EFFECT OF VARYING SURFACTANT CONCENTRATION ON INTERFACIAL TENSION IN TERTIARY RECOVERY OF CRUDE OIL

by

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To

My Parents
ACKNOWLEDGEMENTS

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ABSTRACT

During the past several years significant and considerable research has been carried out on the tertiary recovery of trapped residual oil remaining within the producing formations. One method that has received much attention and intensive study over these years is the use of surfactant based chemical flooding. The interfacial tension between heavy crude oil and injection water under reservoir conditions plays a significant role in the process of enhanced oil recovery. This interaction between the oil and water phases is a function of temperature, pressure, and composition of both the hydrocarbon and aqueous phases.

This study experimentally determines the influence of surfactant concentration on oil recovery. The interfacial tension between brine and kerosene was studied with the use of sodium dodecyl sulphate (SDS) as a means of lowering the interfacial tension. The spinning drop tensiometer (Krüss, SITE 100) was used to measure the interfacial tension due to its ability to measure ultralow interfacial tensions.

This study reveals the variation of IFT with varying surfactant concentration. The IFT reduces as the surfactant concentration increases and reaches a point (CMC) after which the IFT remains more or less constant. Thus we are able to find a critical surfactant concentration which is very important from the economic point of tertiary recovery (chemical flooding) since the use of surfactants is expensive.
LIST OF ABBREVIATIONS USED

CMC – Critical Micelle Concentration (mM)
IFT – Interfacial Tension (mN/m)
\( N_c \) – Capillary Number
\( \nu \) - Flow rate (m\(^3\)/s, bbl/day)
\( \mu \) – Viscosity (Pa.s, cp)
\( \gamma \) - Interfacial Tension (mN/m)
\( r \) - Radius of drop (m)
\( \infty \) – Rotational frequency (rpm)
\( \rho_H \) - Density of heavy phase (kg/m\(^3\))
\( \rho_L \) - Density of Light Phase (kg/m\(^3\))
CHAPTER 1: INTRODUCTION

1.1 BACKGROUND

The initial or primary phase of recovering oil from an underground reservoir takes advantage of the natural pressure existing in the reservoir, assisted by pumps (if needed) to lift the oil to the surface. But only about 10 percent of a reservoir's original-oil-in-place (referred to as OOIP) is typically produced during primary recovery.

To extend the productive life of an oil field, most oil producers have used secondary recovery methods. Such secondary methods generally involve injecting water into the underground reservoir to displace the oil and drive it into the wellbore where it can be lifted to the surface by pumps. In some cases, natural gas (often produced simultaneously with the oil) is re-injected to maintain reservoir pressure, thus driving the oil into the wellbore. Secondary recovery methods generally raise the overall oil recovery to 20 – 40 percent of the original-oil-in-place. Thus, even after the secondary phase of recovery, about 60 – 80 percent of the oil still remains in the reservoir. (http://www.eoearth.org/article/Petroleum_crude_oil?topic=49478)

As the world continues to use more crude oil and world oil reservoirs are depleted, new ways of extracting oil and gas must be developed to get every drop possible from existing sources. Enhanced Oil Recovery (abbreviated EOR) is a generic term for tertiary techniques used to further increase the recovery of oil from an oil field. Using EOR, 30 – 60 %, or more of the reservoir’s original oil-in-place can be recovered compared with 20 – 40% using primary and secondary recovery, effectively doubling or tripling the amount of the oil produced from the field. It is estimated that the full use of enhanced oil recovery in United States could generate an additional 240 billion barrels of oil (United States Department of Energy, 2011).
Various enhanced oil recovery methods are being employed to overcome viscosity, interfacial tension and capillary forces that keep this vast amount of oil trapped in the reservoir. These methods which are in use today are still under current development to achieve maximum oil recovery at low cost. These techniques, employed to overcome forces that trap residual oil at different depths, must be suitable to account for the effects of increasing temperature, pressure and salinity.

Surfactant addition has become very attractive because of its ability to reduce surface/Interfacial tension between immiscible fluids thereby increasing the capillary number necessary for mobilizing residual hydrocarbons in the reservoir. The behaviour of surfactants with varying temperature, pressure and salinity will determine the necessary concentrations to maximize oil recovery.

1.2 OBJECTIVES
The primary objectives of this project were to:

1) Measure the IFT between Kerosene and brine using the spinning drop tensiometer.

2) Measure the IFT between kerosene and brine with the addition of SDS surfactant.

3) Determine a critical surfactant concentration (CMC) for very low IFT.
CHAPTER 2: LITERATURE REVIEW

2.1 OIL RECOVERY

The overall performance of oil reservoirs is largely determined by the nature of the energy, i.e., driving mechanism, available for moving the oil to the wellbore. Oil recovery is separated into three phases: primary, secondary and tertiary, which is also known as Enhanced Oil Recovery (EOR).

2.1.1 PRIMARY OIL RECOVERY

Producing reserves are called “primary” when they are produced by primary recovery methods using the natural energy inherent in the reservoir. The driving energy may be derived from the liberation and expansion of dissolved gas, from the expansion of the gas cap or of an active aquifer, from gravity drainage, or from a combination of these effects. Ahmed (2006) defines six basic drive mechanisms that provide natural energy necessary for oil recovery: rock and liquid expansion drive; depletion drive; gas cap drive; water drive; gravity drainage drive and combination drive.

1. **Rock and liquid expansion drive:** This occurs when an oil reservoir initially exists at a pressure higher than the bubble-point pressure. Crude oil, connate water and rock are the materials present in a reservoir at pressures above the bubble-point. Hence, as reservoir pressure declines, rock and fluids expand due to their compressibilities. This causes a reduction in pore volume. As the expansion of the fluids and reduction in the pore volume occur with decreasing reservoir pressure, the crude oil and water will be forced out of the pore space to the well bore (Ahmed, 2006).
2. **Depletion drive:** This drive mechanism occurs when production of oil from the reservoir is a result of the expansion of the original oil volume with its original dissolved gas (solution gas). Due to declining pressure below the bubble point, gas bubbles are liberated within the microscopic pore spaces; the bubbles expand and force the crude oil out of the pore space. (Ahmed, 2006).

3. **Gas cap drive:** The formation of a gas cap in a reservoir is due to the presence of a large amount of gas that could be dissolved in the oil at the pressure and temperature of the reservoir. The excess gas segregates to occupy the top part of the reservoir. As the oil is produced, the expansion of the gas in the gas cap pushes down on the oil and fills the pore spaces formerly occupied by the produced oil. (Ahmed, 2006).

4. **Water drive:** Oil/gas reservoirs exist as large, continuous, porous formations with the oil/gas occupying a portion of the formation. The formation below the oil/gas is saturated with brine at very high pressure. Thus when oil/gas is produced, lowering the pressure in the well, the brine expands and moves upwards, pushing the oil/gas out of the formation and occupying the pore spaces vacated by the produced oil. (Ahmed, 2006).

5. **Gravity drainage drive:** The gravity drainage mechanism occurs in reservoirs due to differences in densities of the reservoir fluids. The fluids in a petroleum reservoir have been subjected to forces of gravity as evidenced by the positions of the fluids shown in figure 2.1. Gas on top, oil underlies the gas, and water underlying the oil. (Ahmed, 2006).
6. **Combination drive:** It is possible that more than one of these drive mechanisms occur simultaneously; the most common combination being gas cap drive and natural aquifer drive, where both water and free gas are available in some degree to displace the oil toward the producing wells. (Ahmed, 2006).

2.1.2 **SECONDARY OIL RECOVERY:**

The natural or primary driving mechanism is a relatively inefficient process and results in a low overall oil recovery. The lack of sufficient natural drive in most reservoirs has led to the practice of supplementing the natural reservoir energy by introducing some form of artificial drive, the most basic method being the injection of gas or water, and other techniques to increase reservoir pressure, thereby replacing or increasing natural reservoir drive. Usually, the selected secondary recovery process follows the primary recovery but it can also be conducted concurrently with the primary recovery. Water flooding is perhaps the most common method of secondary recovery.
**Water Flooding:** Water Flooding is a method of secondary oil recovery in which water is injected into the reservoir formation to displace the residual oil. The water sweeps some of the remaining oil through the reservoir into the producing wells and can recover 5-50% of the remaining oil in place. The injected water is usually oil field brine from separators or treated water from other sources. This injected water must be compatible with the producing formations, not causing reactions that decrease the permeability of the flooded formation. The injected water is either pumped under pressure down the well or is fed by gravity from storage tanks at a high elevation. Injection wells are either drilled or converted from producing wells. (Hyne, 2001)

### 2.1.3 TERTIARY/ENHANCED OIL RECOVERY

Enhanced Oil Recovery refers to the process of producing oil by methods other than the conventional use of the natural energy inherent in the reservoir or the reservoir repressurizing schemes with gas or water. On average, the primary and secondary recovery methods will produce from a reservoir about 30% of the initial oil in place. The remaining oil, nearly 70% of the initial resource, is a large and attractive target for enhanced oil recovery methods. (Lake, 1989)

Enhanced oil recovery processes can be classified into four categories: (Terry, 2001)

1. Miscible flooding process
2. Chemical flooding process
3. Thermal flooding process
4. Microbial flooding process
1. **Miscible Flooding Process:** A miscible process is one in which the interfacial tension is reduced to zero; that is, the displacing fluid and the residual oil mix to form one phase. If the interfacial tension is zero, then the capillary number becomes infinite and the displacement efficiency is maximized. Taber (1979) states that the capillary forces responsible for trapping oil within the pores of reservoir rock are generally described by a dimensionless number known as the capillary number. Capillary number is defined as the ratio of viscous forces to capillary forces. There are, in general, two types of miscible processes. One is referred to as the single-contact miscible process and involves such injection fluids as liquefied petroleum gases (LPGs) and alcohols. The injected fluids are miscible with residual oil immediately on contact. The second type is the multiple-contact or dynamic miscible process. The injected fluids in this case are usually methane, inert fluids, or an enriched methane gas supplemented with a C2–C6 fraction. The injected fluid and oil are usually not miscible on first contact but rely on a process of chemical exchange between phases to achieve miscibility. (Stalkup, 1983)

2. **Chemical Flooding Process:** Chemical flooding is the addition of one or more chemicals to an injected fluid so as to reduce the interfacial tension between the reservoir oil and the injected fluid or to improve the sweep efficiency of the injected fluid.

   Chemical flooding can be classified into 3 general methods: (Terry, 2001)

   a) Polymer Flooding
   b) Micellar-Polymer Flooding
c) Alkaline Flooding

a) **Polymer Flooding** is the process in which large macromolecule is used to increase the displacing fluid viscosity. In the flooding process the increased viscosity will affect the mobility ratio between the injected fluid and the reservoir fluid. The improved mobility ratio will lead to better vertical and aerial sweep efficiencies and thus higher oil recoveries. (Terry, 2001)

b) **Micellar-Polymer Flooding** is the process in which a surfactant is used to lower the interfacial tension between the injected fluid and the reservoir oil. A surfactant is a surface active agent that contains a hydrophobic part and a hydrophilic part. The surfactant acts at the interface between the oil and water phase and helps to make the two phases more miscible. (Terry, 2001)

c) **Alkaline Flooding** is the process in which an alkaline solution is mixed with certain crude oil as a result of which surfactant molecules are formed. When the surfactant molecule develops the interfacial tension between the brine and oil phases could be reduced. Thus the reduction of interfacial tension causes the displacement efficiency to increase which increase the oil recovery. (Terry, 2001)

3. **Thermal Flooding Process:** The recovery of oil using the primary and secondary methods from reservoirs containing heavy and low gravity crude oil is usually a small fraction of the initial crude oil in place. This is due to the fact that these types of oils are very thick and viscous and as a result will not flow readily to the producing wells. The relation between viscosity and temperature suggests that viscosity decreases with an
increase in temperature. Therefore if the temperature of the crude oil in the reservoir can be increased over the nominal reservoir temperature, the oil viscosity will be decreased and the oil will flow much more easily to a producing well. The temperature of a reservoir can be increased by either one of the following methods, steam cycling/cyclic steam injection, steam drive or in situ combustion.(Prats, 1982)

4. **Microbial Flooding Process**: Microbial enhanced oil recovery (MEOR) flooding involves the injection of microorganisms that react with reservoir fluids to assist in the production of residual oil. There are two general types of MEOR processes—those in which microorganisms react with reservoir fluids to generate surfactants and those in which microorganisms react with reservoir fluids to generate polymers.(Bryant, 1991)
CHAPTER 3: LOW INTERFACIAL TENSION FOR OIL RECOVERY

Chemical Enhanced Oil Recovery (CEOR) represents the most promising solution that can unblock about 300 billion barrels of oil. Mobilizing residual oil requires an interfacial tension sufficiently low to produce capillary forces small enough to allow the oil to flow. Interfacial tension can be lowered by injecting various surfactant compounds. According to the fluid flow mechanics, there are two main forces acting on the residual oil drops, viscous and capillary forces. The displacement efficiency depends on the relative influence or the ratio of these two forces. Melrose and Brander (1974) defined the capillary number as the ratio of viscous forces to capillary forces.

\[
\text{Capillary number } (N_c) = \frac{v \mu}{\gamma \cos \theta} \]

(3.1)

Where \(v\) and \(\mu\) are the velocity and viscosity, respectively of the displacing phase (brine), \(\gamma\) is the interfacial tension between the displaced and displacing phases and \(\theta\) is the contact angle. Therefore by altering the interfacial tension between the water and oil phases, surfactants can cause a significant change in the flow behavior.

3.1 INTERFACIAL TENSION

Interfacial tension is a property of the interface between two immiscible phases. It can be defined as a measurement of the cohesive energy present at the interface arising from the imbalance of the forces between molecules at the interface. When the phases are both liquids it is termed as interfacial tension, when one of the phase is air it is termed as surface tension. The common units
for interfacial tension are dynes/cm or mN/m. Interfacial tension is lowered by the surfactant molecule as they position themselves at the interface. (Schramm, 1992)

### 3.2 SURFACTANTS

The term surfactant (originating from surface-active agent) designates a substance which exhibits some interfacial activity. They are a unique class of chemical compounds consisting of an amphiphilic molecule with a hydrophilic part and a hydrophobic part. Addition of surfactant to oil–water mixtures reduces interfacial tension and/or alters wettability. Depending upon the nature of the hydrophilic part the surfactants can be classified as:

a) **Anionic** - the surface portion of the molecule bears a negative charge.

b) **Cationic** - the surface active portion bears a positive charge.

c) **Amphoteric or Zwitterionic** - both positive and negative charge may be present in the surface active portion.

d) **Nonionic** - the surface active portion bears no apparent ionic charge.

In aqueous solutions with low concentrations, surfactants act much as normal electrolytes but as concentration increases, very different behavior exists. This behavior is explained in terms of the formation of aggregates of molecules called micelles. (Schramm, 1992)
3.3 SURFACTANT AND INTERFACIAL TENSION

As a surfactant is injected it disperses into oil and water and lowers the interfacial tension, thereby increasing the capillary number. As a result more of the otherwise immobile oil becomes mobile. At the same time an oil-in-water emulsion may form, this leads to an improvement in the effective mobility ratio. The injected surfactant continues to mobilize oil and bank it up until the surfactant is diluted or otherwise lost due to adsorption by the rock until it is no longer available to lower the interfacial tension and mobilize the oil.

3.4 CRITICAL MICELLE CONCENTRATION

In low concentrations, surfactants exist as isolated molecules. As the concentration of the surfactant increases above a certain concentration called CMC, some of the physical properties of the solution will change sharply as the surfactant molecules come together spontaneously to form nano sized structures called micelles.

Figure 3.4 Variation of IFT with Surfactant Concentration (http://www.rsc.org/chemistryworld)
CMC values are important in all surfactant applications related to the petroleum industry. The surfactants must be present just higher than the CMC, because the greatest effect of the surfactant whether in lowering the interfacial tension or promoting foam stability is achieved when a significant concentration of micelles is present. (Schramm & Marangoni, 2000)
CHAPTER 4: EXPERIMENTAL SETUP, APPARATUS AND PROCEDURE

This laboratory experiment is aimed at investigating the effect of varying surfactant concentration on the interfacial tension of an oil-brine system. Studies of IFT with surfactants have mostly been carried out at ambient conditions and hence do not represent a true reflection of the reservoir conditions. Therefore, this study describes IFT measurements in a reservoir at constant temperature and fixed brine salinity for varying concentrations of commercial surfactant.

4.1 MATERIALS USED:

- **Salts** - Sodium Chloride (NaCl), Calcium Chloride (CaCl$_2$) and Magnesium Chloride (MgCl$_2$)
- **Oil** - Kerosene, a constituent of crude oil. Used in this experiment due to its hydrocarbon properties and ease of use with the apparatus.
- **Surfactant** - Sodium dodecyl sulphate (SDS) was chosen because of its abundant commercial use.

4.2 APPARATUS: Spinning Drop Tensiometer(Krüss, SITE 100)

The apparatus used for the IFT measurement was the spinning drop tensiometer SITE 100 from KRUSS. It is a computer controlled equipment used for measuring low interfacial tensions.
between two immiscible liquids up to a range of \(10^{-6}\) to 50 mN/m. The equipment consists of a motor which allows a rotational speed of up to 15,000 rpm, a measuring cell, an inlet and outlet for the liquid phases (the bulk phase and the light phase), LED illumination, camera and an electronic module which consists of the power supply, controller and the temperature display.

Figure 4.2: Experimental set up, showing spinning drop tensiometer (Krüss, SITE 100)
<table>
<thead>
<tr>
<th>Measuring range</th>
<th>down to $10^{-6}$mN/m</th>
</tr>
</thead>
<tbody>
<tr>
<td>Revolution speed</td>
<td>up to 15000 rpm</td>
</tr>
<tr>
<td>Capillary diameter</td>
<td>3.5 mm</td>
</tr>
<tr>
<td>Temperature range</td>
<td>0 to 100°C</td>
</tr>
<tr>
<td>Measuring axis</td>
<td>4</td>
</tr>
<tr>
<td>Magnification</td>
<td>2 microscope lenses</td>
</tr>
<tr>
<td>Dimension</td>
<td>30 x 45 x 30 cm</td>
</tr>
<tr>
<td>Weight</td>
<td>15 kg</td>
</tr>
<tr>
<td>Power supply</td>
<td>100 to 240 V</td>
</tr>
</tbody>
</table>

Table 4.2: Technical Data of Krüss SITE100 Spinning Drop Tensiometer(Krüss Worldwide, 2011)

The IFT measured depends on the radius ($r$) of the drop vertical to the axis of rotation, the circular frequency ($\omega$), and the density difference between the two phases ($\rho_H - \rho_L$) where $\rho_H$ and $\rho_L$ are the densities of the bulk or heavy and light phases, respectively. Therefore, at a given rotational speed with known densities of the two phases and a measured drop diameter, the IFT between the two liquids can be calculated (SITE 100 manual).

$$\gamma = \frac{r^3 \omega^2 (\rho_H - \rho_L)}{4} \quad \frac{\text{N/m}}{\text{m}}$$

(4.2)
A condition for accurate measurement is that the length of the drop along the axis of rotation is at least four times the drop diameter \((L \geq 4d)\). The above equation is the Vonegut’s equation for calculating the IFT of elongated drops whose length is more than 4 times the diameter (Currie and Nieuwkoop, 1982).

### 4.3 DENSITY MEASUREMENT

For proper IFT measurements, reliable density data is required. DMA 512P (density meter) from Anton Paar (mPDS 2000 V3), Austria was used to measure the density of kerosene and brine. The density meter measures density from 0 to 3 \(\text{g/cm}^3\) with an accuracy of \(1 \times 10^{-4} \text{g/cm}^3\). The density of kerosene (light phase) was measured as 0.7989 \(\text{g/cm}^3\) (at 41°C) and that of brine (heavy phase) was measured as 2.097 \(\text{g/cm}^3\) (at 41°C).

### 4.4 EXPERIMENTAL PROCEDURE

**Preparation of the brine solution**- In this experimental study the brine was formulated to reflect the one encountered in the Wabamun formation (Western Canadian Sedimentary Basin).

The total dissolved salts were found to be about 14.4g. In this study only Sodium, Calcium, Magnesium and Chloride ions are present to isolate the effect of other cations and anions present in the natural brine. NaCl, CaCl\(_2\) and MgCl\(_2\) were mixed in equal proportions of 4.8wt% each.
Table 4.3 Summary of brine sample location/ Wabamun Formation (SPE 95547)

<table>
<thead>
<tr>
<th></th>
<th>1602 to 1604</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sample Depth (meters)</td>
<td></td>
</tr>
<tr>
<td>Formation Type</td>
<td>Carbonate</td>
</tr>
<tr>
<td>Temperature - Deg C</td>
<td>41</td>
</tr>
<tr>
<td>Pore Pressure – kPag</td>
<td>11920</td>
</tr>
<tr>
<td>Total Overburden – kPag</td>
<td>22400</td>
</tr>
<tr>
<td>ION IN WATER (mg/l)</td>
<td></td>
</tr>
<tr>
<td>Na</td>
<td>40474</td>
</tr>
<tr>
<td>K</td>
<td>0</td>
</tr>
<tr>
<td>Ca</td>
<td>9948</td>
</tr>
<tr>
<td>Mg</td>
<td>3468</td>
</tr>
<tr>
<td>Cl</td>
<td>89614</td>
</tr>
<tr>
<td>SO4</td>
<td>265</td>
</tr>
<tr>
<td>HCO3</td>
<td>535</td>
</tr>
<tr>
<td>Total Dissolved Solids (mg/l)</td>
<td>144304</td>
</tr>
</tbody>
</table>

The solutions were prepared at room temperature. The first solution prepared was using the salts only while the latter solutions were prepared with the addition of surfactant. 4.8 wt% each of NaCl, CaCl₂, MgCl₂ were weighed using an analytical balance, poured into a 100ml volumetric conical flask and the conical flask was filled to the calibration mark with deionised water. For solutions containing brine/surfactant the same amount of salts were weighed and surfactant varying from 0.0 wt% to 0.8 wt% were weighed, poured into a 100ml volumetric conical flask and filled with deionised water.
The Procedure- The bulk phase (brine/surfactant) was injected into the capillary tube of the spinning drop tensiometer, the motor was turned on to run at an rpm of 8500 and the capillary tube was tilted to detect any air bubbles in the tube. Care was taken to remove any air bubble in the tube. A drop of light phase (Kerosene) was then injected into the capillary tube. The rpm was set at 8500 and the brightness and contrast were adjusted to get a clear picture of the kerosene drop. The temperature was then increased and set at 41°C so as to meet the reservoir temperature. Once the temperature which was set on the control unit was in equilibrium with the temperature of the spinning drop tensiometer and when the drop was long enough to meet the Vonnegut condition, the interfacial tension was measured. Measurements were taken at two minute intervals for 10 minutes. After obtaining the IFT measurements the capillary tube was cleaned with ethanol and hot water before carrying out the experiments with other solutions.
CHAPTER 5: RESULTS AND DISCUSSION

5.1 RESULTS
Figure 5.1 shows the IFT results for the brine solution and surfactant/brine solutions for the first, second and third run.

![IFT measurements for the kerosene-brine/surfactant system](image)

Figure 5.1 IFT measurements for the kerosene-brine/surfactant system
In the above figure the blue, red and green dotted lines refer to the first, second and third run respectively, and the dark blue line refers to the average of the three runs.

The graph below represents the average IFT measurements with increasing surfactant concentration in the brine solution.

![Graph](image)

Figure 5.2 Average IFT measurements for the kerosene-brine/surfactant system
5.2 DISCUSSION

The experiments were carried out to show the effect of varying surfactant concentration on IFT of kerosene–brine/surfactant system. Initially the experiment was done with no added surfactant, and the interfacial tension was measured to be 21.13mN/m. This value represents a high IFT and hence a low capillary number.

From the next run onwards SDS surfactant was added to the brine solution varying from 0.01 wt% to 0.8 wt%. From figure 5.2, we can see that as the surfactant was added the IFT started to drop until CMC was attained at 0.3 wt% of SDS surfactant. It is clear that an increase in the concentration of surfactant after CMC had no effect on the IFT.

5.3 STATISTICAL ANALYSIS

For the graph plotted, statistical analysis to calculate the standard deviation was done. Standard deviations are important because they reflect the measure of fluctuations a set of data will experience. The calculations for the standard deviations are tabulated below in the appendix. In this study, the following equations were used for statistical analysis:

\[
\bar{X} = \frac{X_1 + X_2 + X_3}{3}
\]  

(5.41)

Standard Deviation, SD = \sqrt{\frac{\sum (X-\bar{X})^2}{(n-1)}}

(5.42)

\[
S_{\text{pooled}} = \frac{\sum (n-1)SD_i^2}{\sum (n-1)}
\]  

(5.43)

Standard Error = \frac{S}{\sqrt{n}}

(5.44)
CHAPTER 6: CONCLUSIONS AND RECOMMENDATIONS

6.1 CONCLUSIONS

This experiment deals with the variation of interfacial tension with varying surfactant concentration. The experimental data were analyzed to find a critical surfactant concentration. This is very important from the economic point of tertiary recovery (chemical flooding) since the use of surfactants is expensive. The economics of surfactant flooding is a complex function of many elements, such as surface facilities, well operations, reservoir parameters and chemical cost.

Based on the experiment the following conclusions are made:

- There was a decrease in interfacial tension with an increase in SDS concentration.
- From the results obtained a critical SDS surfactant was obtained at 0.3 wt% of SDS.
- Below the critical micelle concentration (CMC), the added surfactant helps to greatly reduce the IFT in a brine-oil solution system. Above the CMC, the added surfactant keeps the IFT unchanged.

6.2 RECOMMENDATIONS

The following recommendations can be made,

- To best determine the CMC of SDS the experiments must be carried out using exact formation brine for accurate results.
• To further verify the influence of surfactants on IFT, effects of temperature, pressure and salinity effects must be considered. This report cannot tell the effect of salinity as just one salt concentration was used for the experiment.

• The addition of additives, for example co-polymers and alcohols, along with surfactants should be taken into account.
REFERENCES

### APPENDIX

**Appendix A: Standard Deviation Calculation:**

<table>
<thead>
<tr>
<th>SDS Conc.</th>
<th>IFT (X1)</th>
<th>IFT (X2)</th>
<th>IFT (X3)</th>
<th>$\bar{X} = (X1+X2+X3)/3$</th>
<th>S.D</th>
</tr>
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<td>0.0854</td>
</tr>
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</table>

$$\bar{X} = \frac{X1+X2+X3}{3}$$

Standard Deviation, $SD = \sqrt{\frac{\sum(X-\bar{X})^2}{(n-1)}}$, where n is the data points at each SDS conc.

The spooled standard deviation is

$$S.D_{pooled} = \frac{\sum(n-1)SD_i^2}{\sum(n-1)}$$, where SDi is the standard deviation at each SDS conc.

$$= \frac{28.68554/19}{1} = 1.50976$$

Standard Error=$\frac{SD}{\sqrt{n}} = 0.07548$
**Appendix B: Average values of IFT for varying SDS concentration**

<table>
<thead>
<tr>
<th>Surfactant Concentration (wt%)</th>
<th>IFT (mN/m)</th>
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<td>0.05</td>
<td>19.69</td>
</tr>
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<td>0.1</td>
<td>16.47</td>
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<tr>
<td>0.15</td>
<td>14.72</td>
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<td>0.8</td>
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</tbody>
</table>
Appendix C: SAMPLE CALCULATION FOR INTERFACIAL TENSION

The IFT measured depends on:

r- The radius of the drop vertical to the axis of rotation.

ω- The circular frequency

($\rho_H - \rho_L$) - The density difference between the heavy phase and light phase

Therefore at a given rotational speed with known densities of the two phases and a measured drop diameter, the IFT between the two liquids can be calculated (SITE 100 manual).

$$\gamma = \frac{r^3 \omega^2 (\rho_H - \rho_L)}{4}$$

r=1.0291mm

ω=8500rpm

$\rho_H=2.097\text{g/cm}^3$, $\rho_L=0.7989\text{g/cm}^3$

Substituting the values in the equation the IFT, $\gamma$ is calculated =7.1mN/m.

Thus the IFT can also be calculated numerically.