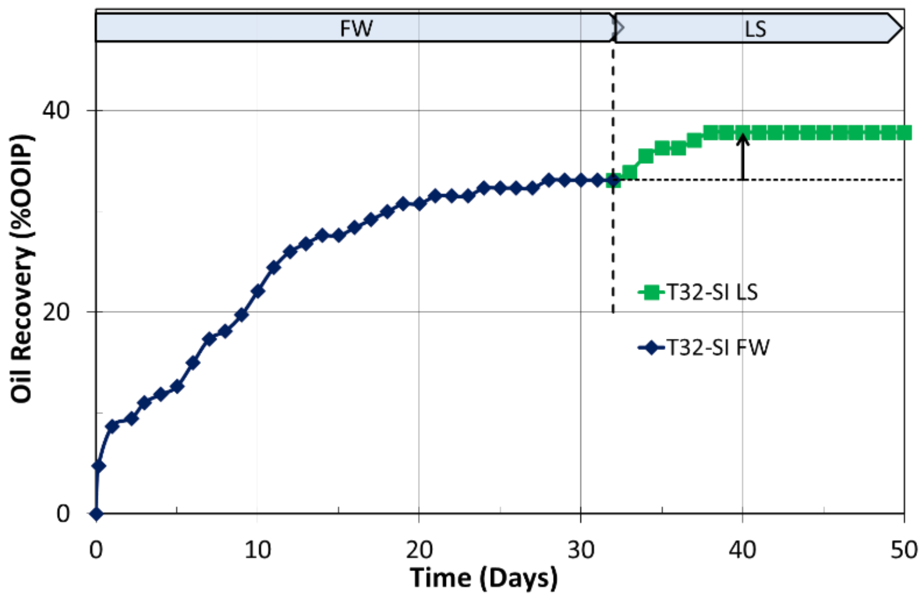


Figure 2.6 Spontaneous imbibition test on core T32 at 60 °C. The core was restored with S_{wi} = 0.20, exposed to 5 PV and aged in Oil T. The core was initially imbibed with FW_T until recovery plateau was reached, followed by Spontaneous imbibition with LS brine.

During Spontaneous Imbibition with FW_T brine, a steady production of oil is observed, reaching an ultimate oil recovery plateau of 33 %OOIP after 28 days. The result confirms that the core behave quite water wet, and capillary forces are able to mobilize more than 80% of the oil produced by viscous flooding during FW_T injection, Figure 2.6.

After 32 days the imbibing fluid is changed to LS brine. A significant increase in oil recovery is observed over the next 6 days reaching a new recovery plateau of 38 as seen in Figure 2.6. The result confirms that LS brine is able induce wettability alteration towards more water wet conditions, mobilizing 15% extra oil compared to FW_T due to generating increased positive capillary forces.

The parameters effecting the capillary forces in porous media could be derived from the equation describing capillary pressure (P_c) for a capillary tube model:

$$P_c = \frac{2 \cdot \sigma \cdot cos\theta}{r} \tag{2.6}$$

Two main parameters will affect the P_c, the wettability as contact angle (θ), and the interfacial tension (σ). In a heterogeneous porous media the capillary forces will also be controlled by the pore size distribution controlling rock permeability, described as the pore radius (r) in the capillary pressure tube model.

The core flooding and Spontaneous Imbibition results confirms that capillary forces need to be accounted for when fluid flow in heterogeneous porous media should described in core experiments and when fluid flow in porous media should be properly described in fluid flow models and upscaled with reservoir simulators.

3 Principles of Waterflooding

The resultant effect of waterflooding is dependent on the interaction between rock minerals and the fluid phases in the reservoir. These interactions are mainly influenced by the composition of the fluid phases, the properties of the rock and temperature. Smith and Cobb (1997) highlights a number of parameters which waterflooding is dependent on. Among them are oil saturation at the start of waterflooding, residual oil saturation to waterflooding, oil and water viscosity, injection rate, connate water saturation, pressure distribution between injector and producer, relative permeability to water and oil. In this section, special focus will be given to the effects of viscous-capillary forces, oil viscosity and injection rate on oil recovery in a waterflooding processes, highlighting some works that have been done in line with them.

3.1 Effect of Oil Viscosity

The viscosity of crude oil systems is an important property which influences the fluid flow of hydrocarbons in the reservoir at various temperatures and pressures. The ability of the oil to flow in the porous medium during a waterflooding or any EOR process is largely dependent on the oil's viscosity among other factors. Flow inefficiencies caused by mobility ratio and pore heterogeneity renders very high viscous oils challenged in flow to production lines, their complex compositions makes them difficult to extract, refine and transport, coupled with its costly rate. The main causes of high viscosity are the presence of solids and high concentrations of heavy fractions and the formation of water-in-oil (W/O) emulsions (Santos et al., 2017). Some research have gone into processes that will lead to oil viscosity reduction in order to improve flow in reservoirs. Dilution of crude oil with alcohols and light oils as a method for viscosity reduction have been looked in to by Hasan et al. (2010), Martínez-Palou et al. (2011) and (Plasencia et al., 2013). Other methods of viscosity reduction such as preparing mixtures with chemical viscosity reducing additives have been investigated by (Junaki et al., 2012); Kuzmić et al. (2008) .

Viscosity effects in a waterflooding process have been examined by Mamudu et al. (2015) who asserted that the displacement efficiency of a waterflood and the resultant oil recovery in a waterflooding process is significantly dependent on the viscosity ratio of the displaced and the displacing fluid. In one case, the viscosity of the displaced fluid was varied while the viscosity of the displacing fluid was kept constant, whiles the second case had the viscosity of the displacing varying and the displaced fluid constant. It was concluded from the study that viscous fluid appreciably improves oil recovery particularly in reservoirs containing viscous oil, and recovery increases with decreasing viscosity ratio and decreases with increasing viscosity ratio.

3.2 Effect of injection rate

Injection and production of fluids in a waterflood is done at rate, thus the injection rate is an important economic and technical factor to consider in undertaking waterflood project. In order to maximize oil recovery in a reservoir in a waterflooding process, an optimized injection rate of the displacing fluid is required. Determining the injection rate informs what types of pumps and equipment to use. The efficiency of the injection rate is partly dependent on reservoir heterogeneity.

Ahmadi et al. (2016) in their work sought to examine the effect of injection rate and temperature in a waterflooding experiment. At varying injection rates and at varying temperature, they examined the performance of the waterflood using water and hot water injection. From the experiment, it was concluded that higher oil recovery can be obtained at a temperature of 90C when at lower injection rate of 0.2cc/min when hot water is used for the waterflooding.

In another work undertaken by Yang et al. (2019),waterflooding was carried out on continental sandstone reservoirs which are very prevalent in China. The objective of the work is to study oil displacement efficiency and water content in an experimental model at different injection rates, and to ultimately determine a plausible or reasonable injection rate as a guide in future development of reservoirs undergoing waterflood. Six high permeability and low permeability sand –filled tube models were used for this experiment. One of the conclusions drawn out of this study was that the water injection rate and the ultimate displacement efficiency showed a relationship, out of which a reasonable injection rate was established and that at that rate highest displacement efficiency can be attained. It was also observed that the permeability of the reservoir system has a relationship with the injection rate.

3.3 Capillary and viscous forces effects

In a waterflooding setup where two immiscible fluids are present, viscous and capillary forces influences the performance of the waterflood. The viscous force refers to the viscous pressure gradient , while the retention force or capillary force is related to the interfacial tension (IFT) between the displacing and displaced fluids (Wang et al., 2007). Capillary forces has been found to be the major driving force in spontaneous imbibition experiments but they are coupled with viscous forces in waterflood experiments. High oil displacement efficiency can be achieved when injection fluid can be sucked into the very smaller pores of the rock to displace the oil present. Significant oil recovery have been observed to be associated with rock systems induced by Smart Water towards more water-wet state, increase in capillary forces and ultimately microscopic sweep efficiency is observed.

Effective mobilization of residual oil i.e. reduction of residual oil saturation, determines the performance of the displacement process which is controlled by microscopic efficiency. In order for an effective recovery of residual oil the displacing fluid causes a viscous force that exceeds the capillary force in a waterflood system (Abrams, 1975; Chatzis and Morrow, 1984).

In a bid to show the influence of viscous and capillary forces, Aghaeifar et al. (2019) performed low rate waterflooding experiments on a low permeable reservoir core. Apart from the viscous flooding experiments, a set of spontaneous imbibition experiments were also conducted. Resorting to a low rate waterflood was to allow wettability alteration and for capillary forces to control oil recovery without the interference of high viscous forces. After the series of experiments, one instrumental conclusion drawn was that similar oil recovery performance was observed in both low rate viscous flooding and spontaneous imbibition experiment, and that led to the confirmation that capillary forces activity in spontaneous imbibition is a major recovery mechanism and must be accounted for in simulation models.

4 Materials, Fluids and Methods

The materials, fluids and methods in the experimental procedure is discussed in this section.

4.1 Materials and Fluids

4.1.1 Rock material

The experiments were conducted on two sandstone outcrop cores namely Leopard core and Bandera Brown core. The cores are low permeable cores which have varying core properties. The core sample, Bandera brown is of the Desmoinesian age while that of the Leopard core is of the Paleozoic. Properties of these cores are presented in Table 4.1 below.

Table 4.1 Sandstone outcrop core properties

Core	**L**	**D**	**V_b**	**Φ**	**k**	**PV**
	(cm)	(cm)	(cm^3)	(%)	(mD)	(ml)
Bandera Brown (BB1)	7.732	3.812	87.10	26.4	7.1	23.03
Leopard (LP1)	7.626	3.792	86.12	25.4	8.3	21.85

The porosity and permeability, as well as the pore volume and bulk volume of the cores were determined by equations stated in section 4.3 of this chapter.

4.1.2 Oils

Pure Marcol oil (Marcol-82) is a mineral oil, colourless liquid obtained from several stages of refined petroleum and forms one of the constituents of the synthetic oil prepared. A synthetic oil used throughout this study constituted a mixture of n-Heptane and Marcol-82 oil at volume proportions. The synthetic oil was prepared according to a mixing by volume ratio of the n-Heptane and the Marcol-82 oil to obtain the viscosity desired. This model oil has no polar components thus the wettability of the core is not expected to be changed. The ratio of the mixture was 50:50, which resulted in the low viscous oil, and will be referred as MO3 throughout the study. Subsequently another model oil was prepared with a mixing by volume ratio of 85:15 to attain a medium viscous oil. This oil will be referred to as MO11 in this study.

- **n-Heptane**: One of the constituents in the model oils prepared is n-Heptane. It is free from surface-active components and apart from its use in the oil preparation, it was used as the non-polar solvent for cleaning the cores saturated with oils.

4.1.3 Brines

The brines used for this study were the formation water (FW) and a diluted formation water (d_5FW). The principal brine i.e. the formation water (100,000ppm) was prepared by mixing Sodium chloride (NaCl) and Calcium chloride dihydrate ($CaCl·2H_2O$). The brines were filtered through a 0.22μm Millipore filters using a filtration pump. The filtration process is to remove undissolved salts and large particle impurities from the brine which may block the core pore throats during flooding. The diluted formation water, on the other hand, is a diluted proportion of the principal brine which is mainly used for establishing the initial water saturation. The proportion of the formation water is diluted five times its volume to get the diluted formation water. The composition of formation water and the properties of the brines used are presented in table 4.2.and 4.3 below respectively.

- **Low salinity brine**: During cleaning of the core, n-heptane is initially flooded which is then followed by low salinity brine. This low salinity brine (1000ppm NaCl) is prepared by mixing 1g of NaCl in a litre of DI water.

Table 4.2 Composition of Formation water

Ion	**mg/L**	**mM**
Cl^-	60985.9	1720.2
Ca^{2+}	3611.3	90.1
Na^+	35402.8	1540
TDS (g/L)	100	

Table 4.3 Brine properties

Brine	**Density(g/cm3)**	**Viscosity(cP) at 20°C**	**Viscosity(cP) at 60°C**	**Bulk pH**
Formation water(100,000ppm)	1.01	1.06	0.76	6.85
Diluted formation water, d_5FW	1.067	1.31	0.864	6.43

4.2 Fluid Properties Measurements

4.2.1 IFT measurements

The interfacial tension (IFT) of the oils were measured by having the formation water as its base. IFT measurements were taken using a Kruss K6 tensiometer at room temperature. The instrument has a torsion wire connected to a ring, which is immersed in the liquid containing two immiscible liquids i.e. oil and formation water. The ring is slowly pulled out from the liquid, resulting in a tensioned liquid lamella forming in the ring when it is being moved from the water phase to the oil phase. The tension at the phase boundary causes the lamella to break off from the ring which the causes a defection of the wire. The IFT is then measured on a scale by means of a drag pointer. An illustration of Kruss K6 tensiometer is presented in figure 4.1

Figure 4.1 Kruss K6 tensiometer

4.2.2 Viscosity Measurements

The viscosity of all the brines and oils used in this study was measured with an Anton Parr Modular Compact rheometer MCR302. The instrument has a rotating core plate which comes into contact with the fluid to determine its viscosity. The viscosity of the fluids were measured between shear rate of 50 (1/s) to 500 (1/s) with 5 checking points. For each fluid, the viscosity measurement was repeated three times to ensure an accurate value.

4.2.3 pH Measurements

All the brines reported in this work had their pH measured using a SevenCompact pH meter from Mettler Toledo. The pH of these brines will be measured to determine the brine's acidity or basicity. The formation water (FW), diluted formation water and the water produced along the oil in the forced imbibition process had their pH measured. Each time the pH meter was to be used, it was calibrated with buffer solutions of pH of 4, 7 and 10. For accuracy and quality assurance, the pH meter has an inbuilt calibration programme.

4.2.4 Density Measurements

Densities of all the brines and oils were measured with an Anton Parr DMA-4500 density meter. The density of each of the fluid was measured by injection of the fluid into an opening on the instrument, where there is a glass tube that the fluid comes into contact with. Any air bubbles can easily be detected in that stage, a short time after that the density is played on the screen on the instrument.

4.3 Methods

4.3.1 Porosity measurements

The length (L) and diameter (d) of the cores are measured to determine the bulk volume of the core. The bulk volume of a core is calculated by;

$$V_B = \frac{\pi d^2 L}{4} \qquad (4.1)$$

The core is saturated with diluted formation in a vacuum chamber after which the saturated weight is measured (W_{sat}). The difference between the dry weight and the saturated weight of the core, divided by the density of the diluted formation water gives the pore volume (PV);

$$PV = \frac{W_{sat} - W_{dry}}{\rho_{dFW}} \qquad (4.1)$$

where:

PV = Pore volume core (cm^3)

W_{sat} = Weight of core 100 % saturated with diluted FW (g)

W_{dry} = Weight of dry core (g)

ρ_{dFW} = Density of diluted FW (g/cm^3)

Finally the porosity of the core is then determined using the relationship between PV and V_B below.

$$\Phi = \frac{PV}{V_B} \qquad (4.2)$$

where:

Φ = Porosity of core (%)

PV = Pore volume of core (cm^3)

V_B = Bulk volume of core (cm^3)

4.3.2 Permeability measurements

The permeability of the core materials was calculated with data retrieved from core flooding test using low salinity brine .At an injection rate of 0.1ml/min, the cores were flooded and the pressure drop across different times in the flooding process were recorded out of which an average pressure drop was taken. Determination of the permeability of the cores were calculated using Darcy's equation, Equation 2.1 in chapter 2.Having the flow rate, pressure drop, water viscosity and the dimensions of the core, the permeability is calculated by rearranging the equation to the form;

$$k = \frac{q}{\Delta P}\frac{\mu . L}{A} \qquad (4.4)$$

4.3.3 Core restoration

Prior to spontaneous imbibition and viscous flooding experiments, the cores went through a restoration process which seek to establish water saturation and oil saturation. The cores were saturated with Swi=20% dFW and Soi=80% of synthetic oil.

4.3.3.1 Establishing Initial water saturation (Swi)

The two cores were initially fully saturated (100%) with diluted formation water in readiness to establish the initial water saturation (S_{wi}) to 20%. After being saturated with the diluted formation water, the pore volume and porosity of the core is determined using the equations 4.1 and 4.2.Figure 4.2 below illustrates the how the cores were saturated with diluted formation water.

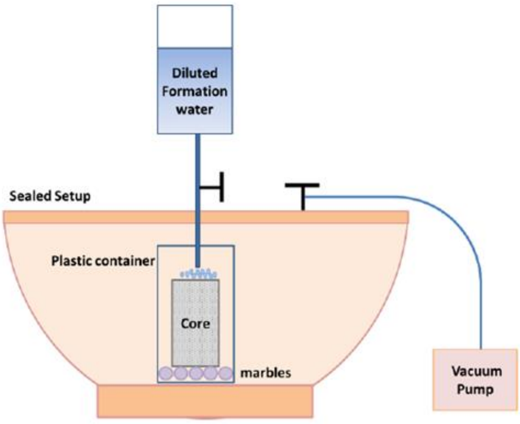


Figure 4.2 Schematic of core saturation with diluted formation water

After saturation, the cores were placed in a dessicator containing silica gel for the absorbed fluid to gradually vaporize until its target weight (Tw) is reached. The silica gel draws and stores water molecules from its immediate environment. Figure 4.3 illustrates the dessicator method.

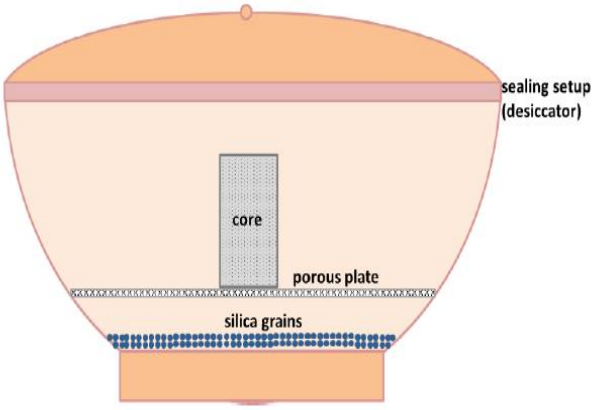


Figure 4.3 Schematic of the core in a dessicator

The weight of the cores were regularly monitored to know when the target weight had reached. The target weight at 20% initial water saturation (S_{wi}) was determined by the equation below.

$$W_{target} = W_{dry} + S_{wi} \cdot VP \cdot \rho_{Fw} \tag{4.3}$$

where

W_{dry}: Dry weight of the core (g)

PV: Pore volume (ml)

S_{wi}: Initial water saturation

ρ_{Fw}: Density of formation water (g/cm^3)

4.3.3.2 Establishing oil saturation

After the cores had been stored, they were ready to be saturated with the model oil. The saturated oil would be occupying the remaining 80% of the pore volume since S_{wi} of 20% had been established. The cores were placed in a saturation chamber and was introduced to vacuum. While under vacuum, the low viscous model oil was flushed gently into the chamber until the core was fully immersed in the oil. The setup was then left overnight for the oil to saturate the pores of the core.

After 24 hours of saturation, the weight of the saturated core is taken. The original oil in place (OOIP) was then calculated to determine the volume of oil that has been absorbed by the pores of the core. To determine the OOIP, the following equation was used;

$$OOIP = \frac{W_{so} - W_{target}}{\rho_{oil}} \tag{4.4}$$

where

OOIP - Oil initially in place (ml)

W_{so} - Saturated weight of core (g)

W_{target} - Target weight (g)

ρ_{oil} - Density of oil (g/cm^3)

Subsequent to determining the OOIP, the percentage of oil accumulation is also determined since after the initial saturation, the oil can occupy the remaining 80% of the pore volume. To determine the percentage of oil accumulation, the following equation is used;

$$OOIP\ (\%) = \frac{OOIP}{PV} * 100 \tag{4.5}$$

where

OOIP = original oil in place (ml)

PV = Pore volume (ml)

4.3.4 Core cleaning

After the core had gone through oil recovery test and no recovery is observed, the cores are finally cleaned by flooding 5PV of n-Heptane from both ends of the core. Subsequently, 5PV of low salinity brine 1000ppm NaCl is flood through the core to remove formation water and any other precipitated salts. The core is then finally dried at 90°C and restored for the next experiment. It is necessary to note that in between the spontaneous imbibition, oil recovery test at low rate and at high rate, the cores were cleaned and restored before an experiment was conducted on them. This is performed in order to clean all residual oil and brines in the core and restore them to their initial state.

4.3.5 Oil recovery by Spontaneous Imbibition.

Following the saturation of core with oil, spontaneous imbibition experiment was then conducted. The saturated core was placed on top marbles at the base of graduated Amott cell. The marbles allow for increased surface area for the imbibition fluid which is the formation water. The setup was conducted in a chamber with temperature of 60°C.The base cell had valves through which the FW is introduced to the core for the imbibition process. Connecting the base cell was a burette which was used to collect and record the volume of displaced oil.

4.3.6 Oil Recovery by Viscous Flooding (VF)

A subsequent oil recovery test was done on the cores, this time the core is consciously imbibed with formation water at an injection rate to displace the oil, unlike the spontaneous method. This method was conducted in low rate and in high rate as well. The procedure is done in a Hassler core holder where the core is held in a horizontal position, while the formation water pumped through one side of the core at a constant rate, forcing the oil to be displaced. The setup is left until no production is observed for 24 hours. The total oil recovery is recorded in %OOIP with respect to time.

5 Results and Discussion

The oil recovery from reservoir systems are dependent on viscous, gravity, and capillary forces. In laboratory core experiments gravity segregation is a very slow process and could be excluded in experiments performed within days or a few weeks, and then oil mobilization is mainly controlled by capillary and viscous forces.

Smart water EOR effects observed in laboratory core experiments is physically explained as a wettability alteration process towards more water wet conditions, inducing increased capillary forces which mobilizing the extra oil observed.

In this laboratory core study, we will evaluate the effect of viscous and capillary forces in oil mobilization from sandstone cores which have not been exposed to crude oil and behave very water wet. This study sought to evaluate the effects of oil viscosity and the effect of injection rate of brine on the oil recovery, as well as looking at capillary forces and its contribution to the mobilization.Two different outcrop sandstone systems have been used, low permeable Bandera Brown (BB) and Leopard (LP) cores. The results are then discussed in line with the objectives of this study.

5.1 Fluids viscosities and Interfacial Tension (IFT)

The synthetic oils used in this study were produced in the laboratory by mixing Marcol 85 mineral oil with different ratios of heptane to generate oils with different viscosities. Principally, a low viscous oil was used throughout the study while a medium viscous oil was employed in a few experiments to examine the effects in viscosity change. The interfacial tension between the synthetic oil mixtures and the FW were subsequently measured.

Figure 5.1 and 5.2 illustrates the viscosities of both the mineral oils and the brine used in this study. They were determined at temperatures of 20°C and 60°C respectively.

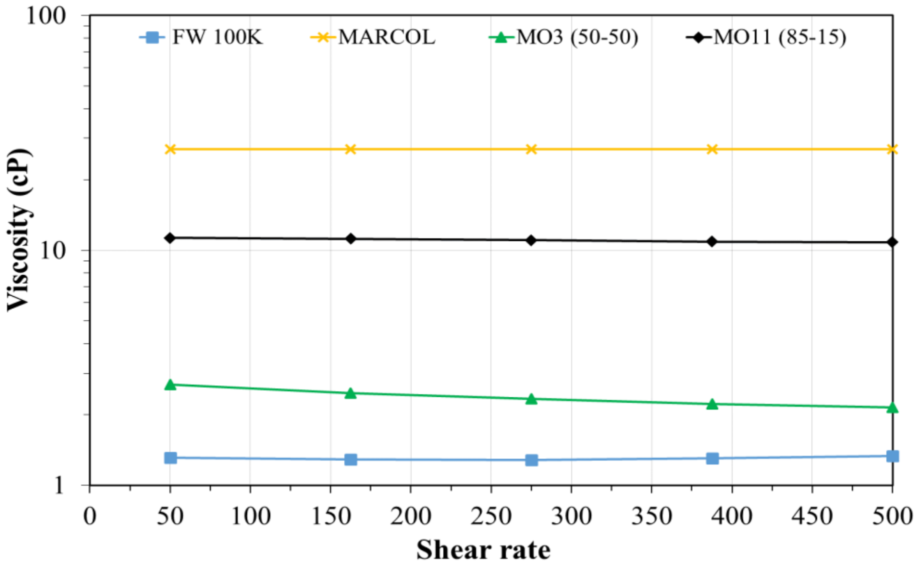


Figure 5.1 Fluid viscosities measured at 20°C

At 20°C the viscosity of the oils were 3cp for MO3, 11cp for MO11 and a viscosity of 27cP was recorded for the pure Marcol oil. Different proportions of n-heptane and Marcol oil in the synthetic oil was tried since a low viscous and a medium viscous oil were desired for this study.

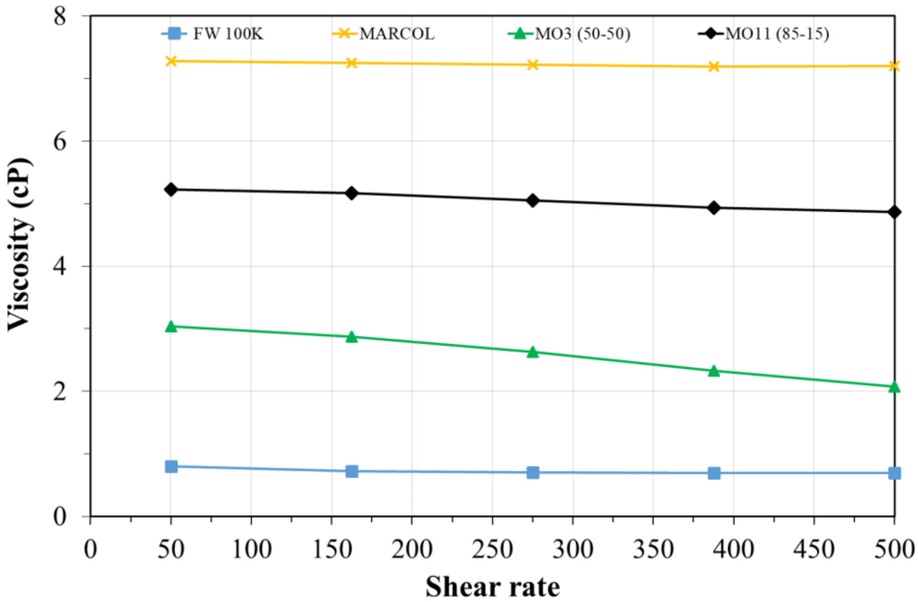


Figure 5.2 Fluid viscosities measured at 60°C

At 60°C, we observe a general decrease of the oil viscosities. At high temperatures, there is thermal cracking of the oil molecules into smaller molecules hence the reduction in viscosity. All laboratory acceptable procedures were followed in measuring the viscosities but the resulting viscosity value of MO3 measured at 60°C was questionable. It was expected that the viscosity will be less compared to its value measured at 20°C, but there was no difference in the values. It is assumed in this work that, since n-Heptane is volatile and easily evaporates at higher temperatures, that could have resulted in the value generated.

Figure 5.1 illustrates the Interfacial tension plot of the mineral oils MO3 and MO11 and brine.

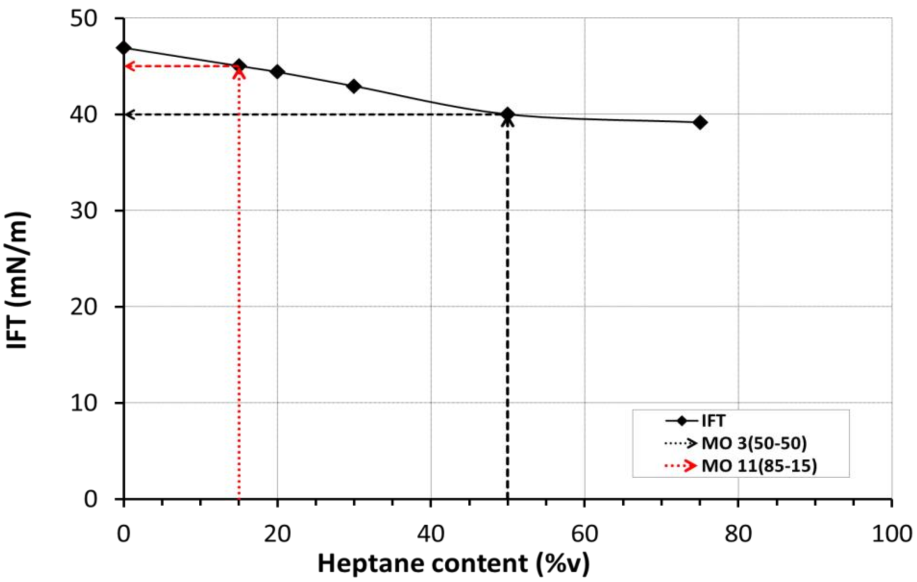


Figure 5.3 Interfacial tension of MO3 and MO11

With MO3 having a 50% heptane content, the IFT value observed was 40 mN/m while that of MO11 was 45 mN/m. From the trend observed in the laboratory studies, the IFT between oil and the brine decreased with decreasing viscosity at atmospheric conditions. IFT of MO3 which has a viscosity of 3cP, between the brine was less than IFT of MO11 with viscosity of 11cP. Pure marcol oil which has a viscosity of 27cP had its IFT value at 47mN/m.

The differences between the IFT of the oils are not large, nonetheless their potential effect on oil recovery can be considered. Some studies suggest that lower IFT between oil and brine can enhance oil recovery and if that claim can be borrowed in this work, it will suggest that MO3 will perform better than MO11 in oil recovery based on their viscosities.

5.2 Spontaneous Imbibition (SI) of Bandera Brown

One way of quantifying the wettability of a core is by performing a spontaneous imbibition experiment on the core. Initially the core BB1 went through a fluid restoration process where initial water saturation of 20% with FW was established before vacuum saturation with the Mineral oil with a viscosity of 3cP at 20°C, MO3.

The spontaneous imbibition experiment was performed at 60°C on the core BB1 using FW as the imbibing brine.

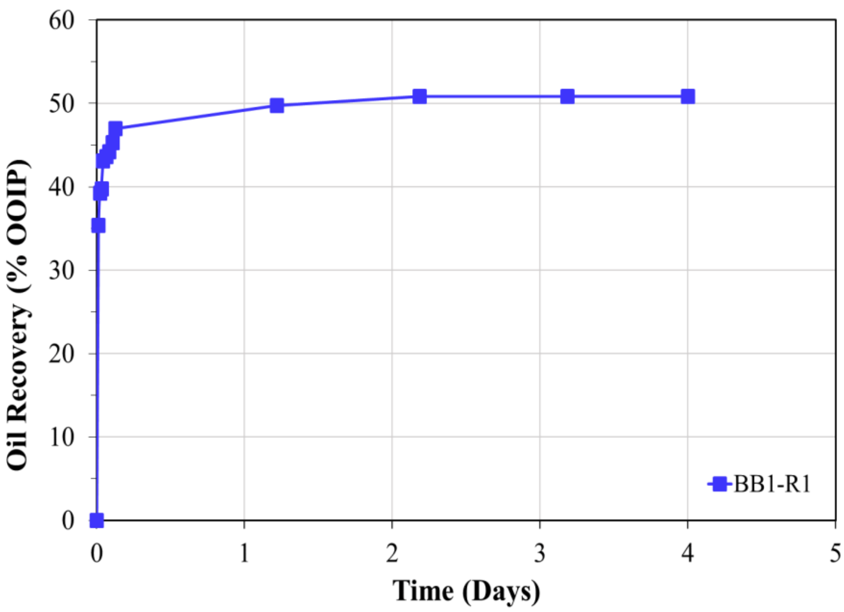


Figure 5.4 Spontaneous imbibition performed on core BB1-R1 at 60°C using FW as the imbibing brine. The core with a permeability of 7 mD was restored with Swi =0.2 and saturated with oil MO3. The oil recovery (%OOIP) is presented vs. time (Days)

The spontaneous imbibition (SI) of the low permeable core BB1 reached the recovery plateau after two days, mobilizing 50 % OOIP as illustrated in figure 5.4. A greater portion of the oil recovered, about 40%OOIP, was mobilized within an hour by the imbibition process. The rapid SI process with high amount of oil mobilization confirms that the core behaves very water wet.

5.3 Viscous Flooding on Bandera brown core using MO3

5.3 .1 Viscous flooding of BB1 at high injection rate

After SI, the BB1 core was cleaned and restored, subsequent to that a viscous flooding (VF) experiment was conducted on the core saturated with MO3. The Bandera brown outcrop core was chosen due to its low permeability and to examine its oil recovery performance.

Oil recovery by viscous flooding (or forced imbibition) was carried out in a hassler core holder at 60°C at high injection rate of 4PV/day.

Formation water (100,000ppm) was pumped at 4PV/day to displace the oil in the core, MO3.

Figure 5.3 illustrates the performance of the BB1 in the VF conducted at high rate.

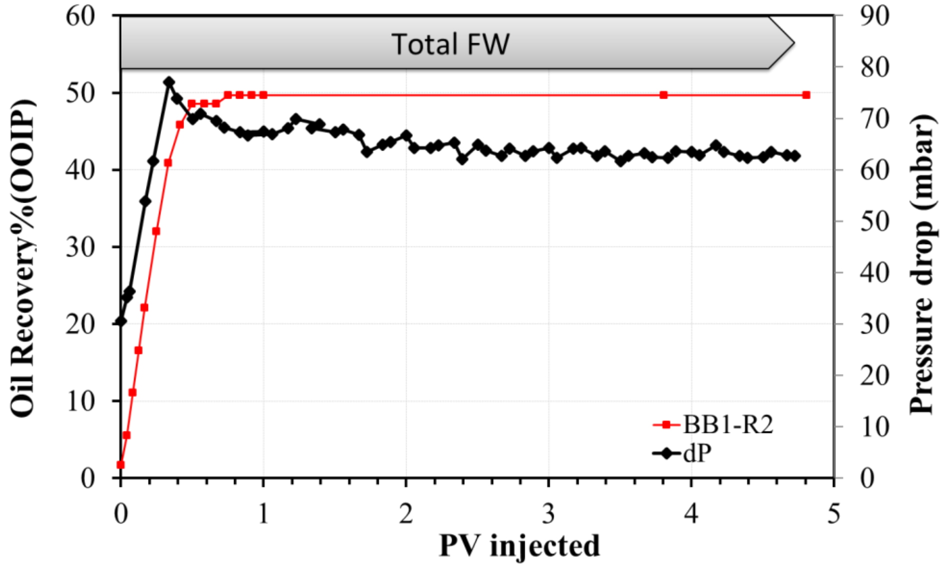


Figure 5.5 Viscous Flooding performed on core BB1-R2 at 60°C using FW as the injection brine. The core was restored with Swi = 0.2 and saturated with MO3 oil. The oil recovery %OOIP is presented vs PV injected at high rate (4PV/day).

We observe a high displacement efficiency, and the first produced water is not observed before 45 %OOIP is produced. An ultimate oil recovery plateau of 50 %OOIP is reached after less than 1 PV injected.

The pressure drop gradually increasing during FW injection reaching a maximum value of 80 mbar after 0.4 PV injected, before it gradually declines to 65 mbar when the recovery plateau is reached. Further FW injection only have minor effects on the pressure drop.

5.3.2 Viscous flooding at low injection rate

After being flooded with formation water at a high injection rate, the core was cleaned and restored for a second VF at a lower injection rate i.e. 1PV/day.

Figure 5.6 illustrates the results obtained when VF was performed at a low rate on the BB1 core.

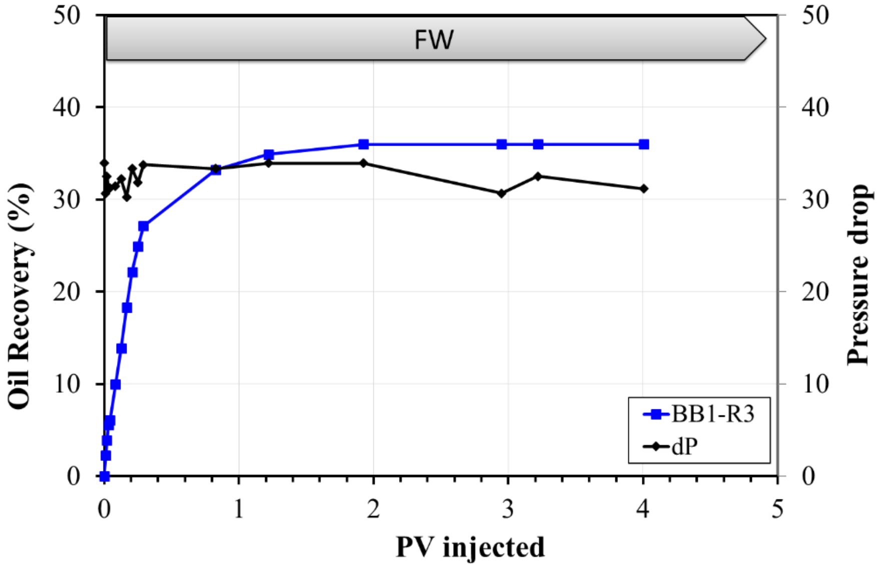


Figure 5.6 Viscous Flooding performed on core BB1-R3 at 60°C using FW as the injection brine. The core was restored with Swi = 0.2 and saturated with MO3 oil. The oil recovery %OOIP is presented vs PV injected at low rate (1PV/day)

A complete different oil recovery profile is observed during low rate injection.

VF at low rate on core BB1-R3 yielded a lower oil recovery as seen for the low rate injection observed in figure 5.6. Continuous oil production is observed until 27 % OOIP produced, and the recovery plateau of 36 %OOIP is reached after 2 PV injected.

The pressure drop profile is also significant different from the results observed at high rate. At the onset of this VF, pressure data was unstable hence could not be captured when oil production began. We observe a lower pressure drop as expected for lower injection rate, but no gradually increase is observed during the start.

5.4 Viscous Flooding of Bandera brown using MO11

For the series of VF experiments conducted up to which the results are presented above, a low viscous oil (MO3) was used. From the results, VF experiments conducted at high rate yields more oil than at low rate with the Bandera brown core. The viscosity of oil was a constant parameter in the VF processes hence oil mobilization was observed with that oil viscosity.

In order to examine the influence of oil viscosity on oil recovery, a mineral oil with a viscosity of 11cP (MO11) was adopted and a VF experiment was conducted after the third restoration of BB1-R3. The injection rate of FW was 4PV/D (high rate). Figure 5.7 below illustrates the oil recovery by VF experiment using the medium viscous oil.

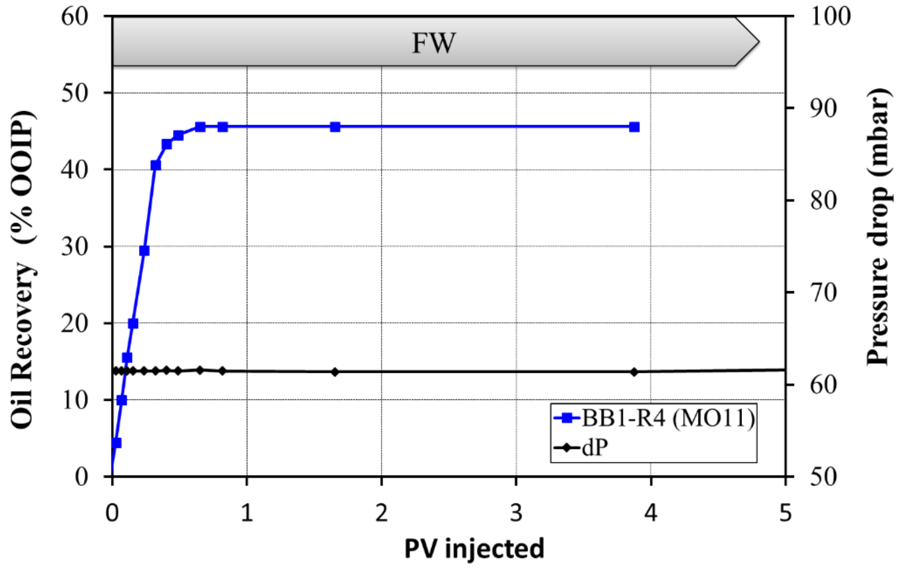


Figure 5.7 Viscous Flooding performed on core BB1-R4 at 60°C using FW as the injection brine. The core was restored with Swi = 0.2 and saturated with MO11 oil. The oil recovery %OOIP is presented vs PV injected at low rate (4PV/day)

We observe a normal recovery profile in this VF experiment. At an injection rate of 4PV/day, an ultimate recovery of 45%OOIP is obtained after 1PV of FW injected. Based on the fast rate of production, the displacement efficiency can be considered as a high one. The pressure drop observed along oil recovery in the VF experiment do not fall in line with typical pressure drop profiles in waterflooding. A seemingly constant pressure drop of 62mbar is observed throughout the process, behaving contrary to what was seen in figure 5.5.

5.5 Spontaneous Imbibition of Leopard Core

The Leopard core, LP1, was subjected to a spontaneous imbibition experiment in a 60°C oven, with the core saturated with MO3.The imbibing brine used for this experiment was the formation water. The performance of the core during the SI experiment is presented in figure 5.8.

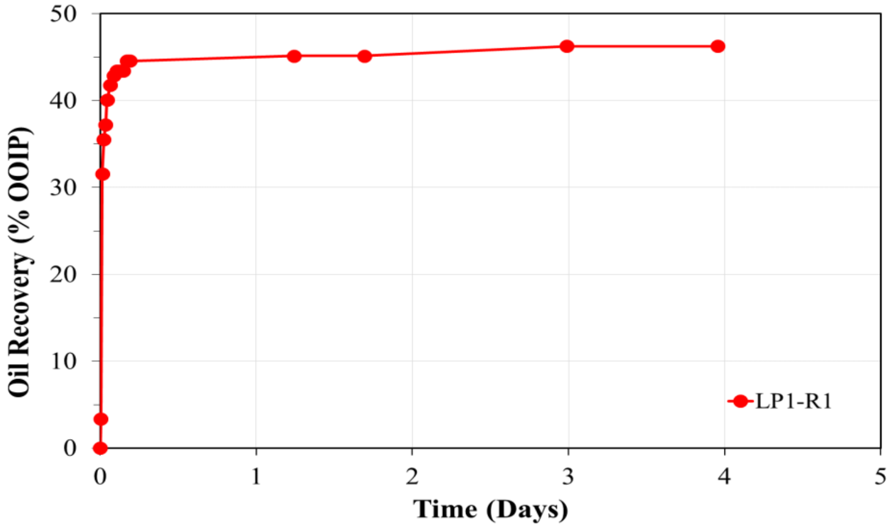


Figure 5.8 Spontaneous imbibition performed on core LP1-R1 at 60°C using FW as the imbibing brine. The core with a permeability of 8mD was restored with Swi =0.2 and saturated with oil MO3. The oil recovery (%OOIP) is presented vs. time (Days)

Oil recovery reached plateau after three days into the imbibition process. Ultimately, 47%OOIP was recovered from the process. LP1 also experiences a fast rate of imbibition as a greater portion of the oil recovered occurred in less than two days.

5.6 Viscous Flooding of Leopard core using MO3

5.6.1 Viscous Flooding at high injection rate

At second restoration of the core LP1, the core underwent a viscous flooding experiment. The core was subjected to the process at a high and low injection rate as seen for the BB1 core. For each injection rate, the core was saturated with the mineral oil, MO3. At a high injection rate, 4PV/day of formation water was used. Figure 5.9 illustrates the oil recovery performance of the LP1 core.

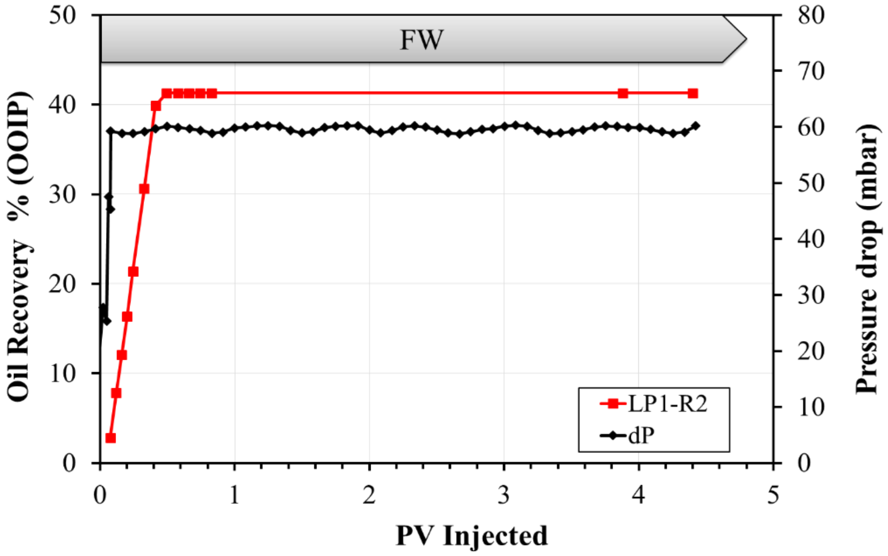


Figure 5.9 Viscous Flooding performed on core LP1-R2 at 60°C using FW as the injection brine. The core was restored with Swi = 0.2 and saturated with MO3 oil. The oil recovery %OOIP is presented vs PV injected at high rate (4PV/day)

Mobilization of oil from LP1 was characterized by a fast rate of recovery as a greater portion of oil was recovered even before 1PV of formation water injected. Oil recovery reached a plateau with 41%OOIP recovered as seen in figure 5.9. Presented on the figure also a pressure drop profile, which starts with a build-up of pressure drop when oil recovery began until it flattens out when before recovery plateau was reached.

5.6.2 Viscous flooding at low injection rate

At third restoration of the LP1 core, the injection rate in the VF experiment was set to low rate (1PV/day) for this phase of this exercise. During the process of cleaning the core LP1 in preparation for the VF at low rate, portions of the core got disintegrated, which then changed the pore volume of the core thus resulting to a decrease in the saturation of the core. An image of the dismembered core is presented in the appendix. Figure 5.10 below illustrates the oil recovery profile of VF conducted at low rate.

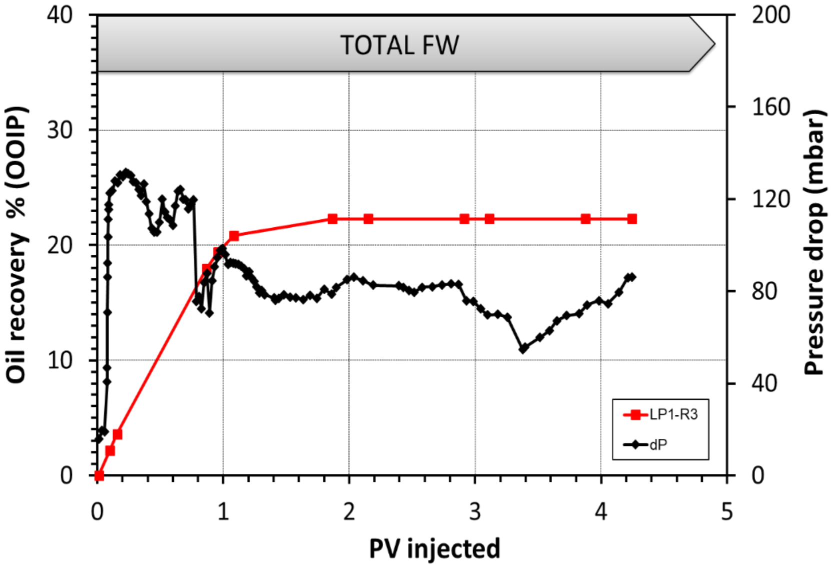


Figure 5.10 Viscous Flooding performed on core LP1-R3 at 60°C using FW as the injection brine. The core was restored with Swi = 0.2 and saturated with MO3 oil. The oil recovery %OOIP is presented vs PV injected at low rate (1PV/day)

We observe a significant decrease in oil production with LP1 at a low injection rate. Oil recovery reached a plateau with 22%OOIP recovered. Recovery plateau was realized after 2PV of FW had been injected. The oil recovery is characterized by pressure build-up at onset of oil recovery until it reaches its peak before recovery plateau. There is an observed decline in the pressure drop as recovery continues until water breakthrough.

5.7 Bandera brown core - Discussions

5.7.1 SI on BB1 - discussion

Spontaneous imbibition experiments are capillary driven thus oil recovery is hugely dependent on the activity of capillary forces. Since there are no external drives to enhance oil recovery in SI, capillary forces tends to be the major driving force. As observed with BB1, 50%OOIP was produced during SI, which is quite a significant amount recovered from a low permeable core. The significant amount of oil recovery can be attributed to the strong capillary forces present. The BB1 core behaves strongly water wet as depicted by the fast rate of imbibition and the subsequent high oil mobilization as seen in figure 5.4.

The BB1 core was saturated with MO3 which has a viscosity of 3cP, and at that oil viscosity, flow should generally be easy thus in the SI experiment, we can observe that oil viscosity did not impede production hence a significant amount of oil was recovered.

Figure 5.11 illustrates the results of series of spontaneous imbibition tests done on both Bandera brown and Leopard cores. The plot on the left represent the oil recovery of cores that were saturated with MO11 while the right plot represent cores saturated with MO3. We observe that there is significant oil recovery from all the cores which depicts that the cores behave water wet, nonetheless the Bandera brown cores seems to yield more oil recovery regardless of the oil viscosity in SI as seen in figure 5.11.

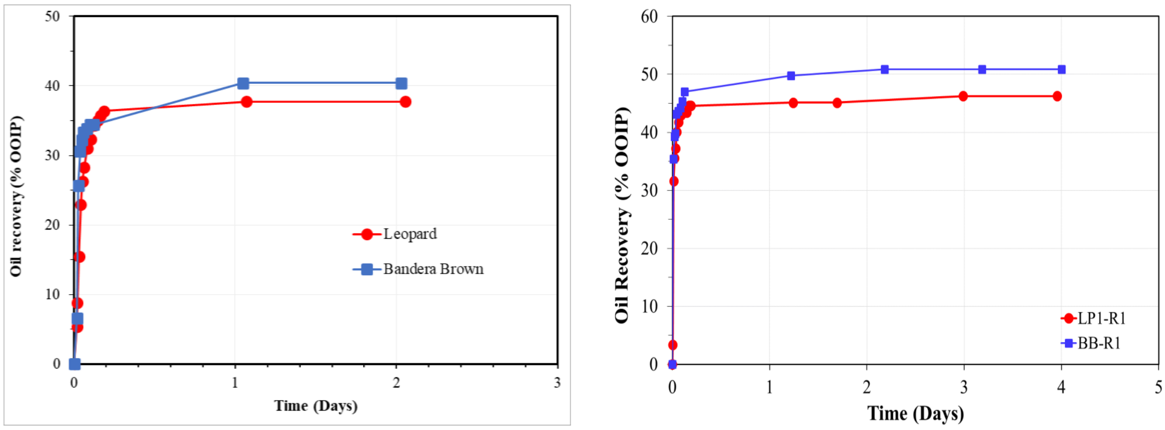


Figure 5.11 Spontaneous imbibition performed on both sets of Bandera brown and Leopard core at 60°C using FW as the imbibing brine. The core were restored with Swi =0.2 and saturated with oil MO11 and MO3. Oil recovery (%OOIP) is presented vs. time (Days)

5.7.2 Viscous Flooding at high injection rate

At second restoration the water wetness of the BB1 core is still intact considering the outcome of the VF and the rate at which the recovery hit plateau. Oil recovery observed by the BB1 core at high rate is 50% as presented in figure5.5.

It is important to note that the oil recovery during the SI experiment and the viscous flooding experiment at high injection rate with the BB1 core was the same, with each experiment producing 50%OOIP. Capillary forces were responsible for driving oil in SI, and what is being observed in this VF experiment indicates that capillary were actively present and strong resulting in the volume of oil that was swept from the core.

Presented on figure 5.6 also is the pressure drop profile during the flooding process. There is a build-up of pressure drop (ΔP) at a certain point in the flooding process. The pressure drop builds up to about 77mbar and then reduces and fluctuates between the ranges of 60 and 70 mbar. Build-up of ΔP is an indication of capillary forces at work, as indicated in figure 5.5. When water begins to enter the core, it finds the easiest ways to imbibe the pores of the core which impedes a rapid pressure build-up. As observed, there the reduction in the pressure drop begins when the recovery was about hitting plateau and subsequently reduced a bit further during the plateau stage. The pressure drop profile is typical of waterflooding experiments as seen figure 2.6 in chapter 2.

5.7.3 Viscous Flooding at low injection rate

In figure 5.6, VF experiment performed on BB1 at low injection rate resulted in an ultimate recovery of 36%OOIP. The recovery reached a plateau after 2PV of total formation water have been injected. At low rate, there were still activity of capillary forces nonetheless, less oil were recovered.

From figure 5.6, there is no observable pressure drop build-up, as seen with the high rate, at onset of oil recovery with reason being that, the pressure drop was very noisy and with a very unstable pressure readings at the onset of oil recovery. No interpretation could be drawn from it hence the pressure system was reset while oil recovery had already began. Just at onset of plateau, through to the end of the experiment, pressure drop was in the range of 30 – 33mbar.

5.2.4 Effect of injection rate on BB1

Conducting a VF on the core at high and low rates yielded different outcomes. Figure 5.12 below illustrates the oil recovery performance of the BB1 core at the different rates.

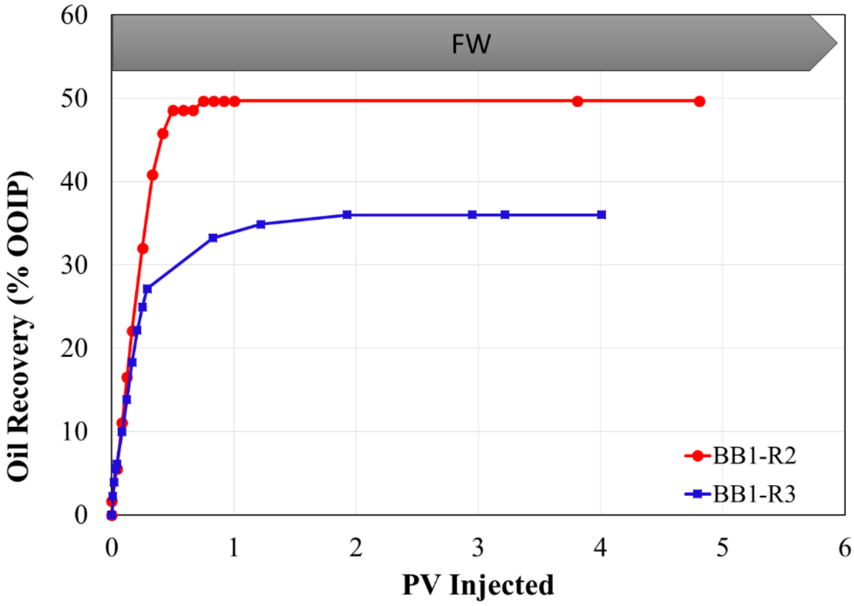


Figure 5.12 Viscous Flooding experiment at 60°C showing oil recovery %OOIP vs PV injected at high rate and low rate for BB1 core.

From figure 5.12, there is a significant difference between the oil recovered at high and low injection rates. During VF experiments, the forces that are at play are capillary forces and viscous forces. Forces of capillary are what induces oil to be swept from the cores and as illustrated in the figure above, it is observed from that at high injection rate, there is more oil recovery than at low injection rate. It can be drawn from this observation that the capillary forces are strong in high rate systems as observed with BB1 core.

At low injection rate, the displacing fluid, in this instance the formation water's efficiency on driving the imbibed oil out of the core is relatively low. The oil viscosity associated in this oil recovery at both low and high injection rate appears not to be a major contribution of the core's recovery efficiency. This is because at either rates, there were oil recovery but at low rate, the injection force could not overcome the oil's adherence on the pores of the rock hence a lower oil recovery. It can be drawn from these observations that, having a low viscous oil in a porous medium like the BB1 core would require flooding at a high rate in order to recover more of the oil.

5.7.5 Oil viscosity effect – VF of BB1 using MO11

The oil recovery observed after the change in oil viscosity was 46%OOIP.The recovery plateau was reached even before 1PV of formation water was injected. With this medium oil viscosity, the percentage of oil recovered was different from what the low viscous oil produced. The oil recovered with medium viscous oil is less than what is recovered with low viscous oil. Due to the relatively high viscous nature of this oil, the capillary forces and the viscous forces which are paramount in VF processes, was unable to displace a significantly high volume of oil.

This experiment saw the pressure drop profile exhibiting some stability along the production. The pressure drop was almost steady at 61mbar from the onset of the VF process to the end of it. Unlike what was observed in earlier experiments where there was a build-up of the pressure drop, this experiment had nothing similar to that.

5.7.6 Viscous flooding of BB2 with MO11

Another set of VF experiments were performed on a different Bandera brown core (BB2), which was saturated with a medium viscous oil (MO11) with viscosity of 11cP. Figure 5.12 below illustrates the oil recovery performance at a high and low injection rate.

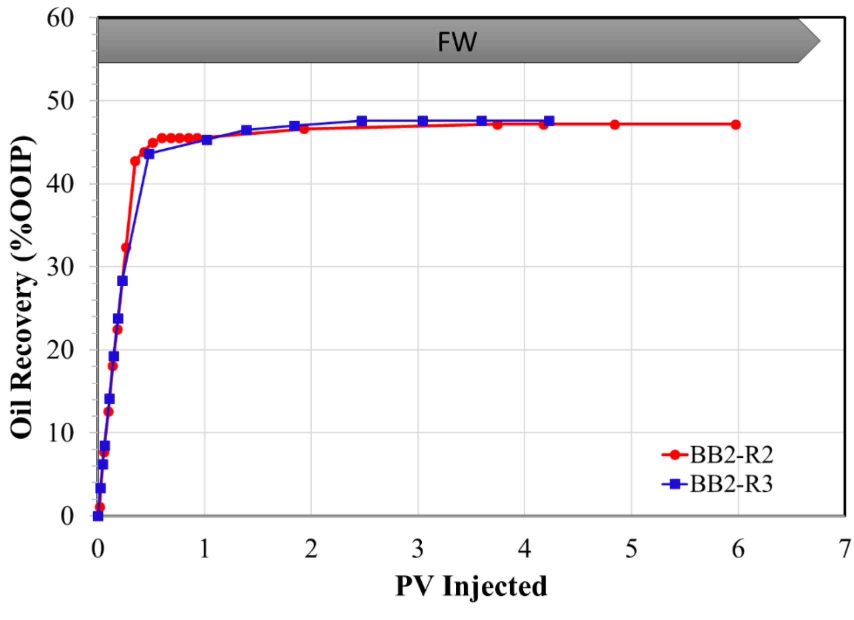


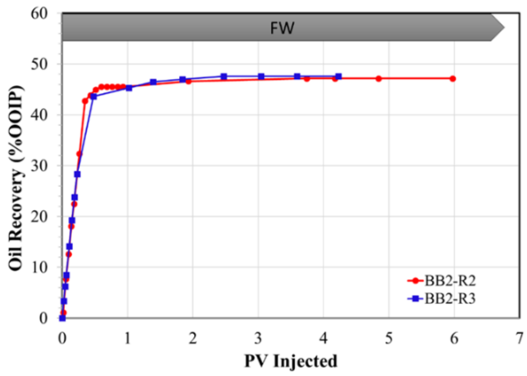
Figure 5.13 Viscous Flooding experiment at 60°C showing oil recovery as a function of PV injected at high rate and low rate for BB2 core saturated with MO11.(Ref. parallel ongoing MS thesis Iyad,2021)

As observed in figure 5.13, the oil recovery recorded at both low and high injection rate was the same. Capillary forces acts strongly in this setting due to the rapid recovery rate considering the plateau hit after injection of 2PV. The variable parameter, which was the injection rate, did not induce any change in the oil recovery. The BB2 core in this experiment has exhibited that injection rate is not an instrumental factor in oil recovery. The activity of capillary and viscous forces are seen to behave similar in both low and high rate experiments.

The viscosity of MO11 which is also observed not to effect any significant change in oil recovery in both low and high injection rate.

The noticeable observation is that at both high and low injection rate, 47%OOIP is recorded for the BB2 core. The oil recovery hit its plateau after injection of 2PV of formation water.

Figure 5.14. presents recovery profiles of Bandera brown core in VF conducted at high rate.



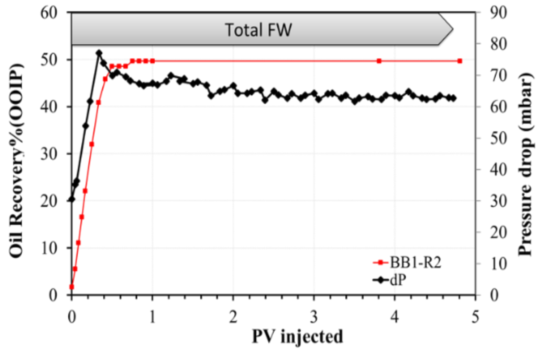


Figure 5.14 Viscous flooding performed on Bandera brown core saturated with MO11 and MO3. The cores were restored with Swi = 0.2 and. The oil recovery %OOIP is presented vs PV injected.

On the water wet Bandera Brown cores we observe the same recovery profiles for high viscosity oil at both high and low injection rate. The low viscosity oil shows the same recovery profile at high injection rate, confirming that capillary forces is important in oil recovery processes. The effect of mobility ratios seems to have less effect.

5.8 Leopard core – Discussions

The idea of choosing the Leopard core was due to its high permeability status. Low salinity (LS) brine injection during core preparation (permeability measurement) may have influenced the core properties.

Tiny particles from the core fell off and eventually disintegration of core was observed when the core was restored. The disintegrated core is presented in figure 5.15 below.

Figure 5.15 Disintegrated Leopard core

5.8.1 Spontaneous Imbibition of LP1

With LP1 core, even though we have a significant low permeability, we still observe high imbibition rate reaching 45%OOIP after only 5 hrs, and an ultimate recovery plateau of 47%OOIP after 3 days, figure 5.5. The results confirms that strong capillary forces are also available for oil mobilization when the permeability is in the lower ranges. The activity of capillary forces earlier mentioned are the driving forces in SI experiments thus they are largely responsible for the outcome with LP1.

There is not much of a difference between the performances of LP1 and BB1 saturated with MO3 in SI. Both cores behave water wet and significant amount of OOIP recovered were observed for both cores as presented in figure 5.15.

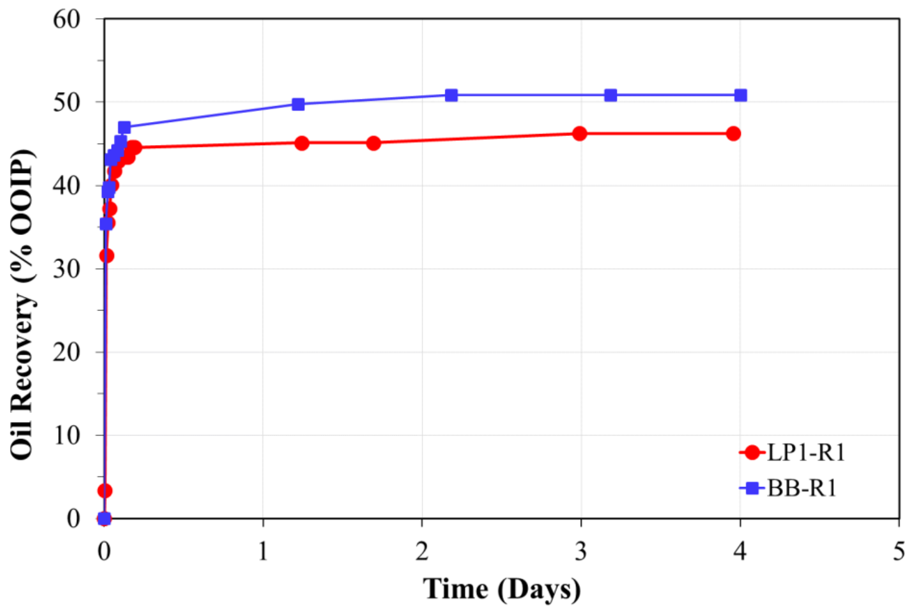


Figure 5.16 Spontaneous imbibition performed on cores BB1-R1 and LP1-R1 at 60°C using FW as the imbibing brine. The cores were restored with Swi =0.2 and saturated with oil MO3. The oil recovery (%OOIP) is presented vs. time (Days)

5.8.2 Viscous flooding at high injection rate

The leopard core saturated with the MO3 was subjected to a VF experiment at a high injection rate at 60°C. At the end of the flooding process, the oil recovery reached 41%OOIP at plateau.

As observed in figure 5.9, there was a rapid rate of oil recovery that saw the plateau being reached with less than 1PV of FW injected. There is a noticeable build-up of pressure drop in the system which are indicative of the action of capillary forces when water begins to enter the core. At plateau the pressure drop was in the range of 60mbar.

The water wetness of LP1 is still intact considering its performance on the oil recovery in this VF experiment. Although the oil recovery in the SI process of LP1 was more than what is observed in viscous flooding at high injection rate, the behaviour of the core is similar.

5.8.3 Viscous flooding at low injection rate

From figure 5.10, it is observed that oil recovery is significantly low as compared to what was observed in the high rate experiment .At a rate of 1PV/day, the oil recovery percentage observed for the leopard core was 22%OOIP. The production reached its plateau after 2PV of FW injected.

Pressure drop build-up is observed with this experiment too and as illustrated in figure 5.11, pressure drop reaches about 130mba before the production reached plateau. Just before and at the onset of 1PV of FW injected the pressure drop reduces and continues to fluctuate through the plateau period until the end of the experiment.

5.8.3 Effect of injection rates on the Leopard core

Performing a VF experiment on the leopard core at different rates produced varying results. Figure 5.17 compares the oil recovery at high and at low rate.

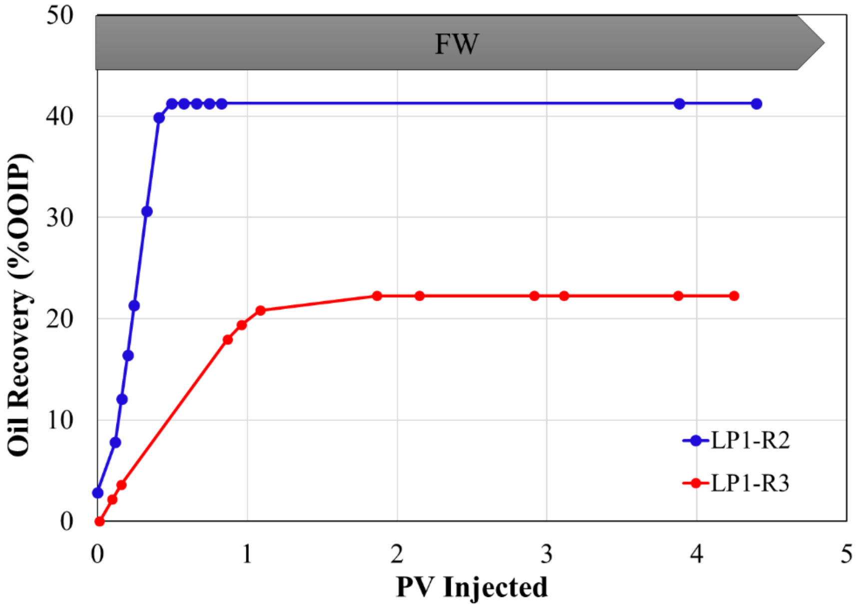


Figure 5.17 Viscous Flooding experiment at 60°C showing oil recovery as a function of PV injected at high rate and low rate for Leopard core.

The resultant oil recovered in this experiment shows a difference when the injection rates are changed. The difference in the recovery is quite significant with the leopard core.

At low rate, it is observed that the oil recovered is significantly less than what is observed at high rate. Flooding at low injection rate and the oil recovered indicates that a major chunk of the oil was not displaced from the core. It can be drawn that capillary forces acting in a low rate setting is relatively weaker than what is observed during high rate. Inability to recover more oil means that oil is still adhered to the surfaces of the pore and were not displaced by the FW.

Figure 5.18 illustrates the performance of VF on the Leopard cores conducted at high injection rate.

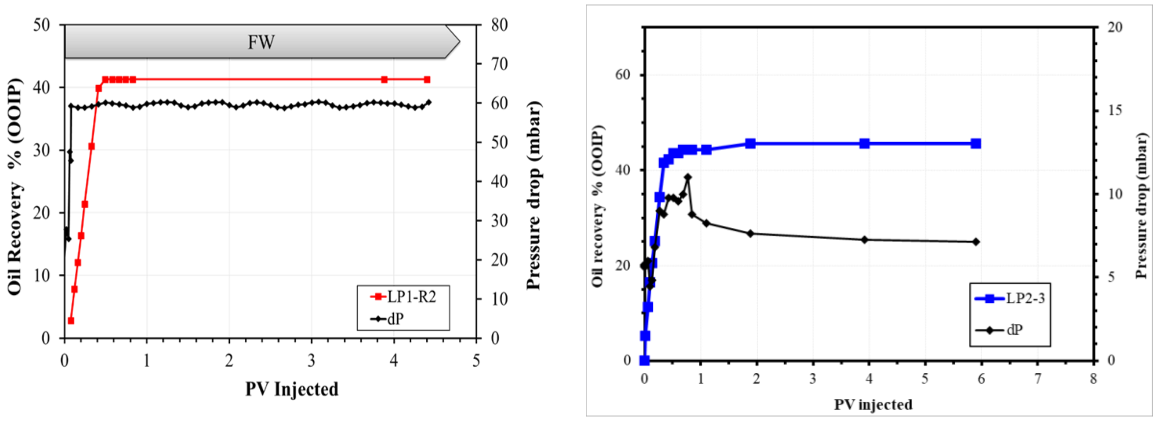


Figure 5.18 Viscous flooding performed on leopard core LP1 saturated with MO3 and LP2 saturated with MO11 at high injection rate (4PV/day)

No significant change in recovery profile and ultimate oil recovery using low and high viscosity oil at injection rate of 4PV/D. It can be drawn from this observation that oil viscosity does not significantly affect oil recovery of the Leopard cores as seen in figure 5.18.

Considering their pressure drop behaviours, at high rate, the pressure drop is quite stable during onset of and the plateau period. However as seen with low rate, the pressure drop profile is quite noisy and unstable.

Sweeping of oil from the pores of the core is partially dependent on the oil viscosity and as have been observed from this VF process, the oil viscosity did not impede recovery.

During the various experiments conducted on the leopard core, it was observed that the core was not consolidated enough which resulted in its particles washing off during restoration process. This phenomena led to disintegration and breaking away of some part of the core.

All the results are not consistent. We observe that the core properties are changing from one core restoration to the next, especially for the Leopard cores. Comparing results where we are varying injection rates and oil viscosity, it seems that capillary forces are important in recovery processes for water wet core systems.

6. Conclusions and Future work

6.1 Conclusion

Laboratory parametric studies of waterflooding of outcrop sandstones in this research opened up series of findings and observations in examining the effect of injection rate and oil viscosity in oil recovery. In light of the objectives set out at the beginning of this study, analysis of the obtained results on the 2 sets of outcrop core material was used in this study demonstrate that:

- Both core systems behaved very water wet which was confirmed by SI.
- Capillary forces are significant and influences the oil recovery in spontaneous imbibition and waterflooding experiments.
- Injection rate seem not to significantly affect oil recovery during waterflooding as observed with all the cores used in this study.
- Oil viscosity seems not to significantly affect the ultimate oil recovery potential from the water wet cores, confirming that capillary forces is important in the recovery process from water wet cores.
- Care must be taken when outcrop cores are selected for laboratory experiments. The core properties may change during a core experiment and from one core restoration to the next which could have a dramatic effect on the laboratory results

In line with the objectives, the results obtained clearly confirmed the influence of capillary forces in mobilization of oil.

6.2 Future work

Even though all the results are not consistent, the oil recovery from water wet outcrop cores seems to be effected by capillary forces. This work should be continued to further evaluate the effect of capillary forces on oil recovery processes, and are also important for evaluating Smart Water EOR potentials from Sandstone reservoirs.

Furthermore, laboratory procedures should be improved and more importantly, studies should be conducted on other outcrop system that could be better alternatives for laboratory parametric studies. Extensive work on this will help build better competence in laboratory parametric studies.

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8 APPENDIX

A1 Density meter

The Anton Paar DMA 4500 was the instrument used in measuring the density of the brines.

Figure A2 Anton Paar DMA 4500 density meter

A2 Rheometer

The viscosity of the fluids at both 20C AND 60C were measured using the Anton Paar rheometer. Figure A3 below illustrates the viscosity measuring instrument.

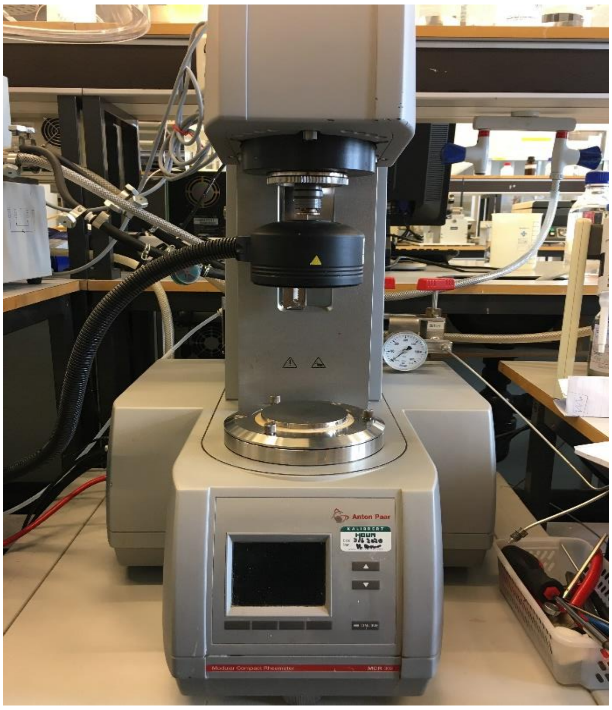

Figure A3 Anton Paar rheometer

A3 pH METER

The pH of the brines were determined using the SevenCompact pH meter. Figure A4 is an illustration of the pH meter.

Figure A4 SevenCompact pH meter from Metler Toledo

A5 Spontaneous Imbibition data

Table A5.1 Spontaneous imbibition of Bandera brown core (BB1)

Time(days)	Oil Recovery (ml)	Oil Recovery (%OOIP)
0.0000	0	0.000
0.0104	6.4	35.379
0.0208	7.1	39.248
0.0313	7.2	39.801
0.0417	7.8	43.118
0.0625	7.9	43.671
0.0833	8	44.223
0.1042	8.2	45.329
0.1250	8.5	46.987
1.2174	9	49.751
2.1826	9.2	50.857
3.1826	9.2	50.857
4.0000	9.2	50.857

Table A5.2 Spontaneous imbibition data of leopard core (LP1)

Time(days)	Oil Recovery (ml)	Oil Recovery (%OOIP)
0	0	0.0000
0.00347222	0.6	3.3860
0.0138889	5.6	31.6027
0.0243056	6.3	35.5530
0.0347222	6.6	37.2460
0.0451389	7.1	40.0677
0.0659722	7.4	41.7607
0.0868056	7.6	42.8894
0.107639	7.7	43.4537
0.128472	7.7	43.4537
0.149306	7.7	43.4537
0.170139	7.9	44.5824
0.190972	7.9	44.5824
1.243056	8	45.1467
1.690972	8	45.1467
2.989583	8.2	46.2754
3.954861	8.2	46.2754

A6 Viscous Flooding data

Table A6.1 Viscous flooding data of Bandera Brown (BB1) saturated with MO2 at high injection rate

PV corrected	Total oil amount(ml)	Oil Recovery (%OOIP)
0.00	0.30	1.66
0.04	1.00	5.52
0.08	2.00	11.04
0.13	3.00	16.57
0.17	4.00	22.09
0.25	5.80	32.03
0.33	7.40	40.86
0.42	8.30	45.83
0.50	8.80	48.59
0.58	8.80	48.59
0.67	8.80	48.59
0.75	9.00	49.70
0.83	9.00	49.70
0.92	9.00	49.70
1.00	9.00	49.70
3.81	9.00	49.70
4.81	9.00	49.70

Table A6.2 Viscous flooding data of Bandera Brown (BB1) saturated with MO2 at low injection rate

PV corrected	Total amount of oil(ml)	Oil Recovery (%OOIP)
0.00	0.00	0.00
0.01	0.40	2.21
0.02	0.70	3.88
0.03	1.00	5.54
0.04	1.10	6.09
0.08	1.80	9.97
0.13	2.50	13.84
0.17	3.30	18.27
0.21	4.00	22.15
0.25	4.50	24.92
0.29	4.90	27.13
0.83	6.00	33.22
1.22	6.30	34.88
1.92	6.50	35.99
2.95	6.50	35.99
3.22	6.50	35.99
4.01	6.50	35.99

Table A6.3 Viscous flooding data of Bandera Brown (BB1) saturated with MO3 at high injection rate

PV Corrected	Total amount of oil(ml)	Oil Recovery (%OOIP)
0.01	0.00	0.00
0.03	0.80	4.45
0.07	1.80	10.01
0.11	2.80	15.56
0.15	3.60	20.01
0.24	5.30	29.46
0.32	7.30	40.58
0.40	7.80	43.36
0.49	8.00	44.47
0.65	8.20	45.58
0.82	8.20	45.58
1.65	8.20	45.58
3.88	8.20	45.58

Table A6.4 Viscous flooding data of Leopard (LP1) saturated with MO2 at high injection rate

PV corrected	Total amount of oil (ml)	Oil Recovery (%OOIP)
0.00	0.40	2.85
0.12	1.10	7.83
0.16	1.70	12.10
0.20	2.30	16.37
0.24	3.00	21.35
0.33	4.30	30.60
0.41	5.60	39.86
0.49	5.80	41.28
0.58	5.80	41.28
0.66	5.80	41.28
0.74	5.80	41.28
0.83	5.80	41.28
3.88	5.80	41.28
4.40	5.80	41.28

Table A6.4 Viscous flooding data of Leopard (LP1) saturated with MO2 at low injection rate

PV corrected	Total amount of oil (ml)	Oil Recovery (%OOIP)
0.01	0.00	0.00
0.10	0.30	2.16
0.16	0.50	3.59
0.87	2.50	17.96
0.96	2.70	19.40
1.08	2.90	20.83
1.87	3.10	22.27
2.15	3.10	22.27
2.91	3.10	22.27
3.11	3.10	22.27
3.87	3.10	22.27
4.24	3.10	22.27

A7 Viscosity data

A7.1 Viscosity of Formation Water

Shear rate	Viscosity [cP] 20°C	Viscosity [cP] 60°C
499.88	1.33	0.694
387.5	1.3	0.691
275	1.28	0.702
162.5	1.29	0.724
50	1.31	0.804

A7.2 Viscosity of Pure Marcol

Shear rate	Viscosity [cP] 20°C	Viscosity [cP] 60°C
499.88	27.03	7.2
387.5	27.03	7.19
275	27	7.22
162.5	26.97	7.25
50	26.97	7.28

A7.3 Viscosity of MO3

Shear rate	Viscosity [cP] 20°C	Viscosity [cP] 60°C
499.88	2.14	2.07
387.5	2.22	2.33
275	2.33	2.63
162.5	2.47	2.87
50	2.68	3.04

A7.4 Viscosity of MO11

Shear rate (1/s)	Viscosity [cP] 20°C	Viscosity [cP] 60°C
499.88	10.83	4.86
387.5	10.9	4.93
275	11.07	5.05
162.5	11.2	5.17
50	11.3	5.22

A8 IFT Data

Fluid	**IFT (mN/m)**	**μ (cP) (average at 50 shear rate)**	**IFT corrected**
Marcol	44.6	26.97	47.0
85/15	42.8	11.3	45.1
80/20	42.2	9.16	44.4
70/30	40.8	5.82	43.0
50/50	38	2.47	40.0
25/75	37.2	1.08	39.2
Heptane		0.376	