EXPERIMENTAL INVESTIGATION OF POLYMER INDUCED FOULING OF HEATER
TUBES IN THE FIRST-EVER POLYMER FLOOD PILOT ON ALASKA NORTH SLOPE

By

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ABSTRACT

Mineral fouling in heat exchangers has been extensively investigated by researchers in recent times. The oil and gas industry has a long history of fouling issues in production systems as a result of produced fluids treatment. Due to decline in production rates in oilfields new technologies are being developed and field tested in pilots. Polymer flooding is one such technology that involves addition of polymers to injection fluids to enhance oil production. A polymer flood pilot has been set up in the Schrader Bluff viscous oil reservoir at Milne Point field on the Alaska North Slope (ANS). The results from the pilot are encouraging, however a major concern of the operator is the influence of polymer on the production system after breakthrough, especially the fouling in heat exchangers.

This study investigates the propensity of polymer fouling on the heater tubes as a function of different variables, with the ultimate goal of determining safe and efficient operating conditions. This work applies a multi-experimental approach to study the severity of polymer-induced fouling in both dynamic and static states of produced fluids as well as studying the stability of polymer solutions at different temperatures. A unique experimental setup was designed and developed in-house to simulate the fouling process on the heating tube. The influence of heating tube skin temperature, tube material, and polymer concentration on fouling tendency was investigated. Each test was run five times with the same tube, and in each run, the freshly prepared synthetic brine and polymer solution was heated from 77°F to 122°F to mimic field-operating conditions. The heating time and fouling amount were recorded for each run.

Dynamic Scale Loop (DSL) tests were conducted to study fouling due to polymer at different temperatures (165°F to 350°F) in a dynamic state of fluid flow where the fluids mimic the residence time of fluids in the heat exchanger on the field pilot.

Cloud point measurement has also been conducted to find the critical temperature at which the polymer in solution becomes unstable and precipitates out. The morphology and composition of the deposit samples were analyzed by environmental scanning electron microscopy (ESEM) and X-ray diffraction (XRD), respectively. It was found that the presence of polymer in produced fluids would aggravate the fouling issues on both carbon steel and stainless-steel surfaces at all tested skin temperatures. Only higher skin temperatures of 250°F and 350°F could cause polymer-induced fouling issues on the copper tube surface, and the fouling tendency increased with polymer concentration. At the lower skin temperatures of 165°F, no polymer-induced fouling was identified on the copper tube. A critical temperature that is related to the cloud point of the polymer solution was believed to exist, below which polymer-induced fouling would not occur, and only mineral scale was deposited but above which the polymer would aggravate the fouling issue. The cloud point of the tested polymer solution was determined to be between 220°F and 230°F.

In the DSL tests it was found that at higher skin temperatures of 250°F and 350°F tube blocking was observed in the DSL tests whereas the tests at 165°F and 200°F did not show any tube blocking in the same time period. These experiments also manifested the influence of cloud point of the solution as deposit rate increased significantly in both carbon steel and stainless-steel tubes when the skin temperature was higher than the solution cloud point. The results of this study have provided guidance to the operator for the field-operations.

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Chapter 1 Introduction

1.1 Background

The oil and gas industry has been a primary source of revenue for the State of Alaska for decades but the oil production from Prudhoe Bay started to decline since 1989 (Bansal and Islam 1994). This necessitated the development of other oil reserves such the West Sak-Schrader bluff formation which contains a major portion of the Alaska North Slope (ANS) oil and gas resources with approximately 12 billion barrels of viscous oil (20 to 20,000 cP) (Pospisil 2011). Waterflooding is being implemented on the ANS but even after three decades of development efforts by different operators, the total viscous oil production rate from all ANS fields just reached 56,000 B/D by May 2017 (Cheng et al. 2018). Enhanced Oil Recovery (EOR) is a tertiary method of oil extraction that involves thermal, chemical, or fluid phase behavior effects to reduce or eliminate the capillary forces that trap oil within pores, to thin the oil or otherwise improve its mobility or to alter the mobility of the displacing fluids. EOR can involve injecting special chemicals with water into the reservoir to modify the fluid properties. These chemicals can include - Alkalies, surfactants, and polymers. A widely used method of EOR – thermal EOR in which large amounts of steam is injected into the reservoir has been used across the globe to develop heavy oil resources but those methods are not applicable on ANS due to the high cost of generating steam in the Arctic and most importantly the environmental problems associated with the potential of thawing of the permafrost.

Seright (2010) conducted a study to examine if polymer flooding could be a practical and feasible method to recover the viscous oils from the reservoirs of the ANS. They reconsidered screening criteria for polymer selection, carried out fractional-flow calculations to demonstrate improvements that can be achieved in displacement efficiency by implementing polymer flooding

and provided a simple benefit analysis to compare waterflooding and polymer flooding. They concluded that polymer flooding could be a suitable method to improve viscous oil recovery from the ANS in an economical manner. China has been implementing polymer flooding extensively over the last many years with excellent results. Such field cases, extensive laboratory data and analytical studies have led to polymer flooding being identified as a promising EOR method in viscous and heavy oil reservoirs. The advancement in polymer flooding technology and the utilization of horizontal wells has also helped the case of polymer flooding. The United States Department of Energy and Hilcorp Alaska are cosponsoring an advanced polymer flooding technology pilot test in the Schrader Bluff viscous oil reservoir with an in-situ oil viscosity of 330 cop (Dandekar et al. 2019). The polymer used in this pilot project is a hydrolyzed polyacrylamide (HPAM). The description of how a polymer flood works have been shown in **Figure 1.1**. The polymer is dissolved in water and injected into the reservoir using the injection wells. Polymer increases the viscosity of the water phase and reduces the mobility of the water phase creating a favorable mobility ratio to help push the oil out of the reservoir. The increased viscosity of the water phase helps ensure a better sweep of the oil reservoirs as well, which leads to higher oil recoveries. The produced fluids from the production wells contain oil, water (brine), and polymer which are then fed to a production system for treatment before oil sales.

Figure 1.1 Polymer flooding in a reservoir

1.2 Polymer Breakthrough Issues

The description of the polymer flooding pilot on the ANS has been given in the literature by Dandekar et al. (2019). The results of the current field pilot are encouraging as the EOR benefit is approximately 800 B/D (Ning et al. 2020). The promising results of the pilot have encouraged Hilcorp Alaska to apply polymer flood technology in the Schrader Bluff reservoir throughout the Milne Point Field. Although the incremental results of the project are motivating, the operators are concerned about the potential issues associated with produced fluids treatment resulting from polymer breakthrough. The polymer can cause emulsification issues decreasing the separation efficiency of water and oil by forming highly stable oil in water or water in oil emulsions. Additionally, the presence of polymer in produced fluids can affect the water quality also. Chang et al. (2020) have carried out an extensive study to investigate the influence of polymer on the separation behavior of heavy oil emulsions. They found that the presence of polymer in produced fluids when water cut is 50%, can stabilize the emulsion thereby reducing water-oil separation.

They also found that when the polymer is present in produced fluids, the water quality also drops due to the formation of a stable intermediate oil in water emulsion layer irrespective of the water cut. A major problem caused by produced fluids in EOR projects is the issue of aggravated scaling and fouling issues in production facilities, especially in the heat exchanger tubes which are usually operated at high temperatures. Fouling is the source of several problems in equipment including deteriorating heating performance and limiting the useful operating life of the equipment (Pan et al. 2012, Teng et al. 2017). The aim of this study is to investigate the potential fouling issues of polymer-induced fouling on or in the heater tubes in the heat exchangers used in the pilot on ANS by conducting different types of experiments.

The insoluble salts of divalent cations including – calcium carbonate, calcium sulfate, barium sulfate are known to cause mineral fouling problems in heat exchangers in the oil and gas industry. The solubility of these salts decreases with the increase in temperature in contrast with salts of monovalent cations and come out of the solution and deposit. The fouling due to these inverse solubility salts has caused a significant amount of economic costs in maintenance as millions of dollars every year are spent by the oil and gas industry in curing scale problems (Crabtree et al. 1999). Steinhagen et al. (1992) estimated the costs due to fouling issues to be approximately 0.25% of the gross national product of industrialized countries. A study by Muller-Steinhagen (1995) estimated the cost of all heat exchanger fouling in the United Kingdom to be of the order of USD 2.5 billion and in the USA to be equivalent of USD 14 billion. Mineral fouling in heat exchangers has been investigated extensively by researchers in the last few decades. It is a common observation that mineral fouling is more severe under high-temperature conditions as it is caused by the salts exhibiting inverse solubility phenomena. A standard method of studying scaling that has been used by researchers in the last couple of decades is the Dynamic Scale Loop method.

This method involves building a small diameter (usually 1-1.5mm) coiled tubing which is usually placed in equipment that can be heated such as a convection oven. The oven heats the tubing to the desired testing temperature. Solutions that contain the cations and anions to be tested are prepared beforehand of desired concentrations and hardness. Pumps are utilized to circulate the solution through the heated coiled tubing, while pressure transducers measure the differential pressure across the inlet and outlet of the tubing. A sudden rise in differential pressure indicates that the tubing is blocked. While this is an effective method to study fouling under dynamic flow conditions, it does not allow the researcher to collect the fouling deposit effectively from the tubing due to the tubing's narrow diameter and does not provide an option to measure fouling rates directly. To overcome this problem in this study, a novel experimental setup was designed and built in-house to study fouling rates directly. The experimental setup and procedure for this method have been described in detail in Chapter 2.

Calcite fouling in heat exchangers under elevated skin temperatures was investigated by Wylde et al. (2010). They utilized the method of Dynamic Scale Loop (DSL) to evaluate the typical scale inhibitors' performance at elevated temperatures and found that neither of the tested scale inhibitors could prevent scaling at the temperature of fire tubes. Mwaba et al. (2007) experimentally studied fouling due to Calcium Sulfate on a flat plate and investigate the influence of three parameters on fouling – surface temperature, flow velocity, and degree of supersaturation of solution. They found that higher surface temperature led to higher deposition rates while the induction period for scaling reduced with decrease in velocity and increasing degree of supersaturation. Kazi et al. (2015) carried out a detailed study to investigate the influence of different operational parameters on fouling in heat exchangers. They studied the following factors – solution concentration, velocity of fluids, tube material type, and found that the increase in

temperature and solution concentration led to a higher amount of deposition due to the increase in nucleation rate. Teng et al. (2017) studied calcite deposition on a double-pipe heat exchanger with different heat exchanging surfaces. They also studied the influence of various parameters and found that higher concentration of calcite and higher temperatures led to faster deposition whereas an increase in velocity decreased the deposition rate – a conclusion similar to the one made by Mwaba et al. (2007). The reason for the decrease in deposition rate at higher velocities is due to increased shear stress which increases the removal of deposited particles thereby reducing the overall deposition rate. The application of chemical EOR has led to more severe fouling issues in the production system which requires novel research to solve these problems. The industry and academia, both are taking active measures to investigate the potential fouling issues resulting from chemical EOR.

The production systems of EOR projects have the ever-present issues of mineral scaling but fouling issues may also directly result from the chemicals applied. There is an additional concern that the applied chemicals could react with the mineral salts in the brine and aggravate the mineral fouling issues as well. This is a possible concern and has also been shown through previous work by researchers who have demonstrated that polymers used in EOR can react with mineral salts. Moradi-Araghi and Doe (1987) carried out a study where they showed that hydrolyzed polyacrylamides (HPAM) could precipitate in the presence of hard brines. This process is accelerated under high-temperature conditions especially when the temperature is greater than the cloud point of the solution. They found that under the high temperature conditions the calcium ion and other divalent cations in brines can react with the polymer by forming a complex with the acrylic group of the polymer. They also determined safe limits of operating temperature for polymer solution in different concentrations of brines. With the increasing application of chemical

EOR recently, more studies are being conducted to study the fouling issues in the production system. Wylde et al. (2011) studied the fouling in an EOR project and reported that the breakthrough of polymer was a root cause of the increased scaling propensity with the EOR polymer coating the fire tubes which caused overheating of tubes leading to more challenging scaling conditions. Zheng et al. (2011) also studied the influence of the presence of EOR chemicals on the production system and reported that the heat exchangers could be easily fouled by the HPAM flood. They also reported that fire-tube heaters that were being used in the production system were being operated at extremely high skin temperatures and due to the flow mechanism of process fluids in these exchangers, the tubes were at a greater risk of being fouled and leading to the formation of hot spots which could cause equipment failure.

The potential benefits of polymer flooding has motivated the oil and gas companies to conduct pilot scale field testing of polymer floods. These pilots have shown the detrimental effects of the polymer breakthrough on the production systems and this has led to researchers conducting studies to investigate the problems in production systems to come up with possible solutions and alternatives. Wang et al. (2017) conducted a study using Dynamic Scale Loop (DSL) to observe the influence of EOR polymer on the mineral scale fouling and to study the performance of scale inhibitors being used when the polymer is present in the scenario. They found that when the polymer is present, the scale inhibitor performance declines significantly especially at higher temperatures. They also conducted Environmental Scanning Electron Microscopy (ESEM) and X-Ray Diffraction (XRD) on the deposit generated in static bottle tests and found that the morphology and composition of the deposit formed was significantly different from the mineral scale fouling and they recommended that polymer fouling needs to be investigated more to come up with better scale management systems. Mittal et al. (2018) investigated the fouling in production systems with

Dynamic Scale Loop (DSL). They concluded that polymer could increase the fouling in heat exchangers over a critical temperature called the cloud point temperature whereas below the cloud point temperature, the polymer may even inhibit the mineral fouling. A common test done by most researchers to study scaling deposits is the Static Bottle Test in which scaling deposits are generated in bottles but at low temperatures (less than 212°F) and then analyzed using ESEM and XRD. A major limitation of this method is the inability to conduct it at high temperatures which exist on heating tubes in heat exchangers and second is that the deposit generated might not be perfectly representative of the process happening in a heat exchanger as most heat exchanger tubes are of metals. This study presents a unique method which allows conducting tests at much higher temperatures which are also more representative of tube skin temperatures of heat exchangers present on field. This also ensures that the deposit generated during the lab environment resembles the fouling deposit generated in field exchangers much more closely.

1.3 Research Objectives

In this study, a multi-experimental approach has been taken to study the influence of polymer on fouling in heat exchangers

- Investigate the influence of following parameters on fouling –
 - Skin temperature of heater tubes by covering a wide range of temperatures between the range of 165°F to 350°F at suitably spaced intervals
 - Polymer concentration in produced fluids ranging from 0ppm to 800ppm to cover a wide range of possible polymer concentrations that might be observed in the produced fluids in the field pilot
 - Tube material including three different common heating metals – copper, carbon steel and stainless steel. These materials include carbon steel which

is being used presently on the field pilot in heat exchangers, as well as includes stainless steel which is being considered by the operators to be used in new heat exchangers

- Residence time of fluids in heaters to match the residence of fluids in the field heat exchangers to ensure the same contact time between the fluids and the tube material
- Analyze morphology and composition of the fouling deposit utilizing scanning electron microscopy and X-Ray diffraction
- Determine safe and efficient operating conditions for heat exchangers for practical recommendations to minimize polymer induced fouling in heat exchangers

1.4 Brief Description of Chapters

Chapter 1 gives a detailed background of the work done by researchers in the area of fouling issues in heat exchangers, limitations of their work and a description of how this study aims to overcome those limitations and research objectives. Chapter 2, which is a peer-reviewed journal publication, describes the experimental procedure, results and conclusion made after conducting experiments using the novel apparatus designed and built in-house to calculate deposit rates on different materials of tubes at different skin temperatures and different polymer concentrations. It also presents results on the morphology and composition of the deposit generated in the fouling tests as well as cloud point determination experiment to investigate the solution stability at different temperatures.

Chapter 3 describes the experimental procedure, results and conclusions made after conducting Dynamic Scale Loop (DSL) experiments which were also built in-house to study the influence of

skin temperatures on fouling under dynamic flow conditions. This chapter will also be submitted for publication in a peer-reviewed journal.

Chapter 4 presents overall conclusions based on this research work. It also presents some recommendations for future work, and most importantly the pilot.

Chapter 2 Static Test Method – Deposit Rate Test¹

2.1 Abstract

Polymer flooding is being pilot tested for the first time in the Schrader Bluff viscous oil reservoir at the Milne Point Field on the Alaska North Slope (ANS). One of the major concerns of the operator is the impact of polymer on the oil production system after polymer breakthrough, especially the polymer-induced fouling issues in the heat exchanger. This study investigates the propensity of polymer fouling on the heater tubes as a function of different variables, with the ultimate goal of determining safe and efficient operating conditions. A unique experimental setup was designed and developed in-house to simulate the fouling process on the heating tube. The influence of heating tube skin temperature, tube material, and polymer concentration on fouling tendency was investigated. Each test was run five times with the same tube, and in each run, the freshly prepared synthetic brine and polymer solution was heated from 77°F to 122°F to mimic field-operating conditions. The heating time and fouling amount were recorded for each run. Cloud point measurement has also been conducted to find the critical temperature at which the polymer in solution becomes unstable and precipitates out. The morphology and composition of the deposit samples were analyzed by environmental scanning electron microscopy (ESEM) and X-ray diffraction (XRD), respectively. It was found that the presence of polymer in produced fluids would aggravate the fouling issues on both carbon steel and stainless-steel surfaces at all tested skin temperatures. Only higher skin temperatures of 250°F and 350°F could cause polymer-induced fouling issues on the copper tube surface, and the fouling tendency increased with polymer concentration. At the lower skin temperatures of 165°F, no polymer-induced fouling was identified

¹ Dhaliwal, A., Zhang, Y., Dandekar, A. et al 2020. "Experimental Investigation of Polymer-Induced Fouling of Heater Tubes in the First-Ever Polymer Flood Pilot on Alaska North Slope." SPE Prod & Oper 36: 70–82. doi: <https://doi.org/10.2118/200463-PA>.

on the copper tube. A critical temperature that is related to the cloud point of the polymer solution was believed to exist, below which polymer-induced fouling would not occur, and only mineral scale was deposited but above which the polymer would aggravate the fouling issue. The cloud point of the tested polymer solution was determined to be between 220°F and 230°F. From a practical safer design standpoint, we recommend a value of 220°F for operational purposes on the pilot site. The heating efficiency of the tube would be decreased gradually as more fouling material accumulates on its surface. If polymer precipitated and deposited on the surface, it would bond to the mineral crystals to form a robust three-dimensional network structure, resulting in a rigid polymer-induced fouling. The study results have provided practical guidance to the field operator for the ongoing polymer flooding pilot test on ANS.

2.2 Introduction

The ANS contains approximately 12×10^9 barrels of viscous oil (20 to 2,000 cp), which is mainly located in the West Sak-Schrader Bluff formations (Pospisil 2011). The development pace of this vast resource has been slow because of high development costs and low oil recovery using conventional waterflood. Even after three decades of development efforts by multiple operators, the total viscous oil production rate from all ANS fields just reached 56,000 B/D by May 2017 (Cheng et al. 2018). Although thermal enhanced oil recovery (EOR) methods have been recognized as the most effective techniques to recover heavy oil, they are impractical on ANS because of the high cost of generating steam in the Arctic and the potential of thawing the permafrost, which would lead to severe environmental impacts. Recently, polymer flooding has attracted attention and become a promising EOR technique in viscous and heavy oil reservoirs because of the extensive application of horizontal wells and the advancement of polymer flooding technology. Currently, the U.S. Department of Energy and Hilcorp Alaska are cosponsoring an

advanced polymer flooding technology pilot test in the Schrader Bluff viscous oil reservoir with an in-situ oil viscosity of 330 cp (Dandekar et al. 2019).

The EOR performance of polymer flooding in heavy oil reservoirs has been proven by extensive laboratory studies including experiments, simulation, and field applications all over the world, and the current field pilot test (Dandekar et al. 2019) results are encouraging. However, the potential issues of produced fluids treatment resulting from polymer breakthrough are still the main concerns for the operators. Once polymer breaks through, it may cause severe emulsification issues, decreasing oil and water separation efficiency and aggravating the scaling and fouling issues in production facilities, especially on the heater tubes in the heat exchanger. Therefore, this study focuses on investigating the potential of polymer-induced fouling on the heater tubes in the heat exchanger used on ANS.

Mineral fouling caused by salts such as calcium carbonate, calcium sulfate, and barium sulfate is one of the most commonly encountered issues in any oil production system, which can cause significant production problems and substantial economic costs (Crabtree et al. 1999). The mineral fouling issue is generally more severe under high-temperature conditions in the heat exchangers, which has been extensively investigated by researchers. For example, Wylde et al. (2010) reported severe calcite scale issues on fire tubes and higher scaling potential for calcite at elevated skin temperature. Also, they evaluated the typical scale inhibitors' performance at elevated temperatures using dynamic scale loop (DSL), and they found no tested scale inhibitors were stable to prevent scale formation at the temperature of fire tubes. Kazi et al. (2015) investigated the effect of solution concentration, velocity, and material type on fouling issues in heat exchangers, and they found that with increasing temperature and concentration, the amount of deposited mass increased significantly because of higher nucleation rates. They also found that materials with

higher thermal conductivity, such as aluminum, had a higher scale formation in comparison to materials with lower thermal conductivity, such as stainless steel. Then Teng et al. (2017) investigated the calcium carbonate deposition on a double-pipe heat exchanger with different heat exchanging surfaces, and they also studied the influence of various parameters on calcite deposition. They found that a higher concentration of calcite and higher temperatures led to faster deposition, whereas high velocity of fluids decreased the deposition rates because of increased shear stress. Recently, with the wide application of chemical EOR techniques, more severe fouling issues have been noticed in the production system, which is attracting much attention in academics and industry.

In the production systems of chemical EOR projects, besides the typical mineral scaling, fouling issues may directly result from applied chemicals, such as alkali, polymer, and surfactant. Even the used chemicals may react with the minerals aggravating the mineral fouling issues. Previously, the study of Moradi-Araghi and Doe (1987) demonstrated that hydrolyzed polyacrylamides (HPAM) could precipitate when hard brines were present, especially under high-temperature conditions (greater than the cloud point), because the calcium ions could bind with the polymer caused by reacting or crosslinking with the acrylic group of HPAM. Recently, studies have been conducted to investigate the fouling issues in production systems of chemical EOR projects. Cao et al. (2007) reported their novel techniques to solve the severe scaling issues associated with the downhole pumps in producers of an alkaline-surfactant-polymer flooding project in Daqing Oilfield, China. Wylde et al. (2011, 2013) and Zheng et al. (2011) reported and summarized the chemicals, especially the polymer-induced issues in oil and water separation and processing systems in chemical EOR projects, and they all recognized that the problems were particularly challenging in heat exchangers, which were commonly used to promote oil and water separation

by heating the produced fluids. That is because the extremely high skin temperature of the heating tube can decompose the produced HPAM, which would coat the heating tube, further elevating skin temperatures and causing a more challenging scaling regime so that the mineral scale propensity would be further enhanced. Wylde et al. (2011) and Wang et al. (2017) investigated the influence of polymer on mineral scale formation and the performance of commonly used scale inhibitors using the DSL method and static bottle test method. Their study results confirmed that, in the presence of polymer, the overall fouling propensity could be significantly enhanced, and the effectiveness of the typical scale inhibitors could be significantly deteriorated, especially under higher skin temperature conditions. Besides, Wang et al. (2017) analyzed the scale deposits obtained from the bottle test using an ESEM and XRD techniques. They found that the morphology and polymorph of the scale were significantly changed because of the strong interactions between the polymer and mineral deposits, which may make the polymer-induced fouling more challenging to prevent and remove using conventional techniques. Mittal et al. (2018) also investigated the influence of polymer on fouling in production systems using the DSL method. They found that the polymer cloud point is the critical temperature above which the polymer can enhance the scaling propensity, but less than the cloud point, the polymer even can inhibit mineral scale. These studies imply that a new and unique technique may be needed to treat the EOR polymer-induced fouling issues. Although DSL is the most commonly used method to study the fouling problems, it cannot evaluate the fouling tendency quantitatively by calculating the fouling rate and does not allow us to observe the fouling process and severity visually. Also, the inside diameter of the tubing is so small that fouling/deposit samples generally cannot be obtained from the DSL test for morphology and composition analysis. Scale precipitates can be obtained from static bottle tests, which can only be conducted at low temperatures (less than 212°F) for ESEM and XRD analysis, although

these scale precipitates may not accurately represent the fouling material on the heating tube surface generated at high temperatures (greater than 212°F).

In this study, a new experimental device has been designed and built in-house that can simulate the extremely high skin temperatures of the heating tube to investigate the EOR polymer-induced fouling issues in the heat exchanger. The fouling tests were first conducted to identify the primary influence factors for the fouling tendency on the heating tube surface. The influence of various factors, including skin temperatures of the heating tube (165, 250, and 350°F), polymer concentrations (0, 80, 160, 400, 600, and 800 ppm), and heating materials (copper, stainless steel, and carbon steel) on the overall fouling rate was studied. The influence of fouling on heating efficiency of the heating tube was also studied by analyzing heating time change. Also, cloud point measurement was carried out to determine the cloud point of the prepared polymer solutions through temperature scanning (165 to 250°F). The fouling materials directly deposited on the high-temperature copper heating tube were collected for ESEM and XRD analysis. Eventually, all the results are carefully analyzed and discussed.

2.3 Experiment Method

2.3.1 Materials.

The detailed water analysis of the formation brine of the pilot reservoir is listed in **Table 2.1**. The pH of the formation brine was reported to be 6.9, and the hardness of the formation brine was reported to be 1,706 ppm. The synthetic brine is prepared by using deionized water, reagent grade sodium chloride (24,923.6 ppm), sodium bicarbonate (206.3 ppm), and calcium chloride (1,710.0 ppm), where the sodium represents the monovalent cations and the calcium represents the divalent cations in the formation brine. Also, the synthetic brine maintains similar total dissolved solids and hardness as the formation brine of the pilot test reservoir, which should show a similar

fouling/scaling tendency as the formation brine. The pH of the prepared synthetic brine was measured to be 7.2.

Table 2.1 Formation brine composition

Ions	Concentration (ppm)
Sodium (Na^+)	10,086.5
Potassium (K^+)	80.2
Magnesium (Mg^{2+})	281.6
Calcium (Ca^{2+})	200.7
Strontium (Sr^{2+})	17.4
Barium (Ba^{2+})	33.7
Iron (Fe^{2+})	0.5
Chloride (Cl^-)	15,973.1
Silica (SiO_2)	16.7
Bicarbonate (HCO_3^-)	150
Total dissolved solids	26,840.4

A type of partially hydrolyzed polyacrylamide (numbered as Flopaam 3630s; provided by SNF Floerger), with a narrow molecular weight range of 18 to 20 million Da, is used in this study. This polymer can produce a copolymer of acrylamide and acrylic acid after hydrolyzing, and its recommended hydrolysis degree is 30%. The same polymer is being used in the field as well. The tested heating tubes are made from copper, carbon steel, and stainless steel, and all have 0.25-in. outside diameter, as shown in **Fig. 2.1**. Special high-temperature-resistant tempered-glass bottles with strong sealing and a digital control dry oven with glass window were used to conduct the cloud point measurement.

2.3.2 Experimental Setup and Equipment.

A new experimental device was designed and built in-house to simulate the heating process of the heat exchanger at Milne Point, which can operate under extremely high skin temperature conditions (up to 428°F). Figs. 2.2 and 2.3 show the schematic and the picture of the experimental setup, respectively.

Figure 2.1 Heating tubes: (a) carbon steel, (b) copper, and (c) stainless steel

Figure 2.2 Schematic of fouling test setup

Figure 2.3 Actual experimental setup for fouling test

A commercial heating circulator, which is filled with thermal bath fluid, with a heating range of 32 to 428°F, is used to heat the tubes to desired skin temperatures. The U-shaped heating tube is used to heat the prepared solution directly in the glass container. The magnetic stirrer is used to continuously stir the solution during the heating process to keep uniform heating. A temperature probe associated with a data logger is used to monitor and record the solution temperature change. An analytical balance with 0.01-mg accuracy is used to measure the mass of the heating tube before and after each test to calculate the amount of fouling. In addition, ESEM and XRD facilities are used to analyze the morphology and composition of the fouling deposits accumulated on the U-shaped heating tube surface, respectively.

2.3.3 Experimental Scenarios.

To investigate the influence of various factors, including heating tube surface temperature, tube material, and polymer concentration, on fouling tendency, extensive fouling tests were designed and conducted (**Table 2.2**).

Table 2.2 Experimental scenarios

Material	Skin temperature (°F)	Polymer concentration (PPM)
Copper	165	0
		80
		160
		400
		600
		800
	250	0
		80
		160
		400
		600
		800
	350	0
		80
		160
		400
		600
		800
Stainless steel	165	0
		800
Carbon steel	165	0
		800

2.3.4 Experimental Procedure.

The designed fouling deposit test procedure is briefly described as follows.

1.Prepare the test solution: The synthetic brine is prepared by adding sodium chloride (24,923.6 ppm), sodium bicarbonate (206.3 ppm), and calcium chloride (1,710.0 ppm) into deionized water and continuing to stir the solution until all the salts are dissolved. A polymer mother solution of 2,000 ppm is prepared by continuously mixing the polymer and synthetic brine for at least 48 hours until the polymer is completely dissolved, and no lumps are remaining. The pH value of the prepared polymer mother solution was measured to be 7.35. Subsequently, the polymer mother solution is diluted by adding the synthetic brine to prepare the test solution associated with the desired to-be-tested polymer concentration. Three liters of the prepared test solution is poured into the glass jar for the test. The glass jar is then placed into a dry heating oven to preheat the test solution to an initial temperature of 77°F.

2.Preheat the metal heating tube: The metal tube is bent to the designed dimension of the U shape. The U-shaped metal tube with the compression nuts is weighed as W1. The U-shaped metal tube is connected to the heating circulator, and the heating circulator started to preheat the metal tube to the designed to-be-tested skin temperatures, which are 165, 250, and 350°F in this study. The temperature probe measures the tube skin temperature at different positions until the stable desired skin temperature is achieved.

3.Heat the test solution for fouling test: Once the stable desired skin temperature is achieved, the metal tube is immersed in the test solution to heat it. At each tested skin temperature (165, 250, and 350 F), the solution is always heated from 77 to 122°F which are the corresponding inlet and outlet temperatures of the fluids in the heat exchanger on the pilot site. During the test, the heating

circulator is kept running to heat the test solution continuously while magnetically stirring the solution to achieve uniform heating. The temperature of the test solution is monitored by the temperature probe and logged using a data logger every 15 seconds until the test solution reaches the temperature of 122°F.

4. Determine the fouling amount: Once the test solution is heated to 122°F, the heating circulator is stopped, the test solution is removed immediately, and the U-shaped metal tube is allowed to cool down to room temperature. Then, the U-shaped metal tube is disconnected from the heating circulator, and the inside of the tube is cleaned thoroughly using a solvent to remove the residual heating oil. The outside of the tube is cleaned carefully using water while avoiding the loss of any deposit. After cleaning, the metal tube is dried completely, and its dry weight is measured to be W_2 . Thus, the fouling amount during the test can be calculated as $W_2 - W_1$.

For each fouling test, Steps 1 to 4 are repeated five times (i.e., five runs) using the same U-shaped metal tube but with a fresh batch of a testing solution in every run. After five runs, the fouling materials accumulated on the surface of the U-shaped metal tube are scraped off and collected for morphology and composition analysis using ESEM and XRD, respectively.

The cloud point measurement procedure is briefly described as follows.

1. The oven is preheated to the test temperature.
2. The prepared polymer solutions with different concentrations (0, 160, 400, and 800 ppm) are transferred to the special tempered-glass bottles, and the glass bottles are kept inside the oven at the test temperature for 24 hours.

3. After 24 hours, the glass bottles are taken out from the oven and observed carefully for precipitate, cloudiness, or phase separation in the solution, and a photograph is taken of the glass bottles; and
4. The oven is preheated to the next designed test temperature, and Steps 2 and 3 are repeated until all predetermined temperature points are tested.

2.4 Results and Discussion

2.4.1 Effect of skin temperature on fouling tendency

The influence of heating tube skin temperature on the deposit rate at various polymer concentrations is shown in **Figure 2.4**, where the deposit rate is defined by the following equation,

$$\text{Deposit rate} = \frac{\text{Cumulative deposit amount in 5 runs (mg)}}{\text{Total heating time in 5 runs (min)}}$$

The calculated deposit rate is a quantitative parameter to represent the fouling severity on the heating tube surface. The fouling tendency is commonly used to describe fouling severity qualitatively. Thus, the higher the fouling tendency, the higher the deposit rate, representing more fouling severity on the heating tube surface in this study.

Figure 2.4 Deposit rate on copper tube vs. tested skin temperature at various polymer concentrations

As can be seen from **Figure 2.4**, at the same polymer concentration, the deposit rate generally increases with the skin temperature but is much more pronounced between 165°F and 250°F (i.e., the curve slope between 165°F and 250°F) than between 250°F and 350°F. This phenomenon confirms that skin temperature is one of the critical factors affecting the fouling tendency on the heating tube surface, which is consistent with previous studies (Shupe 1981, Ramsden and McKay 1986, Moradi and Doe 1987, Seright and Skjevrak 2015, Xiong et al., 2018). That is because the temperature can significantly affect the degree of hydrolysis of polyacrylamide in the solution (Muller et al., 1980; Moradi-Araghi and Doe 1987; Oliveira et al., 2019). In general, if the degree of hydrolysis of polyacrylamide is lower than the desired value (generally 30%), the HPAM can stably exist in the solution and will not precipitate (Xiong et al., 2018). With the increase in temperature, the degree of hydrolysis can be significantly higher than 30%. The excessive

hydrolysis of polyacrylamide will make the HPAM unstable in the solution and precipitate due to complexing with divalent ions, especially the calcium ion, in the brine. Once the precipitated polymer deposits on the heating tube surface, the coated heating tube will be overheated, which further enhances mineral scale propensity. Thus, more severe fouling issues are caused, which eventually damages the heating tube due to overheating. Higher temperatures, such as 250°F and 350°F in this study, also can increase the rate of chain scission of the polymer backbone and decompose polymer via intramolecular imidization of amide groups, which can make the HPAM unstable in the solution and tend to precipitate. This could further aggravate the fouling issues. A detailed explanation of polymer degradation mechanisms can be found in the literature (Xiong et al., 2018).

2.4.2 Effect of polymer concentration on fouling tendency

The influence of polymer concentration on the deposit rate at different skin temperatures has been described in **Figure 2.5**. As can be seen, at a lower skin temperature of 165°F, the deposit rates at different polymer concentrations are almost the same with and without polymer; however, at higher skin temperatures of 250°F and 350°F, the deposit rates increase steadily with the increase of polymer concentration. The scale deposited on the tube surface at 0-ppm concentration of polymer should be pure mineral scale. The test results showed that, at 165°F, the deposit rates are nearly the same as that of pure mineral scale regardless of the polymer concentration. This finding implies that, at 165°F, it does not matter what the polymer concentration is, only mineral scaling could occur on the heating tube surface. It is believed this is because the lower skin temperature of 165°F in this study would not cause excessive hydrolysis or decompose the HPAM directly, the HPAM could stably exist in the solution and will not precipitate, and the fouling issues will not be aggravated.

Figure 2.5 Effect of polymer concentration on deposit rate on copper tube

Therefore, the skin temperature of 165°F, which is the current operating temperature of the heat exchanger on the pilot site at Milne Point, should be safe to treat the produced fluids associated with various polymer concentrations. However, at higher tested skin temperatures of 250°F and 350°F, the deposit rates increased with polymer concentrations and were all significantly higher than the deposit rate of pure mineral scale. This finding indicates that the higher tested temperatures of 250°F and 350°F already made the HPAM unstable in the solution and precipitated because of excessive hydrolysis or direct decomposition, aggravating the fouling issues. Thus, 250°F and 350°F are not safe operating temperatures for the heat exchanger. According to our analysis and interpretation of the experimental results, there may exist a critical temperature between 165°F and 250°F where the polymer fouling effect begins to manifest. Below the critical temperature, the HPAM will not precipitate, and only mineral scaling occurs on the tube surface, so the existence of polymer in the produced fluids will not aggravate the fouling issues. However, above the critical temperature, the HPAM will precipitate and aggravate the fouling issues.

Besides, we believe this critical temperature may be related to the cloud point of the polymer used. Additional experimental tests have been conducted to confirm this finding, which is going to be discussed later in this paper.

Figs. 2.6 to 2.8 visually depict the accumulated fouling after five runs on the tube surface associated with respective skin temperatures of 165°F, 250°F, and 350°F at different polymer concentrations.

Figure 2.6 Accumulated fouling on copper tube surface at 165°F at polymer concentrations of (a) 0, (b) 80, (c) 160, (d) 400, (e) 600, and (f) 800 ppm

Figure 2.7 Accumulated fouling on copper tube surface at 250°F at polymer concentrations of (a) 0, (b) 80, (c) 160, (d) 400, (e) 600, and (f) 800 ppm

As can be seen obviously from **Fig. 2.6**, compared with Figure 2.6 (a) which shows the pure mineral scale, no aggravated fouling issues were identified from Figure 2.6(b) to 2.6(f) due to the existence of different concentrations of polymer at 165°F. However, from the comparison of Figure 2.7(a) and Figure 2.8(a) with Figure 2.7(b) to 2.7(f) and Figure 2.8(b) to 2.8(f), respectively, it is clear that adding polymer into the solution would significantly aggravate the fouling issues at higher temperatures of 250°F and 350°F, and the higher the polymer concentration, the more severe the fouling. Therefore, **Figures 2.6 to 2.8** qualitatively confirm our quantitative findings drawn from **Figure 2.5**.

Figure 2.8 Accumulated fouling on copper tube surface at 350°F at polymer concentrations of (a) 0, (b) 80, (c) 160, (d) 400, (e) 600, and (f) 800 ppm.

Additionally, when we scraped the fouling materials from the tube surface for ESEM and XRD analysis, we found the pure mineral scale was brittle (refer Figures 2.14 and 2.15) and easily scraped off, but the aggravated fouling material with polymer was tougher and much more difficult to scrape off. This finding indicates that if the heat exchanger were not operated properly, once polymer-induced fouling occurred on the tube surface, it would be much more difficult to remove using the common mechanical methods.

2.4.3 Effect of fouling on heating efficiency

Figure 2.9 shows the time needed to heat testing solutions with different polymer concentrations from 77°F to 122°F at the skin temperatures of 165°F, 250°F, and 350°F, respectively. Here, we focus on analyzing the trend of each individual curve, i.e., the heating time change with the run number at each polymer concentration, but we did not intend to compare different curves with different polymer concentrations. As shown in Figure 2.9 (a), there is no common trend for each

curve, and each curve is associated with some fluctuation at a lower test skin temperature of 165°F. However, Figures 2.9 (b) and (c) show a generally increasing trend with the run number for each individual curve at higher tested skin temperatures of 250°F and 350°F, respectively. The small fluctuations associated with the heating time trend of each curve in Figure 2.9 (a) may result from the weak adhesiveness of mineral scale on the tube surface. As mentioned previously, only the mineral scale would be produced and deposited on the tube surface at the lower skin temperature of 165°F, which was easily scraped off. Thus, the mineral scale may alternatively deposit on the tube surface and then be washed off, which may cause an alternate change in the heating efficiency of the tube. Accordingly, the heating time in different runs has fluctuated. However, at 250°F and 350°F, polymer-induced fouling would be deposited on the tube surface, and they generally could not be washed off. Thus, the accumulation of polymer-induced fouling would continuously reduce the heating efficiency of the heating tube, which explains the consistent increase in heating time of each curve in Figures 2.9 (b) and 2.9 (c).

(a)

(b)

(c)

Figure 2.9 Effect of fouling on heating time of each test at (a) 165°F, (b) 250°F, and (c) 350°F

2.4.4 Effect of heating tube material on fouling tendency

The influence of heating tube material including copper, carbon steel, and stainless steel on fouling tendency also has been investigated. For each heating tube material, the fouling tendency was evaluated without the polymer (0 ppm) and at 800 ppm polymer concentration. Note that all the tests were conducted at the skin temperature of 165°F since the carbon steel and stainless-steel tubes could not be heated to the stable higher skin temperatures of 250°F and 350°F (see Table 2.2). Figures 2.11 shows the accumulated fouling or deposit after 5 runs on the tube surface, and Figure 2.12 illustrates the calculated deposit rates for each tube material at 0 ppm and 800 ppm polymer concentrations, respectively. Our interpretation of previous tests (Figures 2.4 – 2.8) has confirmed that the existence of polymer in the solution would not aggravate the fouling issues on the copper tube surface at a lower skin temperature of 165°F.

Figure 2.10 Accumulated fouling Accumulated fouling on copper tube surface at 350°F at polymer concentrations of (a) 0, (b) 80, (c) 160, (d) 400, (e) 600, and (f) 800 ppm.

Figure 2.11 Deposit rates on different heating tube material

As can be seen from Figure 2.10, compared with stainless steel and copper, there was much more rust which may be iron oxide deposits on the surface of the carbon steel tube, which can explain why the deposit rates on the carbon steel tube surface were higher than those on the stainless steel and copper surface at either polymer concentrations as shown in Figure 2.11. In addition, compared to Figure 2.10(a), with 800 ppm polymer in the test solution, we could observe more rust and some additional white deposits which were believed to be polymer-induced fouling on the surface, as shown in Figure 2.10(d). This observation indicates that the redox reactions on the carbon steel surface may be intensified with the existence of polymer in the solution. Since previous tests have confirmed that lower skin temperature of 165°F cannot directly cause polymer fouling issues on the surface, the observed polymer fouling material in Figure 2.10(d) may result from the redox reactions and their products. This finding tells us that the existence of polymer in the solution

would aggravate the fouling issues on the carbon steel surface even at a lower skin temperature of 165°F, which can be further confirmed by the fact that the deposit rate on carbon steel surface at 800 ppm polymer concentration was higher than that without polymer (i.e., 0 ppm) in the solution, as shown in Figure 2.11.

As can be seen from Figure 2.10(b), the stainless steel surface was still clean after all tests if there was no polymer in the solution. However, the stainless-steel surface would be coated with a white fouling layer which was also believed to be polymer-induced fouling if 800 ppm polymer existed in the solution. That is why the calculated deposit rate on the stainless-steel surface at 800 ppm polymer concentration was significantly higher than that at 0 ppm polymer concentration, as shown in Figure 2.11. Thus, we can confirm that the existence of polymer in the solution can aggravate the fouling issues on the stainless-steel surface even at lower skin temperature of 165°F. Besides, as can be seen from Figure 2.11, at 800 ppm of polymer concentration, the calculated deposit rate on copper tube surface was much lower than those on both carbon steel and stainless-steel surfaces. Without the polymer, the deposit rates on the copper tube and stainless tube surface were much lower than that on the carbon steel surface. These calculated higher deposit rates at either polymer concentrations all result from the aggravated polymer-induced fouling issues, which has been explained. However, without the polymer, the calculated deposit rate on the copper tube surface was a little bit higher than that on the stainless-steel surface. As mentioned previously, only the mineral scale deposited on the surfaces without polymer in the solution. Under the same test conditions, we found that the heating time needed for stainless steel tube was much longer than that for the copper tube due to the lower heat conductivity of the stainless-steel tube. Thus, according to Equation (1), the calculated deposit rate on the copper tube surface was higher than that on the stainless-steel surface. All of these findings indicate that copper tube would be the best

choice for heat exchanger from the technical viewpoint to treat the produced fluids, especially when polymer exists in the produced fluids.

2.4.5 Cloud point measurement

As shown in Figure 2.12, the temperature at which the cloudy appearance of the solution was first observed at 230°F. Therefore, it is believed that the cloud point of the prepared polymer solutions should be between 220°F and 230°F.

Figure 2.12 (a) Freshly prepared polymer solutions before a test, (b) polymer solutions after heating at 220°F/104°C for 24 hours, and (c) polymer solutions after heating at 230°F/110°C for 24 hours

According to our observation, when the test temperature points are lower than the cloud point, the polymer solutions were all clear without precipitate no matter how long they were heated at that temperature, which implies that the prepared polymer solutions are very stable and would not precipitate out below the cloud point. However, once above the cloud point, the polymer would precipitate out very quickly, causing the cloudiness of the solution. In our test, we observed the cloudy appearance of the polymer solutions in 30 minutes after we started the test at 230°F. We also observed that the amount of precipitate increased with the elevating of the temperature. These tests further confirmed that temperature has a significant effect on the hydrolysis rate of polymer, which is consistent with the findings of Ryles (1988). At elevated temperatures, the pendent amide groups tend to hydrolyze more, therefore increasing the total carboxylate content in the solution. As hydrolysis increases, the excess hydrolyzed polyacrylamides, if in the presence of divalent metal ions, such as Ca^{2+} , would interact strongly with them to form precipitates. These findings and mechanisms are consistent with our fouling experiment results. At 165°F which is below the cloud point, the polymer hydrolysis rate is relatively low, so the polymer could stably exist in the solution and would not precipitate out. That is why the fouling tendency would not be aggravated at this skin temperature. However, at 250°F and 350°F which are above the cloud point, the polymer hydrolysis rate is significantly enhanced, and excess hydrolyzed polyacrylamides interact with the Ca^{2+} in the solution to precipitate out, aggravating the fouling tendency. Therefore, the cloud point of the polymer solution is a critical temperature, below which the polymer would not enhance the fouling tendency regardless of the polymer concentration, but above which, the existence of polymer in the solution would aggravate the fouling issues. Although the cloud point of the tested polymer solutions has been determined to be between 220°F and 230°F, from a

practical safer design standpoint, we recommend a value of 220°F for operational purposes on the pilot site.

2.4.6 Effect of polymer on morphology and composition of the deposit

The impacts of polymer on the morphology and composition of the fouling deposit on the heating tube surface can also be reflected in the ESEM and XRD analyses. In this study, only the fouling deposit on the copper tube surface generated at the skin temperature of 350°F, as shown in Figure 8, was characterized by ESEM. The ESEM pictures of fouling deposits at respective polymer concentrations of 0 ppm, 160 ppm, 400 ppm, and 800 ppm are shown in Figure 2.13.

Figure 2.13 ESEM pictures of fouling generated at the polymer concentrations of (a) 0, (b) 160, (c) 400, and (d) 800 ppm on the copper tube at a skin temperature of 350°F

Figure 2.13(a) shows the morphology of the pure mineral scale since the polymer concentration was 0 ppm (i.e., there was no polymer in the solution). As can be seen, the mineral crystals are

irregular and naturally compact together, so the bonding between the mineral crystals is weak and the mineral crystals generally have less adhesion on the tube surface, which can explain why the pure mineral scale is brittle and easily scraped off as mentioned previously. Compared to Figure 2.13(a), Figures 2.13 (b), (c), and (d) illustrate that morphology of the polymer-induced fouling is different from that of pure mineral scale. As can be seen, once the polymer precipitated and deposited on the tube surface, it would be bonded to the mineral scale crystals forming a three-dimensional network structure, becoming denser with the increase of polymer concentration. In general, this kind of network structure of polymer-induced fouling is stronger than the simple compaction of the pure mineral scale, and it also has more adhesion to the tube surface. That is why, as mentioned previously, the polymer-induced fouling was tougher and more challenging to be scraped off.

Among the deposit samples characterized in Figure 2.13, two of them were analyzed by XRD to compare their composition difference. The results of XRD analysis have been depicted in Figure 2.14, where the blue color represents the XRD pattern of deposit generated using 800 ppm polymer solution while the red color represents the XRD pattern of deposit generated using 0 ppm polymer solution (i.e., without polymer in the solution). The compound codes below the pattern represent sodium chloride - Halite (01-070-2509) and calcium carbonate - Calcite (00-066-0867). It is necessary to point out that XRD analysis is only able to identify mineral salts of sodium and calcium in the deposit, but polymer fouling cannot be identified as diffraction peaks in the XRD pattern, since X-Rays cannot detect elements below sodium and polymer is only composed of carbon, hydrogen, oxygen, and nitrogen. Furthermore, the compositional analysis for the two deposit samples was also conducted by HighScore Plus software based on the obtained XRD patterns.

Figure 2.14 XRD scan of deposits on the copper tube at a skin temperature of 350°F at polymer concentrations of 0 and 800 ppm. Compound codes: halite (01-070-2509) and calcite (00-066-0867)

As can be seen from Figure 2.14, the most significant difference in the two patterns occurs at the angle of approximately $2\theta = 29$ which represents calcite (CaCO_3) peak. The peak at $2\theta = 29$ was obtained in the blue pattern (with polymer) but it was absent in the red pattern (without polymer). This difference indicates that, compared to the solution without polymer, the presence of polymer in the solution may cause one more type of calcite mineral scale. Besides, noticeable background noise can be observed in the two patterns between the angles of $2\theta = 15$ and $2\theta = 24$, which may represent some byproducts resulting from the interaction between polymer and mineral salts. Since X-Rays cannot detect C, H, O, and N, these byproducts cannot be detected as a peak in the pattern. According to compositional quantification results for mineral scale in both deposit samples, it has been found that 98% of the mineral scale is Halite and the remaining 2% is Calcite in the deposited

sample generated from the solution without polymer. However, the presence of polymer in the solution decreased the Halite composition in the mineral scale to 80% and increased the calcite composition to 20%. Therefore, this finding further confirms the previous conclusion that the presence of polymer in the produced fluids can enhance the mineral scale propensity.

2.5 Conclusions

The tests performed in this study to investigate the fouling tendency on the heating tube surface, especially when polymer exists in the produced fluids, yield the following general conclusions:

- 1) At a lower skin temperature of 165°F, the existence of polymer in the fluids would not aggravate the fouling tendency on the copper tube surface, but it would enhance the fouling tendency on the carbon steel and stainless-steel surfaces. However, at higher skin temperatures of 250°F and 350°F, the fouling tendency on the copper tube surface would be enhanced by polymer, and it generally increased with the polymer concentration.
- 2) Thus, only from the technical viewpoint, the copper tube would be the best choice in this study for the heat exchanger used on the pilot site.

In addition, the following conclusions are drawn based on the fouling tests conducted only using the copper tubes:

- 3) The cloud point of the prepared polymer solutions was determined to be between 220°F/104°C and 230°F/110°C. There exists a critical temperature that is believed to be related to the cloud point of the polymer solution, below which the polymer would not enhance the fouling tendency regardless of the polymer concentration but above which the existence of polymer in the solution would aggravate the fouling issues.

- 4) With fouling material accumulating on the tube surface, the heating efficiency of the tube would be reduced, which is the main reason causing overheating of the heating tube and its eventual failure.
- 5) Compared to the pure mineral scale, the polymer-induced fouling possesses a stronger three-dimensional network structure, making the fouling material harder and more difficult to be removed from the tube surface.
- 6) The presence of polymer in the fluids can alter the characteristics of the mineral scale.

In summary, the current operating skin temperature of 165°F at the pilot site should be a safe operation condition, which, however, may not be able to treat produced fluids of polymer flooding effectively. To promote the water-oil separation efficiency for the ongoing polymer flooding pilot test, the skin temperature of the heat exchanger could be increased up to 220°F, which would not make the HPAM unstable and precipitate. Although the HPAM would not break down and precipitate out under 220°F, the currently used carbon steel heating tube may still be subjected to aggravated polymer-induced fouling issues since redox reactions on the carbon steel tube surface may cause HPAM to precipitate.

2.6 References

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Chapter 3 Dynamic Scale Loop Method²

3.1 Abstract

A polymer flood pilot has been ongoing in the Schrader Bluff viscous oil reservoir at Milne Point on the Alaska North Slope (ANS). The results from the pilot are encouraging, however a major concern of the operator is the influence of polymer on the production system after breakthrough, especially the fouling in heat exchangers. This work applies a multi-experimental approach to study the severity of polymer-induced fouling in both dynamic and static states of produced fluids to determine safe operating conditions. Dynamic Scale Loop (DSL) tests were conducted to study fouling due to polymer at different temperatures (165°F to 350°F) in a dynamic state of fluid flow where the fluids mimic the residence time of fluids in the heat exchanger on the field pilot. Deposit tests were also conducted at similar temperatures of 165°F to 250°F using a novel experimental apparatus designed and built in-house. It was found that at higher skin temperatures of 250°F and 350°F tube blocking was observed in the DSL tests whereas the tests at 165°F and 200°F did not show any tube blocking in the same time period. The deposit test showed that the stainless-steel tubing is much better suited for application if the polymer is present in the solution. These experiments also manifested the influence of cloud point of the solution as deposit rate increased significantly in both carbon steel and stainless-steel tubes when the skin temperature was higher than the solution cloud point. The study has been a source of practical guidance to the field operations.

² This chapter is co-authored by Dhaliwal, A., Zhang, Y., Dandekar, A. et al., and is an article in – prep for publishing in a Society of Petroleum Engineers Production and Operations Journal.

3.2 Introduction

The Alaska North Slope (ANS) is well known for its abundant resources of oil and gas. Heavy oil with API gravity ranging from 8 to 22 degrees is a significant portion of this resource (Cheng 2018). Studies estimate heavy oil resources to be between 20-25 billion barrels with the Schrader Bluff occupying a major portion of the heavy oil resource (Targac et al. 2005). Despite the presence of such a vast resource, its development pace has been slow due to various factors such as – high development costs, the inapplicability of thermal methods due to the presence of continuous permafrost, and low oil recovery using conventional waterflooding methods. Polymer flooding has been successfully tested in China and Canada (Wang 2013, Delamaide et al. 2014). The presence of suitable factors including low temperatures and low water salinity which keep the polymer stable and the advancements in horizontal well technology has made polymer flooding an ideal candidate for application on the ANS. Since 2018, a polymer flooding pilot is being field tested at Milne Point which is co-sponsored by the US Department of Energy and Hilcorp Alaska LLC.

The field pilot has been running for more than 26 months in the Schrader Bluff viscous oil reservoirs and the results of the pilot have been very promising (Ning et al. 2020). Polymer breakthrough has been detected in February 2021, after 25 months of operation. Although pilot results are promising, a major concern of the operators is the additional challenges caused in produced fluid treatment system from polymer breakthrough. Therefore, the practical significance of this study can be readily realized given the polymer breakthrough in both producers after more than two years of the pilot commencement. The presence of polymer can cause emulsification issues, lowering the oil and water separation efficiency and cause fouling issues in the produced fluid production system, especially on the heating tube in heat exchangers. This study aims to

focus on investigating polymer induced fouling on the heater tubes in the heat exchanger used on ANS.

Fouling in heat exchangers in oilfield operations due to mineral salts has been thoroughly investigated throughout the years by researchers. Zhang and Farquhar (2001) studied calcium carbonate scaling rates in oilfield wellbore environments and found that the scaling rate is influenced by the water flow velocity. They found that as the velocity of water increased the scaling rate increases up to a value of 0.05 m/s and became stable post that up to 0.7 m/s, after which it started decreasing with increase in velocity. Kukulka and Devgun (2007) studied the influence of fluid temperature and velocity on fouling on heat exchanger surfaces and they found that increasing velocity reduced the fouling tendency on the surface. Raharjo et al. (2015) investigated the scaling due to calcium carbonate in copper pipes in the laminar flow regime. They found that increasing flow rate decreased the amount of deposit, that is, increasing flow rate decreased scaling. Similar results were found by Teng et al. (2017), where they discovered that the high velocity of fluids decreased the deposition of calcium carbonate as the shear stress increased at high fluid velocities. The shear stress exerted by the liquid helps reduce the deposit as it forces the deposited particles to be removed from the tube walls leading to a reduced overall calcium carbonate deposition. The introduction of polymer flooding technique to increase oil recovery has been a blessing for the heavy oil reservoirs but it brings with itself additional severe fouling challenges that need to be investigated thoroughly.

The application of chemicals such as – alkali, polymer, and surfactant in EOR projects can lead to additional fouling issues besides the commonly existing mineral fouling issues. Moradi-Araghi and Doe (1987) observed that when hydrolyzed polyacrylamides are present in hard brines and under specific temperature conditions (greater than the cloud point), they could precipitate out of

the solution by forming complexes with the divalent cations from the hard brine. Zheng et al. (2011) and Wylde et al. (2011, 2013) have reported issues due to applications of chemicals in the production systems mentioning that the problems were particularly challenging in the heat exchangers which due to high skin temperatures led to polymer induced fouling on the heating tubes. Wang et al. (2017) studied the influence of polymer on fouling inhibitors using DSL tests and also investigated the structure and morphology of the deposit generated in static bottle tests using XRD and ESEM techniques. They found the polymer could significantly increase fouling as the tube-blocking time decreased when polymer was present in the brine. They also found that the presence of polymer significantly alters the structure and morphology of the scale due to strong interactions between the polymer and the mineral scale, which could be more challenging to prevent and remove using conventional techniques. While the DSL tests utilized in these works demonstrated polymer could increase the overall fouling propensity but could not give a detailed analysis of how much fouling occurs in a period of time. Dhaliwal et al. (2020) developed a unique method and conducted deposit tests which measure fouling rates in a static manner, and they found that in the absence of polymer, the fouling rates would be significantly lower at all operating temperatures; however, above a critical temperature related to the cloud point temperature, the polymer induced fouling would be much more severe. However, while the static tests measure the deposit rates quantitatively, they cannot describe what would happen in a dynamic state of fluid flow. Thus, this work, is an extension of the previous study in which the influence of polymer on fouling will also be studied in a dynamic state of fluid flow using DSL. This work also aims to extend the deposit tests conducted by Dhaliwal et al. (2020) to different tube materials at different temperatures and polymer concentrations to analyze which tube materials would be appropriate at different operating temperatures.

In this study, DSL experiments in conjunction with static deposit tests have been carried out to investigate the fouling issues caused by the EOR polymer in the heat exchanger. In the static deposit tests, the influence of skin temperature (165, 200, 250°F), tube metallurgy (copper, stainless steel, and carbon steel) and presence of polymer on fouling were studied and analyzed. The DSL tests were carried out to study and confirm the influence of temperature (165°F, 200°F, 250°F and 350°F), residence time and presence of polymer on fouling in heat exchangers. Cloud point measurement was carried out to determine the cloud point of the prepared polymer solutions through temperature scanning in the range of 165 to 250°F.

3.3 Experiment Method

3.3.1 Materials.

The chemical composition of formation brine is shown in Table 3.1 (Dhaliwal et al., 2020). The pH reported for the formation brine was 6.9, and the hardness measured was found to be 1,700.6 ppm. In our lab tests, synthetic brine was used to conduct all the tests. The synthetic brine was prepared using deionized water, reagent grade sodium chloride (24,923.6 ppm), sodium carbonate (206.3 ppm), and calcium chloride (1,710.0 ppm), where the sodium represents the monovalent cations. The calcium represents the divalent cations in the formation water, which also causes the hardness in the synthetic brine. Measures were taken to ensure the synthetic brine maintains similar total dissolved solids and hardness as the formation brine of the pilot test reservoir showing a similar fouling tendency as the formation brine. The pH of the prepared synthetic brine was measured to be 7.2.

Table 3.1 Formation brine composition

Ions	Concentration (ppm)
Sodium (Na^+)	10086.5
Potassium (K^+)	80.2
Magnesium (Mg^+)	281.6
Calcium (Ca^{2+})	200.7
Strontium (Sr^{2+})	17.4
Barium (Ba^{2+})	33.7
Iron (Fe^{2+})	0.5
Chloride (Cl^-)	15973.1
Silica (SiO_2)	16.7
Bicarbonate (HCO_3^-)	150
TDS	26840.4

3.3.2 Experimental Setup

DSL test and static deposit test were conducted to investigate the fouling tendency on the heating tube. The DSL test was used to study fouling issues with the purpose of mimicking the dynamic flow conditions in the heat exchangers. The static deposit test is to directly measure fouling rates and to compare different tube materials for best suitability for the field pilot. Fig. 3.1 shows the schematic of the DSL test equipment.

Figure 3.1 Schematic of DSL test

The DSL test setup consists of testing solution stored in a container which is pumped using a continuous flow rate dual piston pump at the desired flow rate. The solution is circulated through a pre-heated stainless steel tubing coil with a linear length of 10.08 ft. The convection oven containing the coiled tubing maintains the constant skin temperature during the experiment. Pressure is maintained using a back pressure regulator (BPR), with a differential pressure across the test section measured using a differential pressure transducer to monitor for tube blocking. The differential pressure transducer measures the differential pressure at fixed constant intervals of time and feeds it to a computer where the data is recorded for the duration of test.

3.3.3 Experimental procedure

The procedure for preparing the test solution and conducting the static deposition tests is the same as described in our earlier paper (Dhaliwal et al., 2020) and thus not repeated here; therefore, only details pertaining to the DSL test are included below:

1. Prepare the test solution: The synthetic brine is prepared by adding sodium chloride (24923.6 ppm), sodium bicarbonate (206.3 ppm), calcium chloride (1710.0 ppm) into deionized water, and continuing to stir the solution until all the salts are dissolved. A polymer mother solution of 2,000 ppm is prepared by continuously mixing the polymer and synthetic brine for at least 48 hours until the polymer is completely dissolved, and no lumps are remaining. The pH value of the prepared polymer mother solutions was measured to be 7.35. Subsequently, the polymer mother solution is diluted by adding the synthetic brine to prepare the test solution associated with the desired to-be-tested polymer concentration. The prepared polymer is unsheared. On the field, the polymer undergoes shearing and degradation primarily due to fluid lifting by ESPs. Studies done on degradation by one of the project group members suggest that the polymer would degrade by 60-70% as it will breakthrough, and the breakthrough concentration is 700 ppm. This however would also mix with a number of streams coming from other pads on the field and would be diluted, therefore the tested polymer concentration in this study of 400 ppm adequately represents a similar situation as the field.

2. Preheat the coiled tubing (see Figure 3.1): The convection oven is set to the required temperature to heat the tubing to the desired skin temperature. The tubing is heated for at least 1 hour pre-test.

3. Blank water test: Once the stable desired skin temperature of tubing is achieved, a blank run was carried out, where DI water was circulated through the experimental setup and differential pressure across tubing was measured. This was done to ensure the tubing and fittings do not have any pre-deposited foulant/scale, which could give misleading results. In our test, the differential pressure of the blank run should not show any abrupt peaks when run at a flow rate of 3.94 ml/min.

4. Circulate prepared solution: The prepared solution was circulated through the coiled tubing using the dual piston constant flow rate pump to achieve desired residence time of the fluids inside

the heated tubing. Differential pressure across the tubing was measured constantly and stored by the computer. A sudden and constant rise in differential pressure signifies that the tubing is blocked due to fouling and the experiment is stopped immediately.

The detailed experimental procedures for the static deposit test and cloud point test have been described in our previous paper Dhaliwal et al. (2020).

3.3.4 Experimental scenarios

Table 3.2 shows the experimental scenarios for static deposit tests, and Table 3.3 shows the experimental scenarios for the DSL experiments.

Table 3.2 Experimental scenarios for static deposit test

Tube Material	Skin Temperature (°F)	Polymer Concentration (ppm)
Stainless Steel	165	0
		800
	200	0
		800
	250	0
		800
Carbon Steel	165	0
		800
	200	0
		800
	250	0
		800
Copper	165	0
		800
	200	0
		800
	250	0
		800

Table 3.3 Experimental scenarios for Dynamic Scale Loop Test

Skin Temperature (°F)	Polymer Concentration (ppm)	Residence Time (minutes)
165	0	1.194
165	400	1.194
200	400	1.194
250	400	1.194
350	0	1.194
350	400	1.194

3.4 Results and Discussion

3.4.1 Deposit Rate Test Results.

3.4.1.1 Effect of Skin Temperature on Fouling Tendency in Deposit Test.

The effect of the tube skin temperature on deposit rate at different polymer concentrations and tube material can be seen in **Fig. 3.2**, where the deposit rate is defined by the following equation:

$$\text{Deposit rate} = \frac{\text{Cumulative deposit amount in 5 runs (mg)}}{\text{Total heating time in 5 runs (min)}}$$

As can be seen from **Fig. 3.2**, in both the scenarios – with and without polymer in solution, the deposit rate generally increases with skin temperature, but the effect is much more pronounced between 200°F and 250°F than between 165°F and 200°F. This finding is consistent with the findings of Dhaliwal et al. (2020), where the deposit rate increased with skin temperature for copper tubes at the same polymer concentration. This again confirms that irrespective of tube

material, skin temperature is a critical factor affecting fouling tendency in heat exchanger tubes. Studies conducted previously by Shupe (1981), Moradi-Araghi and Doe (1987) have found similar results and this can be explained by the effect of temperature on the degree of hydrolysis of the polyacrylamide in the solution (Moradi-Araghi and Doe 1987; Oliveira et al. 2019). The degree of hydrolysis can increase with the temperature to the point that HPAM becomes unstable in the solution and precipitates due to complexing with the divalent cations in the brine, especially the calcium ion. The rate of chain scission of polymer backbone also becomes much more pronounced at a temperature of 250°F, which causes the polymer to decompose via intramolecular imidization of amide groups, thereby increasing the polymer instability in solution and resulting in its precipitation. These mechanisms of polymer degradation have been discussed in detail in the study done by Xiong et al. (2018).

Figure 3.2 Effect of temperature and polymer concentration on deposit rate on carbon steel (CS), stainless steel (SS) tube and copper (CU)

3.4.1.2 Effect of tube material on fouling tendency

The influence of the tube material on deposit rate at different skin temperatures can also be seen in Fig. 3.2. As shown, for all tested scenarios, the deposit rate on stainless steel tube is less than carbon steel tube. The copper tube and stainless steel tube exhibit nearly similar deposit rates at the temperatures 165°F and 200°F when the polymer concentration is 0ppm; however, when polymer concentration is 800ppm the stainless steel tube shows a relatively higher deposit rate than copper. For the carbon steel tube, the deposit rate at all skin temperatures, are generally high even when the polymer concentration is 0ppm in the solution. In contrast, the stainless steel tube exhibits much lower deposit rates when polymer is absent in the solution at the temperatures of 165°F and 200°F. The copper tube shows nearly equal rates for deposit rates for 0ppm and 800ppm polymer concentration when the temperatures are 165°F and 200°F. Kazi et al. (2010 and 2015) found that a combination of factors including surface roughness and thermal conductivity influence the mineral fouling in different heat exchanger surfaces. The common thermal conductivities for stainless steel, carbon steel and copper are 16 W/m °C, 45 W/m °C and 386 W/m °C respectively (Touloukian et al. 1970). Higher thermal conductivities lead to higher mineral fouling rates (Kazi et al. 2010 and 2015). The roughness values for copper, stainless steel and carbon steel are 0.0015 mm, 0.03mm and 0.15mm to 1 mm respectively (Neutrium 2021). The higher roughness values lead to a greater number of sites for the particles to deposit and foul the tube. Additionally, the carbon steel tube is prone to redox reactions whereas the stainless steel tube (which contains chromium) and copper are resistant to such reactions (CAI YiDong et al. 2010). The redox reactions increase the tube roughness which creates additional fouling sites on the carbon steel tube surface. A combined effect of surface roughness and thermal conductivity would determine the severity of fouling in each material; however, the extent of influence of the two

factors could be different with one of the factors playing a dominant role in a particular experimental condition. The thermal conductivity of copper is significantly higher than stainless steel and carbon steel which probably leads to higher deposit rates for copper at 0 ppm (mineral fouling only) polymer concentration. However, as the experiment proceeds and carbon steel gets oxidized its surface roughness increases which would cause maximum deposit rates on carbon steel tube overall while the stainless steel tube having lower values of both thermal conductivity and roughness resulting in lowest deposit rates at 0ppm polymer concentration for all skin temperatures among the three tube materials. The polymer which is a non-mineral foulant has a different influence on the deposit rates as the deposit rates for stainless steel at 165°F and 200°F were higher than copper which could probably be due to the surface roughness playing a dominant role below the cloud point temperature, however once the temperature goes beyond the cloud point temperature the polymer starts degrading and now possibly the thermal conductivity becomes the controlling factor for deposit rates as the copper tube showed the highest deposit rates amongst the three materials followed by carbon steel and stainless steel.

3.4.1.3 Effect of Presence of Polymer on Fouling Tendency in Deposit Test

The effect of the presence of polymer on deposit rate can also be seen in Fig. 3.2. As shown, for all temperature scenarios for all three tube materials when the polymer was present (800 ppm) in the testing solution, the deposit rate was higher than the deposit rate for the case when polymer is absent (0 ppm) in the testing solution. This can be attributed to the fact that the polymer molecules can combine with the divalent cations present in the solution and precipitate. This phenomenon increases with the increase in temperature as described above which leads to higher deposit rates in the presence of polymer in the solution as a larger number of molecules are available to deposit on to the tube surface.

3.4.2 Cloud point measurement

As shown in **Fig. 3.3**, a cloudy appearance was first observed at a temperature of 230°F. This means that the temperature at which the solution exhibits cloud point should be between 220°F and 230°F. Based on the results of the cloud point experiment, the polymer solution remains stable at temperatures below the cloud point, but once the temperature is increased above the cloud point, the solutions start becoming unstable and leading to precipitation, as can be seen in **Fig. 3.3 (c)**.

Figure 3.3 (a) Freshly prepared polymer solutions before a test, (b) Polymer solutions after heating at 220°F for 24 hours, and (c) Polymer solutions after heating at 230°F for 24 hours

The findings of this work show that temperature has a significant influence on the hydrolysis of the polymer which is similar to the findings of Ryles (1988). Polymer hydrolysis increases at elevated temperatures, which increases the carboxylate content in the solution making the polymer prone to precipitation by combining with divalent Ca^{2+} cations from the brine. The results of the cloud point experiment are consistent with the findings from the deposit tests as it can be seen that at the temperatures of 165°F and 200°F which are below the cloud point, the fouling tendency is not very severe. In contrast, there is an abrupt increase in terms of deposit rate when the tube skin temperature is 250°F which is above the cloud point temperature as the polymer hydrolyzes to a higher extent and combines with Ca^{2+} cations to precipitate and aggravate the fouling tendency on the heating tube. This led Dhaliwal et al. (2020) to conclude that the cloud point could be a critical factor that needs to be considered when operating the heat exchangers on the field pilot as below the cloud point the polymer may not aggravate fouling but above the cloud point temperature, the polymer can aggravate the fouling issues in the heat exchangers.

3.4.3 DSL Test Results

3.4.3.1 Effect of Skin Temperature on DSL tests.

The influence of skin temperature on fouling has been shown in **Fig. 3.4** to **Fig. 3.11**. In dynamic tests the two primary parameters that influence fouling are tube velocity and the residence time. Clearly, both cannot be concurrently satisfied in any lab scale flow loop; however, we believe that residence time is the most critical and a rigorous parameter to match with field conditions. Accordingly, the flow rate for these experiments was determined by calculating the residence time of fluids on the field pilot. Based on the flow rate and heat exchanger tube length data obtained from the operators, it was determined that the produced fluids on the field pilot spend 1.194 minutes in the heat exchangers. Since residence time is the time the fluids come in contact with

the hot tubing, it is imperative that the same residence time is maintained in the lab experiments. To meet this criterion, based on our experimental setup, a flow rate of 3.94 mL/min was determined to obtain the same residence time (1.194 minutes) for fluids as on the field pilot. Based on the extensive results obtained in our previous study (Dhaliwal et al. 2020) where it was found fouling issues in the absence of polymer are not of practical importance, the project team decided to concentrate the majority of experiments on scenarios where the polymer is present in the testing solution. For comparison, some tests were still done for conditions when polymer concentration is 0 ppm in the solution. **Fig 3.4** shows the result of the DSL experiment conducted at a skin temperature of 350°F and a polymer concentration of 0ppm that is pure brine. During the experiment, there was no fluctuation in the differential pressure across the tubing and based on the results of the previous work (Dhaliwal et al. 2020) it was decided to run the experiment only for a period of 4 hours. **Fig 3.5** shows the result of the DSL experiment conducted at a skin temperature of 165°F and a polymer concentration of 0 ppm with a fluid residence time of 1.194 minutes. During this experiment, no fluctuation or peaks were observed in the differential pressure, and therefore, the test was stopped after running for 4 hours. Based on the above two described results and results of the static deposit test and cloud point experiment, it can be concluded that at 0 ppm polymer concentration, there will not be any severe fouling issues in the heat exchangers at any skin temperature that may disrupt the production system.

Fig. 3.6. shows the result of the DSL experiment conducted at a skin temperature of 350°F and a polymer concentration of 400ppm. A sudden rise in differential pressure was seen at about 68 hours after the start of experiment and the pressure remained high constantly. The tubing was blocked, and the experiment was stopped completely to prevent any bursting due to pressure buildup. This showed that there is a danger of fouling in the heat exchangers if they are operated

at 350°F. As described in the text earlier, the cloud point was determined to a critical temperature above which there could be severe fouling issues and as 350°F is well above the cloud point temperature, fouling issues can be expected if the polymer is present in the solution.

Figure 3.4 Differential Pressure Data for 350°F at polymer concentration of 0ppm

Figure 3.5 Differential Pressure Data for 165°F at polymer concentration of 0ppm

Figure 3.6 Differential Pressure Data for 350°F at polymer concentration of 400ppm

Fig. 3.7 shows the result of the DSL experiment conducted at a skin temperature of 250°F and a polymer concentration of 400ppm. A sudden rise in differential pressure was seen at about 174 hours after the start of the experiment. The tubing was blocked, and the experiment was stopped completely to prevent any tubing bursting due to pressure buildup. There was an increase in the time it took for the tubing to be blocked as it took 174 hours at 250°F compared to 68 hours at 350°F, which confirms that in dynamic flow conditions, the tube skin temperature will be a crucial parameter affecting fouling in heat exchangers as increasing the heating skin temperature reduces the tube blocking time in DSL tests. At 250°F which is significantly lower than 350°F the amount of polymer and mineral salts precipitating are less and thus it takes a longer time for tube blocking at 250°F in comparison to 350°F. The static deposit test for stainless steel has shown that at a skin temperature of 250°F, there would be significantly more amount of fouling than at lower skin temperatures of 165°F and 200°F when the polymer is present in the solution. The cloud point experiments have also demonstrated that above 230°F, the polymer would degrade and precipitate out of the solution. The results obtained from these different experiments prove that at above the cloud point temperature, there will be severe fouling issues in both dynamic and static tests, and it will be an unsafe temperature to operate the heat exchangers on the field pilot.

Figure 3.7 Differential Pressure Data for 250°F at polymer concentration of 400ppm

Fig. 3.8 and **Fig. 9** show the results of the DSL experiments conducted at a skin temperature of 200°F and 165°F, both at a polymer concentration of 400 ppm. In both experiments, the differential pressure across the ends of the tubing remained stable without any sudden peaks. The fluid output was also at the constant flow rate without any fluctuation. These two experiments were run for a longer duration of time than the 250°F experiment to check if the skin temperature of 200°F and 165°F can cause fouling issues at similar flow conditions in the same amount of time. An additional experiment was done simultaneously with these two experiments. This experiment was done in a similar manner as the cloud point test as described by Dhaliwal et al. (2020). Polymer solutions of 160 ppm and 400 ppm concentration were prepared in brine. The solutions were transferred to transparent glass bottles and placed in the oven at the same temperature environment as the DSL test (165°F and 200°F). The solutions were constantly heated for the same period of time as the duration of the DSL experiments. After the DSL experiment was stopped, the cloud point experiment glass bottles were also taken out, and picture was taken for the 200°F and 165°F temperature and are shown in **Fig 3.10** and **3.11**, respectively. There was no cloudiness seen, and

the solutions remained perfectly transparent. This shows that the polymer solution would be stable at low skin temperatures for extended periods of time and polymer-induced fouling will not be an issue. The DSL experiments showed that at temperatures below the cloud point, the fouling due to polymer does not appear to be a severe issue in the heat exchangers to cause major damage to the equipment in a time period taken by temperatures above the cloud point to foul the equipment severely.

The static deposit test at 165°F and 200°F show that there will be some fouling on the stainless steel tube surface at all temperatures; however, on comparison with DSL tests, it can be said that the fouling will not be severe enough to cause operational problems in dynamic flow conditions in the field heat exchangers. It should be noted that irrespective of the temperatures, especially below the cloud point, prolonged operations of a given heat exchanger will lead to some mineral fouling that may be combined with likely polymer degradation. However, from a practical standpoint, as far as the polymer pilot is concerned, it is important to point out that this fouling is typical and time-delayed. In contrast, operations at or above the cloud point will lead to rather rapid fouling and stalling the downstream end of the field pilot. Therefore, the residence time is of prime importance in these operations, and that is the reason the authors believe for all practical purposes, if the skin temperature of the heat exchanger tubes is kept below the cloud point and with a similar brine composition, then there will not be disruptions in the processing of produced fluids.

Figure 3.8 Differential Pressure Data for 200°F at polymer concentration of 400ppm

Figure 3.9 Differential Pressure Data for 165°F at polymer concentration of 400ppm

(a)

(b)

Figure 3.10 (a) 160 ppm polymer solution after heating for 250 hours at 200°F (b) 400 ppm polymer solution after heating for 250 hours

(a)

(b)

Figure 3.11 160 ppm polymer solution after heating for 250 hours at 165°F (b) 400 ppm polymer solution after heating for 250 hours

3.5 Conclusions

Based on the results in this study obtained from the multi-experimental approach taken, the following general conclusions have been made:

1. The presence of polymer significantly worsens the fouling in both carbon steel and stainless-steel tube; however, the influence in stainless steel tube is much more pronounced at a higher skin temperature of 250°F.
2. Stainless steel tube performs much better than carbon steel in both the scenarios of polymer concentration of 0ppm as well as 800ppm.
3. There exists a critical temperature, called the cloud point above which polymer becomes unstable in hard brine and begins to precipitate.
4. The Dynamic Scale Loop tests confirm the findings of the other experiments conducted in a dynamic flow environment as well. In situations with similar residence times and water chemistry, polymer induced fouling will be much more severe at higher tube skin temperatures of 250°F and 350°F whereas the system can be safely operated at the lower tube skin temperatures of 165°F and 200°F.
5. Fouling will also occur even at a lower skin temperature of 165°F. However, the severity of polymer induced fouling at lower skin temperatures will be significantly reduced and the production systems on field will not need any major revamp to cope up with the scale and fouling management.
6. Based on the experimental data collected in this work, and the polymer breakthrough, the processing conditions of skin temperature of 200°F and residence time of 1.194 minutes are deemed safe for operation.

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Chapter 4 Conclusions and Recommendations

4.1 Conclusions

This study reveals the influence of polymer on fouling in heat exchangers and the influence of various operating parameters on the severity of fouling issues. This study also provides explanations behind the potential fouling issues and present solutions to these issues which could help prolong the equipment life and provide a future basis for other authors to continue the work.

The following conclusions were drawn from the results of this work:

- 1) Fouling tendency in heat exchangers is affected by skin temperature, polymer concentration, and tube metallurgy.
- 2) The presence of polymer in the solution does not influence fouling issues on a copper tube at a skin temperature of 165°F.
- 3) At a skin temperature of 165°F, carbon steel and stainless-steel tubes experience aggravated fouling issues when the polymer concentration is 800ppm in comparison to when the polymer concentration is 0ppm.
- 4) The fouling tendency on copper is enhanced by polymer at skin temperatures of 250°F and 350°F. The fouling tendency also increased with polymer concentration in the solutions.
- 5) There exists a critical temperature for polymer brine solutions which is directly related to the cloud point of the solution. This temperature is a crucial factor to determine the occurrence of fouling.
- 6) In the DSL tests, tube blocking was observed at temperatures above cloud point at a significantly faster rate and the blocking time decreased as the tube skin temperature was increased. At temperatures below the cloud point, even though no blocking was observed, but based on the deposit rate test it can be said that there is fouling at all temperatures.

Additionally, for copper tubes following observations were also made –

- 7) The heating efficiency of the heating tube was reduced significantly at the temperatures above the cloud point.
- 8) The polymer induced fouling has a different morphology and structure as shown by the ESEM results.
- 9) X-Ray Diffraction confirms that presence of polymer worsens mineral fouling.

A combined conclusion based on the different type of experiments conducted in this study and the results obtained is – fouling will occur at all skin temperatures, polymer concentrations, tube material and residence time of fluids. However, for all practical purposes by having an optimum skin temperature for the brine-polymer fluids the extent of polymer induced fouling can be minimized. This will prevent the relatively frequent workover of heat exchangers, thereby saving significant maintenance costs to the operator.

4.2 Recommendations

Based on the research documented in this thesis, the following tasks are recommended for future work-

- 1) The results of this study suggest to operate the heat exchangers below a temperature of 230°F, therefore the inhibition of polymer induced fouling at high temperatures using additives can be studied to achieve a higher operating temperature. That would allow better water oil separation and an overall lower economic costs with a reduced equipment footprint.
- 2) Characterization of deposit formed using other methodologies for better selection of additives

Modeling studies can be carried out to predict scaling index by incorporating the polymer in a software package to predict system behavior.

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