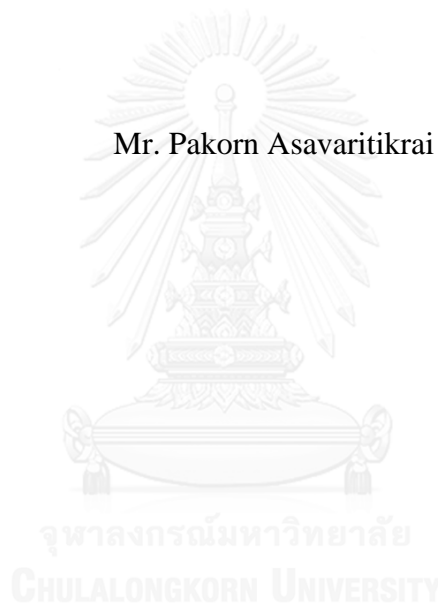


INTERFACIAL TENSION MEASUREMENT OF LIGHT OIL FROM FANG
OILFIELD WITH ALKALINE-POLYMER SOLUTION

Mr. Pakorn Asavaritikrai



บทคัดย่อและแฟ้มข้อมูลฉบับเต็มของวิทยานิพนธ์ตั้งแต่ปีการศึกษา 2554 ที่ให้บริการในคลังปัญญาจุฬาฯ (CUIR)
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การวัดค่าความตึงผิวของน้ำมันเบาจากแหล่งน้ำมันฝางด้วยสารละลายอัลคาไลน์-พอลิเมอร์



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ปกรณัม อัสวฤทธิไกร : การวัดค่าความตึงผิวของน้ำมันเบาจากแหล่งน้ำมันฝางด้วยสารละลายอัลคาไลน์-พอลิเมอร์ (INTERFACIAL TENSION MEASUREMENT OF LIGHT OIL FROM FANG OILFIELD WITH ALKALINE-POLYMER SOLUTION) อ.ที่ปริกษาวิทยานิพนธ์หลัก: ศศ. ดร.เกรียงไกร มณีอินทร์, 78 หน้า.

การเพิ่มการผลิตน้ำมันโดยเฉพาะกระบวนการอัดฉีดสารละลายอัลคาไลน์-พอลิเมอร์เป็นวิธีที่สำคัญในการเพิ่มปริมาณการผลิตน้ำมัน กระบวนการดังกล่าวเกี่ยวข้องกับการอัดฉีดอัลคาไลน์เพื่อลดความตึงผิวระหว่างน้ำมันและน้ำรวมถึงการอัดฉีดพอลิเมอร์เพื่อปรับปรุงอัตราส่วนของการเคลื่อนที่เพื่อที่จะผลิตน้ำมันได้มากยิ่งขึ้น ในการศึกษาครั้งนี้จะทำการวัดค่าความตึงผิวของน้ำมันเบาจากแหล่งน้ำมันฝางด้วยสารละลายอัลคาไลน์-พอลิเมอร์และตรวจสอบถึงผลกระทบของปัจจัยอื่น ๆ อันได้แก่ความดัน อุณหภูมิ ความเข้มข้นของสารละลายเกลือ ชนิดของสารละลาย และความเข้มข้นของสารละลายที่มีต่อความตึงผิว

ผลการศึกษาแสดงให้เห็นว่าความดันมีผลกระทบต่อความตึงผิวน้อยเนื่องจากระบบที่ทำการศึกษาเป็นของเหลว สำหรับผลกระทบเนื่องจากชนิดของสารละลายอัลคาไลน์นั้น เบสแก่จะให้ประสิทธิภาพสูงกว่าเบสอ่อนในการลดค่าความตึงผิวเนื่องจากเบสแก่สามารถแตกตัวได้อย่างสมบูรณ์ในสารละลาย ทำให้มีปริมาณไอออนสูงกว่า ด้วยเหตุนี้จึงส่งผลให้ปริมาณของสารลดความตึงผิวมีมากขึ้นและสามารถลดความตึงผิวได้มาก

ความเข้มข้นของอัลคาไลน์มีบทบาทสำคัญในการลดความตึงผิวโดยมีผลถึง 99.49% ในขณะที่ความตึงผิวมีค่าลดลงตามอุณหภูมิที่เพิ่มขึ้นสำหรับสารละลายทุกชนิด ส่วนการเพิ่มความเข้มข้นของพอลิเมอร์มีแนวโน้มที่จะเพิ่มความตึงผิว

ความเข้มข้นของสารละลายเกลือสามารถเพิ่มความตึงผิวเมื่ออัลคาไลน์มีความเข้มข้นต่ำ ในขณะที่สามารถลดความตึงผิวเมื่ออัลคาไลน์มีความเข้มข้นสูง นอกจากนี้ไควาเลนต์ไอออนมีผลกระทบต่อความตึงผิวต่ำ ผลเหล่านี้สามารถนำไปใช้เป็นข้อมูลพื้นฐานสำหรับการศึกษิต่าง ๆ ในอนาคตเช่นการทดสอบการอัดฉีดหินตัวอย่างและการจำลองวิธีช่วยในการผลิตน้ำมัน

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PAKORN ASAVARITIKRAI: INTERFACIAL TENSION MEASUREMENT OF LIGHT OIL FROM FANG OILFIELD WITH ALKALINE-POLYMER SOLUTION. ADVISOR: ASST. PROF. KREANGKRAI MANEEINTR, Ph.D., 78 pp.

Enhanced oil recovery especially alkaline-polymer flooding is an important technique to improve oil recovery. It involves the injection of alkali to reduce the interfacial tension (IFT) between oil and water, and the injection of polymer to improve mobility ratio to produce more oil. In this study, the interfacial tension of light oil from Fang oilfield with alkaline-polymer solution will be measured and the effects of parameters such as pressure, temperature, salinity, types of solution and solution concentration on the interfacial tension are investigated.

The results present that pressure has less effect on the interfacial tension because the experiment is in the liquid phase. For the effect of types of alkaline solution, strong base has higher performance in lowering the interfacial tension compared with weak base because strong base can completely dissociate in the solution so that the amount of ions are higher. This results in the higher amount of the in-situ surfactant and thus lowering more interfacial tension.

Concentration of alkali plays a key role in the interfacial tension reduction accounting for 99.49%. Interfacial tension reduces with the increase of temperature for every type of the solution. Increasing polymer concentration tends to increase the interfacial tension.

Salinity can increase the interfacial tension at low alkali concentration while decrease the interfacial tension at high alkali concentration. Divalent ions have low impact on the interfacial tension. The results can be used as the fundamental data for future studies such as the core flooding test and simulation for enhanced oil recovery.

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LIST OF ABBREVIATIONS

AP	Alkaline-Polymer
ASP	Alkaline-Surfactant-Polymer
DAS	Drop Analysis System
IFT	Interfacial Tension
EOR	Enhanced Oil Recovery
HPAM	Hydrolyzed Polyacrylamide
LPG	Liquid Petroleum Gas
OOIP	Original Oil In Place
SAGD	Steam Assisted Gravity Drainage
SP	Surfactant-Polymer
WAG	Water Alternating Gas
wt.%	Percent by Weight

NOMENCLATURE

E_a	Areal sweep efficiency
E_{do}	Displacement efficiency
E_{ro}	Overall oil recovery efficiency
E_{vo}	Volumetric sweep efficiency
E_v	Vertical sweep efficiency
k'_{rw}	End point relative permeability of water
k'_{ro}	End point relative permeability of oil
M	Mobility ratio
m	Mass
P	Pressure
R	Radius of curvature
S_{oi}	Initial oil saturation
S_{or}	Residual oil saturation
V	Volume

GREEK LETTER

γ	Interfacial tension
λ_o	Mobility of oil
λ_w	Mobility of water
μ_o	Oil viscosity
μ_w	Water viscosity
ρ	Density

SUPERSCRIPTS

'	End point indicator for relative permeability
---	---

SUBSCRIPTS

a	Areal
o	Oil
v	Vertical
w	Water

CHAPTER 1

INTRODUCTION

1.1 Oil Recovery

Nowadays, the world becomes more dependent on fossil fuels, supplying more than 80% of the world's energy (U.S. Energy Information Administration, 2015). Oil production needs to be produced more to serve this increasing demand. Typically, oil is produced by the natural drive energy in the reservoir. The sources of the energy are from solution gas, gas cap, water influx and gravity drainage. This process is categorized as a primary recovery. However, the primary recovery can not deliver the satisfied amount of oil. Therefore, water is injected as a secondary recovery to maintain and build up the pressure so that more oil can be brought out of the reservoir. This process is renowned as waterflooding. In oil production, waterflooding is the most widely used method to increase oil recovery due to its low costs and simple operations (Sedaghat et al., 2013). The concept of waterflooding is shown in Figure 1.1.

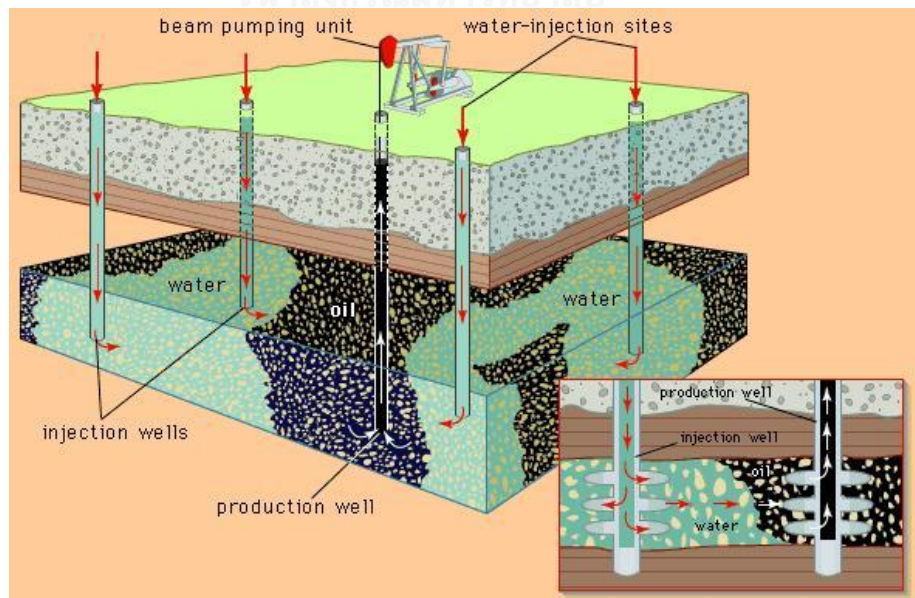


Figure 1.1 Schematic of waterflooding (Baker, 1985)

Unfortunately, the weakness of waterflooding is that it has low sweep efficiency. Volumetric sweep efficiency can indicate the effectiveness of the displacing agent, water in this case, that could contact the reservoir. It is defined as the ratio of oil volume contacted by the injected fluid to initial volume of oil in place. The efficiency is even lower in heavy oil reservoirs because high mobility contrast between oil and water can cause fingering effects (Sedaghat et al., 2013). According to Doscher and Wise (1976), a large amount of oil droplets which is around 70% of the original oil in place (OOIP) are trapped by capillary forces due to the high interfacial tension (IFT) between water and oil. Consequently, tertiary recovery, a method of injecting special fluids such as gases, chemicals, or the injection of thermal energy, can help in a significant increase of oil recovery. This method is called Enhanced Oil Recovery (EOR).

1.2 Enhanced Oil Recovery Technologies

EOR technology is gaining more attention because of the higher performance comparing to primary and secondary recoveries. Applying EOR processes can give an incremental recovery of 5-30% (Abidin et al., 2012). The main objective of EOR processes is to enhance the oil recovery efficiency, which is the product of the sweep efficiency and the displacement efficiency. The displacement efficiency is defined as the fraction of oil that has been recovered from a zone swept by the injecting fluid. EOR can be classified mainly into 4 groups: chemical flooding, gas injection, thermal recovery, and others (Olajire, 2014). Figure 1.2 shows the typical EOR methods in the petroleum industry.

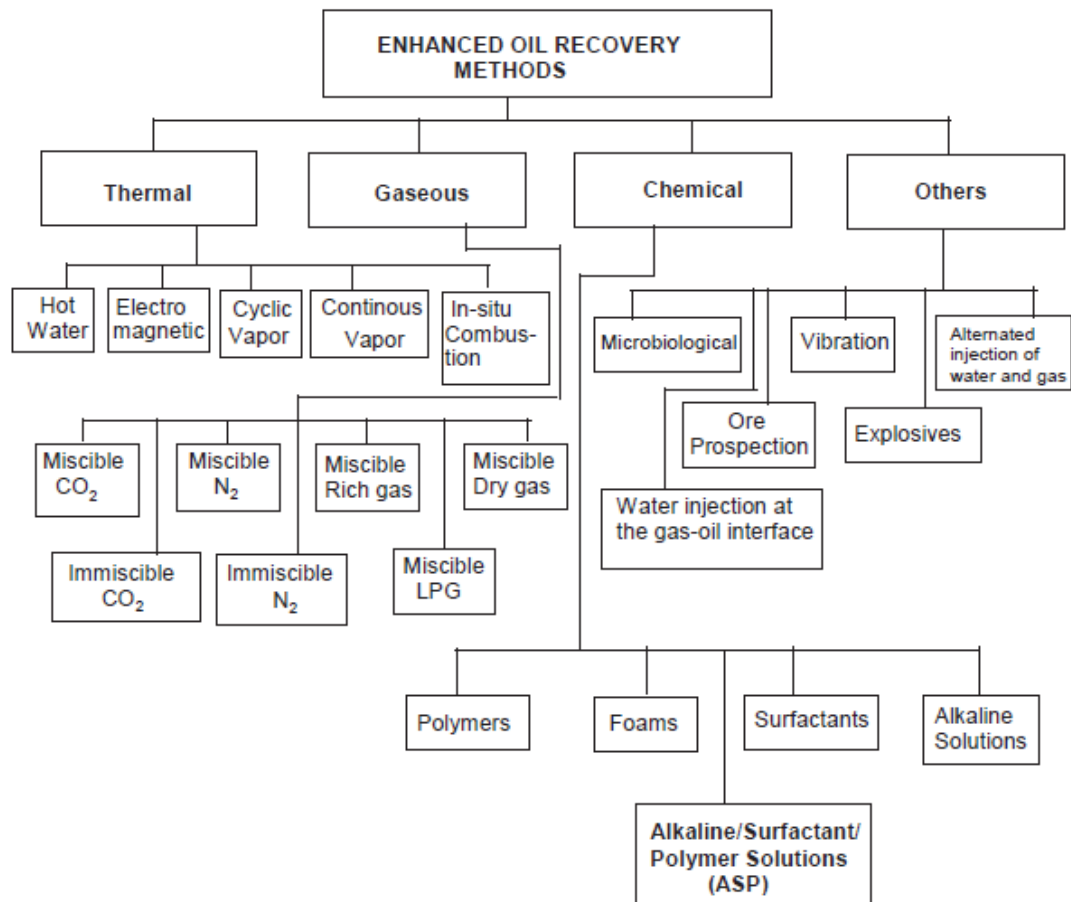


Figure 1.2 Classification of EOR processes (Olajire, 2014)

Thermal method improves oil recovery by using heat carriers which can reduce the viscosity of oil. This method is mostly used in reservoirs containing heavy oil (Farouq Ali, 1986). Examples of thermal methods are steam flooding, huff and puff, steam assisted gravity drainage (SAGD), and in-situ combustion. The disadvantages of this method are that it is only efficient for shallow reservoir and applying with low viscous crude cannot give significant improvement compared to an ordinary waterflooding (Romero-Zerón, 2012).

Gas injection is the method that improves oil recovery by means of injecting gas into reservoir fluids at the reservoir conditions. The principle mechanism of this method is to reduce the oil viscosity when the gas solution is dissolved into the oil. It

can be separated into miscible and immiscible gas injection. Examples of gaseous methods are carbon dioxide (CO₂) flooding, liquid petroleum gas (LPG) flooding, and nitrogen (N₂) flooding. Gas injection especially the miscible flooding is suitable for high viscosity crude with gas availability in the nearby location. However, there are some limitations for using gas injection such as poor sweep efficiency, gravity override, and early breakthrough (Romero-Zerón, 2012).

For chemical flooding, oil recovery is improved by means of injecting fluid which is immiscible with the displaced phase. Different types of chemicals have different mechanisms in yielding a higher recovery. So, different chemicals are often combined together to create a more effective solution. The disadvantage of chemical flooding is that there is a chance of the chemical degradation at high temperature. Also, some chemicals are quite expensive such as surfactants (Romero-Zerón, 2012).

In Fang oilfield, chemical flooding is considered to be a suitable method to increase light oil production due to the low viscosity of oil. Furthermore, there is low risk for the degradation of chemicals since the reservoir temperature is low. So this method will be explained in details in the next topic.

Other methods are not used often compared to the above 3 methods. Examples of other methods are microbial flooding, water alternating gas (WAG) flooding, vibration, etc. (Olajire, 2014).

1.3 Chemical Flooding

Chemical flooding, sometimes called chemical injection, is a method of injecting chemicals together with water into the reservoir. These chemicals would increase the sweep efficiency, the displacement efficiency, or both (Wang et al., 2010). Most commonly used chemicals are polymer, surfactant, and alkaline. Polymer increases the viscosity of water by one or even two orders of magnitude to make it closer to that of oil so that it is easier to sweep oil out of the reservoir (Zhu et al.,

2013). Surfactant and alkaline can reduce the IFT between water and oil and thus increase the displacement efficiency.

Using more than one chemical component is called chemical combination flooding or combined flooding. Some studies indicate that chemical combination flooding is an interesting method that can increase oil recovery significantly due to the integration of their unique functions (Abidin et al., 2012). Examples of chemical combination flooding are alkaline-polymer (AP) flooding, surfactant-polymer (SP) flooding, and alkaline-surfactant-polymer (ASP) flooding. The chemical combination flooding does not only improve the sweep efficiency but it can also improve the displacement efficiency by increasing the capillary number (Wang et al., 2010). The most important substance is the polymer because it is used in every type of the combined flooding (Abidin et al., 2012). Since the IFT can affect the recovery efficiency of oil, AP solutions in different concentrations and conditions will be studied to observe the effect on the IFT.

1.4 Objectives of This Research

1. To measure the IFT of light oil from Fang oilfield as the fundamental data for AP flooding
2. To investigate the effect of parameters such as pressure, temperature, salinity, types of solvent and solvent concentration on the IFT measurement

This study will provide the IFT data at different conditions when AP flooding is applied at Fang oilfield. The results will be used as the fundamental data for future studies such as the core flooding test to find the oil recovery and simulation for enhanced oil recovery. The details in each chapter is explained below.

Chapter 2 presents theory and literature review describing the fundamental theory of the polymer flooding, alkaline flooding, etc. Previous studies related to the research topic are also presented. Experiment mentioned in Chapter 3 is divided into two parts. The first part presents materials and equipment required in this research. The second part of this chapter explain the experimental procedure with conditions to be done in the laboratory. Results and discussion will be presented in Chapter 4. The experimental result from the IFT measurement as well as the effects of parameters on the IFT between crude oil and brine are discussed such as pressure, temperature, concentration of alkali and polymer, salinity and divalent ions. Finally, Chapter 5 will conclude the results from the previous chapter by explaining the effect of each parameter. Also, recommendations are provided for future study.



CHAPTER 2

THEORY AND LITERATURE REVIEW

As mentioned in the previous chapter, chemical flooding is the interested topic for this study especially the AP flooding. This chapter will explain the fundamental theory of the interfacial tension, polymer flooding, alkaline flooding, etc. Previous studies related to the research topic are also presented.

2.1 Interfacial Tension

Interfacial tension (IFT) is the force that holds the surface of a particular phase together and is normally measured in mN/m. This term relates to the liquid/liquid and liquid/solid phase boundaries, while for the liquid/gaseous interface it can be referred to as surface tension and surface free energy can be used for the solid/gaseous interface. It is a function of pressure, temperature, and the composition of each phase.

IFT is somewhat similar to surface tension in that cohesive forces are also involved. However the main forces involved in IFT are adhesive forces (tension) between the liquid phase of one substance and either a solid, liquid or gas phase of another substance. The interaction occurs at the surfaces of the substances involved, that is at their interfaces.

The significance of the IFT in oil recovery is that, if the IFT is reduced by means of chemicals such as alkalis and surfactants, the organic phase can be mobilized after flooding with water.

The measurement of the IFT can be obtained by several methods. Two methods that are widely used are pendant drop and spinning drop method. For the pendant drop method, the shape of a drop on a needle in a bulk liquid phase is

determined. The IFT can be ascertained from the image of the drop using drop shape analysis. For the spinning drop method, a horizontal capillary filled with a bulk phase and a drop phase is set in rotation. The diameter of the drop which is elongated by centrifugal force correlates with the IFT.

Some studies on factors which affect on the IFT are described below. Hassan et al. (1953) concluded that the IFT would slightly change with pressure at constant temperature in the range of 1 to 204 atm. According to Wei (2005), increasing the temperature can exponentially increase the solubility of water in oil, which reduces the free energy between two immiscible fluids and thus decreasing the IFT. Also, the study of Okasha and Alshiwaish (2009) concludes that intermolecular forces at the oil/water interface weakens when temperature increases, and this can lead to the lowering of the IFT. Trujillo (1983) concluded that calcium ions can destroy the capability of alkali to reduce the IFT when its concentration is above 200 ppm.

2.2 Polymer Flooding

Polymer flooding is the EOR technology that can produce the remaining oil after waterflooding have been exhausted. It has been used for more than 40 years due to its promising increase in oil recovery over the waterflooding technique for about 5-30% of OOIP (Pope, 2007). Furthermore, the capital cost of polymer flooding is relatively lower than that of waterflooding because less water is produced while more oil is obtained. The amount of polymer injected is in the range of 0.7 to 1.75 pounds of polymer per barrel of incremental oil production (Pope, 2007).

With the long chain structure of polymer molecules, they are capable of dragging the residual oil out of the retention area and create steady oil channels to increase oil recovery (Wang and Liu, 2014). Another interesting mechanism is that the adsorbed polymer molecules resist the flow of aqueous phase, thereby decreasing the water relative permeability (Wang and Liu, 2014).

It is inferred that the injected polymer in EOR helps increase the viscosity and decreases the relative permeability of water, which leads to the reduction of the mobility ratio of water to oil (Qiao et al., 2012). Mobility ratio is defined as the ratio of the mobility of the displacing fluid to the mobility of the displaced fluid (Olajire, 2014). The displacing fluid normally means water and the latter refers to oil. The mobility ratio, M , can be expressed as follows:

$$M = \frac{\lambda_w}{\lambda_o} = \frac{k'_{rw} / \mu_w}{k'_{ro} / \mu_o} \quad (2.1)$$

where λ_w and λ_o are mobilities of water and oil (mD/cp), respectively; k'_{rw} and k'_{ro} are end point relative permeabilities of water and oil (mD), respectively; μ_o and μ_w are oil and water viscosities (cp), respectively.

The favorable condition occurs when M is one or slightly less, in which the displacing pattern of oil by the water will be piston-like (Sastry et al., 1999), allowing no oil to be bypassed. As a result, the volumetric sweep efficiency will be improved. This could happen when the viscous solution is injected to displace non-viscous oil, and it becomes the reason why polymer flooding works well with light oil. By contrast, if the mobility ratio is greater than one, the water phase will bypass some of the oil in the reservoir. This leads to the viscous fingering of water in the reservoir and lower the sweep efficiency. Figure 2.1 illustrates the difference between the piston-like displacement (stable displacement) and the viscous fingering (unstable displacement).

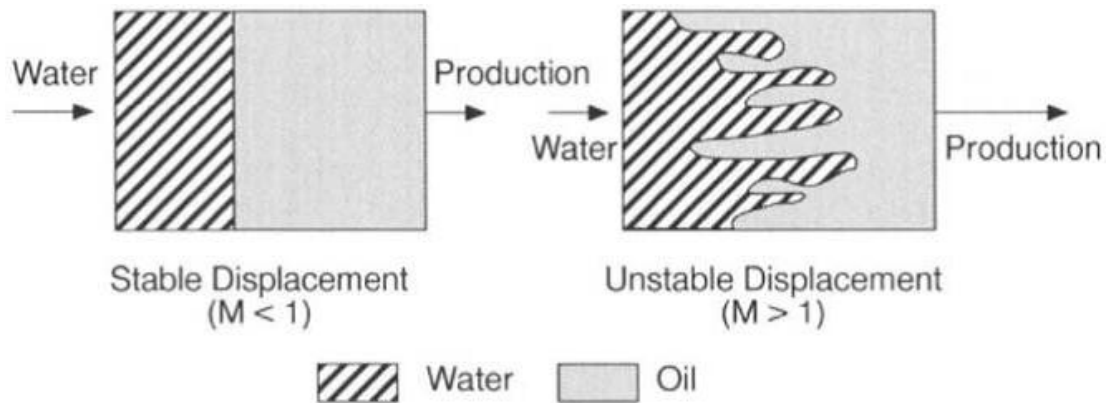


Figure 2.1 Difference between piston-like displacement and viscous fingering
(Source: Sofoil LLC, sofoil.com)

Also, the lower mobility ratio results in an increase in fractional flow; so, higher recovery is attained. Needham and Doe (1987) concluded that polymer solution increases oil recovery by (1) influencing fractional flow as shown in Figure 2.2, (2) reduction of water-oil mobility ratio, and (3) diversion of injected water toward swept zones. Comparing with other chemicals individually, polymer gives the highest incremental oil recovery (Sedaghat et al., 2011). Therefore, polymer is considered to be the most effective substance among other chemicals (Needham and Doe, 1987).

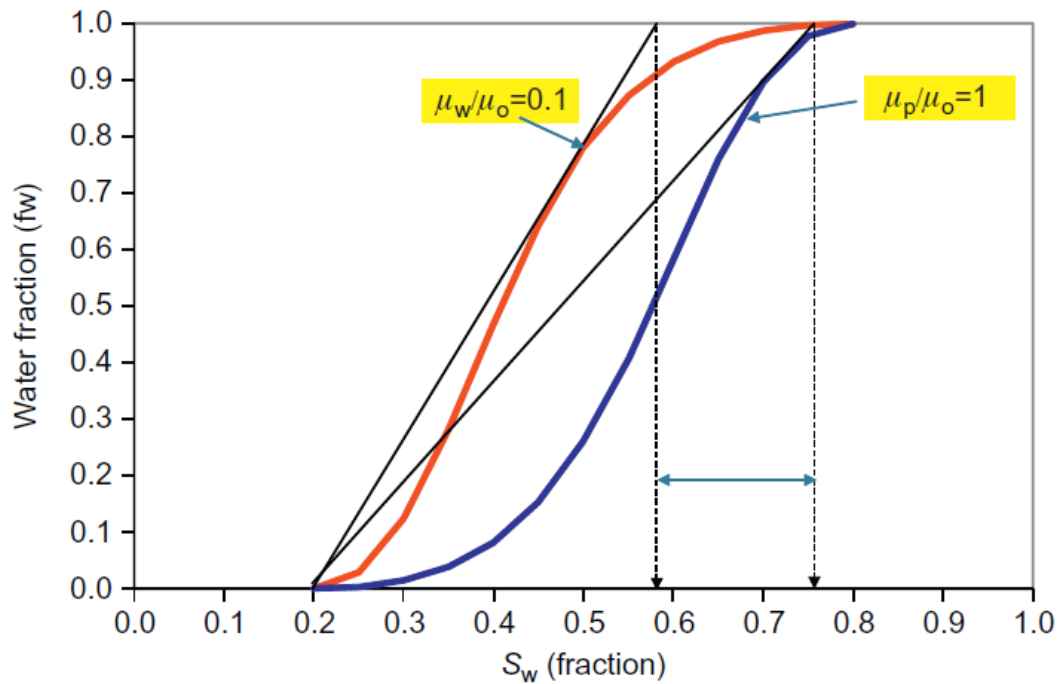


Figure 2.2 Effect of viscosity ratio on the fractional flow curve (Sheng, 2013)

Polymers that are used in EOR applications can be categorized into two groups, namely biopolymers and synthetic polymers. Biopolymers mostly always mean xanthan gum. The structure of xanthan gum can be shown in Figure 2.3. With its semirigid rod-like structure, the polymer is somewhat resistant to the mechanical degradation. The average molecular weight of xanthan biopolymer used in the EOR process is from 1 to 15 million Daltons (Sheng, 2011).

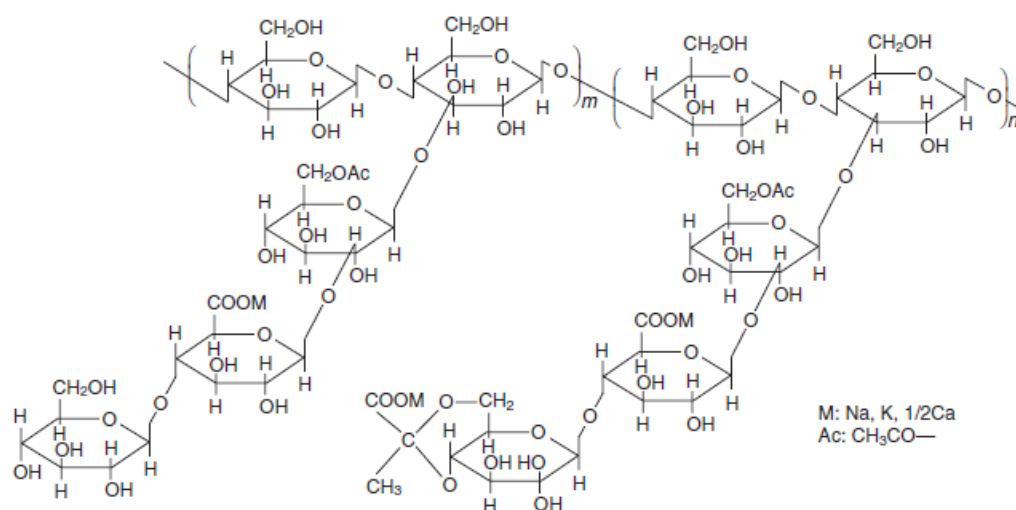


Figure 2.3 Molecular structure of xanthan gum (Sheng, 2011)

For the synthetic polymers, the most well-known polymer is hydrolyzed polyacrylamide (HPAM). The molecular structure of HPAM is illustrated in Figure 2.4.

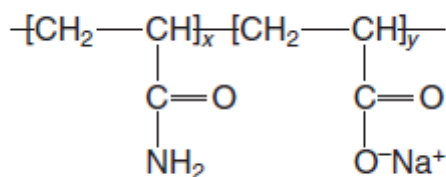


Figure 2.4 Molecular structure of HPAM (Sheng, 2011)

HPAM is derived by partially hydrolyzing polyacrylamide with a base such as sodium or potassium hydroxide or sodium carbonate. This reaction substitutes some of the amide groups (CONH₂) with the carboxyl groups (COO⁻) to reduce the adsorption behavior of polyacrylamide on mineral surfaces. The degree of hydrolysis, which is the mole fraction of the substituted amide groups, is normally between 15 to

35% (Sheng, 2011). The molecular weight of HPAM that are used in EOR process can be available up to 30 million Daltons. Both factors, the degree of hydrolysis and the molecular weight, could affect the performance of the polymers (Abidin et al., 2012).

HPAM is quite popular for the use in the EOR process because the price of the polymer is low compared to that of other polymers while its viscosifying property is satisfying (Abidin et al., 2012). Also, HPAM is relatively easy to be used and could improve the oil recovery efficiency significantly (Abidin et al., 2012). Comparing with xanthan solutions, HPAM solutions provide better oil recovery at the same conditions due to their greater viscoelasticity (Wang et al., 2006).

Due to the variety of structures in HPAM, Zhao (1991) concluded that the polymer has suitable characteristics to be used in EOR. Firstly, carbon chain in the backbone gives good thermal stability, so that the degradation would not be severe below 110°C. The amide groups (CONH₂) prevent the precipitation of the polymer with calcium and magnesium ions and lead to good chemical stability. The carboxyl groups (COO⁻) make the polymer a good viscosifier and reduce the adsorption on sandstones because of the repulsion between chain links.

Although polymer flooding shows high capability in recovering additional oil, there are some considerations that might prevent polymer from reaching its best efficiency. The following studies explain about factors affecting the polymer's performance.

Szabo (1975) conducted the experiment by flooded polymer solution into the stratified reservoir model created from different sand layers. The purpose is to study the effect of the polymer concentration, sand permeability, and the salinity of the solution on the performance of polymer flooding. The concentration was used at 300, 600 and 1200 ppm. It was found that higher polymer concentration led to higher incremental oil recovery, but with different habits governed by the permeability of the reservoir. For the low-permeability sand, at 173 md in this study, lower concentration of polymer was required to improve the recovery. Using high concentration in this

case could not result in any better recovery. The reason was because the retention of polymer in the reservoir was high. In contrast, the higher amount of the polymer was needed in the high-permeability sand, at 1,200 md in this study, due to low polymer retention. The effect of salinity was observed by replacing brine with tap water. It is found that the salinity reduced oil recovery at low polymer concentrations and has less effect at high polymer concentrations.

Liberatore et al. (2003) studied the effect of the polymer concentration and the solution composition on the rheological and rheo-optical properties under shear flow. The experiment was carried out to measure the viscosity and the transmittance as a function of time and shear rate. The polymer concentration was varied from 10 to 4000 ppm. The results showed that at higher concentration, the polymer exhibited higher viscosity and formed the phase-separated droplets under shear. For the rheo-optical properties, polymers at any concentration became turbid and take several days to return their transmittance up to the original value. Also, salts were added to the solution at various concentrations (2 to 40 g/L). They found that the performance of the polymer, reflected by the viscosity, dropped as the salinity was increased. The reason was because salt ions prevented negative charges on polymer's backbone from repelling one another, leading to the compression of the polymer structure and the lower viscosity.

Zhang et al. (2011) tested parameters that could affect drag reduction of the polymer in a turbulent flow. They varied polymer concentrations (10, 30, 50, 100, and 200 ppm) and temperatures (25, 40, and 80°C) to observe the percentage of drag reduction via a rotating disk apparatus. The polymer used in this study was poly(acrylamide-co-acrylic acid). They found that the higher concentration of the polymer could provide the higher percentage of drag reduction. Also, the mechanical degradation of the polymer was more critical for the one with the lower concentration. It is explained that each part of the low concentration solution would experience more turbulence of flow, so the polymer chain was rapidly broken. The degradation behavior could be seen obviously at high temperature (80°C in this experiment). The reason was that intermolecular hydrogen bonds that prevented the polymer from

degradation were destroyed at high temperature. They also found that the shear viscosity was lower at the high temperature condition.

Cook et al. (1992) examined the effect of pressure on the viscosity of polymers. Polymers were dissolved in different kinds of solvents such as polystyrene in tetrahydrofuran and HPAM in water. Results showed that higher pressure led to higher solution viscosity, but with different trend for each type of solvents. The viscosity rose exponentially for the organic solvent while the trend increased at a slower rate for the aqueous solvent. The reason was because hydrogen bonds between water molecules were interrupted at high pressure.

Zhao (2001) inspected 2 nearby wells (30 meters apart) to study the polymer flooding method comparing with the traditional waterflooding method. The results showed that polymer flooding can alter the mobility ratio between oil and water and enhance the sweeping volume. The displacement efficiency was initially observed to be improved, comparing with the water flooded well. Later core test showed that the displacement efficiency from the waterflooding also increases over time. They concluded that polymer flooding can increase the volumetric sweep efficiency but not the displacement efficiency.

The volumetric sweep efficiency (E_{vo}) and the displacement efficiency (E_{do}) both affect the overall oil recovery efficiency (E_{ro}) which is the primary goal to be maximized in oil production. The relationship can be shown in the equation 2.2;

$$E_{ro} = E_{vo} E_{do} = E_a E_v E_{do} \quad (2.2)$$

where E_a is the areal sweep efficiency, E_v is the vertical sweep efficiency.

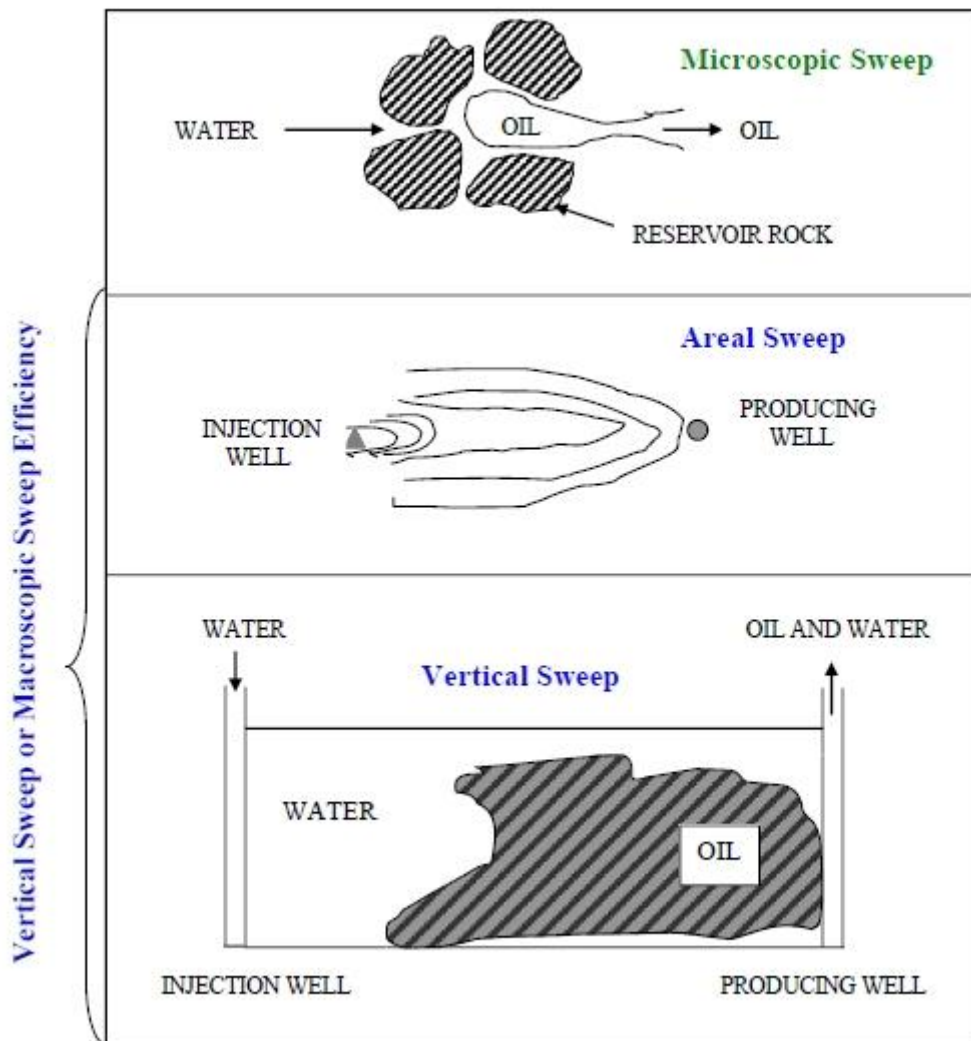
The microscopic or displacement efficiency denotes the ability of the displacing fluid to displace oil in place when they are in contact. It is the ratio of the amount of oil recovered to the initial oil presented in place which can be shown in terms of saturation as the equation 2.3;

$$E_{do} = \frac{S_{oi} - S_{or}}{S_{oi}} \quad (2.3)$$

where S_{oi} is the initial oil saturation, S_{or} is the residual oil saturation after oil recovery process.

The displacement efficiency depends on various factors such as time, liquid viscosities, relative permeabilities, IFTs, wettabilities and capillary pressures. In case all of the oil is contacted with the injected water when perform waterflooding, only some of the oil would be mobilized. This is due to the high IFT between water and oil that can cause trapping of oil droplets in the reservoir. Summarily, the microscopic efficiency can be increased by reducing the IFT between the displacing fluid and oil or by decreasing the oil viscosity (Olajire, 2014).

The macroscopic or volumetric sweep efficiency is the measure of the effectiveness of the displacing fluid that can contact the volume of the reservoir. High volumetric sweep efficiency implies that the displacing fluid has high performance to sweep the oil volume out of a reservoir, both areally and vertically, and can effectively displace oil toward production wells. The sweep efficiency is the product of two terms which are areal sweep efficiency and vertical sweep efficiency. Areal sweep efficiency denotes the fraction of the total area reached by the displacing fluid; vertical sweep efficiency represents the fraction of the total cross-sectional area in the vertical plane swept by the injected fluid. The volumetric sweep efficiency depends on the flooding pattern, well characteristics and locations, reservoir fractures, reservoir thickness, position of gas-oil and oil-water contacts, heterogeneity, mobility ratio, density difference between the displacing and the displaced fluid, flow rate, etc. (Olajire, 2014). To improve the volumetric sweep efficiency, mobility control methods can be implemented such as polymers, foams and WAG injection process. Figure 2.5 shows a schematic of sweep efficiencies.



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Figure 2.5 Schematics of microscopic and macroscopic sweep efficiencies (Olajire, 2014)

2.3 Alkaline Flooding

Alkaline flooding, sometimes called caustic flooding, is the method of injecting the alkali to react with the organic acid in crude oil to generate the in-situ surfactant (soap) that can lower the IFT. Alkalis that are commonly used are sodium hydroxide, and sodium carbonate. Other alkalis include sodium orthosilicate, sodium tripolyphosphate, sodium metaborate, ammonium hydroxide, and ammonium carbonate can also be used. Currently, sodium carbonate is often selected more than

sodium hydroxide due to the lower scaling problems. The price of sodium carbonate is also lower because it could be obtained from sodium carbonate/bicarbonate mines (Hirasaki and Zhang, 2004).

In order to generate the in-situ soap, the alkali must react with petroleum acids, which are composed mostly of carboxylic acids. This process is known as the saponification reaction. The overall reaction between these two substances is given by



The overall equation can be decomposed into the partitioning of the organic acid between the oleic and aqueous phases,



and an aqueous hydrolysis,



HA denotes single acid component in oil, A denotes an anionic surfactant. It can be interpreted from the equation that some portions of petroleum acids are ionized when reacting with alkali. Both ionized and neutral acids can form hydrogen bonds and result in the formation of acid soaps. This reaction takes place at the oil/water interface. So, when soaps are formed at the interface, the IFT between oil and water is instantaneously reduced. The schematic of the reaction can be shown in Figure 2.6.

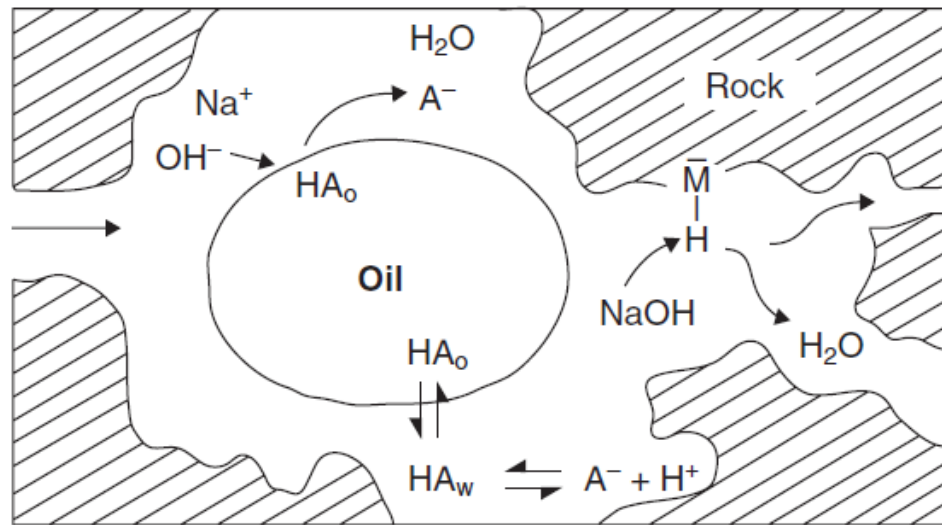


Figure 2.6 Schematic of alkaline flooding reaction (Sheng, 2011)

Emulsification is another important mechanism. This process depends on the IFT between oil and water, i.e. the emulsification can occur easily when the IFT is low. When the emulsifying ability is great, the residual oil is dispersed into tiny drops. These droplets become mobile and coalesce to form a continuous oil bank, so the oil can be displaced easily.

Several operating mechanisms on caustic flooding were proposed. Johnson (1976) summarized them into the following categories: (1) emulsification and entrainment, (2) emulsification and entrapment, (3) wettability reversal (oil-wet to water-wet), (4) wettability reversal (water-wet to oil-wet), and (5) emulsification and coalescence. The occurrence of each mechanism depends on various parameters of the system such as pH, acid number, salinity, pore structure, etc. At least the in-situ surfactant generation and emulsification appear on most of the mechanisms.

Although the use of alkali for flooding seems interesting, it can cause a serious scaling problem during the production. Alkalis can react with divalent ions such as calcium and magnesium to form precipitates. This would have a bad impact on the oil lifting process, so ceramic screw pumps are used instead of alloy pumps (Zhu et al.,

2013). Also, scale inhibitor could be added in order to prevent scaling (Liang et al., 2011). Berger and Lee (2006) proposed the use of organic alkalis which are derived from the sodium salts of weak polymer acids because they do not react with divalents.

The effect of alkali concentration on the IFT is explained from the following studies. Green and Willhite (1998) observed that the minimum IFT of 0.01 mN/m could be obtained at the narrow concentration range between 0.05 and 0.1 wt.%. Jennings (1975) reported that a minimum value of the IFT with a North American crude could be seen at about 0.1 wt.% of sodium hydroxide. Also, Mungan (1981) has concluded from a review of all published literature that the minimum value of the IFT occurs, for the most part, in the sodium hydroxide concentration ranges of about 0.05-0.2 wt.% and the pH value of about 12.5.

Zhao et al. (2002) measured the alkali/oil IFT at different concentrations. They varied the concentration of alkali from 10^{-4} to 10^{-2} mol/L. The results showed that at the low concentration (1×10^{-4} mol/L), the IFT was higher than 10 mN/m because the amount of generated in-situ soap was low. For the little higher concentration (5×10^{-4} mol/L), the low IFT was obtained for a short period of time and rose up thereafter. This was because the soap at the interface began to dissipate to the aqueous phase, leading to the higher IFT. At medium concentrations (1×10^{-3} mol/L and 5×10^{-3} mol/L), the IFT was low for the entire period. For the high concentration (1×10^{-2} mol/L), the IFT was initially low and increased later when the soap left the oil/water interface. Different IFTs, which are instantaneous, minimum, and equilibrium IFT, were plotted against the alkali concentration. The lowest IFTs were not obtained at the highest concentration, but rather at some optimum points in the middle of the range.

According to Kumar et al. (1989), the lower the pH of an alkali, the smaller the amount of the in-situ surfactant produced and thus lower amount of oil is displaced. Also, the oil production rate is drastically reduced at the lower pH due to the high ion exchange rate. Thus, using the alkali at a high pH could overcome the chromatographic ion-exchange retardation of the alkali.

Saengnil (2015) measured the IFT of light oil from Fang oilfield and the alkaline solution. Alkalis used in this study are sodium hydroxide and sodium carbonate. Effects of parameters such as pressure, temperature, alkaline type, alkaline concentration, salinity, and divalent ions were studied. The results showed that effect of pressure on the IFT can be neglected since the experimental system were liquid phase. Sodium hydroxide can reduce the IFT better than sodium carbonate because it can completely dissociate and form higher amount of in-situ surfactant. Increasing temperature, alkaline concentration, and salinity leads to the lower IFT. Divalent ions has small effect on the IFT.

2.4 Alkaline-Polymer Flooding

As discussed above, polymer flooding can aid in recovering additional oil to some extent. It has the ability to improve the sweep efficiency, but not the displacement efficiency. On the contrary, alkaline flooding could increase the displacement efficiency for the recovery process. Using both the alkali and the polymer could minimize their weaknesses and enhance even more hydrocarbon recovery. In other words, alkaline-polymer (AP) flooding can enhance both the sweep efficiency and the displacement efficiency.

Polymers are believed to have little impact on the IFT (Sheng, 2011). However, when the polymer is added to the alkaline solution, they would work together to achieve the better performance. The following researches explain about the effectiveness of the AP flooding method.

Yang et al. (2010) conducted a pilot field test in Yangsanmu oilfield, China from 1998 to 2008. They applied AP flooding technique with the condition of no fresh water supplied. Produced water was used to mix chemicals. Sodium carbonate was used as an alkali while HPAM was used as a polymer. The optimum condition was at 1% of alkali and 1500 ppm of polymer. The results showed that using AP flooding reduce the oil/brine IFT from 0.1 to 0.001 mN/m. The oil recovery increased

by 22.8% of the original oil in place although the AP solution was injected at the water cut of 90%.

Krumrine and Falcone (1983) investigated the effect of chemical injection sequence on the percentage of residual oil recovery after waterflooding. Three combinations of injection were made; (1) alkali followed by polymer (A/P), (2) polymer followed by alkali (P/A), (3) polymer and alkali at once (A+P). HPAM was used at 5,000 mg/L as a polymer, while sodium orthosilicate (Na_2SiO_4) was used as an alkali. The viscosity of the oil used in this experiment was 180 mPa.s. The recovery factor for the A+P case was the best comparing with both sequential injection and single injection processes. This was due to the synergy between the alkali and the polymer, where the polymer could control the mobility of the injected fluid and the alkali could generate the soap which reduces the IFT. The authors also observed the use of a biopolymer or less viscous oil (62 mPa.s). All of the experiments resulted in a consensus that injecting polymer and alkali together (A+P) yielded the highest residual oil recovery factor.

Sheng et al. (1993) studied the effects of polymer hydrolysis, aging time, and the type of alkali on the IFT. The condition for the experiment was at 60°C and the acid number was 0.5 mg KOH/g. Alkali's concentration were used at 1% for sodium hydroxide and 3% for sodium carbonate. The authors observed that the size of polymer impact on the IFT depended on the type of alkali used. For the same alkali concentration, IFT between sodium carbonate + HPAM solution and oil was lower than that of sodium hydroxide + HPAM solution and oil. Moreover, AP solution could decrease the IFT over time. The degree of polymer hydrolysis also affected the IFT in the way that higher percentage of hydrolysis would decrease the alkali + HPAM/oil IFT.

The study from Levitt et al. (2010) concluded that the extensive hydrolysis of HPAM will occur under alkaline conditions and significantly enhance the polymer's viscosity.

Since the previous work from Saengnil (2015) is the IFT measurement of light oil from Fang Oilfield with the alkaline solution, in this study, another chemical, HPAM polymer, is combined with alkali to enhance the efficiency of the solution for oil recovery. Therefore, the effect of polymer combined with alkali can be investigated on the IFT reduction with the conditions at Fang Oilfield.



CHAPTER 3

EXPERIMENT

3.1 Materials and Equipment

3.1.1 Oil Properties

Oil sample is obtained from Fang oilfield, Thailand. The viscosity of oil is 145 cP at 80°C by the measurement of the viscometer and the acid number is 0.89 mg KOH/g (Saengnil, 2015). Oil composition were tested with gas chromatography (GC), a technique that is used to analyze volatile substances in the gas phase. In gas chromatography, the injected sample is transported into a separation tube known as column by the mobile phase or a carrier gas which usually are inert gas such as helium or nitrogen. Inside the column, various components are separated when interacting with the microscopic layer made from liquid on an inert solid support at the wall. This layer is known as the stationary phase. The instrument measures the amount of the components at the column exit. Each component will be separated at a different time; it is the retention time of the compound. The value will be compared to the standard sample peak retention time to determine the type of the unknown component.

The composition of oil ranges from C7 to C35+ alkane and the distribution are as shown in Table 3.1.

Table 3.1 Composition of oil sample (Saengnil, 2015)

Component	Percent by weight (%)
C7	0.05
C8	0.68
C9	0.93
C10	1.00
C11	1.45
C12	1.84
C13	3.06
C14	3.52
C15	4.86
C16	3.87
C17	4.71
Pristane (C ₁₉ H ₄₀)	2.44
C18	3.49
Phytane (C ₂₀ H ₄₂)	0.82
C19	3.89
C20	4.41
C21	4.81
C22	4.48
C23	4.97
C24	4.26
C25	4.42
C26	4.33
C27	4.56
C28	3.58
C29	3.97
C30	3.72
C31	3.27
C32	2.87
C33	3.64
C34	1.70
C35+	4.40

The density of oil is measured at the temperature of 70, 80, and 90°C. Mass and volume of oil are obtained separately. After the oil sample is heated, mass would be measured by the precision weighing machine, and syringe is used to determine the sample volume. Therefore, the density is calculated using the equation 3.1;

$$\rho = \frac{m}{V} \quad (3.1)$$

where ρ is the density of sample; m is the mass of the sample; V is the sample volume

The measured density of oil sample can be shown in Table 3.2.

Table 3.2 Density of oil sample (Saengnil, 2015)

Temperature (°C)	Oil density (g/cm ³)
70	0.850
80	0.849
90	0.848

3.1.2 Brine Properties

Brine composition is duplicated according to the composition of the produced water at Fang oilfield as shown in Table 3.3.

Table 3.3 Composition of the produced water (Saengnil, 2015)

Chemical ions	Concentration (ppm)
Sodium, Na	256
Calcium, Ca	6.58
Magnesium, Mg	2.13
Barium, Ba	0.74
Chloride, Cl	21
Sulfate, SO ₄	18.7
Carbonate, CO ₃	54.0
Bicarbonate, HCO ₃	598
Hydroxide, OH	0

Simulated brine is prepared based on main components in the produced water which are sodium (26.7%), chloride (2.2%), carbonate (5.6%), and bicarbonate (62.5%).

Sodium chloride (NaCl) and sodium bicarbonate (NaHCO₃) purchased from Ajax, with the purity of 99.9% and 99.7% respectively, are dissolved in the distilled water to make the salinity close to the salinity of produced water. Divalent ions such as calcium and magnesium are neglected in the brine preparation since the amount of these ions are very low and can be neglected. However, the effect of these divalent ions on IFT reduction will be studied further.

Alkaline solution is obtained by mixing the simulated brine with sodium hydroxide (NaOH) or sodium carbonate (Na₂CO₃) purchased from Ajax, with the purity of 97.0% and 99.8% respectively. Hydrolyzed polyacrylamide (HPAM) is obtained from Sigma-Aldrich.

3.1.3 Equipment for Interfacial Tension Measurement

To measure the IFT between two liquids, the IFT apparatus from the Vinci Company Model IFT 700 is used in this study. The instrument is as shown in Figure 3.1. The fluids interfacial properties are determined from the shape of a rising drop which is generated at the end of a capillary needle immersed in a bulk fluid at the desired conditions. The cell volume which contains a bulk fluid is 25 cm³. The generated drop is detected with an accurate and calibrated video lens system and analyzed with Drop Analysis System software (DAS). Pressure and temperature in the system can be adjusted up to the maximum value of 69 MPa (10,000 psi) and 453.15 K (180°C), respectively. This equipment can measure the IFT in a range of 0.01 to 72 mN/m. The accuracy of this equipment is within 0.01 mN/m. The software can automatically calculate the IFT by using Young Laplace Equation as shown;

$$\Delta P = \frac{2\gamma}{R} \quad (3.2)$$

where ΔP is pressure difference across the fluid interface; γ is the IFT; R is the radius of curvature



Figure 3.1 The IFT 700 instrument (Source: Vinci Technologies, vinci-technologies.com)

3.1.4 Density Meter

Density meter from the Anton Paar Company Model DMA 4500 M is the instrument used for measuring the density of the liquid sample. The measuring range is between 0 to 3 g/cm³ and the accuracy is within 0.00005 g/cm³. Pressure and temperature can be measured up to the maximum value of 10 bar and 95°C respectively. The volume of the sample needed is approximately 1 mL.

3.1.5 Viscometer

Viscometer used to measure the viscosity of oil sample from Fang oilfield is purchased from Brookfield Model DV2TLV by using cone and plate. It will determine absolute viscosity of small samples under conditions of defined shear rate and shear stress. Its cone and plate spindle geometry requires a sample volume of only 0.5 mL and generates shear rates in the range of 0.6 to 1,875 per second. The instrument's sample cup is jacketed to control the temperature by using temperature bath with glycol. The cone and plate viscometer will measure viscosities from 0.1 cP to 2.6 million cP depending on the size of the spindle.

3.2 Experimental Procedure

3.2.1 Solution Preparation

To prepare the AP solution, sodium hydroxide and HPAM will be dissolved in the simulated brine. The solution and the crude oil will be heated to the desired temperature. At the certain temperature, the density of the solution is measured by using the density meter. The AP solution would be injected to the IFT instrument together with the crude oil at the desired pressure to measure the IFT. The results are obtained from the integrated software provided by the Vinci Company. The cleaning process requires acetone for removing oil, and the distilled water for parts containing the AP solution. Parameters could be varied as shown in Table 3.4.

Table 3.4 Experimental operating conditions for this study

Parameter	Value
Pressure (psig)	500, 1,000, and 1,500
Temperature (°C)	70, 80, and 90
Salinity (ppm)	500, 750, and 1,000
Polymer concentration (ppm)	500, 1,000, and 2,000
Alkali concentration (wt.%)	0, 0.025, 0.05, and 0.1
Type of alkali	NaOH and Na ₂ CO ₃

3.2.2 Interfacial Tension Measurement

A brief instruction for determining the crude oil/brine IFT is to fill the cell with the brine, pressurize it to the desired pressure, and inject oil and produce oil rising drop via the needle, respectively.

The temperature inside the view chamber is controlled with a temperature indicator which consists of a NiCr-Ni thermocouple; the accuracy of the temperature sensor is ± 0.1 K and heat loss is prevented by the covering jacket. The designated temperature in the system can be reached by using the heater. Keep the temperature and the pressure to be stable, crude oil can then be injected slowly into the cell. When the droplet is formed, measurement is started and the results are recorded to be further analyzed. The observation of droplets continues until the view chamber reach its equilibrium.

3.3 Methodology of This Research

Methodology flowchart of the study can be shown in Figure 3.2

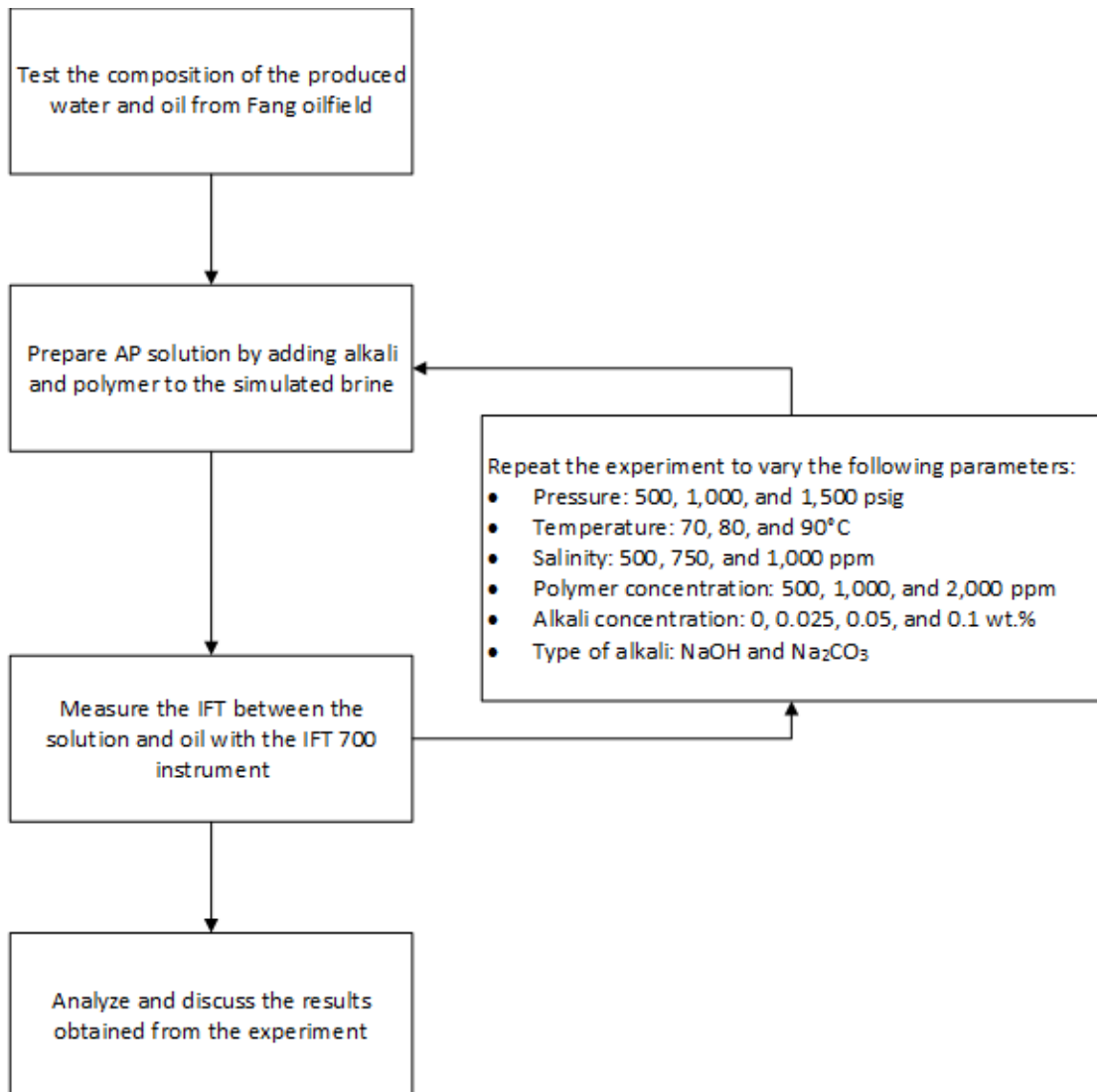


Figure 3.2 Flowchart of methodology

CHAPTER 4

RESULTS AND DISCUSSION

In this chapter, experimental results will be shown and discussed for the effects of parameters such as pressure, temperature, concentration of alkali and polymer, salinity and divalent ions on the IFT between crude oil and brine.

4.1 Equipment Verification

Before the study began, the equipment has been tested to verify the equipment and procedure by comparing with the literature (Saengnil, 2015) in which the alkaline solution are used. Testing conditions are at 0.05 wt.% of sodium hydroxide, pressure of 1,000 psi, salinity of 750 ppm. Temperatures are varied at 70, 80, and 90°C. The result of the verification is shown in Figure 4.1 and Table 4.1.

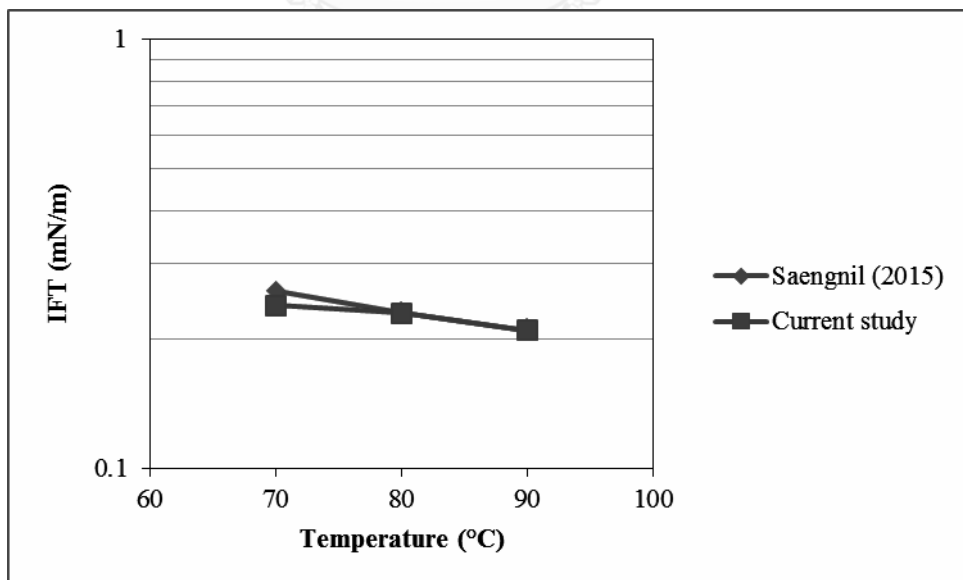


Figure 4.1 Equipment verification result (NaOH concentration = 0.05 wt.%, pressure = 1,000 psi, salinity = 750 ppm)

Table 4.1 Equipment verification result (NaOH concentration = 0.05 wt.%, pressure = 1,000 psi, salinity = 750 ppm)

IFT (mN/m)	Temperature (°C)		
	70	80	90
Saengnil (2015)	0.26	0.23	0.21
Current study	0.24	0.23	0.21
% Error	7.69	0	0

The result showed that the IFT from both studies at the same conditions are quite similar, with the maximum error of 7.69%. Thus the equipment is valid to be used in this research.

4.2 Effect of Pressure on the Interfacial Tension

Since the initial pressure of the reservoir in Fang oilfield is 950 psi (Chumkratoke, 2004), the pressure used in this study is between 500 and 1,500 psi to cover the wide range of operations such as the injection of water and the decline of the reservoir pressure.

The results showed that pressure has small effect on the IFT. It can be observed from Figure 4.2 and Table 4.2 that the IFT does not change much when pressure changes. The percent difference is 0% and 4.55% when pressures change from 500 to 1,000 psi and from 1,000 to 1,500 psi, respectively. The different of 0.01 mN/m occurred due to the accuracy of the equipment which is 0.01 mN/m. These results corresponds to the study from Saengnil (2015) which concluded that pressure does not have much effect on the IFT and can be neglected in the application of alkaline flooding for Fang oilfield.

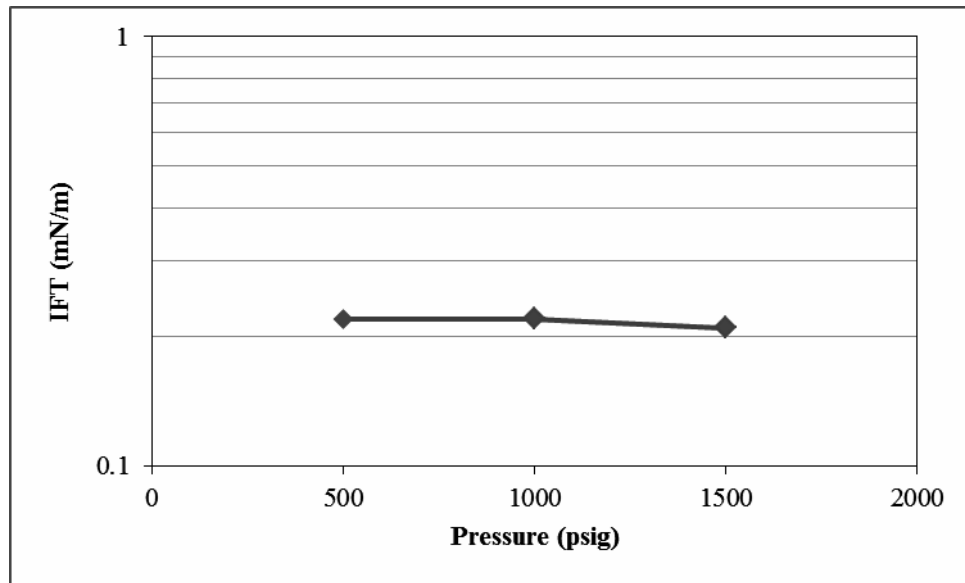


Figure 4.2 Effect of pressure on the IFT (NaOH concentration = 0.05 wt.%, HPAM concentration = 1,000 ppm, temperature = 80°C, salinity = 750 ppm)

Table 4.2 Effect of pressure on the IFT (NaOH concentration = 0.05 wt.%, HPAM concentration = 1,000 ppm, temperature = 80°C, salinity = 750 ppm)

Pressure (psi)	500	1,000	1,500
IFT (mN/m)	0.22	0.22	0.21

The reason for the slight change in the IFT is that the oil/water system which is liquid phase has high intermolecular force compared with the gas phase system so the IFT is not affected by the change of pressure. Hassan et al. (1953) concluded that the IFT would slightly change with pressure at constant temperature in the range of 1 to 204 atm. Therefore, the measurement would be operated at the pressure of 1,000 psig throughout this study.

4.3 Effect of Type of Alkaline Solution on the Interfacial Tension

There are 2 types of alkali used in this study, which are sodium hydroxide and sodium carbonate. The results for all of the conditions are shown in Table 4.3 to 4.5 based on the types of the alkali used. The comparison of results among two alkalis and that without alkali at different concentrations are shown in Figure 4.3 to 4.5.

Table 4.3 Results of the IFT of HPAM solution (in mN/m)

Conc. of polymer (ppm)	Salinity (ppm)	Temperature (°C)		
		70°C	80°C	90°C
500	500	36.48	35.59	34.32
	750	34.34	33.88	29.97
	1,000	32.27	31.61	28.74
1,000	500	38.79	37.68	36.94
	750	38.24	37.27	35.83
	1,000	34.96	33.30	32.46
2,000	500	42.33	41.93	40.93
	750	40.62	37.10	35.99
	1,000	37.52	36.47	35.64

Table 4.4 Results of the IFT of NaOH-HPAM solution (in mN/m)

Conc. of NaOH (wt.%)	Conc. of polymer (ppm)	Salinity (ppm)	Temperature (°C)		
			70°C	80°C	90°C
0.025	500	500	16.72	15.50	12.00
		750	21.24	18.86	15.04
		1,000	26.49	22.12	18.34
	1,000	500	18.67	17.17	15.69
		750	22.49	20.69	18.35
		1,000	29.69	25.35	22.59
	2,000	500	26.72	24.33	19.41
		750	27.84	26.74	22.29
		1,000	33.53	29.44	25.39
0.05	500	500	0.24	0.22	0.19
		750	0.25	0.23	0.21
		1,000	0.31	0.27	0.21
	1,000	500	0.25	0.22	0.18
		750	0.30	0.22	0.20
		1,000	0.37	0.28	0.21
	2,000	500	0.42	0.33	0.26
		750	0.53	0.38	0.30
		1,000	0.72	0.51	0.45
0.1	500	500	0.23	0.19	0.19
		750	0.22	0.19	0.19
		1,000	0.21	0.20	0.17
	1,000	500	0.30	0.23	0.21
		750	0.22	0.19	0.18
		1,000	0.22	0.20	0.18
	2,000	500	0.32	0.29	0.28
		750	0.27	0.25	0.23
		1,000	0.25	0.19	0.19

Table 4.5 Results of the IFT of Na₂CO₃-HPAM solution (in mN/m)

Conc. of Na ₂ CO ₃ (wt.%)	Conc. of polymer (ppm)	Salinity (ppm)	Temperature (°C)		
			70°C	80°C	90°C
0.025	500	500	26.36	25.56	24.52
		750	31.42	28.72	26.44
		1,000	32.84	31.42	30.20
	1,000	500	28.83	27.73	26.59
		750	33.95	29.96	27.35
		1,000	34.74	32.47	31.15
	2,000	500	34.74	33.51	32.15
		750	35.37	34.24	32.70
		1,000	35.85	34.71	33.22
0.05	500	500	26.54	23.91	20.42
		750	25.28	22.49	20.25
		1,000	24.41	21.99	19.98
	1,000	500	28.56	24.89	22.54
		750	24.85	22.49	21.28
		1,000	24.71	22.70	20.29
	2,000	500	32.37	27.18	24.65
		750	29.43	26.65	22.77
		1,000	26.40	24.55	22.20
0.1	500	500	0.80	0.66	0.56
		750	0.64	0.52	0.43
		1,000	0.61	0.51	0.43
	1,000	500	1.20	0.93	0.60
		750	0.97	0.68	0.49
		1,000	0.78	0.59	0.47
	2,000	500	1.76	1.22	1.03
		750	1.27	1.02	0.72
		1,000	0.94	0.80	0.59

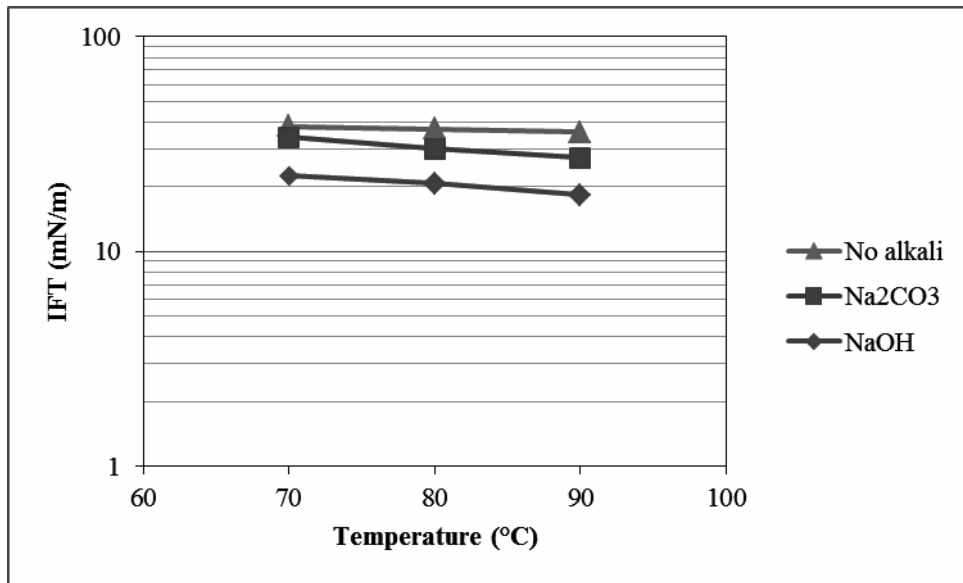


Figure 4.3 Effect of type of alkaline solution on the IFT at 0.025 wt.% alkali concentration (HPAM concentration = 1,000 ppm, salinity = 750 ppm)

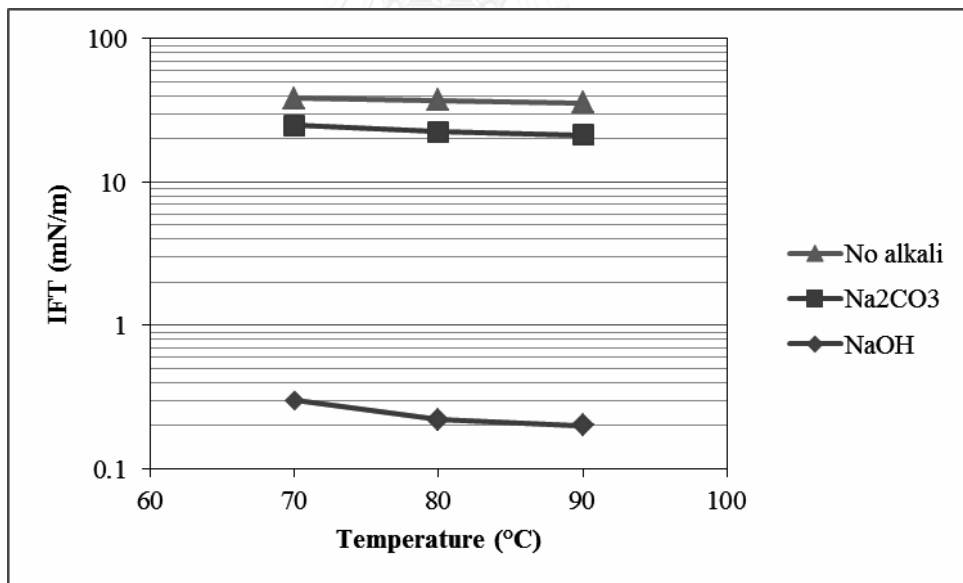


Figure 4.4 Effect of type of alkaline solution on the IFT at 0.05 wt.% alkali concentration (HPAM concentration = 1,000 ppm, salinity = 750 ppm)

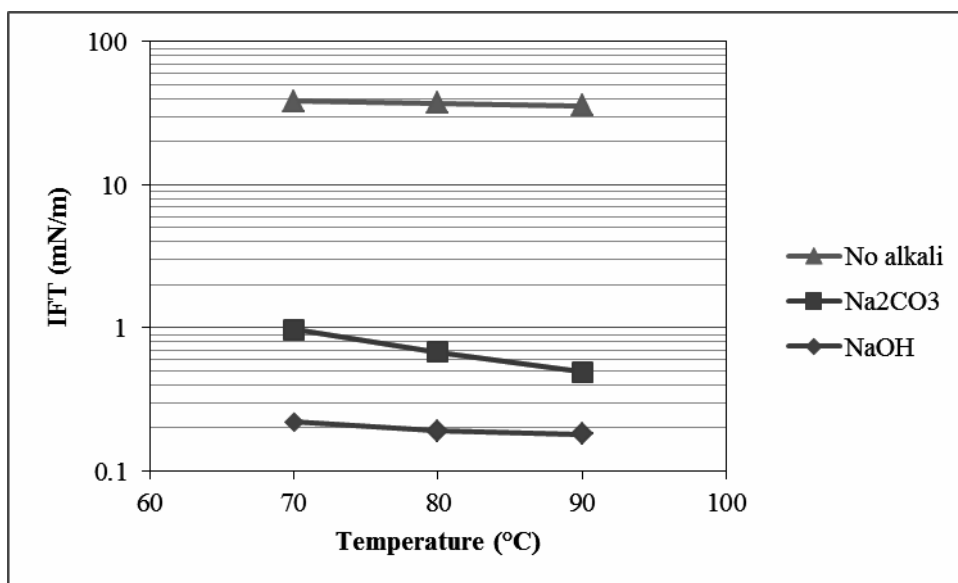


Figure 4.5 Effect of type of alkaline solution on the IFT at 0.1 wt.% alkali concentration (HPAM concentration = 1,000 ppm, salinity = 750 ppm)

In all cases, the results showed that using sodium hydroxide as an alkali solution always provide the lower IFT compared with the use of sodium carbonate and without alkali solution. At the concentration of 0.025 wt.%, the IFT resulted from the use of both alkalis are in the order of 10 mN/m. At the concentration of 0.05 wt.%, the IFT for NaOH-HPAM solution drastically drop below 1.00 mN/m, while the IFT for Na₂CO₃-HPAM solution and no alkali solution are still more than 10 mN/m. At the concentration of 0.1 wt.%, the IFT for both type of alkalis are less than 1.00 mN/m. Using sodium hydroxide as an alkali, the IFT can be reduced up to 99.50%, while the use of sodium carbonate can reduce the IFT up to 98.63%.

Sodium hydroxide is a strong base. It can completely dissociate to sodium ions and hydroxide ions. On the other hand, sodium carbonate is a salt between strong base (sodium hydroxide) and weak acid (carbonic acid). The following salt can totally breakdown forming sodium ions and carbonate ions. These anions undergoes a hydrolysis reaction forming bicarbonate ions and hydroxide ions. Since the second reaction is reversible, the amount of hydroxide ion formed is quite low compared with

the reaction of strong base. Therefore, the solution is mildly basic. Reactions of sodium carbonate as explained can be shown below.



Consequently, at the same concentration, sodium carbonate could provide lower amount of hydroxide ions compared with sodium hydroxide and thus generating less amount of the in-situ surfactant. Also, sodium hydroxide has higher pH; therefore, the performance of reducing the IFT when comparing at the same alkali concentration is better. According to Kumar et al. (1989), the lower the pH, the smaller the amount of the in-situ surfactant produced and thus lower amount of oil is displaced. Also, the oil production rate is drastically reduced at the lower pH due to the high ion exchange rate. Thus, using the alkali at a high pH could overcome the chromatographic ion-exchange retardation of the alkali.

4.4 Effect of Alkali Concentration on the Interfacial Tension

The concentration of sodium hydroxide is initially varied from the base case conditions to see the amount of IFT reduction and to choose some appropriate concentrations to be used with other cases. From Figure 4.6 and Table 4.6, the concentration is studied at 0, 0.025, 0.03, 0.04, 0.05 and 0.1 percent by weight (wt.%).

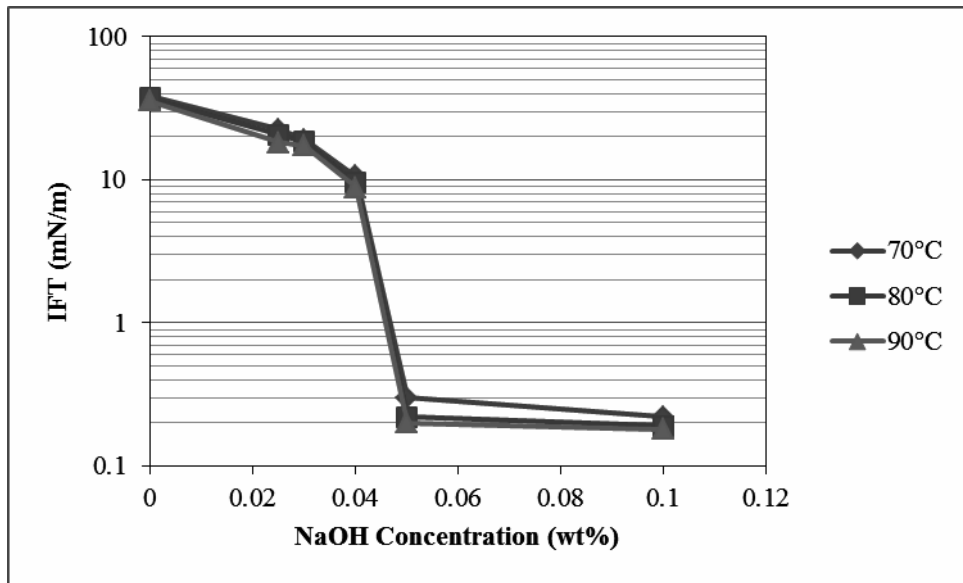


Figure 4.6 Effect of NaOH concentration in the wide range on the IFT (HPAM concentration = 1,000 ppm, salinity = 750 ppm)

Table 4.6 Effect of NaOH concentration in the wide range on the IFT (HPAM concentration = 1,000 ppm, salinity = 750 ppm)

Conc. of NaOH (wt.%)	0	0.025	0.03	0.04	0.05	0.1
IFT at 70°C (mN/m)	38.24	22.49	19.07	10.61	0.30	0.22
IFT at 80°C (mN/m)	37.27	20.69	18.38	9.57	0.22	0.19
IFT at 90°C (mN/m)	35.83	18.35	17.31	8.82	0.20	0.18

It can be clearly seen that the IFT drops drastically at the concentration of 0.05 wt.%, so this concentration will be used as the base value for the alkali concentration. Other concentrations that will be used in this research are 0, 0.025 and 0.1 wt.%. Figure 4.7 and 4.8 show the effect of alkali concentration ranging from 0 to 0.1 wt.% on the IFT reduction for sodium hydroxide and sodium carbonate, respectively.

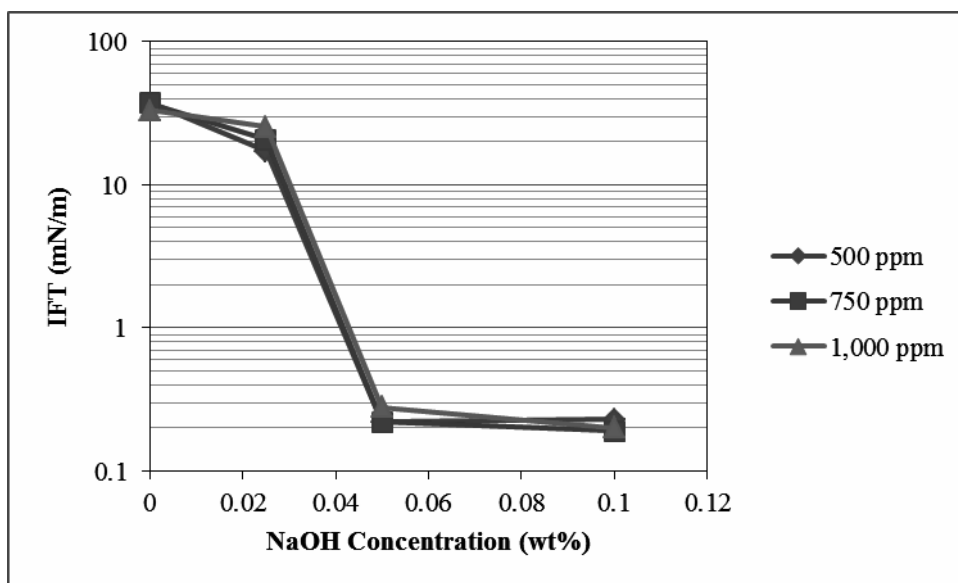


Figure 4.7 Effect of NaOH concentration on the IFT (HPAM concentration = 1,000 ppm, temperature = 80°C)

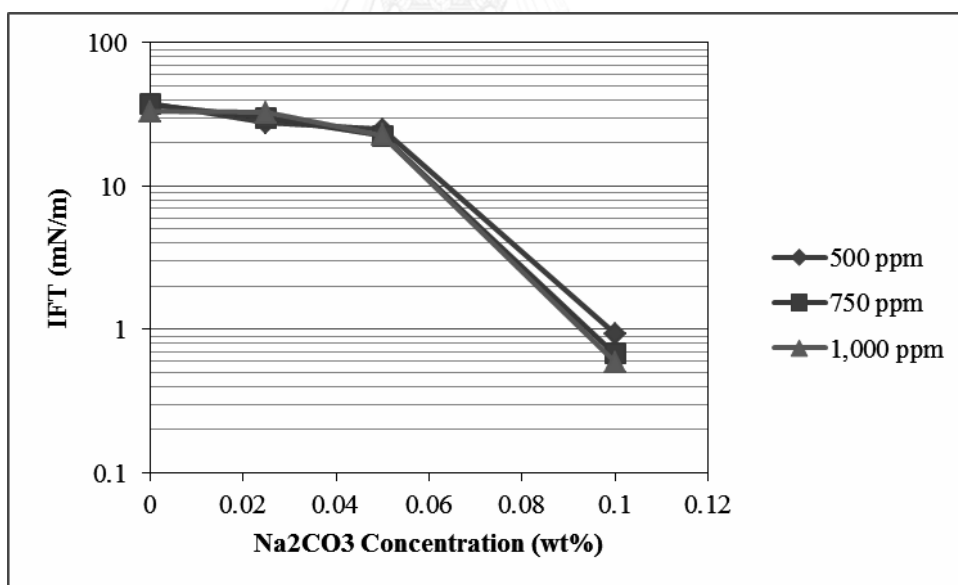


Figure 4.8 Effect of Na₂CO₃ concentration on the IFT (HPAM concentration = 1,000 ppm, temperature = 80°C)

The results showed that the increase of the alkali concentration can effectively reduce the IFT for both types of alkali solution. For the NaOH-HPAM solution, the increase of the alkali concentration can drastically reduce the IFT up to 99.49%. This huge IFT reduction occurs mostly at the concentration above 0.05 wt.%. It can be explained that at higher alkali concentration, the in-situ surfactant can be formed at higher rate, thus resulting in lowering the IFT. Moreover, IFT becomes less than 1 mN/m when the alkali concentration is more than 0.05 wt.%. Beyond this concentration, the IFT is almost stable because there are sufficient amount of the in-situ surfactant at the oil/water interface.

The results for the NaOH-HPAM solution corresponds with previous works about the alkaline flooding. Jennings (1975) reported that a minimum value of the IFT with a North American crude could be seen at about 0.1 wt.% of sodium hydroxide. Also, Mungan (1981) has concluded from a review of all published literature that the minimum value of the IFT occurs, for the most part, in the sodium hydroxide concentration ranges of about 0.05-0.2 wt.% and the pH value of about 12.5.

For the Na₂CO₃-HPAM solution, higher concentration of sodium carbonate can also reduce the IFT more effectively, but at a lower degree compared with that of sodium hydroxide. The IFT would be less than 1 mN/m when the concentration of sodium carbonate is at 0.1 wt.%. Sodium carbonate can reduce the IFT up to 98.23%. The reason is that sodium carbonate is less efficient in the IFT reduction because it is a salt between strong base and weak acid. This salt makes the solution mildly basic, and the amount of hydroxide ion is lower compared with strong base. So the amount of the in-situ surfactant generated by basic salt is typically less than that of strong base as mentioned in the previous section.

4.5 Effect of Temperature on the Interfacial Tension

Temperature is initially varied in the wide range, from 50 to 90°C, to see the direction of change in the IFT. The results can be seen from Figure 4.9 and Table 4.7 that increasing temperature always leads to the reduction of the IFT for every type of the solution. The percentages of the IFT difference when increasing temperature range from 9.09 to 31.58% for sodium hydroxide as an alkali and 2.94 to 9.50% for sodium carbonate cases.

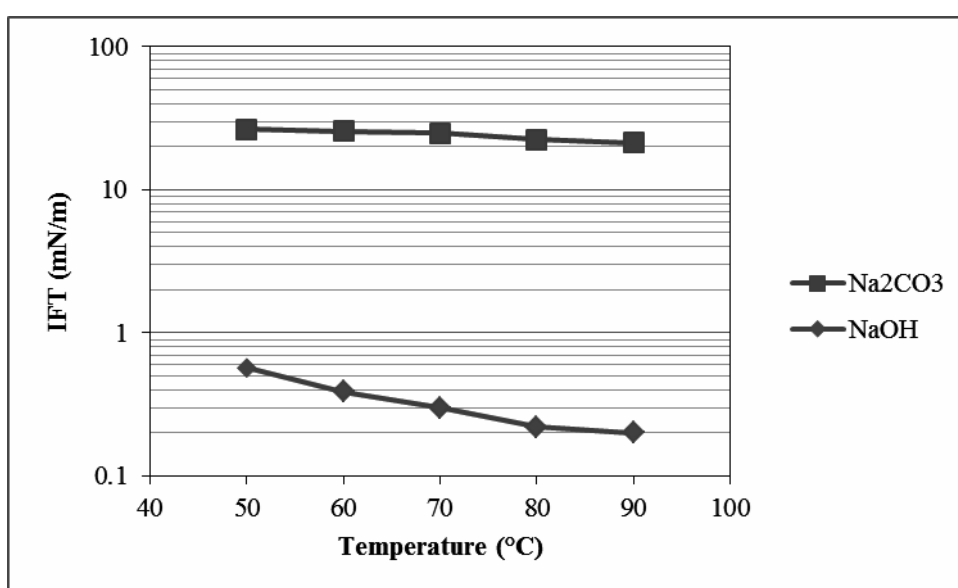


Figure 4.9 Effect of temperature on the IFT (Alkali concentration = 0.05 wt.%, HPAM concentration = 1,000 ppm, salinity = 750 ppm)

Table 4.7 Effect of temperature on the IFT (Alkali concentration = 0.05 wt.%, HPAM concentration = 1,000 ppm, salinity = 750 ppm)

IFT (mN/m)	Temperature (°C)				
	50	60	70	80	90
NaOH-HPAM solution	0.57	0.39	0.30	0.22	0.20
Na ₂ CO ₃ -HPAM solution	26.49	25.71	24.85	22.49	21.28

For other conditions, the temperature in this study was used at 70, 80, and 90°C according to the average reservoir temperature in Fang oilfield of 630°R or 76.85°C (Chumkratoke, 2004). So temperatures that are used in the experiment could cover most of the conditions found in Fang oilfield. The results are shown in Figure 4.10 to 4.12 based on the types of the alkali used.

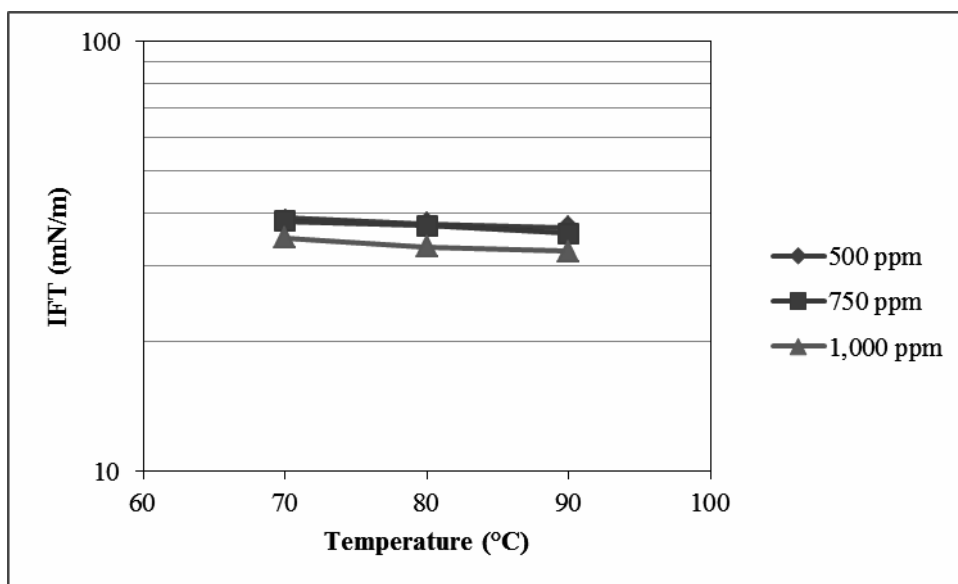


Figure 4.10 Effect of temperature on the IFT with HPAM solution (Alkali concentration = 0 wt.%, HPAM concentration = 1,000 ppm)

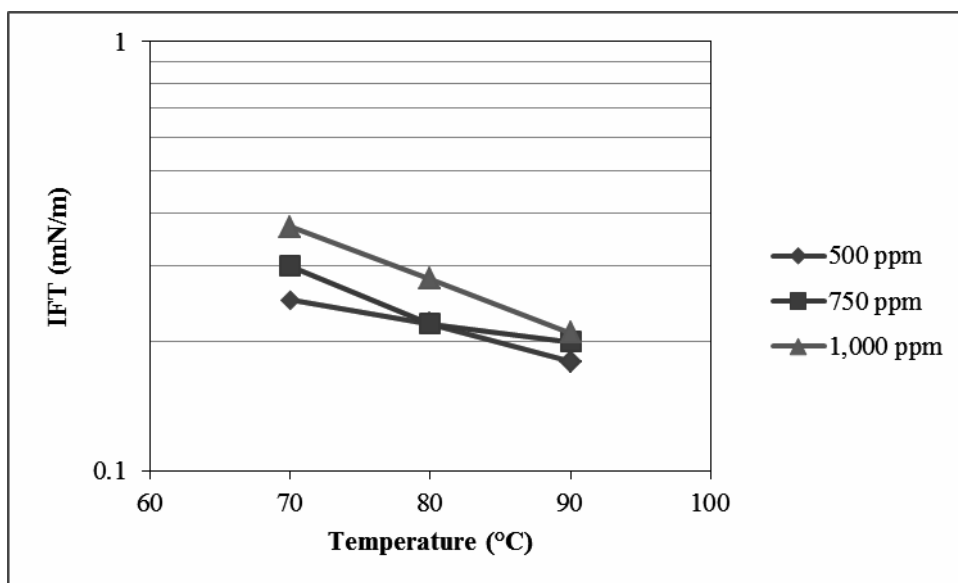


Figure 4.11 Effect of temperature on the IFT with NaOH-HPAM solution (NaOH concentration = 0.05 wt.%, HPAM concentration = 1,000 ppm)

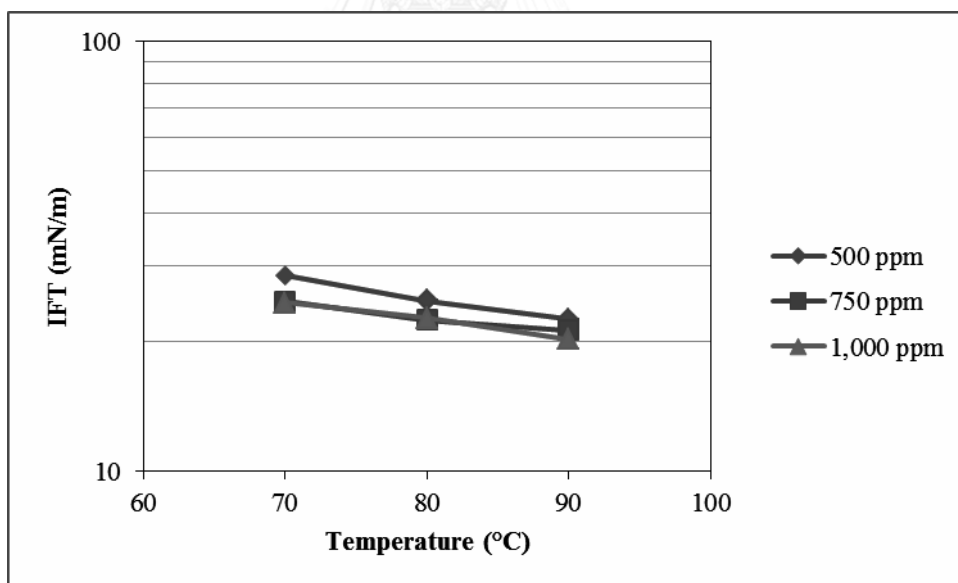


Figure 4.12 Effect of temperature on the IFT with Na₂CO₃-HPAM solution (Na₂CO₃ concentration = 0.05 wt.%, HPAM concentration = 1,000 ppm)

From Figure 4.11 and 4.12, the IFT reduces with the increase of temperature when the alkali is present. For the sodium hydroxide-HPAM solution, the percentage of the IFT reduction when increasing temperature ranges from 9.09 to 26.67% whereas the percentage for sodium carbonate-HPAM solution ranges from 5.38 to 12.85%. Temperature has impact on the IFT because at higher temperature, more in-situ surfactant can be formed at the oil/water interface. The reduction in the IFT for sodium hydroxide-HPAM solution is found to be more efficient comparing with the sodium carbonate-HPAM solution because it contains a stronger base when comparing at the same concentration, thus generating more in-situ surfactant.

However, as shown in Figure 4.10, the IFT could also reduce with increasing temperature in the HPAM solution despite the fact that there is no alkali present in the solution. The reason is that there is a small amount of sodium bicarbonate in the solution (around 722 mg/l under the salinity of 750 ppm). Sodium bicarbonate which is partially dissolved in water could be considered as weak base when comparing with sodium hydroxide at the same concentration. This explains why the percentage of IFT reduction for HPAM solution is quite low, for about 1.96 to 4.75%.

There are various mechanisms that could explain the IFT reduction phenomenon. At higher temperature, a larger amount of molecules has enough kinetic energy to overcome the activation energy for the saponification reaction than at lower temperature. So the rate of the saponification reaction increases, and this generates the higher amount of the in-situ surfactant that can lower the IFT. According to Wei (2005), increasing the temperature can exponentially increase the solubility of water in oil, which reduces the free energy between two immiscible fluids and thus decreasing the IFT. Also, the study of Okasha and Alshiwaihs (2009) concludes that intermolecular forces at the oil/water interface weakens when temperature increases, and this can lead to the lowering of the IFT. The experimental results are consistent with the study from Hjelmeland and Larrondo (1986).

4.6 Effect of Polymer Concentration on the Interfacial Tension

The polymer that is used in this study is hydrolyzed polyacrylamide (HPAM). Normally, polymer concentrations used in polymer flooding range from 250 to 2,000 ppm (Lyons and Plisga, 2004). Consequently, the concentrations of HPAM in this study are used at 500, 1,000, and 2,000 ppm to see the effect on the IFT as presented in Figure 4.13 to 4.15.

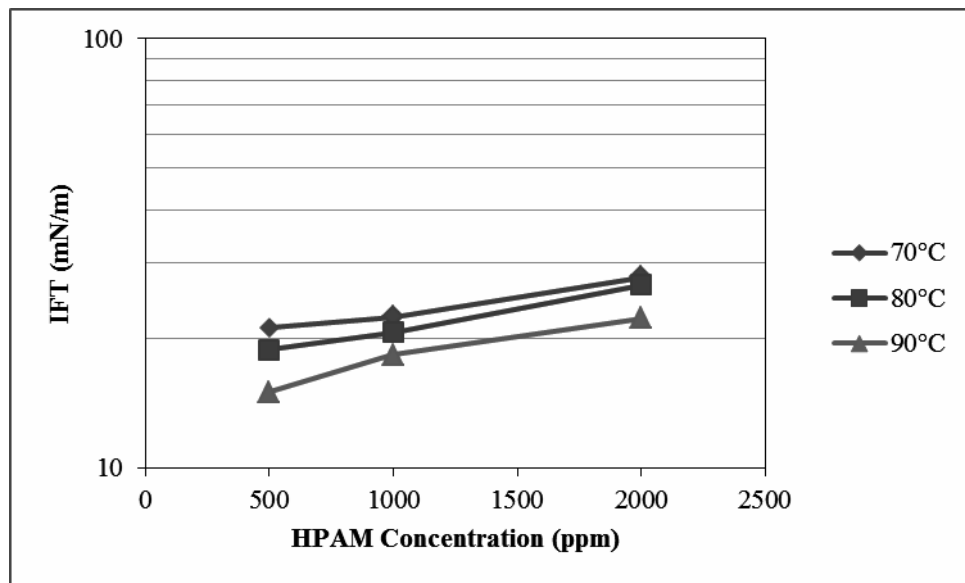


Figure 4.13 Effect of polymer concentration on the IFT at 0.025 wt.% NaOH concentration (Salinity = 750 ppm)

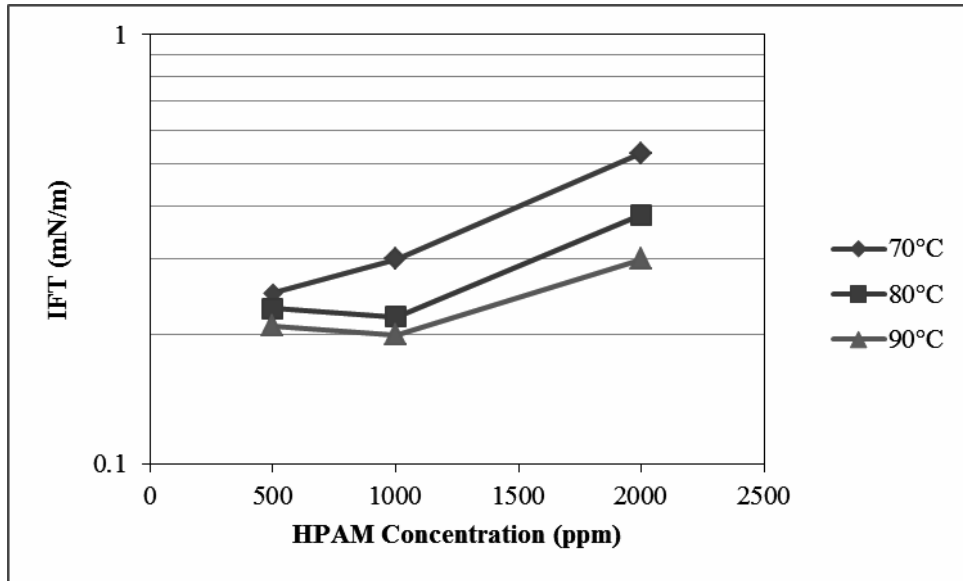


Figure 4.14 Effect of polymer concentration on the IFT at 0.05 wt.% NaOH concentration (Salinity = 750 ppm)

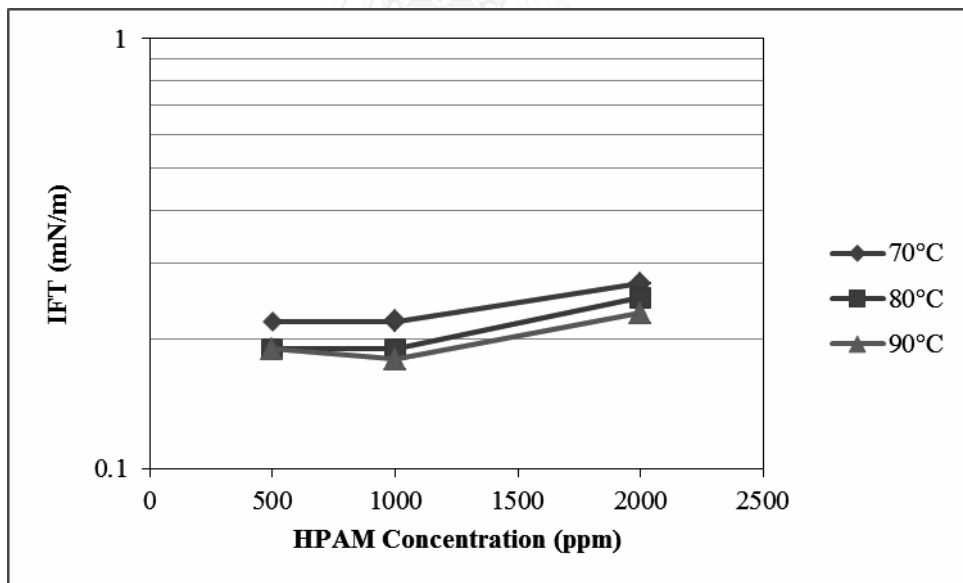


Figure 4.15 Effect of polymer concentration on the IFT at 0.1 wt.% NaOH concentration (Salinity = 750 ppm)

The results show that the concentration of polymer from 500 to 2,000 ppm does not help in the IFT reduction. Instead, increasing HPAM concentration tends to increase the IFT especially when the concentration is increased from 1,000 to 2,000 ppm. The percentage of increasing the IFT is found to be up to 76.67%. However, the small decrease of the IFT can be seen at some point which is within the accuracy of the equipment (0.01 mN/m).

The reason that increasing the polymer concentration can increase the IFT is that HPAM can react with NaOH as the polymer is hydrolyzed. Therefore, the alkali is consumed and its concentration decreases. The amount of in-situ surfactant decreases and results in the higher IFT. The results corresponds to the study from Levitt et al. (2010) that the extensive hydrolysis of HPAM will occur under alkaline conditions and significantly enhance the polymer's viscosity. Thus, HPAM cannot help in the IFT reduction. However, the increasing trend is quite small at the NaOH concentration of 0.1 wt.% because the amount of alkali is high enough that it could generate the excess amount of the in-situ surfactant at the oil/water interface.

4.7 Effect of Salinity on the Interfacial Tension

According to Table 3.3 which shows the composition of the produced water from Fang oilfield, main ions in brine are sodium (26.7%), chloride (2.2%), carbonate (5.6%), and bicarbonate (62.5%). Therefore, the brine used in this study was obtained by mixing sodium chloride and sodium bicarbonate in the distilled water. The amount of these salts are simulated from the produced water from Fang oilfield and the proportion at each salinity can be found in Appendix A. The salinity was studied at 500, 750, and 1,000 ppm to see the effect on the IFT. The results are illustrated in Figure 4.16 and 4.17.

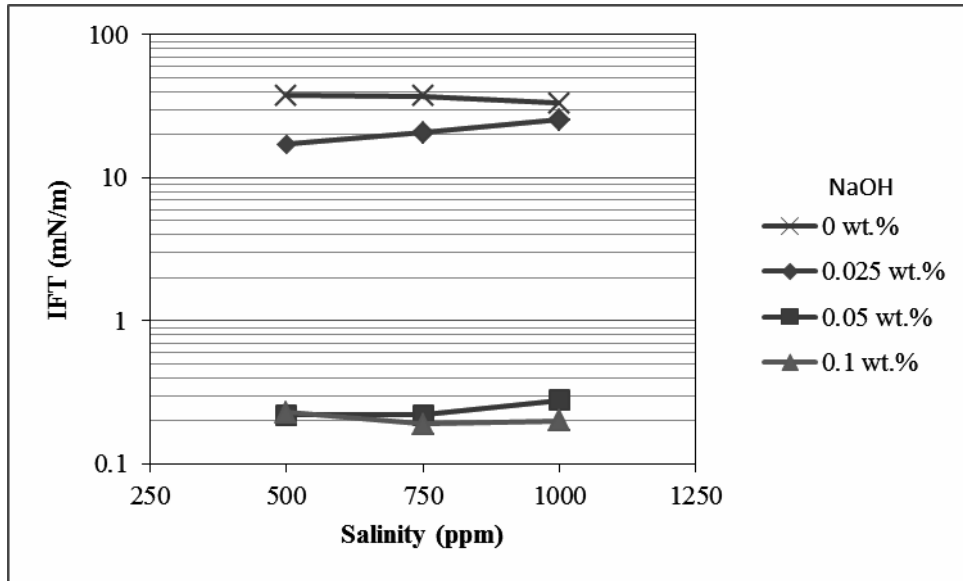


Figure 4.16 Effect of salinity on the IFT (NaOH-HPAM solution, HPAM concentration = 1,000 ppm, temperature = 80°C)

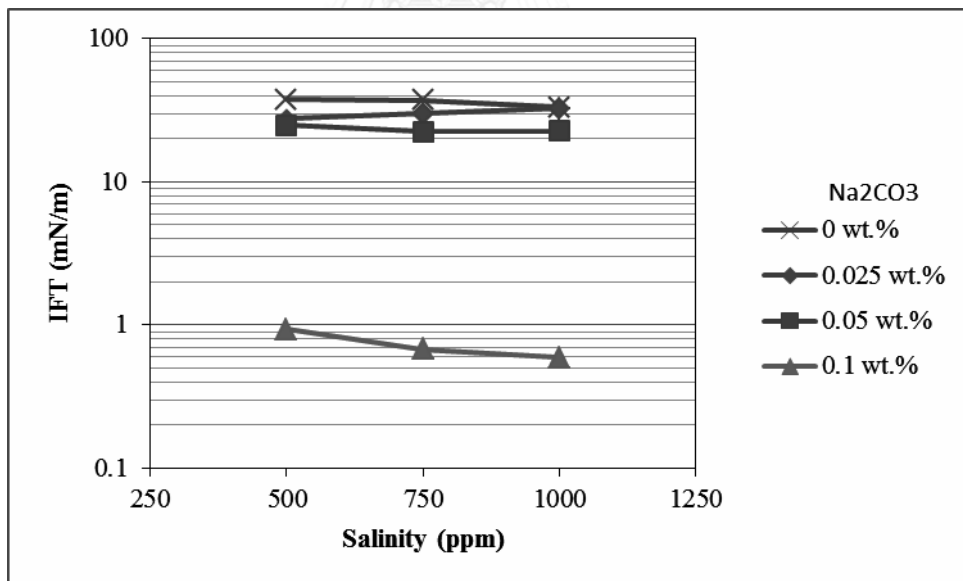


Figure 4.17 Effect of salinity on the IFT (Na₂CO₃-HPAM solution, HPAM concentration = 1,000 ppm, temperature = 80°C)

The results show that the effect of salinity ranging from 500 to 1,000 ppm on the IFT has different directions depending on the concentration of the alkali. For alkali concentrations at 0.025 and 0.05 wt.% for sodium hydroxide and 0.025 wt.% for sodium carbonate, the IFT is increased with the higher salinity. Salinity can increase the IFT up to 27.27%. According to Sheng (2011), salt ions prevented negative charges on polymer's backbone from repelling one another. Since the charge is neutralized, the polymer structures are compressed. These compressed and neutralized polymers can interfere with the link between the nonpolar (hydrophobic) part of the in-situ surfactant and oil so that the IFT is increased instead of decreased.

However, for alkali concentrations at 0.1 wt.% for sodium hydroxide and 0.05 and 0.1 wt.% for sodium carbonate, the IFT is decreased with the increasing salinity. From the graph, the percentage of decrease can be up to 26.88%. One mechanism that can explain this phenomenon is that when the amount of the alkali is high, salt ions could impact on the alkali rather than the polymer. High salt charges could push more in-situ surfactant to the oil/water interface, leading to the lower IFT (Saengnil, 2015).

When there is no alkali presented in the solution, the IFT seems not to be affected by the salinity. This is valid except for the salinity of 1,000 ppm, where the IFT is slightly reduced which could be due to the large amount of sodium bicarbonate. Sodium bicarbonate is normally considered as a weak alkali and is not often used in alkali flooding because of its low capability to reduce the IFT (Sheng, 2011). This explains why the IFT reduces little when the salinity is high.

All of the mechanisms explained above occur at the same time, but each mechanism dominates at different alkali concentrations. It is possible that there might be some alkali concentration where the strength of different mechanisms are equal and the trend of the IFT changes at that point. This requires further study on the competition of mechanisms as affected by the alkali concentration.

4.8 Effect of Divalent Ions on the Interfacial Tension

Since for all of the experiments explained in previous sections did not include the divalent ions in brine, the effect of divalent ions on the IFT will be investigated in this part. The divalent ions are not included in other cases because based on the data from Table 3.3, the amount of them are very low and can be neglected, 6.58 ppm for calcium ion (0.7%) and 2.13 ppm for magnesium ion (0.2%). Calcium chloride and magnesium chloride are added to the solution to make the proportion of ions similar to the produced water from Fang oilfield. The solution which contains divalent ions are tested at various temperatures for both alkali types to compare the result with the solution that has no divalent ions. The result can be shown in Figure 4.18 and Table 4.8.

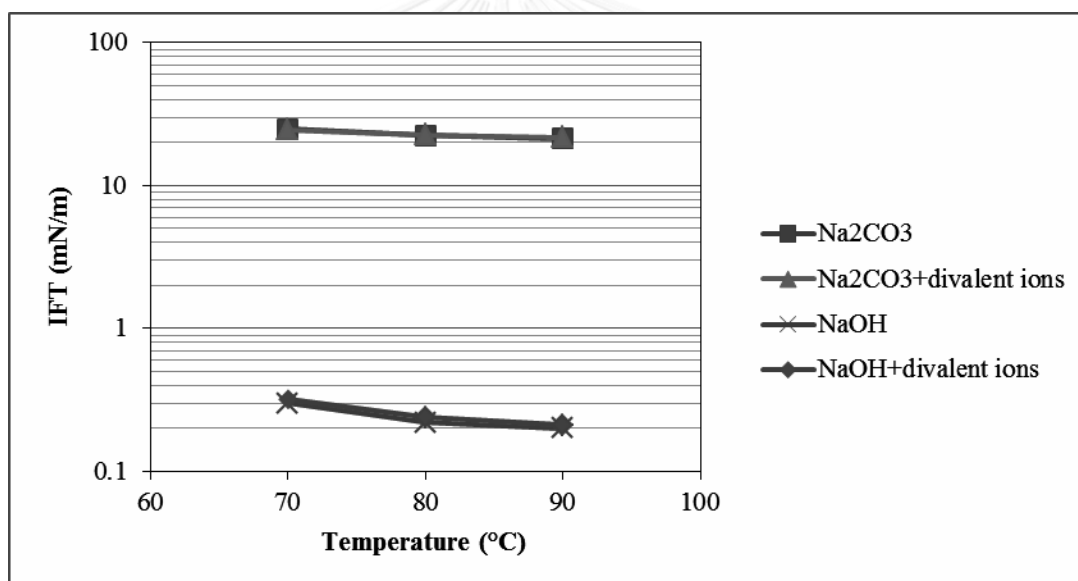


Figure 4.18 Effect of divalent ions on the IFT (Alkali concentration = 0.05 wt.%, HPAM concentration = 1,000 ppm, salinity = 750 ppm)

Table 4.8 Effect of divalent ions on the IFT (Alkali concentration = 0.05 wt.%, HPAM concentration = 1,000 ppm, salinity = 750 ppm)

IFT (mN/m)	Temperature (°C)		
	70	80	90
NaOH-HPAM solution	0.30	0.22	0.20
NaOH-HPAM solution with divalent ions	0.32	0.24	0.21
Na ₂ CO ₃ -HPAM solution	24.85	22.49	21.28
NaOH-Na ₂ CO ₃ solution with divalent ions	24.65	22.78	21.69

It can be seen that the IFT are quite similar for the cases with and without divalent ions. Theoretically, calcium ions can destroy the capability of alkali to reduce the IFT when its concentration is above 200 ppm (Trujillo, 1983). In other words, high amount of calcium ions can increase the IFT. For this study, the amount of calcium ion is only 6.58 ppm, so it could not have a significant impact on the IFT. Therefore, divalent ions can be neglected in this study.

CHAPTER 5

CONCLUSIONS AND RECOMMENDATION

This chapter concludes the results from the previous chapter. Also, recommendations are provided for future study.

5.1 Conclusions

In this study, effects of parameters such as concentration, pressure, temperature, and salinity on the IFT of oil from Fang oilfield and AP solution are investigated. The IFT is measured by the IFT 700 equipment which detect the rising oil drop in the solution.

From the results, AP solution can reduce the IFT down to 0.17 mN/m for the NaOH-HPAM solution and 0.43 mN/m for the Na₂CO₃-HPAM solution. In order to obtain a low IFT, good combination of various parameters are required. The effect of each parameters on the IFT are concluded below.

1. The pressure used in this study is between 500 and 1,500 psi. The results show that pressure has small effect on the IFT. Thus the effect of pressure can be neglected in the application of alkaline flooding for Fang oilfield.

2. There are 2 types of alkali used in this study, which are sodium hydroxide and sodium carbonate. Although both alkalis are capable of reducing the IFT, sodium hydroxide always provide the lower IFT given the same concentration. In other words, sodium hydroxide has higher performance in lowering the IFT compared with sodium carbonate. The reason is that strong bases such as sodium hydroxide can completely dissociate in the solution so the amount of ions are higher. This results in the higher amount of the in-situ surfactant and thus lowering the IFT.

3. The alkali concentrations used in this study are 0, 0.025, 0.05 and 0.1 wt.%. Increasing the alkali concentration to some value can effectively reduce the IFT. For the solution that contains sodium hydroxide, the IFT drops drastically at the alkali concentration of 0.05 wt.% and becomes less than 1.00 mN/m. Beyond this concentration, the IFT is almost stable because there are sufficient amount of the in-situ surfactant at the oil/water interface. For the solution that contains sodium carbonate, the IFT would be less than 1.00 mN/m when the concentration of sodium carbonate is at 0.1 wt.%.

4. Temperature was varied in the wide range, from 70 to 90°C. It can be concluded that increasing temperature always leads to the reduction of the IFT for every type of the solution.

5. The concentration of HPAM is used at 500, 1,000, and 2,000 ppm. The results show that the concentration of polymer does not help in the IFT reduction. Instead, increasing HPAM concentration tends to increase the IFT especially when the concentration is increased from 1,000 to 2,000 ppm. However, the increasing trend is quite small at the NaOH concentration of 0.1 wt.% because the amount of alkali is high enough that it could generate the excess amount of the in-situ surfactant at the oil/water interface.

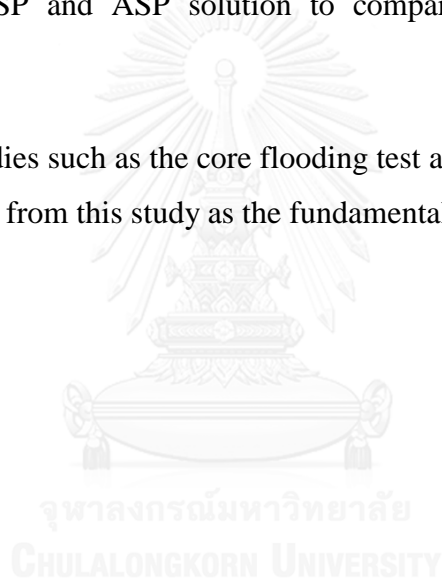
6. The salinity was studied at 500, 750, and 1,000 ppm. The change of the IFT as affected by the salinity has different directions depending on the concentration of the alkali. At low alkali concentrations, 0.025 and 0.05 wt.% for sodium hydroxide and 0.025 wt.% for sodium carbonate, the IFT is increased with the higher salinity. However, at high alkali concentrations, 0.1 wt.% for sodium hydroxide and 0.05 and 0.1 wt.% for sodium carbonate, the IFT is decreased with the increasing salinity.

7. Divalent ions have less impact on the IFT. Therefore, its effect is neglected in this study.

5.2 Recommendation

The following issues are recommended for future study.

1. Since the salinity used in current study is fresh water, seawater can be tested to see the effect on the IFT at high salinity.
2. The study on the competition of mechanisms when the salinity is changed as affected by the alkali concentration.
3. IFT measurement of oil and other combination of chemicals can be performed such as SP and ASP solution to compare the effectiveness of each combination.
4. Further studies such as the core flooding test and simulation for EOR can be done using the results from this study as the fundamental data.



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APPENDIX



จุฬาลงกรณ์มหาวิทยาลัย
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APPENDIX A

SOLUTION COMPOSITION

The brine used in this study was obtained by mixing sodium chloride and sodium bicarbonate in the distilled water to make its proportion close to that of Fang oilfield. The salinity was prepared at 500, 750, and 1,000 ppm. The amount of each salt at different salinity can be shown in the table below.

Table A.1 Composition and the pH value of the simulated brine

Salinity (ppm)	Sodium Chloride (mg/l)	Sodium Bicarbonate (mg/l)	pH
500	18.8	481.2	8.70
750	28.2	721.8	8.85
1,000	37.6	962.4	8.88

APPENDIX B

EFFECT OF EACH PARAMETER

The description of effects of each parameter on the IFT is as described in chapter 4.

Effect of Pressure on the Interfacial Tension

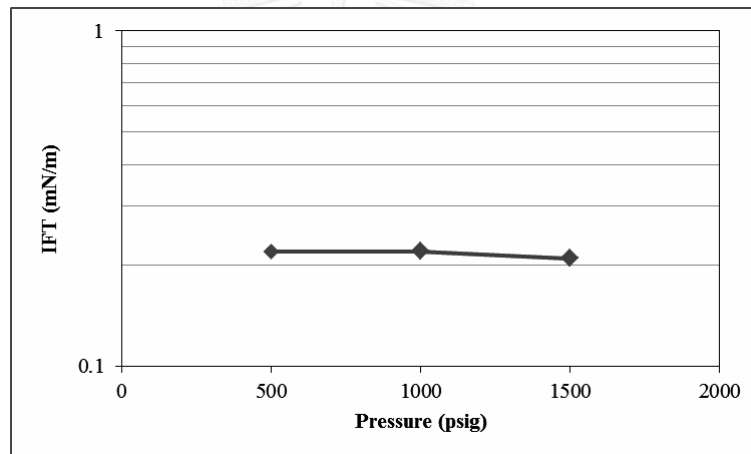


Figure B.1 Alkali concentration 0.05 wt.%, NaOH-HPAM Solution

Effect of Alkali Concentration on the Interfacial Tension

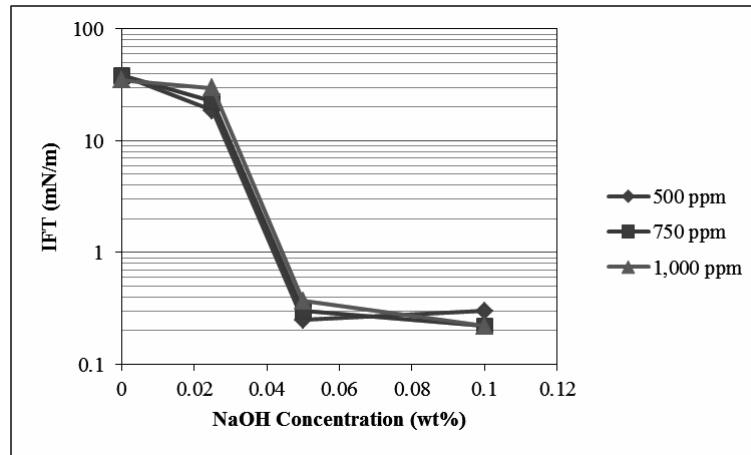


Figure B.2 Temperature 70°C, NaOH-HPAM Solution

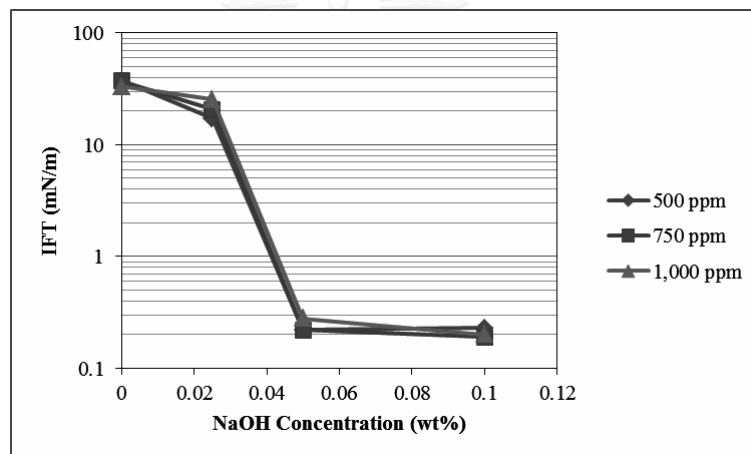


Figure B.3 Temperature 80°C, NaOH-HPAM Solution

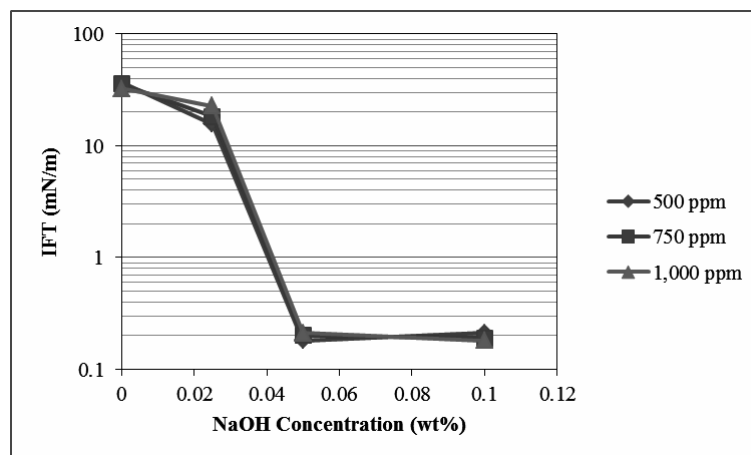


Figure B.4 Temperature 90°C, NaOH-HPAM Solution

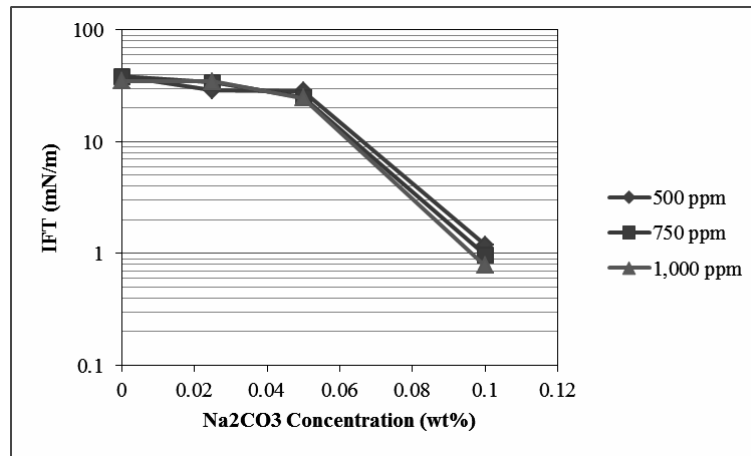


Figure B.5 Temperature 70°C, Na₂CO₃-HPAM Solution

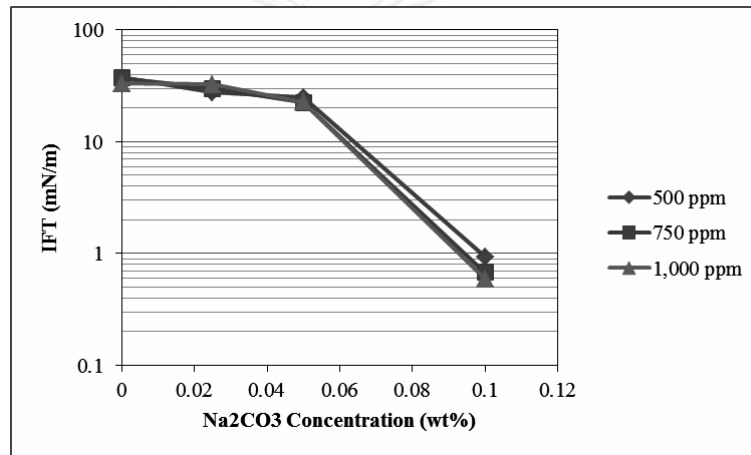


Figure B.6 Temperature 80°C, Na₂CO₃-HPAM Solution

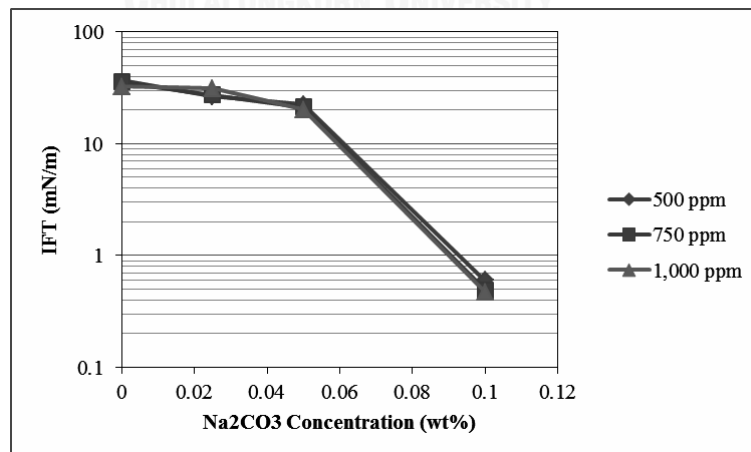


Figure B.7 Temperature 90°C, Na₂CO₃-HPAM Solution

Effect of Temperature on the Interfacial Tension

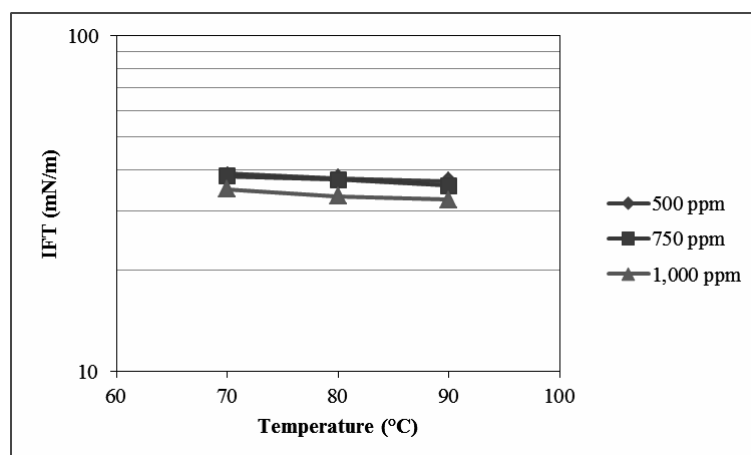


Figure B.8 Alkali concentration 0 wt.%, HPAM Solution

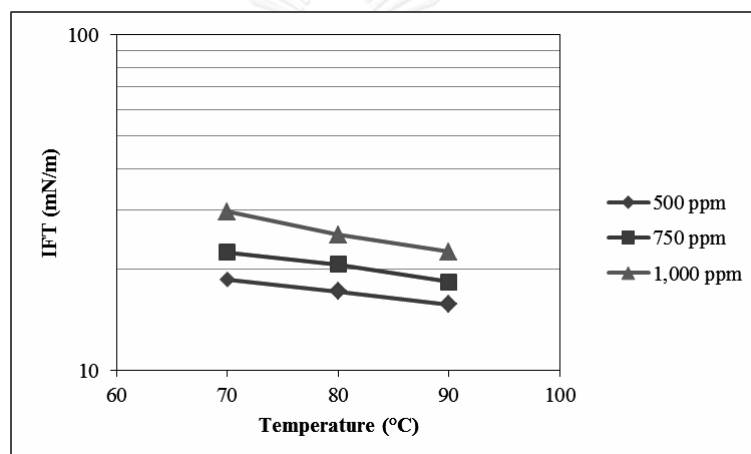


Figure B.9 Alkali concentration 0.025 wt.%, NaOH-HPAM Solution

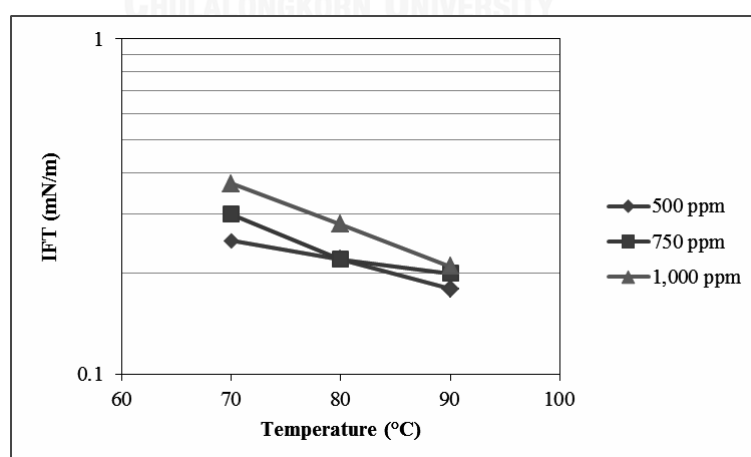


Figure B.10 Alkali concentration 0.05 wt.%, NaOH-HPAM Solution

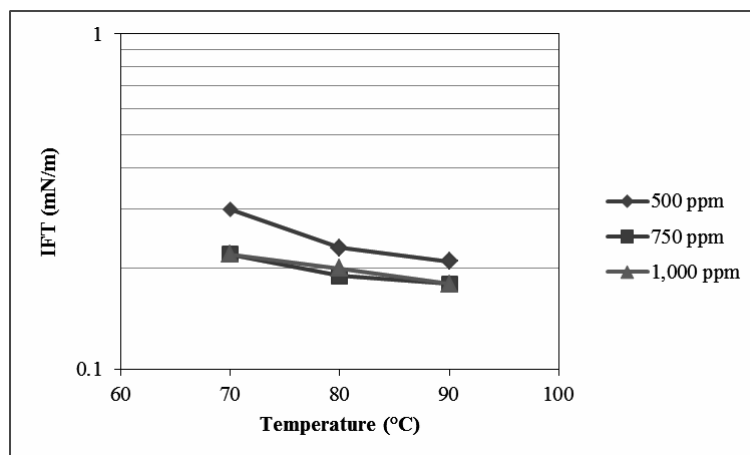


Figure B.11 Alkali concentration 0.1 wt.%, NaOH-HPAM Solution

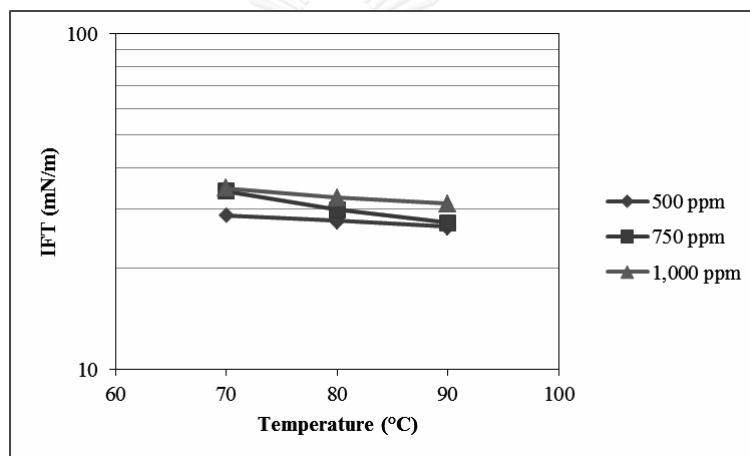


Figure B.12 Alkali concentration 0.025 wt.%, Na₂CO₃-HPAM Solution

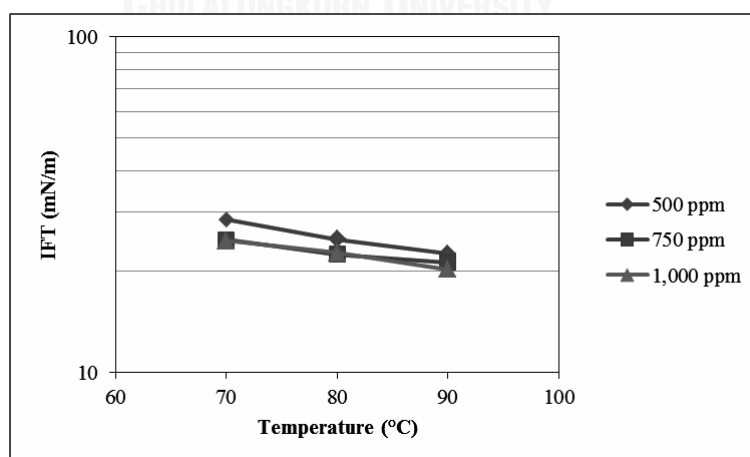


Figure B.13 Alkali concentration 0.05 wt.%, Na₂CO₃-HPAM Solution

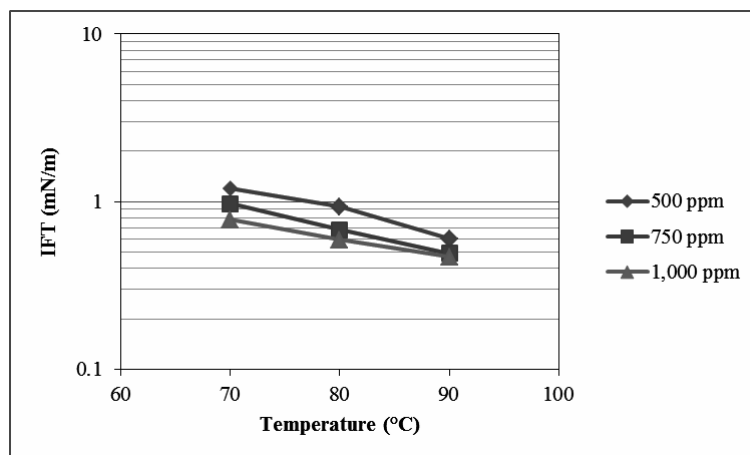


Figure B.14 Alkali concentration 0.1 wt.%, Na_2CO_3 -HPAM Solution

Effect of Polymer Concentration on the Interfacial Tension

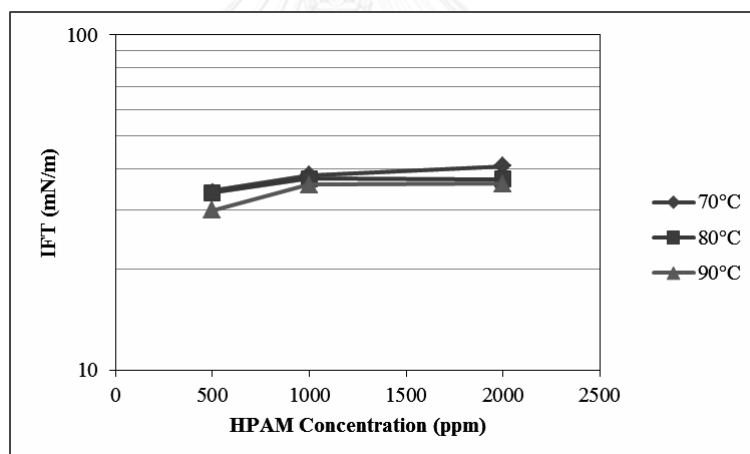


Figure B.15 Alkali concentration 0 wt.%, HPAM Solution

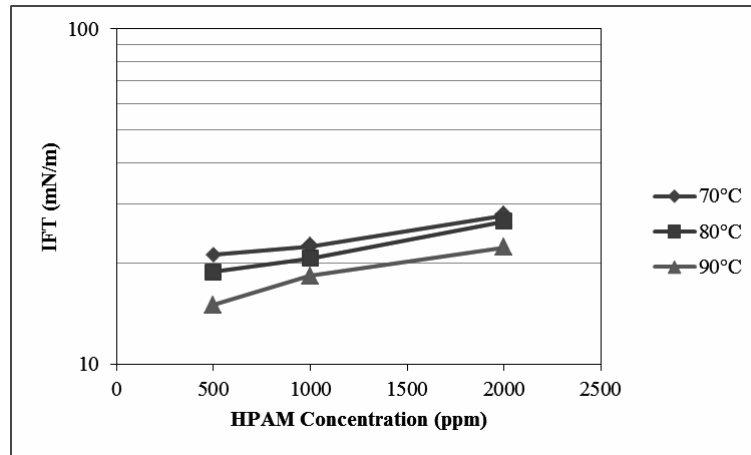


Figure B.16 Alkali concentration 0.025 wt.%, NaOH-HPAM Solution

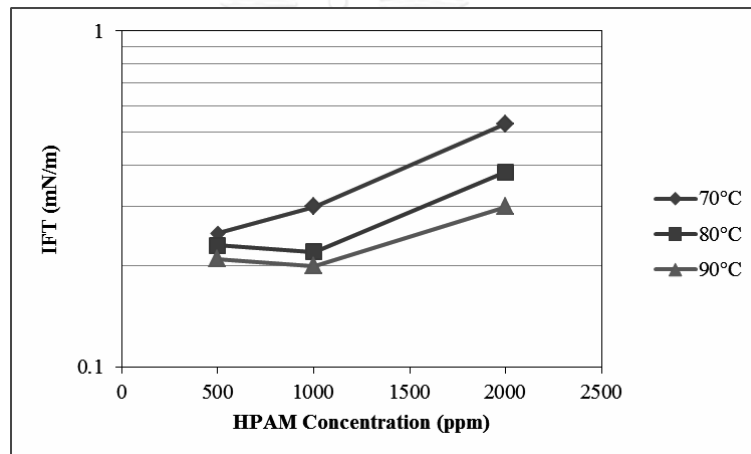


Figure B.17 Alkali concentration 0.05 wt.%, NaOH-HPAM Solution

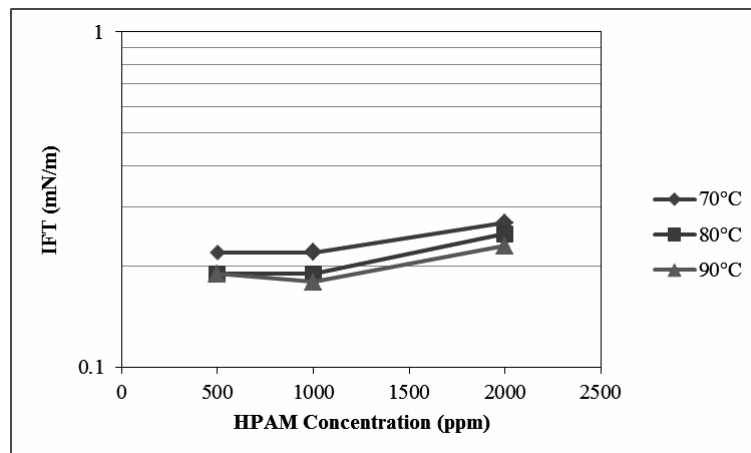


Figure B.18 Alkali concentration 0.1 wt.%, NaOH-HPAM Solution

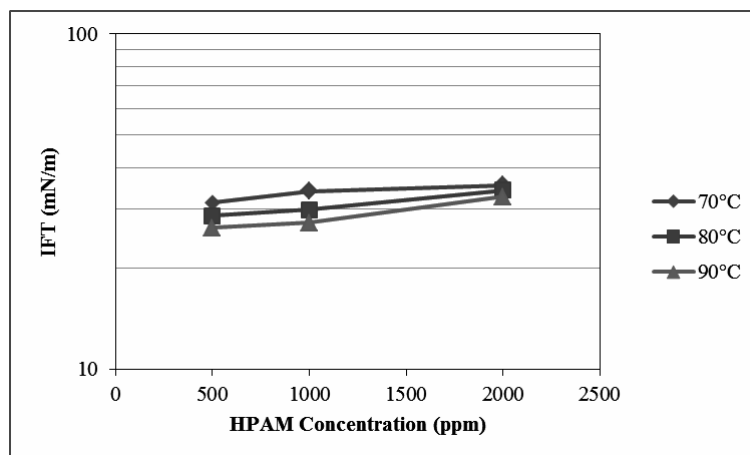


Figure B.19 Alkali concentration 0.025 wt.%, Na_2CO_3 -HPAM Solution

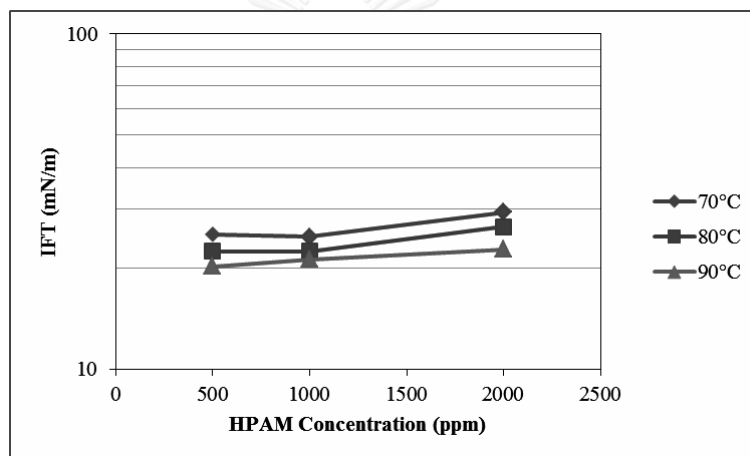


Figure B.20 Alkali concentration 0.05 wt.%, Na_2CO_3 -HPAM Solution

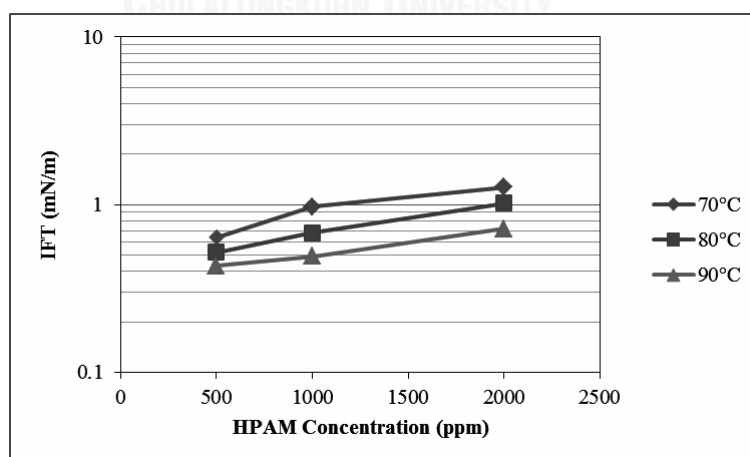


Figure B.21 Alkali concentration 0.1 wt.%, Na_2CO_3 -HPAM Solution

Effect of Salinity on the Interfacial Tension

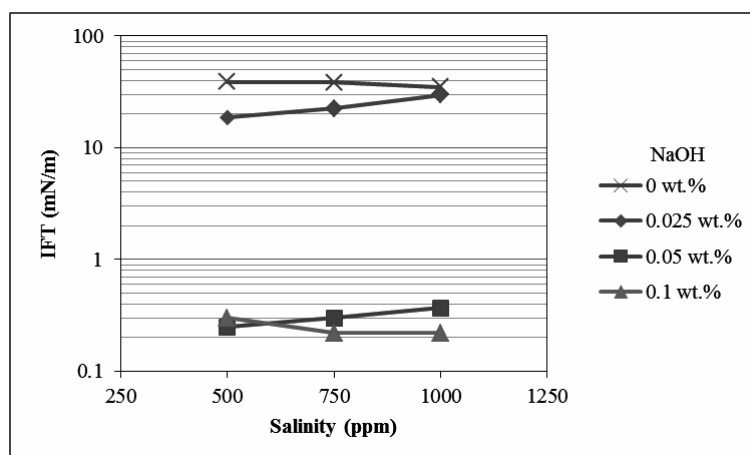


Figure B.22 Temperature 70°C, NaOH-HPAM Solution

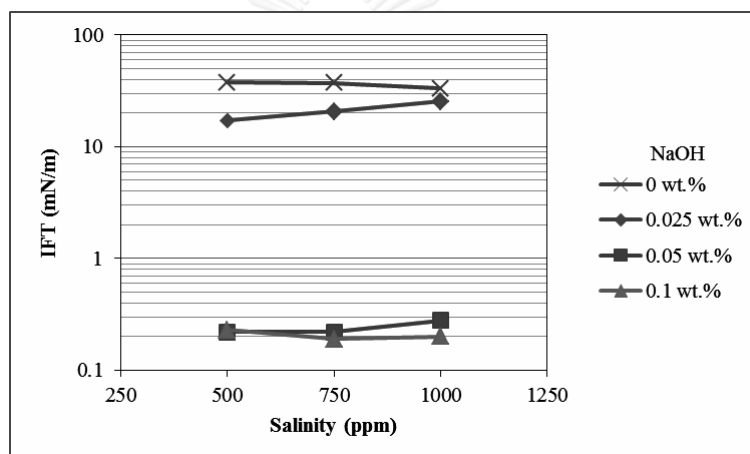


Figure B.23 Temperature 80°C, NaOH-HPAM Solution

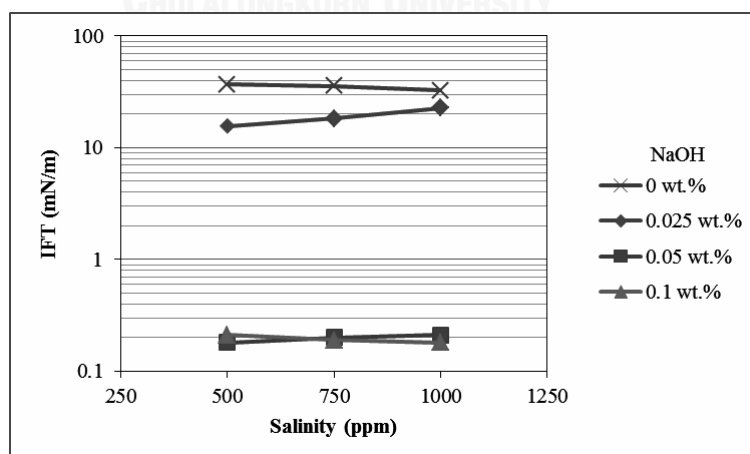
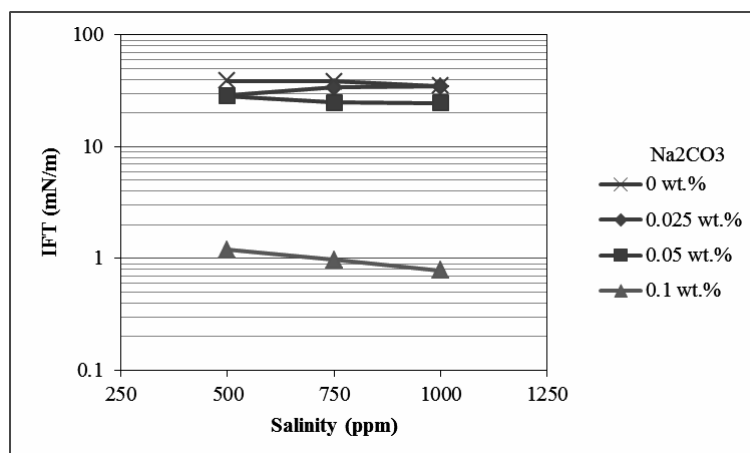
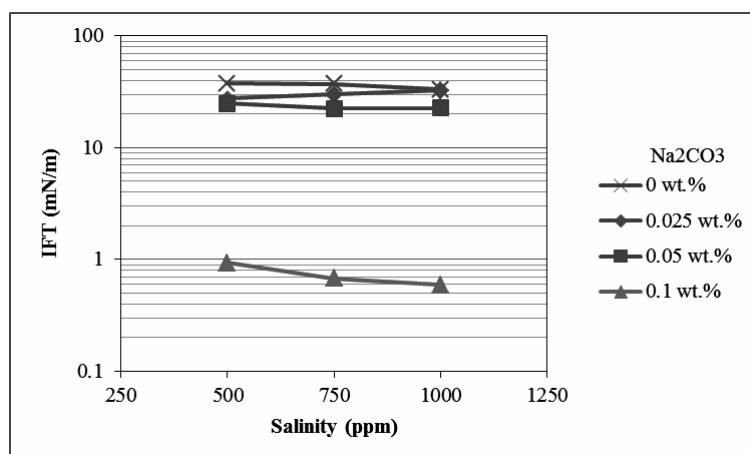
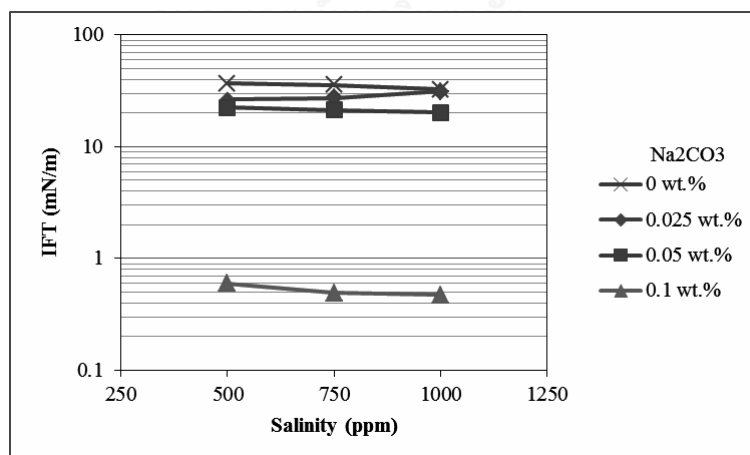


Figure B.24 Temperature 90°C, NaOH-HPAM Solution

Figure B.25 Temperature 70°C, Na_2CO_3 -HPAM SolutionFigure B.26 Temperature 80°C, Na_2CO_3 -HPAM SolutionFigure B.27 Temperature 90°C, Na_2CO_3 -HPAM Solution

APPENDIX C

PERCENT DIFFERENCE TABLE

The IFT from various conditions are compared with the base case value to see the direction and the impact of each parameter. The percent difference table can be concluded as shown in Table C.1 to C.6.

The base case solutions are 1) HPAM solution at 1,000 ppm of polymer concentration, 750 ppm of salinity, 80°C, 2) NaOH-HPAM solution at 0.05 wt.%, 1,000 ppm of polymer concentration, 750 ppm of salinity, 80°C, and 3) Na₂CO₃-HPAM solution at 0.05 wt.%, 1,000 ppm of polymer concentration, 750 ppm of salinity, 80°C.

Table C.1 Percent difference of pressure effect on the IFT

Pressure (psig)	500	1,000	1,500
NaOH-HPAM solution	0	0	-4.55

Table C.2 Percent difference of type of alkaline solution effect on the IFT

Type of solution	% difference
HPAM solution	0
NaOH-HPAM solution	-99.41
Na ₂ CO ₃ -HPAM solution	-39.66

Table C.3 Percent difference of alkali concentration effect on the IFT

Alkali concentration (wt.%)	0	0.025	0.05	0.1
NaOH-HPAM solution	16,840.91	9,304.55	0	-13.64
Na ₂ CO ₃ -HPAM solution	65.72	33.21	0	-96.98

Table C.4 Percent difference of temperature effect on the IFT

Temperature (°C)	70	80	90
HPAM solution	2.60	0	-3.86
NaOH-HPAM solution	36.36	0	-9.09
Na ₂ CO ₃ -HPAM solution	10.49	0	-5.38

Table C.5 Percent difference of polymer concentration effect on the IFT

Polymer concentration (ppm)	500	1,000	2,000
HPAM solution	-9.10	0	-0.46
NaOH-HPAM solution	4.55	0	72.73
Na ₂ CO ₃ -HPAM solution	0	0	18.50

Table C.6 Percent difference of salinity effect on the IFT

Salinity (ppm)	500	750	1,000
HPAM solution	1.10	0	-10.65
NaOH-HPAM solution	0	0	27.27
Na ₂ CO ₃ -HPAM solution	10.67	0	0.93

VITA

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