

**APPLICATION OF POLYMER FLOODING IN HIGH SALINITY CONDITIONS IN  
UZEN FIELD**

by

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## **ORIGINALITY STATEMENT**

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## **ABSTRACT**

This research investigates improved oil production techniques for high-salinity oil reserves focusing on Uzen Field in Kazakhstan. According to standard primary and secondary recovery practices current operations in mature reservoirs recover only limited quantities of the initial oil before EOR techniques become essential. Polymer flooding represents an advanced EOR method which offers successful viscosity increase for water injection which leads to superior sweep efficiency together with reduced water output.

The extreme salinity of formation water in the Uzen Field (TDS reaches 60,000 ppm) creates conditions that degrade polymers and decreases their viscosity. Through lab experiments developed for real reservoir conditions this research thoroughly screened polymer materials utilizing hydrolyzed polyacrylamide (HPAM) as the main focus. The study performed laboratory work by conducting tests for rheology and thermal stability and static adsorption and injectivity testing. Additionally, ion modification experiments were performed to determine the effects of selectively adding  $\text{Na}_2\text{SO}_4$ ,  $\text{CaCl}_2$ , and  $\text{MgCl}_2$  on polymer performance without altering the overall salinity of the formation water.

As evidenced through experimental testing appropriate control of ions results in major improvements of polymer stability alongside maintaining viscosity levels. The addition of  $4\times \text{Mg}^{2+}$  ions produced better injectability by generating elevated resistance factors and decreased viscosity loss during core flooding assessments. A high  $\text{Ca}^{2+}$  content affected the repeated configurations of polymer chains which caused viscosity levels to deteriorate. The addition of measured  $\text{Na}_2\text{SO}_4$  amounts that rose sulfate concentration moderately strengthened polymer performance yet raising the amount too high decreased viscosity by damaging the polymer chain structure. Multiple studies including Jouenne (2020) and Saha et al.(2021) and Hu et al.(2024) confirm that achieving the right balance of ions is essential for optimizing polymer flooding operations under high-salinity conditions.

Field research conducted at Daqing, Shengli, Mangala, Pelican Lake, and Burgan locations around the world validates how polymer flooding solves high water cut conditions in heterogeneous reservoirs. The examples show that proper polymer choice together with customized ion control strategies result in significant enhancement of oil recovery when dealing with challenging extreme reservoir conditions.

The study introduces an effective method to enhance polymer performance which merges laboratory testing methods with ion modification techniques. The obtained results help understand polymer flooding techniques while providing essential discoveries for enhancing Uzen Field oil extraction. Follow-up pilot testing combined with sustained monitoring should be conducted to improve polymer formulation methods and injection practices leading to efficient sustainable EOR operations.

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## 1. INTRODUCTION

The pursuit of energy resources to cater to the world demand draws a general picture of the necessity to exploit oil recovery from the subsurface to the maximum. Conventional primary and secondary recovery methods bring out only a fraction of the original oil in place, so Enhanced Oil Recovery (EOR) techniques have come to play a pivotal role.

Recovery of oil from reservoirs with high water cut poses important challenges presented in these formations that lead to decreased production efficiency and increase in operational costs.

Reservoirs that send out a big share of water compared to oil become less efficient in both output and cost, making oil production more difficult. When wells draw water from different sections of the reservoir, problems such as water coning and water production from high permeable sections of the reservoir makes the producer water cut very high. Understanding these water problems helps us develop ways to keep oil flowing better from such reservoirs. To profitably maintain aging oil fields, we must create advanced EOR methods that improve oil production efficiency.

Operating in established or marginally profitable oil fields becomes challenging when too much water runs with the oil, reducing the amount of value oil produced and increasing the cost of processing and disposing of the water. Strict oil and gas production regulations need less water flow because greater rates hasten corrosion and equipment degradation, requiring businesses to halt operations more frequently to address problems. When companies must follow stringent guidelines for disposing of the water they draw from the reservoir, the issue is made worse, particularly in areas where these rules are severe. In order to boost oil production, preserve improved reservoir performance, and reduce costs, oil operators strive to reduce the amount of water in their fluids. According to Alvarado and Manrique (2010) and Bai et al. (2015), field lifespan and financial performance may both be improved by reducing the water flow from older oil fields.

We classify the various techniques used by researchers and operators to reduce water cut into two primary strategies: mechanical systems and chemical treatments. Chemicals like relative permeability modifiers and polymers/gels are used to change how fluids travel and flow in reservoirs. To stop water from entering the wellbore, we use mechanical tools like packers, well recompletions, and downhole water shut-off devices to block water production zones or seal off water-prone intervals. Real-world experiences at the Daqing Oilfield have demonstrated that

polymer flooding can substantially enhance oil recovery and reduce water cut percentages. For example, studies by Sun and Sheng (2002) and Sheng (2011) have documented that the application of polymer flooding in Daqing not only improved sweep efficiency but also helped to decrease the amount of water produced with the oil. The authors note that these investigations reinforce the utility of including high molecular weight polymers into EOR schemes to improve mobility controls and other recovery activities in heterogeneous reservoirs. Like this, field experiments in the Permian Basin have shown that mechanical water blocking can successfully control water production. This has been shown by field case studies following research by Kirkpatrick et al. (2003) to significantly restrict water flow through high permeability channels. In more complicated reservoir settings characterized by water breakthrough, channels can be selectively blocked, which specifically helps operations control the water cut during recovery and increases oil production efficiency. All together they underline that both chemical (polymer flooding) and mechanical (water blocking) intervention can contribute an important role to improve oil recovery.

Ma et al. (2019) focuses on innovative strategies for managing high water cut in oil fields, particularly through the optimization of water injection techniques and the reconfiguration of flow fields in line pattern wells. The study introduces methodologies for accurately determining the injection quantities in stratified injection wells, aiming to improve water flooding efficiency and stabilize oil production. The study presents a comprehensive approach, combining detailed reservoir characterization with advanced injection and production strategies to enhance oil recovery in high water cut stages.

One of other ways to control high water cut is improved Downhole Water Sink/Drainage (DWS) system. Traditional methods, such as partial perforation and chemical injections, had limited success in mitigating water breakthrough in reservoirs. The DWS system, a dual completion method allowing simultaneous oil and water production, was developed to address these challenges (Qin et al., 2017). By designing a system that produces water through a hollow sucker rod and oil through a tubing string, the improved DWS system effectively reduced water cut and increased oil production in pilot wells. This approach demonstrates significant potential for managing high water cut issues in similar geological.

The study discussed by Al-Hulail et al. (2017) explores the effectiveness of Relative Permeability Modifiers (RPM) as a chemical treatment for reducing water production in high-water-cut oil wells. The RPM system, a hydrophobically modified water-soluble polymer, is

adsorbed onto the rock surface, altering its characteristics to selectively reduce water's effective permeability while facilitating increased hydrocarbon flow. Laboratory experiments on synthetic and formation cores from a Central Arabia field showed significant reduction in water permeability and enhancement in oil permeability, demonstrating the RPM system's potential for water control in similar geological settings.

Jaramilo et al. (2010) explores the use of Viscous Disproportionate Permeability Modifier (VDPM) fluids in high-water-cut oil wells to improve oil production and reduce water cut. The study reports on the application of VDPM fluids in conjunction with acid treatments to selectively enhance oil flow while minimizing water production. Initial field applications demonstrated that the treatment could significantly increase oil production and reduce water cut, offering a cost-effective method for enhancing recovery in mature fields with high water challenges. This approach presents a promising alternative to traditional methods, combining chemical treatment with physical diversion techniques to address the high-water-cut issue effectively.

Elverhoy (2018) explores Autonomous Inflow Control Valves (AICVs) as a novel solution for optimizing oil production in wells by minimizing unwanted water and gas production. Utilizing AICVs leads to a more balanced inflow along the horizontal well sections, effectively reducing water cut and gas-to-oil ratios. Through simulations, AICVs demonstrated the capability to significantly lower water cut from 60% to 29% in medium oil reservoirs and reduce gas breakthrough in light oil reservoirs, thereby enhancing oil recovery while addressing environmental concerns related to produced water and flared gas.

The study by Chiappa et al. (1998) investigates the effects of polymer adsorption on siliceous surfaces for water-cut control in oil recovery. It emphasizes the crucial role of electrostatic interactions between polymers and rock surfaces, influenced by rock lithology and brine composition. The study finds that polymer adsorption can significantly reduce water permeability, thereby enhancing oil recovery. It also notes the importance of clays in the adsorption process and the varying effects of brine salinity and ionic strength on polymer effectiveness. This research contributes to the optimization of water control treatments in oil wells. Another study done by White et al. (1973) elaborates on the success of employing polymers to mitigate water production in high-water-cut oil wells, particularly in the Mid-Continent region. It highlights how polymers, through mechanisms such as viscosity, viscoelastic effects, and residual resistance, selectively reduce water permeability without significantly affecting oil flow. This

treatment has been applied in nearly 200 wells, resulting in a significant decrease in water-oil ratios (WOR) by 60 to 90 percent in most cases, alongside considerable increases in oil production in many instances.

Chemical EOR techniques remain necessary to boost oil recovery even where polymers work well in reducing water production and overall water content. These techniques help make precise changes that cut down too much water production and improve oil production efficiency. They make treatments using both polymers and gels to handle specific conditions. They can manage difficult situations in oil extraction such as water coning, high contrast between permeabilities, and reservoir heterogeneity across the field. The application of chemical methods is often driven by the need to optimize the mobility ratio and control unwanted water flow while maintaining oil production efficiency. According to research by Seright et al. (2003), field-scale applications demonstrate how these methods may greatly enhance oil recovery, especially in established or water-dominated reservoirs. In addition to being essential in stand-alone treatments, these chemical techniques provide the basis of hybrid EOR techniques such as ASP floods.

Real-world field studies have long demonstrated that many mature oil reservoirs struggle with high water cut issues during waterflooding operations.

Several mature fields in Kazakhstan have faced the same type of water management issues, with some reservoirs suffering water cuts of almost 90% in long waterflooding operations (Dauyltayeva et al., 2023). The recurring problem of high-water cuts in these fields emphasizes the necessity of developing advanced EOR techniques. This situation provides a compelling rationale for focusing on the Uzen Field—a sandstone reservoir that, despite prolonged waterflooding for pressure maintenance, still suffers from extremely high-water production. These challenges motivate the application of Polymer flooding to improve sweep efficiency and oil recovery under harsh conditions.

This thesis focuses on the application of polymer flooding to enhance oil recovery in the Uzen Field, Kazakhstan, a sandstone reservoir experiencing high water cut issues and has been undergoing waterflooding as a method for pressure maintenance since the early stages of its development. Despite these efforts, the field has experienced a field-wide water cut reaching up to 90%, which severely impacts the efficiency of oil production and increases operational costs. (Yerniyazov et al., 2023)

To address this challenge, a systematic study was conducted to evaluate the potential of polymer flooding, specifically using Hydrolyzed Polyacrylamide (HPAM) polymers, to enhance oil recovery by reducing water cut. The study focused on selecting the optimum polymer based on various criteria including viscosification, thermal stability, adsorption tendency, and injectivity. This approach aimed at improving oil production by controlling water-cut effectively in the Uzen Field.

The field's fluid and rock properties, such as waxy oil, sandstone lithology, and permeability and porosity within the range of 100–500 md and 24–27% respectively, make it analogous to other fields where polymer flooding has been successfully implemented. The crude oil in the Uzen Field has a density of around 0.80 g/cc, and the viscosity of the oil is 4.5 cp at a reservoir temperature of 63°C. Additionally, the oil contains 13–15 wt% asphaltenes and 20–28 wt% paraffin content. The FW of the Uzen Field has a high salinity of 120,000 ppm with a high concentration of monovalent and divalent ions, posing additional challenges for EOR techniques.

In our previous study, "Polymer Screening for Efficient Water Cut Reduction in a Sandstone Oilfield in Kazakhstan" (Yerniyazov et al., 2023), we designed a polymer flooding process based on the use of Caspian seawater (CSW) for polymer screening. However, it was later determined that CSW was not available in sufficient quantities to support large-scale field applications. As a result, we shifted our focus to using high-salinity FW from the Uzen Field as the solution brine for polymer flooding.

This transition brings new set of challenges. Incorporation of high salinity FW into polymer can precipitate polymer components, which prevent polymers from performing as well as they should in reducing oil water interfacial tension and modifying rock wettability effectively. In addition, the raised salinity levels may result in higher chemical consumption, operation cost, and greater process overloads. Enhanced scavenging of contaminants may occur between high salinity water and reservoir rock with subsequent porosity loss and permeability decrement resulted from formation damage and poor oil recovery efficiency.

To address these issues, the current research is focused on the efficiency of polymer flooding and refinement of the polymer selection process under high salinity conditions. Considering what may be a novel perspective on EOR to the Uzen Field, where CSW is unavailable and high salinities are prevalent, we aim to explore polymer performance in FW.

This research studies the Uzen Field's response to polymer flooding and compares it to similar fields and dissects what is a good practice to increase the oil recovery, what is a challenge and what can be a solution to the problem.

The direction of work is towards two main areas to deal with the challenges posed in the above. In the first step we have conducted an extensive selection of best performing polymer under high saline conditions. The reason behind choosing FW was the limitation of SW, so at the first step we designed the polymer for FW. The critical parameters in this selection process include rheology and adsorption behavior in FW, along with thermal stability. We have paid second attention to the modification of the formation brine itself, for example, from the change of concentration of calcium, magnesium, and sulfate. We decided to evaluate the improvement in the performance of the polymer by adjustment of the FW. It was done by ions adjustment, which is cheap and does not need fresh water.

The research focuses on overcoming limitations of high salinity conditions in the Uzen Field by combining a careful selection of an optimum polymer with targeted brine modification. Also, the objective of this integrated approach is not only to enhance the economic performance of polymer flooding but also to realize improved water production and maximum oil recovery in mature reservoirs.

## 2. LITERATURE REVIEW

### 2.1 Overview of Polymer Flooding

#### 2.1.1 General Description of Polymer Flooding

In mature reservoirs that normally extract only 30% or 35% of the original oil in place through conventional primary and secondary recovery methods, EOR techniques have been critical to capturing the rest of the oil remaining in the reservoir. Among the various EOR methods, polymer flooding has emerged as an effective strategy to improve oil recovery by increasing the viscosity of the injected water, thereby enhancing sweep efficiency and reducing the water cut. Polymer flooding has been shown in field applications to enhance oil production and reduce production of water. These real-world examples underscore the value of polymer flooding in heterogeneous reservoirs with high water cut challenges.

The role of polymer flooding in EOR lies primarily in its ability to alter the mobility ratio between the displacing water and the displaced oil. Polymers increase the viscosity of the injected water, thus creating a more uniform displacement front, contributing to a reduction of the likelihood of fingering and channeling in the reservoir. This mechanism is essential for ensuring that the injected fluid can effectively sweep the oil toward production wells. The studies by Alvarado and Manrique (2010) have shown that such mobility control directly affects the efficiency of the recovery and that the economic benefits were demonstrated for reducing water production by optimized polymer flooding as done by Bai et al. (2015). Figure 1 illustrates the general impact of increased polymer viscosity on enhancing sweep efficiency in field applications.

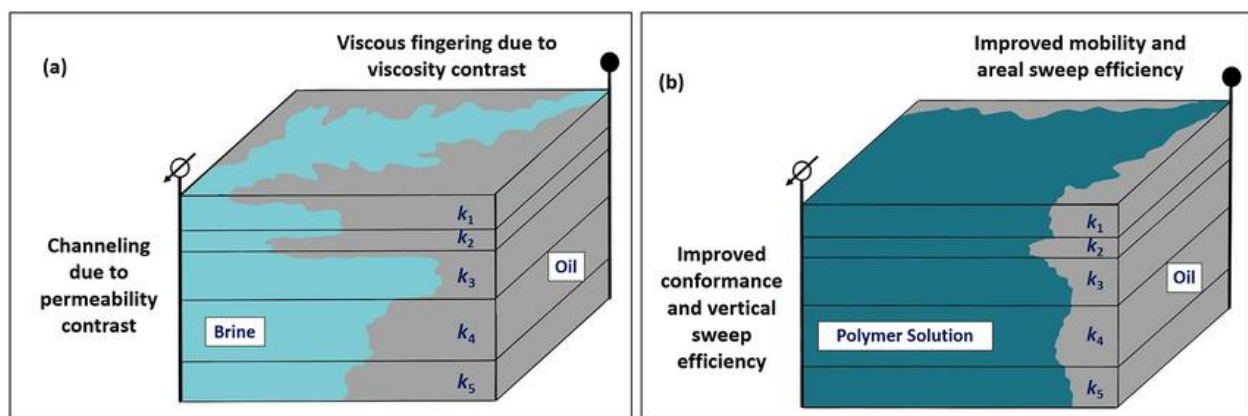


Figure 1. Schematic of Macroscopic Sweep Efficiency Enhancement by Polymer Flooding. (a) Viscous fingering and channeling in heterogeneous formations reduce sweep efficiency; (b) Polymer injection improves fluid mobility and conformance (Zeynalli et al., 2023)

With polymer flooding as a chemical EOR technique operators introduce polymer solutions to enhance sweep efficiency in oil reservoirs through increased water viscosity. Polymer flooding performance is highly dependent on reservoir heterogeneity, permeability, temperature, and water salinity.

Recent developments in polymer flooding technology focused on optimizing the composition and concentration of the polymers for better efficiency but with reduced environmental impact and operational costs. Gbadamosi et al. (2022) emphasize the need for a choice of polymers, as well as the conditions of their application in an appropriate EOR process, and describe the method of polymer flooding, evaluating the challenges and opportunities of the method in the context of different reservoir conditions.

The addition of polymers improves the viscosity of the displacing fluid, optimizing the mobility ratio between the displacing fluid and the displaced oil. This viscosity enhancement leads to a more uniform displacement front, minimizing fingering phenomena and thereby augmenting sweep efficiency across the reservoir.

Quantitative aspects crucial to understanding these processes must be studied after clearing up basic principles behind polymer flooding operations. The next subsection presents the core math and principles of mobility control that explain how polymer viscosity increases improve sweep efficiency.

## 2.2 Fundamental Concepts and Equations

Several important formulas are central to understanding and optimizing polymer flooding, the mobility ratio ( $M$ ) is defined as the ratio of the mobility of the displacing fluid to the mobility of the displaced fluid. It is a critical factor in determining the efficiency of the flood.  $M$  less than 1 is generally desired for stable displacement and is given by:

$$M = \frac{(k_{rD}/\mu_D)S_D}{(k_{rd}/\mu_d)S_d}, \text{ where:}$$

$k_{rD}$  - displacing phase's relative permeability;

$\mu_D$  - displacing phase's viscosity;

$k_{rd}$  - displaced phase's relative permeability;

$\mu_d$  - displaced phase's viscosity;

$S_D$ - displacing phase saturation behind the displacing phase front;

$S_d$  - displaced phase saturation before the displacing phase front.

When the  $M$  exceeds 1, sweep efficiency decreases, leading to unfavorable displacement and the occurrence of fingering. Conversely, with  $M \leq 1$ , there's an enhanced sweep efficiency and more favorable displacement conditions. This concept is visually illustrated in Figure 2. This rationale underpins the use of polymers in mobility control, as they effectively reduce the mobility ratio by augmenting the viscosity of the water phase, which is the displacing fluid.

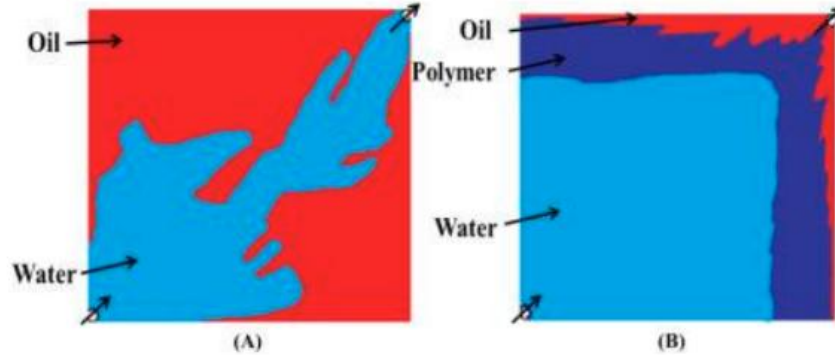


Figure 2. Mobility control before (a) and after (b) polymer injection. (Li et al., 2021)

Sweep efficiency is an indicator of how effectively the injected fluid covers the reservoir. It can be further divided into areal sweep efficiency ( $E_a$ ) and vertical sweep efficiency ( $E_v$ ), with total sweep efficiency ( $E_t$ ) being the product of the two.

Another key parameter is the residual resistance factor (RRF). It measures permeability reduction which results from polymer adsorption and retention. It is expressed as:

$$RRF = \frac{k_{\text{initial}}}{k_{\text{post-flood}}}$$

A high RRF indicates that a significant portion of the polymer is retained within the formation, which can be beneficial for diverting subsequent water floods but may also increase injection pressures.

The pseudoplastic nature of polymer solutions follows power-law relationships to describe their non-Newtonian behavior. The power-law equation:

$$\mu_{\text{apparent}} = K \times \gamma^{n-1}$$

Where  $\mu_{\text{apparent}}$  is apparent viscosity,  $\gamma$  is shear rate,  $K$  is the consistency index and  $n$  is flow behavior index ( $n < 1$  indicating shear-thinning behavior). The dynamic characteristics of

polymer solutions depend on shear-dependent viscosity to maintain proper mobility ratios in heavy oil reservoirs by adjusting to changing flow conditions.

These fundamental concepts provide essential quantitative basis for polymer flooding design. We will now examine HPAM polymers as the principal polymer component within ASP flooding treatments while using previous understanding of mobility control fundamentals. The following subsection discusses the advantages and challenges associated with HPAM, setting the stage for understanding their role in EOR under challenging reservoir conditions.

### **2.3 HPAM Polymers in EOR: Performance and Challenges**

HPAM are widely used as the polymer in chemical enhanced oil recovery (cEOR) processes for their capacity to increase the viscosity of flooding solutions. The viscoelastic properties of HPAM are crucial for the success of EOR operations, attracting considerable research focus.

Nonetheless, HPAM polymers encounter significant challenges, including thermal and chemical degradation under high-temperature and high-salinity (HTHS) conditions found in many oil reservoirs. Such degradation can markedly diminish their utility in EOR applications, affecting overall recovery efforts.

Gbadamosi et al. (2022) provided a comprehensive review on the application of polymers for EOR, elucidating the mechanisms and evaluating various polymer types, including synthetic and natural polymers. Their review underscores the pseudoplastic behavior of most polymers under shear forces, highlighting HPAM's prominence due to its balance of performance and cost-effectiveness

A complete introduction to polymer flooding and its basic approach is now followed by a study of how polymer solutions perform by themselves. The next section focuses on understanding how polymer performance is influenced by key parameters including viscosity along with thermal stability and adsorption effects particularly in context of water chemistry within highly saline formations.

## **2.4 Influence of Water Chemistry on Polymer**

### **2.4.1 Impact of Salinity, pH, and TDS**

The properties of water solutions, notably salinity and pH, play crucial roles in the effectiveness of polymer flooding techniques. These factors impact the behavior of injected chemicals, their interaction with reservoir rocks and fluids, and ultimately, the overall success of oil recovery operations.

Salinity significantly influences the performance of polymer flooding. High salinity levels can affect the solubility and optimal functioning of polymers used in the process. Guo et al. (2015) highlighted the importance of adjusting the salinity levels of the injection water to enhance the recovery rates achievable through polymer flooding.

The pH of the water solution influences the ionization state of the polymer's functional groups and the surface charge of the rock, which can affect polymer adsorption and overall oil recovery efficiency. Adjusting the pH can alter the rock surface charge, enhancing the adsorption or repulsion of surfactant molecules, thereby improving the mobilization of oil. Sagyndikov (2022) compared polymer and ASP flooding, noting that the careful management of pH and salinity in polymer solutions could significantly enhance oil recovery, especially in reservoirs with complex mineralogy.

Polymer flooding performances decline when injecting water containing large amounts of calcium and magnesium ions which comprise the bulk of water hardness content. The interaction of pumpable ions with polymer molecules results in precipitation together with decreased viscosity that affects the performance of the flooding process.

Moreover, the concentration of total dissolved solids (TDS) in the injection water plays a role in the osmotic pressure differences across the reservoir, which can influence fluid flow and the mobilization of oil. Elevated levels of TDS can also affect the solubility and stability of the polymer solutions making it necessary to tweak the formula to ensure its effectiveness. Chavan et al. (2019) provided a comprehensive review on low-salinity-based EOR, establishing screening criteria including the impact of TDS on EOR benefits, underscoring the importance of salinity range for effective EOR strategies.

The specific ionic composition of the water, beyond general salinity levels, plays a critical role in polymer flooding. The presence of specific ions, such as sulfates, chlorides, and bicarbonates, can influence the chemical reactions between polymer solutions and reservoir rock,

affecting polymer stability and overall oil recovery efficiency. The adjustment of ionic composition to optimize polymer flooding formulations can lead to improved recovery rates, highlighting the nuanced role of water chemistry in polymer flooding processes.

Although not an inherent characteristic of the water, the temperature of both the reservoir and the injection water profoundly affects how water properties interact with polymer. Higher temperatures can accelerate chemical reactions and impact the viscosity of polymers. Considering the temperature of the reservoir is essential when crafting polymer flooding strategies, as it ensures they are tailored for peak efficiency under the given thermal conditions.

The discussion about how water chemistry affects polymer performance including salinity levels and pH ranges and total dissolved solids content now changes to advanced polymer systems with comparative studies evaluation. The section discusses novel polymer compositions together with hybrid crossbreeds that address the challenges created by high-salinity conditions.

## **2.5 Key Performance Parameters for Polymer Solutions**

The fundamental properties of polymer solutions need complete examination to optimize their functioning within EOR operations. Multiple core properties of polymers in solutions determine viscosity properties as well as stability behavior which directly affects their performance within the reservoir.

The molecular weight of a polymer as well as its chain length grows in direct proportion to the number of monomers within the polymer chain. The viscosity of the solution increases when polymers extend their lengths because longer chains easily merge during entanglements. The augmented viscosity serves as a crucial element for mobility control in polymer flooding operations since it controls the mobility ratio between the injected fluids. According to Teraoka (2002) the size of polymeric chains determines macroscopic properties while showing that extended polymer chains enhance oil recovery operations because they improve mechanical strength and viscosity.

The radius of gyration is a measure of the spatial distribution of a polymer chain around its center of mass. It provides insight into the polymer's size and conformation in solution. In good solvents or under conditions that promote polymer expansion, the radius of gyration is larger, which generally correlates with higher solution viscosity. The radius of gyration diminishes in poor solvents together with high-salinity environments which causes the polymer chain contraction

that frequently results in viscosity reductions. Teraoka (2002) explains how the correct understanding of radius of gyration helps predict polymer chain responses to changing conditions of temperature and solvent which are critical for high-salinity reservoir analysis.

Chemical potential represents the change in Gibbs free energy associated with the addition of polymer molecules to a solution. The thermodynamic parameter plays an essential role for predicting polymer stability as well as solubility behavior. A favorable chemical potential ensures that the polymer remains well-dissolved and does not phase separate under reservoir conditions. Teraoka (2002) offers in-depth analysis of chemical potential in polymer systems which shows its impact on polymerization processes and solution behavior of polymers. In the context of EOR, controlling the chemical potential helps in designing polymer formulations that remain stable under the fluctuating conditions of the reservoir.

Viscosity is perhaps the most critical parameter for polymer flooding, as it directly influences the mobility of the injection water. The solution viscosity grows as the number of monomers raises and when chains become more tangled together. This property is essential for reducing the mobility ratio between water and oil, which in turn minimizes issues such as viscous fingering and channeling. Teraoka (2002) explains that the viscosity of a polymer solution is a direct function of its molecular weight and the interactions between polymer chains and the solvent. The development of effective polymer solutions requires deep knowledge about how these solutions react under powerful salinity reservoir conditions.

Measuring refractive index in polymer solutions helps to characterize polymer-solvent interactions since it demonstrates the degree at which light bending occurs during medium passage. Research techniques using refractive index measurements perform light scattering methods to both measure polymer-chain molecular size and determine their weight distribution ranges. Although refractive index itself does not impact flow behavior it gives essential information about polymer molecule dispersion and conformational state. Variations in refractive index show clear links to polymer concentration and interactions as per Teraoka (2002) through which researchers gain valuable knowledge for enhancing polymer performance in EOR applications.

Osmotic pressure reflects the tendency of a solvent to move into a polymer solution through a semipermeable membrane and is closely related to the polymer's concentration and molecular weight. The determination of osmotic pressure reveals information about how solutes interact with solvent molecules and measures the extent of polymerization because these aspects determine

polymer solution thermodynamics. In the context of EOR, controlling osmotic pressure is important for predicting how polymer solutions will behave under reservoir conditions, particularly regarding swelling and retention within the pore spaces. The equilibrium characteristics of polymer solutions depend heavily on osmotic pressure according to Teraoka (2002) as this affects the success of maintaining optimal polymer concentrations in saline water conditions.

A complete foundation for polymer solution behavior emerges from the combination of seven intrinsic parameters consisting of size factors, chemical potential and physical factors. Details about polymer behavior act as a fundamental requirement for developing formulation designs which persist through the harsh operating environment of high-salinity reservoirs while preserving polymer flooding efficiency.

## **2.6 Polymer Performance in High-Temperature and High-Salinity Reservoirs**

The implementation of polymer flooding in EOR operations becomes challenging due to conditions with high temperatures and salinity. Formation water in Middle East regions displays 170000 ppm salinity values and the reservoir temperature reaches 120°C. Typical polymers fail drastically in these harsh settings because the elevated temperatures enhance both hydrolysis and viscosifying power loss along with ion-strength-caused precipitation. The selection and conditioning process of polymers for EOR becomes more complex because of the combination of reservoir heterogeneities with variable permeability in addition to compatibility issues with other oil recovery chemicals. HTHS reservoirs require the creation of stronger polymer formulations which demonstrate adequate resistance to severe chemical and thermal operational conditions.

In the research by Alfazazi et al., 2019, the authors examine different strategies because of the ongoing difficulties in the fields. Reservoir preconditioning happens by injecting low-salinity make-up brines in front of polymer injection. Polymer stability and viscosity retention occurs when introducing a slug of water with reduced salinity because it minimizes contact between formation water and the polymer. The stability of polymers applicable in high temperature environments improves when researchers create engineered polymers that incorporate stabilizing comonomers and modify polymer backbones with partially HPAM. Laboratory tests demonstrate that optimal implementation of polymer flooding in HTHS reservoirs can generate additional oil extraction levels between 10% and 15%. Testing under reservoir conditions with sulfonated polyacrylamide

at 3000 ppm yielded 11% increased oil recovery through method preconditioning that additionally boosted mobility ratio and total recovery. The successful implementation of polymer flooding depends on both optimal polymer concentration and slug size determination and diligent heterogeneity monitoring within these reservoirs.

## **2.7 Influence of Salinity and Ion Composition on Polymer Performance**

The behavior of polymer solutions in salty wells depends heavily on the particular salt and water minerals contained within formation waters. Study by Jouenne (2020) show NaCl solution speeds the hydrolysis of acrylamide (AM) groups faster than seawater and CaCl<sub>2</sub> and way faster than deionized water (DI) while AMPS hydrolysis shows parallel results except DI solution expedites reaction time. The presence of specific salts within the system controls both chemical degradation rate and the complete stability level of polymers throughout flooding operations. The intrinsic viscosity of polymers exhibits an anomaly when NaCl concentration rises from 5 to 50 g/L because lower-charged polymers have minimal value reduction yet highly charged polymers display substantial decreases. The behavior is essential because viscosity controls the effectiveness of the mobility ratio during flooding processes.

The intrinsic viscosity rises with decreasing salt concentrations alongside increasing degree of hydrolysis thus showing potential engineering possibilities for polymers that work better in lower salinity solutions. Temperature combines with these effects to reduce viscosity through strong carboxylate–Ca<sup>+2</sup> interactions while sulfonate–Ca<sup>+2</sup> interactions produce less viscosity changes in selected polymers such as SAV10. Long-term aging tests under extreme salinity conditions prove that copolymers which contain high amounts of AMPS stay viscous thus demonstrating enhanced stability at elevated salinity levels.

These analysis results will establish optimal practices for deploying polymer flooding technologies. Jouenne (2020) explains the approach for choosing polymers and their chemical compositions that function in extreme temperature and salinity environments to illustrate proper customized formulation requirements for thermal stability and mobility management. The complex interplay between salinity, ion composition, and polymer structure necessitates a comprehensive approach to brine chemistry management. Scientists modify NaCl and CaCl<sub>2</sub> salt concentrations together with other salts to optimize viscosity and minimize adsorption losses which helps maintain polymer functionality in difficult reservoirs.

New research confirms that polymer flooding success depends equally on brine formulation alongside the durability of polymers when exposed to harsh reservoir conditions. Experimental results demonstrate that polymer intrinsic viscosity decreases in a non-linear way with rising NaCl levels but polymers that are hydrolyzed heavily and designed with specific electrostatic properties maintain their viscosity-enhancing abilities under divalent and multivalent ions. SAV10 advanced polymers demonstrate robust temperature independence in their viscosity while keeping optimal relaxation periods across different conditions because proper modification techniques prevent precipitation along with degradation effects. Figure 3 in the document shows experimental flow curves of SAV10 at 25°C in Brine D at a concentration range of 1000–5000 ppm. The data include intrinsic viscosity and relaxation time at different temperatures. The presented model curves show the temperature-insensitive behavior of SAV10 which represents a crucial characteristic for reservoir performance maintenance. Laboratory research demonstrates that polymer optimization systems should merge with ion management operations to optimize oil recovery within Uzen Field's high-temperature and high-salinity environment.

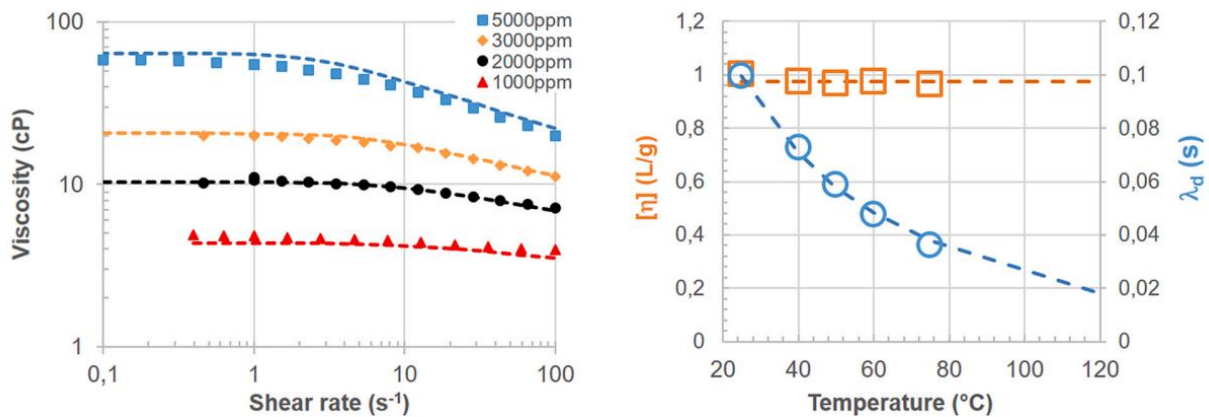


Figure 3. The experimental flow curves (symbols) monitoring behavior SAV10 at 25 °C in Brine D at 290 g/L while varying from 1000–5000 ppm. (Jouenne, 2020)

The intricate effects of salinity along with pH and different ion constituents on polymer characteristics are now better understood through recent research studies. Saha et al. (2021) performed a quantitative analysis of pH together with salinity effects on water-absorbing polymers (WAPs) employed in drought planning. Research showed that the hydrolytic rates of polymer functional groups occur in a particular sequence which starts with NaCl causing the highest impact then seawater and finally reaches its minimum in deionized water conditions. The change in NaCl concentration from 5 to 50 g/L subjected intrinsic viscosity to a non-monotonic pattern where

strongly charged polymers experienced exponentially greater viscosity decrease. The research found that polymers were more receptive to single-charge ion  $\text{Na}^+$  than double-charge ions  $\text{Ca}^{2+}$  which caused significant water absorbency reduction from rising ionic strength. Laboratory results validated with ANOVA procedures and empirical models proved salt concentration and different ion types have an influential effect on how polymers work. The research by Saha et al. (2021) investigates agricultural polymers yet its fundamental mechanisms that involve polymer chain shortening and osmotic pressure changes correspond to HPAM degradation in high-salinity reservoirs. Studies highlight why precise brine chemical composition and polymer design become essential for combating detrimental effects within EOR applications that occur because of high salinity.

## **2.8 Detailed Analysis of Salinity and Ion Effects**

The latest research improves our knowledge regarding how formation water ions control polymer responses when operated in high-salinity environments.

The research published by Hu et al. (2024) confirms that  $\text{Fe}^{2+}$  and  $\text{Fe}^{3+}$  high-valence ions create the greatest effect on lowering viscosity when compared to single-valence ions  $\text{Na}^+$  and  $\text{K}^+$ . The viscosity of a 2500 mg/L polymer solution decreased gradually when the experiment used mineralized water containing only  $\text{Na}^+$  and  $\text{K}^+$  at various concentrations. The rate of viscosity decline slowed after the  $\text{Na}^+$  concentration reached 1200 mg/L while  $\text{K}^+$  affected viscosity at 0.93 times  $\text{Na}^+$  impact. The viscosity of the solution decreased dramatically when  $\text{Fe}^{2+}$  at high valence was present even in small concentrations. Polymer solution viscosity decreased substantially after adding divalent cations including  $\text{Ca}^{2+}$  and  $\text{Mg}^{2+}$  to the solution. The experimental data demonstrates that solutions containing only monovalent ions preserve viscosity stability for 0 to 50 days better than other solutions where retention rates reach above 83%.  $\text{Na}^+$  ions contributed viscosity changes of 1.5 to 7.6 ( $\text{mPa}\cdot\text{s}/(\text{mg}\cdot\text{L}^{-1}\cdot\text{d}^{-1})$ ) while  $\text{Fe}^{2+}$  ions caused greater effects ranging from 82.4 to 152.1 ( $\text{mPa}\cdot\text{s}/(\text{mg}\cdot\text{L}^{-1}\cdot\text{d}^{-1})$ ) to the solution. Laboratory work carried out with a Brookfield DV-II viscometer proved that proper control over ionic composition serves as a main factor for protecting polymer performance. A detailed evaluation shows that the stability and viscosity of polymeric solutions depend considerably on which type of salt ion exists alongside what concentration level. These discovery results play a crucial role in improving polymer flood

operations under high salinity conditions to help guide engineers in designing both polymer systems and brine salts for EOR projects.

## **2.9 Advanced Polymer Systems and Hybrid Approaches in ASP Flooding**

### **2.9.1 Hybrid Polymer Formulations and Their Performance**

The study by Zhu et al. (2013) explores a novel solution for enhancing oil recovery in challenging high-temperature and high-salinity reservoirs, where traditional methods like using partially hydrolyzed polyacrylamide (HPAM) are less effective. By integrating HPAM with erucyl dimethyl amidobetaine (EDAB) to create hybrids, this research aims to overcome HPAM's limitations in harsh conditions. The key findings reveal that HPAM/EDAB hybrids exhibit superior thermal stability and salt tolerance compared to HPAM alone, making them more suitable for environments like those found in the Class III reserve of Shengli Oil Field in China, with temperatures above 85°C and high salinity levels exceeding 30000 mg/L. Preliminary core flooding experiments under simulated conditions showed that these hybrids achieve better oil recovery factors, attributed to the synergistic effects between HPAM and EDAB.

Figure 4 shows RF, water cut and flooding pressure against injected pore volume. The EOR observed with the hybrid samples is primarily due to the reinforced micelles formed by incorporating HPAM's long chains, making them more resistant to disruption compared to regular micelles. The collaborative interaction between HPAM and EDAB in these hybrids contributes to their remarkable long-term thermal stability and contributes to a notable increase in oil recovery. This synergistic effect ensures that the HPAM/EDAB hybrids maintain a consistent apparent viscosity over time, even in the challenging conditions of high-temperature, high-salinity oil reservoirs. This stability in viscosity is key to effectively improving the water-to-oil mobility ratio, leading to increased oil production (Zhu et al., 2013).

Table 1. Chemicals used in the study. (Zhu et al., 2013)

Sample name	HPAM (wt%)	EDAB (wt%)
P30	0.3	0
E30	0	0.3
P25E5	0.25	0.05
P20E10	0.20	0.10
P15E15	0.15	0.15
P5E25	0.05	0.25

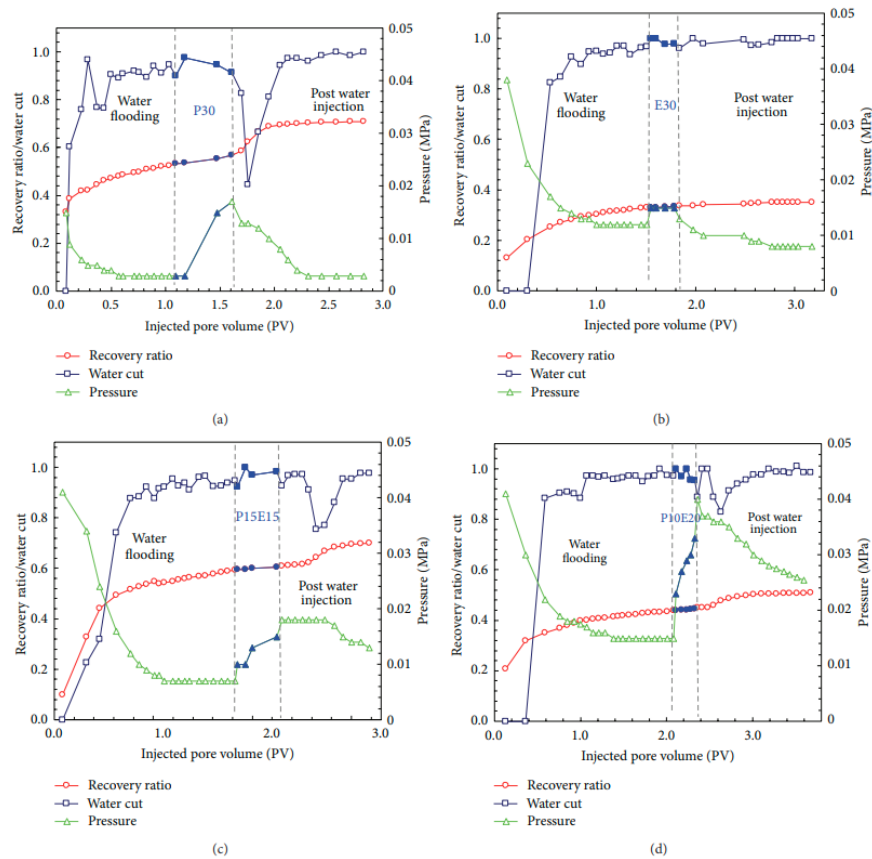


Figure 4. RF, water cut, and flooding pressure vs PV: (a) P30, (b) E30, (c) P15E15, and (d) P10E20 (TDS = 32,868 mg/L,  $[Ca^{(2+)}] + [Mg^{(2+)}] = 873$  mg/L; injected volume = 30% PV; injected rate = 0.23 mL/min. (Zhu et al., 2013)

## 2.10 Alternative Polymer Systems and Comparative Studies

The research by Kamal et al. (2015) examined thermoviscosifying polymers (TVPs) for EOR applications in hot saline reservoirs showing these polymers switch from thermo-thinning behavior to thermo-thickening mechanics at high temperatures and salt concentrations. Our research focuses on traditional HPAM optimization rather than testing thermoviscosifying

polymers because HPAM remains a widely used and proven polymer choice for polymer flooding operations.

The Figure 5 shows a remarkable 22% increase in oil recovery using TVP and SP injection compared to conventional methods, particularly in HTHS conditions where traditional polymers like HPAM suffer from significant viscosity loss. This thermo-thickening behavior, enhanced by high temperature and salinity, underscores the potential of TVP systems in EOR applications, offering a promising alternative for recovering oil from reservoirs where HPAM is less effective.

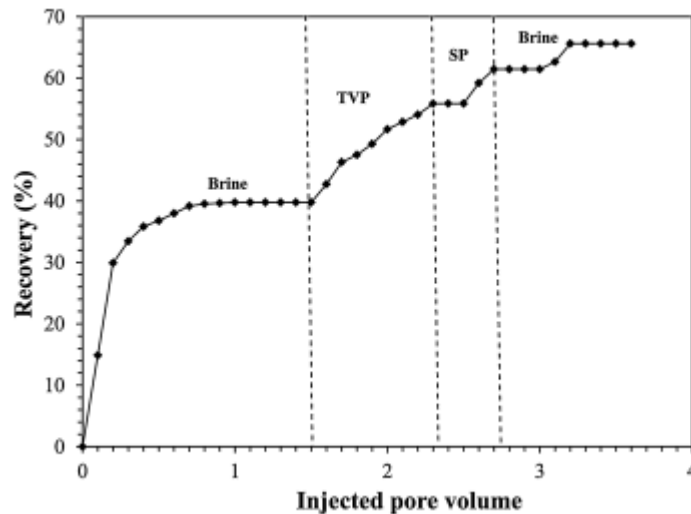


Figure 5. Oil RF for SP system with 0.25 % TVP and 0.05 % surfactant (Kamal et al., 2015)

The research by Li et al. (2019) showed that developing proper polymer concentration standards enables optimal viscosity enhancement achievements. The regulation of polymer mobility gains special importance when operating under high-salinity conditions since these conditions decrease the viscosity and create challenges to flow behavior. The analysis shows how water mineralization levels change fluid properties and how viscosity together with other performance-related factors transform during this process. The research confirms that controlling brine composition stands vital for sustaining successful polymer flooding procedures.

In the recent study conducted by Hasiri et al. (2023), increasing salinity levels significantly influence the degradation rate of HPAM gels, with higher salinity environments facilitating more rapid degradation. This effect is attributed to the impact of electrolytes on molecular chain dynamics, specifically the contraction of polymer chains due to electrostatic screening effects. For instance, as salinity increases from 0 to 10000 ppm, the accumulated energy required for gel

degradation decreases, highlighting the mitigating role of salinity on the energy demand for gel breakdown.

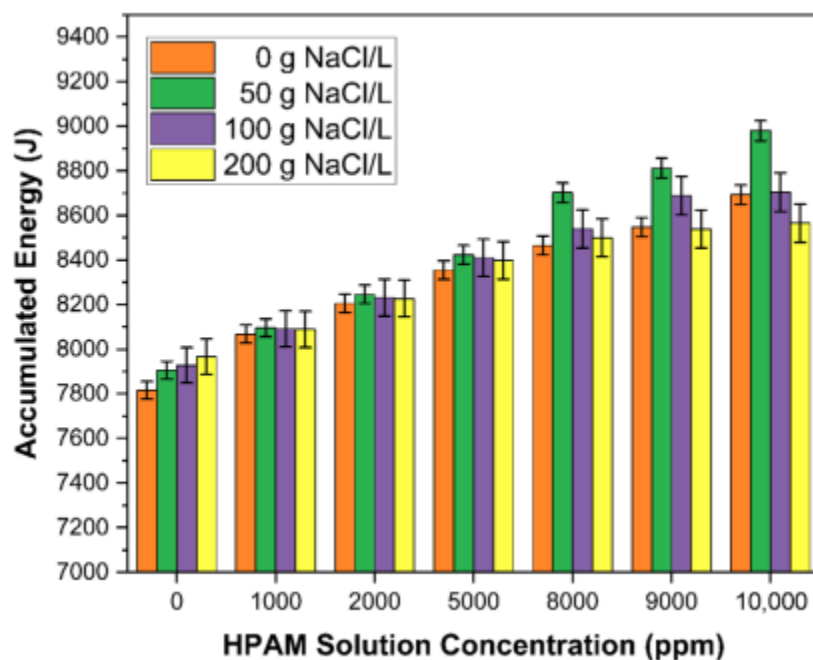


Figure 6. The energy needed to break down 1 g of gel within a 2-minute ultrasonic treatment at 20 kHz and 500 W power, starting with a gel particle of 1 g, across various salinity levels and concentrations of HPAM solution. (Hasiri et al., 2023)

Figure 6 shows that the degradation sensitivity of HPAM gels to changes in salinity becomes more pronounced with higher polymer concentrations. At a polymer solution concentration of 10000 ppm, a salinity increase from 50 to 200 g NaCl/L results in a notable decrease in accumulated energy required for degradation, underscoring the interplay between polymer concentration and salinity in determining gel behavior.

The study by Oliviera et al. (2019) investigates the thermal stability of partially HPAM in high-salinity environments, focusing on its behavior and efficiency for EOR applications in the petroleum industry. It reveals that HPAM undergoes significant hydrolysis and potential precipitation in the presence of divalent cations ( $\text{Ca}^{2+}$  and  $\text{Mg}^{2+}$ ) at elevated temperatures, leading to a decrease in its intrinsic viscosity. Hydrolysis of HPAM increases with temperature, with notable changes observed at 70, 85, 90, and 95°C, indicating a temperature-dependent degradation process.

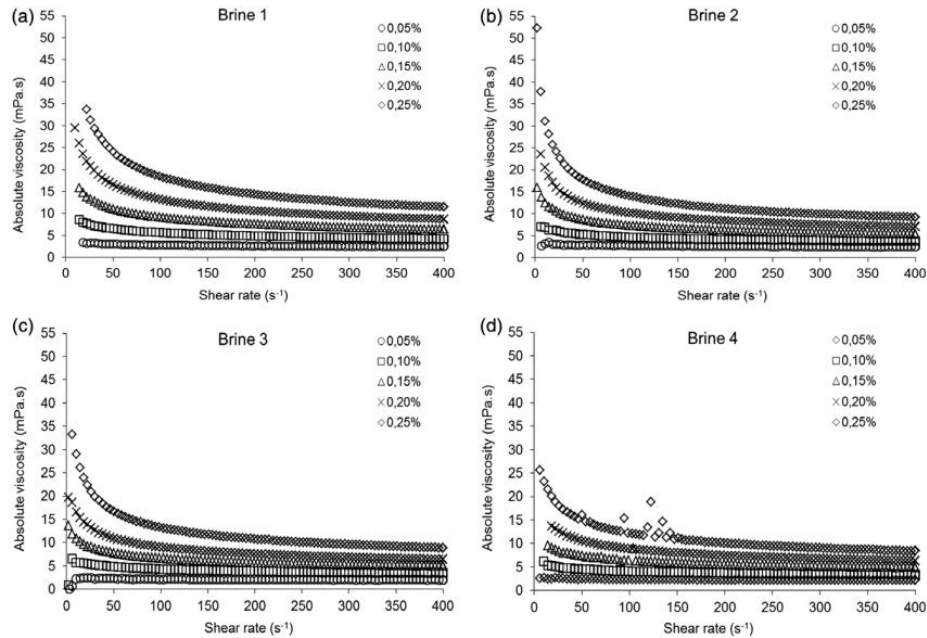


Figure 7. Relationship between absolute viscosity and shear rate for varying concentrations of HPAM across four distinct brine compositions. (Oliviera et al., 2019)

According to Figure 7, the tested solutions displayed non-Newtonian behavior, with viscosity decreasing as shear rate increased, characteristic of pseudoplastic fluids. However, at shear rates beyond  $350 \text{ s}^{-1}$ , this change in viscosity slowed, signaling a shift towards Newtonian fluid behavior, a trend that intensified with greater salt concentrations at reduced shear rates. For a more detailed analysis of salt concentration's impact on viscosity, the least concentrated solutions (0.05% m/v) were examined over a shear rate range of 6 to  $400 \text{ s}^{-1}$ . Viscosity values for HPAM solutions varied minimally within specific ranges across different brines, with the narrowest ranges observed in Brines 3 and 4, which presented higher TDS values (46866 and 58990 ppm, respectively). This suggests that at dilute concentrations, the polymer chains exist independently, their interactions minimal, and their spatial volume defined by their interaction with the solvent.

The presence of high salinity and specific ion concentrations adversely affects HPAM stability, reducing its effectiveness in EOR applications. This is particularly evident in environments with higher concentrations of divalent cations, where early precipitation of the polymer was observed, underscoring the challenges of using HPAM in high-temperature, high-salinity reservoirs. The study emphasizes the need for careful selection of EOR polymers based on reservoir conditions to ensure their long-term stability and effectiveness in oil recovery processes.

Seright (2016) discusses the optimization of polymer concentrations and viscosities in polymer floods especially in high water cut scenarios. The study highlights that the design of polymer floods has evolved, with recent applications using significantly higher polymer concentrations and viscosities to improve sweep efficiency and reduce water cut.

The study by Levitt et al. (2011) provides a comprehensive analysis of the challenges and key findings related to the application of polymer flooding in high-temperature, high-salinity, low-permeability carbonate oil reservoirs. It highlights the significant impact of calcium sulfate minerals, such as gypsum and anhydrite, on chemical flooding. These minerals, often present in carbonate formations, have been recognized as obstacles due to their interaction with EOR chemicals. The study showcases an 83°C carbonate field, initially containing evaporitic water, flooded with an ASP slug mixed in seawater, followed by a polymer drive in diluted seawater. It discusses the geochemical equilibria of carbonate reservoirs, detailing how EOR chemicals transport through formations rich in calcium and magnesium is affected. The paper illustrates the challenges of managing calcium uptake from calcium sulfate mineral dissolution, which can vary significantly based on water salinity and temperature, impacting polymer viscosity. The results from experiments are promising, with the identification of a suitable chemical formulation that demonstrates high oil recovery in different limestone cores (Figure 8).

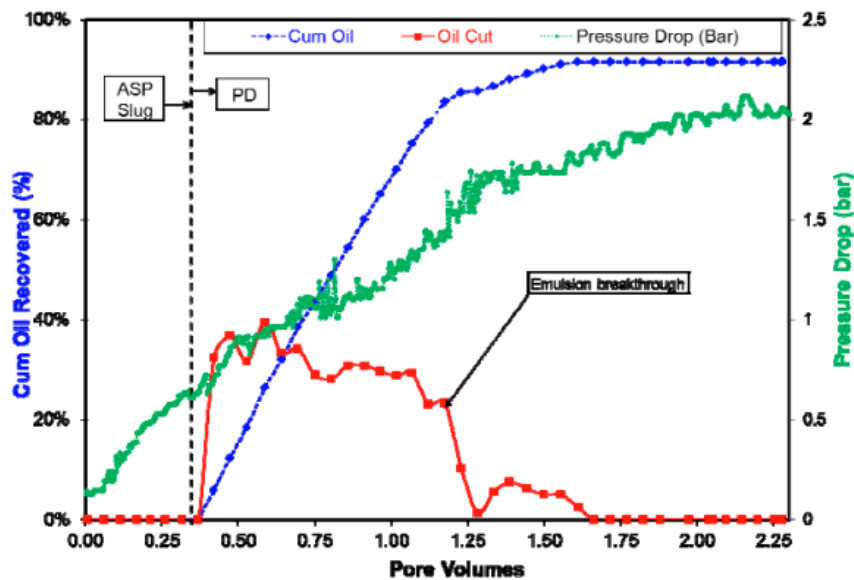


Figure 8. Pressure data and coreflood oil recovery. (Levitt et al., 2011)

The practical deployment of EOR technologies relies on field tests which verify laboratory-reported improvements in EOR performance. This section includes studies of international reservoirs where ASP flooding techniques are applied to the Daqing region and Al Khalata alongside Shengli and Pelican Lake and Mangala to understand real-world field implementations.

## **2.11 Field Applications and Case Studies**

Various field applications of polymer flooding worldwide have proven successful especially through pilot projects which took place in Canada alongside the United States and China where they displayed their ability to boost oil extraction. The Daqing field benefited from polymer flooding simulations performed by Liu et al. (2007) which showed marked improvements in oil recovery according to their study. Similarly Chang et al. (2006) discovered through their research that this method delivered up to 14% extra oil reserves in the Daqing field and Shengli field both located in China. Field observations confirm that polymer flooding practices effectively address the challenges in heterogeneous reservoirs marked by high water production. Reservoirs with extreme high-salinity concentrations of 200,000 ppm specifically in the Middle East experience acute polymer degradation which degrades their viscosity integrity and operational effectiveness.

Researchers studied pre flush injection techniques as solutions against these challenges according to Algharaib et al. (2014). Research showed that water slugging before injecting the polymer can minimize polymer formation water interaction by matching the water salinity characteristics to the formation salinity. An evaluation of important design parameters including polymer concentration and pre flush and polymer slug sizes took place during their core flooding experiments. Under experimental conditions consisting of 175°F temperature and 20 s<sup>-1</sup> shear rate and 30,000 ppm salinity the results showed that polymer concentrations exceeding 2000 ppm to 3000 ppm to 4000 ppm resulted in enhanced oil recovery that established a viscosity threshold of approximately 10 cP. The combination of a 0.2 PV optimal polymer slug volume with lowered preflux saline solution levels brought improved oil recovery to 86% as opposed to continuous polymer injection at 70%.

### **2.11.1 Global Field Examples**

Polymer flooding has been applied across a range of reservoirs worldwide, demonstrating varied levels of success in enhancing oil recovery, particularly in fields characterized by high water

cut and a lot of oil remaining in the reservoir scenarios. These case studies underscore the critical aspects of reservoir properties, polymer formulation, and operational strategies in determining the efficacy of polymer flooding.

The Daqing Oil Field in China stands as a quintessential example of successful Polymer and ASP flooding, particularly noted for its application in sandstone reservoirs akin to those in the Uzen Field. The implementation of polymer flooding in Daqing to address high water cut scenarios offers valuable insights, as discussed by Lu et al. (2022). Their review of the world's largest polymer flood project, situated in a vast field characterized by multi-layered, heterogeneous sandstone reservoirs, underscores the significance of understanding reservoir and fluid characteristics. This understanding is crucial for grasping reservoir heterogeneity and boosting the efficiency of EOR processes, providing a solid foundation for contemplating the application of Polymer flooding in the Uzen Field, given its similar reservoir attributes. Specifically, similar characteristics are sandstone lithology, oil density between 33 to 39° API, depths of 900-1200 meters, permeability between 500-1000 mD, porosity of 25 to 30%, and high wax content. The notable difference is the oil's viscosity at 35 cP. Initial polymer injection trials in this field resulted in a 12% increase in oil recovery. By 2019, polymer flooding was responsible for an additional 6.03 million tons of oil production, as depicted in Figure 9, indicating the technique's effectiveness in enhancing oil output (Ezeh et al., 2021).

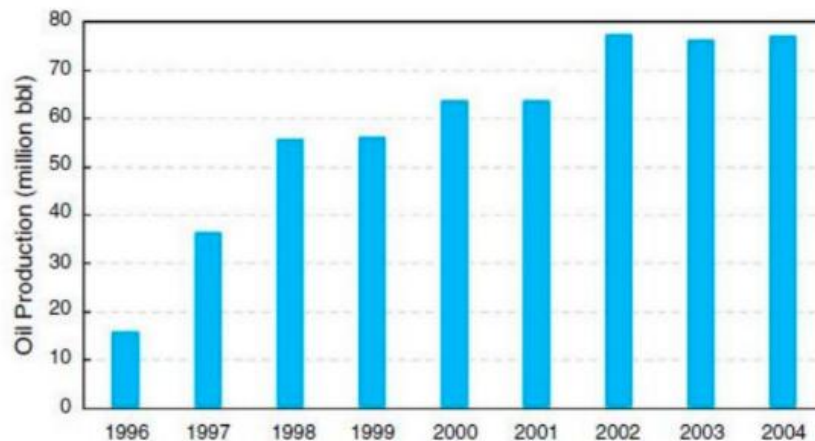


Figure 9. Polymer flooding and Oil production in Daqing Oilfield. (Ezeh et al., 2021)

Polymer flooding was effectively applied in the Al Khalata reservoir in Oman, characterized by sandstone lithology, a density of 22° API, and a viscosity of 90 cP. The reservoir's

permeability spans from 100 mD to 2 Darcy, with porosity between 25 to 30%. Following the implementation of polymer flooding, a reduction in water cut of 2-30% was observed, along with a 25% boost in oil production (Singh et al., 2021). The outcomes, including the increase in oil recovery and the decrease in water cut post-polymer injection, are detailed in Figure 10.

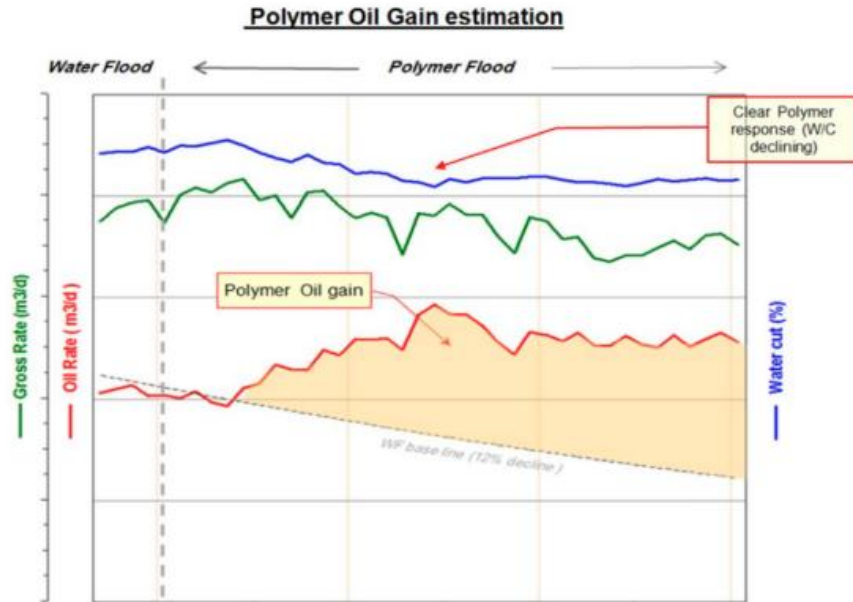


Figure 10. Water Cut and Oil Gain estimation (Singh et al., 2021)

The Shengli Oilfield operates as a key site for polymer and ASP flooding studies regarding difficult high-temperature high-salinity reservoirs according to Guo et al. (2017). In Shengli, reservoir temperatures reach up to 69°C in the blocks where ASP 15 and ASP 16 tests were conducted, significantly higher than the 45°C typical of fields like Daqing. The high temperature together with thick oil viscosity and strong divalent cation concentrations in formation brines creates significant challenges for both polymer durability and effectiveness. Despite these difficulties, beneficial factors—such as a favorable crude oil acid value and high permeability—have supported the application of ASP flooding, though field tests revealed specific issues. For example, a smaller well spacing in ASP 15 (60 m) and ASP 16 (212 m) led to serious scaling and sand production, with sand volumes ten times greater than those observed during water flooding. Incremental oil recovery in Shengli was lower than in Daqing; however, achieving a 15% incremental oil recovery under such harsh conditions was deemed a significant success. The research findings emphasize the necessity of developing customized polymer solutions combined

with strengthened ion control methodologies as useful concepts to enhance polymer driving operations at the Uzen Field and similar brine-heavy reservoirs.

In Canada, Pelican Lake presents a case study focused on polymer flooding, a technique that precedes and complements ASP flooding, with a specific aim to manage the viscosity of heavy oil thereby enhancing oil displacement. The experiences from Pelican Lake, particularly in viscosity management, offer guidance for the application of polymer flooding in the Uzen Field. The lessons learned regarding polymer selection and formulation could prove pivotal in improving oil recovery in reservoirs that harbor heavy oil with viscosity and density characteristics resembling those found in the Uzen Field.

The Mangala oil field, located in the Barmer basin of Rajasthan, India, serves as an exemplary study in the complexities and achievements of implementing EOR techniques. Characterized by its fluvial sandstones of the Fatehgarh Formation, Mangala boasts high permeability sandstone reservoirs that are well-suited for EOR operations. The reservoir's medium gravity, waxy, viscous crude oil, with an API gravity of 20-28 and viscosity ranging from 9-17 cP, poses unique challenges for recovery efforts. These features significantly impact oil mobility, making polymer flooding an attractive option to decrease oil viscosity and improve flow (Zaitoun et al., 2022).

The significant heterogeneity and permeability range of the Mangala reservoir, from 200 millidarcies to several Darcies, affects the efficiency of polymer sweeps. This heterogeneity has led to the exploration of innovative solutions like Microgel technology to address these challenges and enhance oil recovery. The extensive size of the reservoir, with oil in-place volumes of 1.3 billion barrels and an estimated recovery factor of 43% with polymer flood, facilitated large-scale EOR operations, including one of the largest polymer floods globally. This effort transitioned to ASP flooding to further augment recovery outcomes (Pandey et al., 2020).

Thermal aspects of the reservoir, particularly the wax appearance temperature close to the reservoir temperature (59°C compared to 65°C), necessitated initial hot water injection strategies to maintain the waxy crude oil's fluidity. This aspect underscores the thermal considerations crucial to EOR chemical processes. Moreover, the field encountered significant water-cut issues, initially exceeding 90%. The polymer flooding pilot project's success in reducing water-cut to 20-30% showcases the technique's effectiveness in not only enhancing oil recovery but also in efficiently managing water production (Prasad et al., 2022).

The Greater Burgan Field in Southeast Kuwait operates as the world's biggest oil field together with the largest sandstone reservoir which exists globally. The five reservoirs which constitute this field include Wara and Burgan as the largest among them while producing half of Kuwait's crude oil. Production in Burgan began in 1946 with strong aquifer support, but as the reservoir has matured, water production has steadily increased. This strategy involved conducting the Long-Term Polymer Injectivity Test (LTPIT) in Wara reservoir with effluent water containing up to 170000 ppm TDS and tested a pre-chosen sulfonated polymer. Under sub-fracturing conditions the test demonstrated that polymer injection boosted reservoir conformance by decreasing effective water permeability by about 20%.

The polymer flooding tests in Burgan Field also explored different polymer concentrations—specifically, 1800 ppm and 600 ppm—with maximum injection rates of 3400 bbl/d and 4100 bbl/d, respectively. The technique demonstrated ten-year-and-running success in recovering additional petroleum which confirms its extended benefits for matured oil reservoirs. The dissolution process for ZLPAM 40520 occurred within two hours while the polymer reached full dissolution in high-TDS water. ZLPAM 40520 is a ter-polymer (ATBS/AMPS HPAM) with active solid contents higher than 88% and 15–20% of ATBS/AMPS content. Notably, the presence of high concentrations of ions did not adversely affect its dissolution or injectivity, and no significant mechanical shear degradation was observed as the polymer solution passed through perforations. The research confirms how well the polymer performs at high-salinity reservoirs and demonstrates its strong capabilities for such conditions.

Temperature also plays a critical role in polymer performance at Burgan Field. Studies showed ZLPAM 40520 achieved maximum viscosity of 2.75 cP at 55°C reservoir temperature conditions that reduced to 30°C in the near-wellbore region. The pseudoplastic behavior of the polymer solution enabled it to maintain favorable mobility ratios, which are essential for improving sweep efficiency. Special equipment allowed the test to control both high TDS and temperature levels together with ion composition by preparing highly concentrated solutions to mitigate thermal and chemical degradation. Figure 11 illustrates cumulative oil recovery from the injection of the 1,800 ppm polymer with 40-acre spacing, providing a clear visual of the enhanced recovery performance in the Burgan Field.

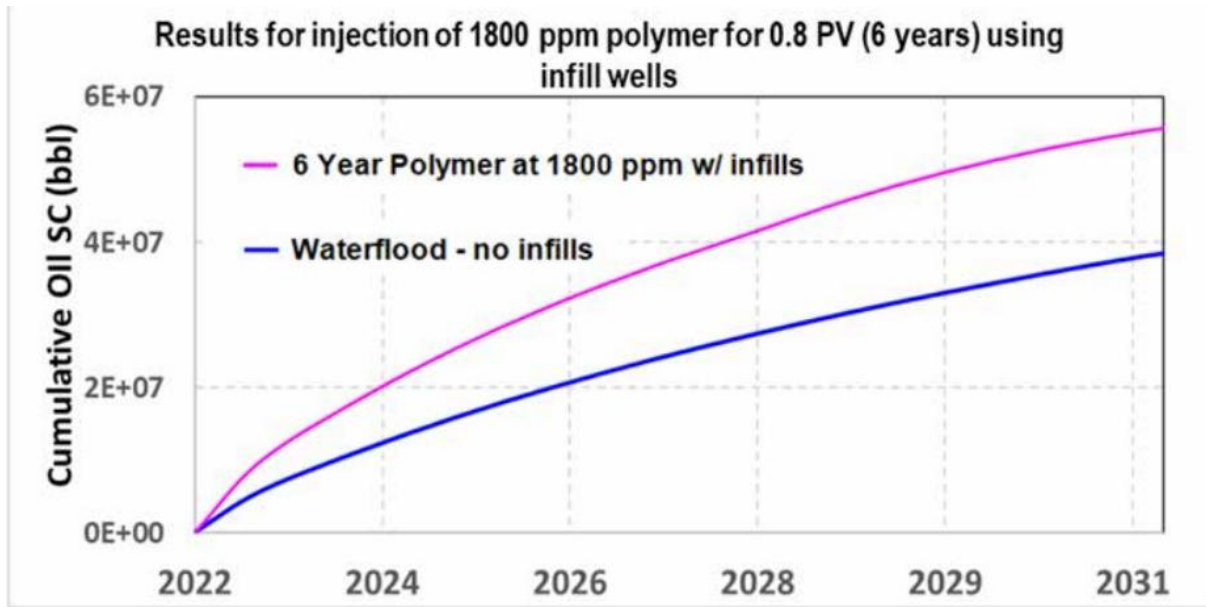


Figure 11. Injection of polymer with 1800 ppm for 0.8 PV for 6 years using 40 acre spacing (Al-Murayi et al., 2022)

The Bhagyam Oilfield exhibits reservoir properties that are highly conducive to polymer flooding (Koduru et al., 2021). Characterized by a relatively low reservoir temperature, high permeability, high initial oil saturation, and low connate water salinity, the field provides ideal conditions for the application of polymer flooding techniques. Despite these favorable conditions, waterflood performance was suboptimal due to pronounced heterogeneity in rock properties, which led to early water breakthrough and the recycling of injected water. The existing difficulties in the oil production process led to the development of polymer flooding as a new EOR method.

The pilot tests at Bhagyam well B-113 and B-118 demonstrated that the polymer maintained acceptable rates of both injectivity and retention. Further success from these tests inspired the field development that included starting eight new wells and changing 24 existing producers to become injectors and ultimately resulted in drilling 28 additional wells. The first polymer injection cycle began by pumping water with polymerized water viscosity ranging from 20–30 cP throughout all the injection wells. The adoption of this strategic approach brought transformative effects because it reduced water–oil ratio from 16 to approximately 10 and increased production rates from 10500 to peak levels around 16000 BOPD. The positive flood outcomes were supported by analytical simulations and history matching through which polymer

flood behavior produced accurate models with 1.5 residual resistance factor and 40  $\mu\text{g/g}$  rock adsorption.

The field-level data in Figure 12 displays WOR reduction as well as the increase in oil and gas production rates since polymer flooding was started at the site. The field results from Bhagyam Oilfield confirm that polymer flooding succeeds in difficult reservoir environments and create vital knowledge regarding maximizing sweep performance and water conservation techniques. The results confirm that polymer flooding stands ready to become a reliable EOR operation when deployed in reservoirs which share comparable operational challenges.

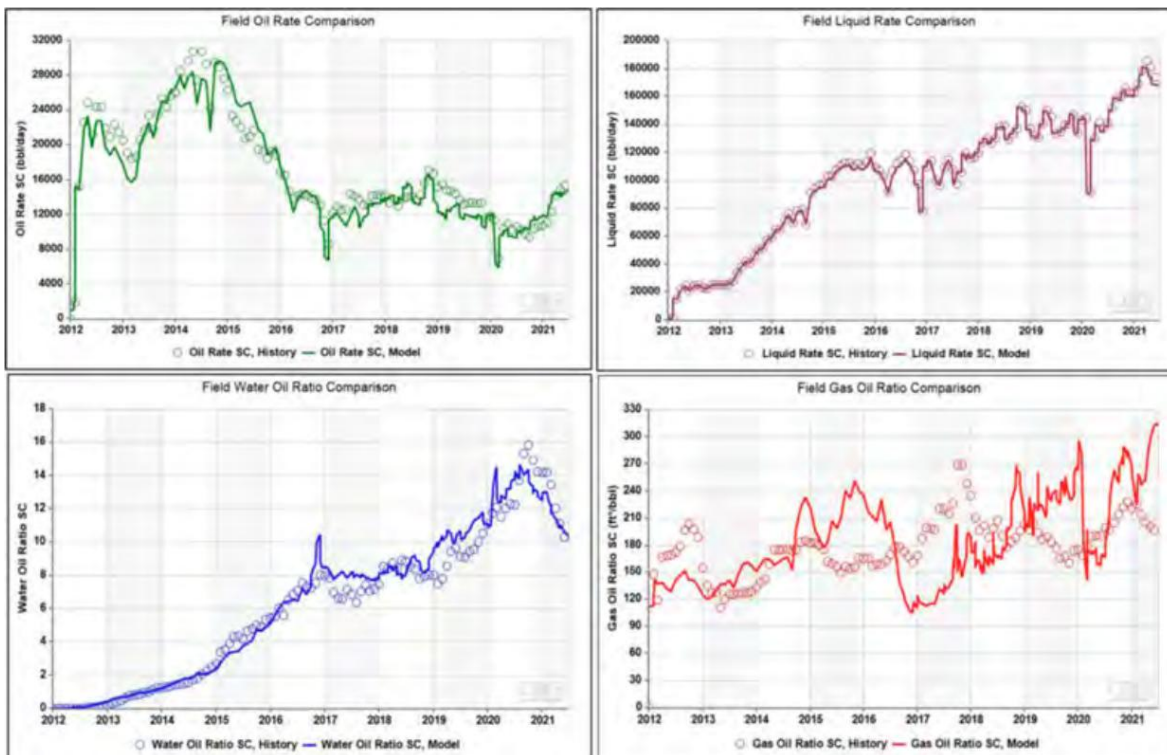


Figure 12. Bhagyam Oil field's production data history match (Koduru et al., 2021)

From the studies, ASP flooding works well in fields like Uzen, showing strong results in similar reservoirs that have already used this method: Daqing, Al Khalata, Shengli, Pelican Lake, Mangala fields, etc. The results show that polymer flooding works well in sandstone wells with high permeability and moderate to high porosity that produce lots of water. By studying real-world applications of polymer flooding, we discover how to better handle reservoir irregularities, salt content, and high viscous oil as we boost oil recovery and solve field operations and environment issues. With Uzen Field's similar geological makeup of rock type, depth, flow capacity, porosity

levels, and oil properties, we should consider using adapted polymer flooding methods to improve oil recovery and extend the field's operational life.

## **2.12 Field Challenges in Kazakhstan and Implications for Uzen Field**

Uzen Field has experienced fluctuating production rates since its inception. The early production in the field worked well because of high reservoir pressure and low water extraction. However, extended waterflooding operations resulted in increased water cut (90%), which has become a persistent challenge. (Dauyltayeva et al., 2023)

Daily production exceeded 50000 barrels of oil during the best production years of 1975 to 1985. The production numbers dropped sharply in the years after the 1990s, mainly because of low reservoir pressure and early water migration through easily permeable zones. Scientists now use new ways to boost oil recovery, like injecting polymers and chemicals into the reservoir, to help solve these problems. Water cut data also reveals significant heterogeneity in reservoir properties, with water breakthrough primarily affecting high-permeability zones. The uneven arrangement of oil in these rocks leaves oil remaining in low-permeability spots, so we must use special polymers that can work in hot conditions, stick to the rock surface for longer, and prevent bacterial growth.

The application success rates and constraints of polymer flooding become clear based on real-world study of various reservoir environments. The following section details our current investigation's objectives for optimizing polymer flooding operations under high-salinity conditions which are prevalent in the Uzen Field.

## **2.13 Prior Work, Problem Statement, and Research Objectives**

### **2.13.1 Review of Prior Polymer Screening Studies**

In the previous study by our team (Yerniyazov et al., 2023), HPAM polymers prepared in CSW were evaluated for their rheological properties, thermal stability, and adsorption behavior under reservoir conditions of 63°C. These tests identified a specific HPAM polymer that exhibited 13-14% lower static adsorption compared to alternatives, making it the preferred choice for field implementation. Results from these rheology tests and thermal stability curves (Figure 13 and 14) illustrate the performance of the selected polymer, demonstrating its ability to be good candidate for polymer flooding tests.

This research underscores the importance of comprehensive screening, including polymer characteristics and their interaction with the ionic and non-ionic components of make-up brine, for effective water cut reduction in oilfields.

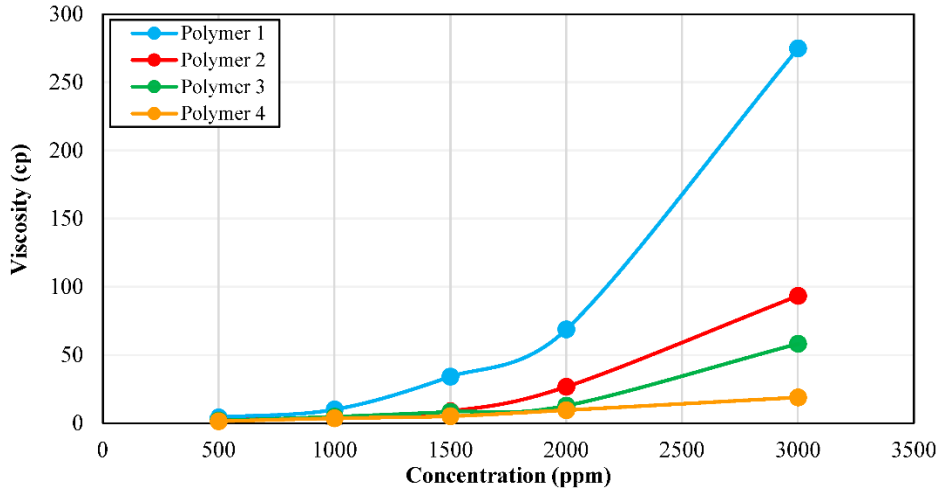


Figure 13. Rheology results for 4 polymers prepared in CSW (Yerniyazov et al., 2023)

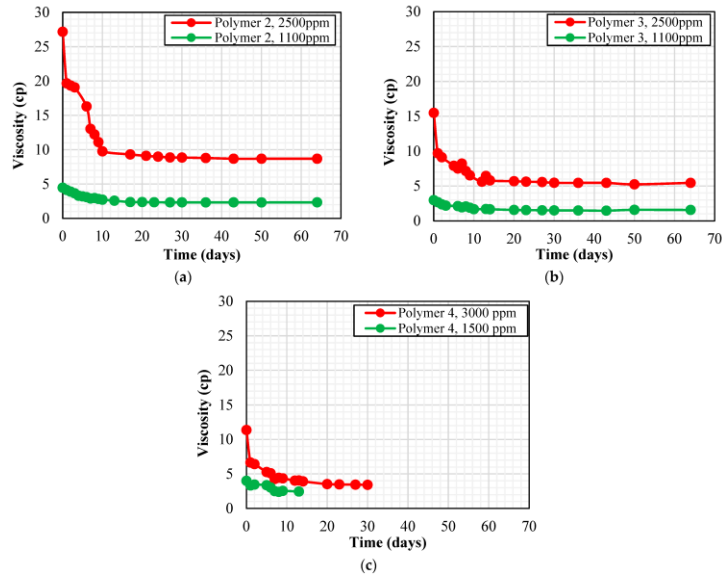


Figure 14. Thermal stability results 3 polymers prepared in CSW (Yerniyazov et al., 2023)

The experimental analysis involved Shakeel et al. (2024) who utilized the ASP3 polymer solution at its optimal concentration of 2500 ppm during coreflood testing on Uzen Field cores. A coreflood procedure started with SW injection and proceeded to polymer flooding followed by a SW postflush. The first step involved SW injection to measure Sorw after standard waterflooding

operations yielded 43% recovery of OOIP. The ASP3 polymer flood operation ran until oil production reached a standstill where it recovered a total of 91% OOIP through additional 48% obtained after the initial 43% achieved by conventional waterflooding. A seawater postflush operation followed the polymer flood process to measure residual resistance factor (RRF) along with un-adsorbed polymer recovery from the reservoir. The experimental pressure drop data shown in Figure 15 accompanies the recovery factor observations from this test.

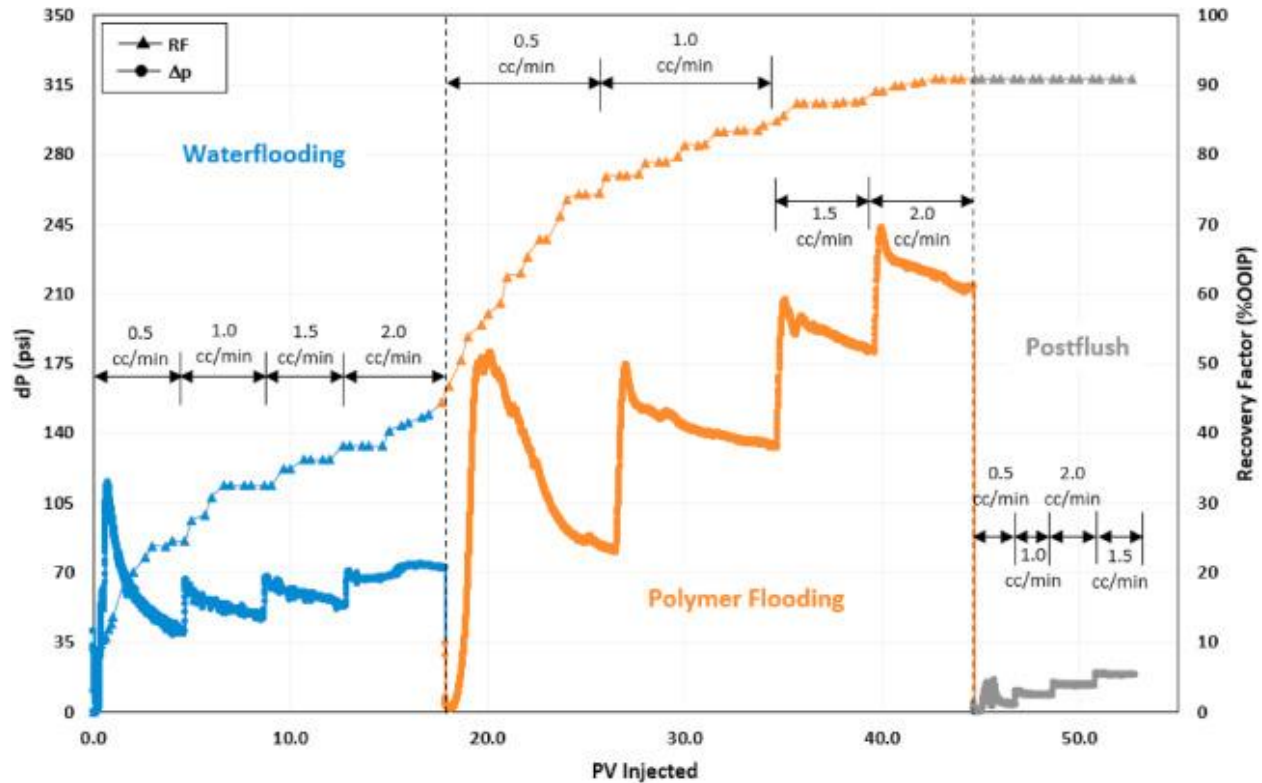


Figure 15. Pressure drop history and Recovery factor of polymer flooding test. (Shakeel et al., 2024)

The experimental results demonstrate successful oil recovery because the ASP3 polymer both reduced mobility and moved the oil bank efficiently during the tests. The outcomes hold great value for Uzen Field specifically because of its resistance to salinity and its complex reservoir structure. Such laboratory tests successfully demonstrated that polymer flooding operations can recover 91% of initial oil in place alongside desirable operational characteristics including high injectivity and minimal polymer adsorption. The research conducted by Shakeel et al. (2024) validates both the effectiveness of polymers for high-salinity conditions and the need to plan injection schemes and polymer compositions properly to achieve maximum oil recovery from mature fields.

### **2.13.2 Integrated Strategies, Problem Statement, and Research Objectives**

The research team has also suggested integrated strategies that combine chemical and polymer flooding. These strategies use the complementary advantages of both techniques to meet the dual problems of excessive water cut and low residual oil recovery. Experiments conducted at the laboratory and field scale have yielded encouraging results using this all-encompassing approach.

The Uzen Field faces critical challenges in implementing effective EOR strategies due to the unavailability of CSW for polymer flooding. Due to this restriction, FW, which has a high salinity, must be used. Because of molecular coiling and interactions with brine ions, high salinity conditions can have a substantial effect on polymer performance by decreasing their viscosity, thermal stability, and efficiency in sweep operations.

Assessing how different polymers behave in high salinity environments is crucial to overcoming these difficulties and determining which ones are most appropriate for usage in FW. Furthermore, to guarantee that polymer flooding improves oil recovery, it is essential to comprehend how polymer performance may be improved through techniques like ion management or formulation changes. This research aims to systematically investigate the interaction of polymers with high-salinity FW, identify the optimal polymer for these conditions, and explore strategies to enhance its performance for application in the Uzen Field.

The primary objective of this study is to evaluate the efficiency and performance of polymer flooding under high-salinity conditions specific to the Uzen Field. Due to the unavailability of CSW for polymer preparation, FW must be used as the solution brine, posing unique challenges to polymer behavior and performance. This research seeks to identify which polymer among the six tested samples demonstrates optimal properties, including viscosity, thermal stability, adsorption, and incremental oil recovery, when prepared in FW.

A critical component of the study involves understanding the impact of ion composition and salinity levels on polymer rheology and performance. The research looks at methods for managing specific ions, including calcium, magnesium, and sulfate, to improve the viscosity and stability of polymers when forming a solution in salty water. These enhancements aim to mitigate the detrimental effects of salinity on polymer performance and optimize injectivity control during flooding operations.

By systematically screening and selecting the most effective polymer, this study also aims to provide insights into improving polymer flooding efficiency in heterogeneous reservoirs. The research focuses on tailoring polymer formulations to suit the challenging conditions of the Uzen Field while ensuring economic viability and operational feasibility for EOR applications.

### 3. METHODOLOGY

A comprehensive experimental program is in place to develop optimized polymer flooding strategies for the Uzen Field. The research methodology systematically evaluates key performance characteristics of polymer solutions in reservoir conditions. Laboratory rheological measurements assess shear-thinning behavior and viscosity, while thermal stability tests determine resistance to temperature degradation over extended exposure. Static adsorption techniques measure polymer retention on rock surfaces, and ion surrogate tests examine the impact of different salts on polymer effectiveness. Core flooding injectivity tests evaluate the dynamic behavior of polymer solutions in porous media. These tests provide critical data to refine polymer formulations and brine solutions, enhancing oil recovery in high-salinity environments.

#### 3.1 Materials

##### 3.1.1 Polymers

The study aimed to identify the most suitable polymer for application in high-salinity FW conditions. Six polymer samples were selected based on a preliminary analysis, each prepared in the FW samples to mimic the actual production conditions. Their performance was compared with polymer samples prepared in CSW solutions, to compare the polymer flooding in both high and low salinity brine solutions. The names and identifiers of the polymer samples are listed below:

Table 2. Polymer Samples and their identifiers

Polymer Sample	Description
1	ASP2 (A HPAM polymer, Provided by KMGE)
2	ASP3 (A HPAM polymer, Provided by KMGE)
3	Polyacrylamide R1 (We named it ASP5)
4	Aspiro p 5411 (Polyacrylamide) (We named it ASP6)
5	Softpusher NP 1 (Polyacrylamide) (We named it ASP7)
6	Superpusher (We named it ASP8)

##### 3.1.2 Brines

The primary brines used in this study were FW sourced directly from the Uzen Field and CSW. The FW was emphasized due to its relevance, as CSW was unavailable for the project. The

composition of FW presents challenges, such as polymer degradation and reduced viscosity, necessitating careful adjustments to its ionic composition to optimize polymer performance.

The brine compositions are summarized in the table below:

Table 3. Brine compositions

Component	FW Concentration (ppm)	CSW Concentration (ppm)
Na <sup>+</sup>	18,902	3,513.1
Ca <sup>2+</sup>	3,307	400.8
Mg <sup>2+</sup>	972.8	790.4
Cl <sup>-</sup>	36,159	6,026.6
SO <sub>4</sub> <sup>2-</sup>	75.8	3,138.0
HCO <sub>3</sub> <sup>-</sup>	390.4	256.2
K <sup>+</sup>	276.0	87.6
CO <sub>3</sub> <sup>2-</sup>	390.4	36.0
Total	60083.0	14248.7

### 3.1.3 Core Samples

Injectivity tests were conducted using two core samples obtained from the Uzen Field. These cores were selected and characterized to reflect the field's reservoir conditions. The critical parameters of the cores are summarized below:

Table 4. Core samples key parameters

Core Number	Well	Depth Interval (m)	Length (mm)	Diameter (mm)	Porosity (%)	Permeability (md)	Dry Weight (g)	Saturated Weight (g)	Pore Volume (cm <sup>3</sup> )
1154	9127	1346.29	54.9	37.7	20	228.8	131.96	143.93	11.97
1028	9127	1315.05	51.1	37.8	21	224.0	128.31	140.18	11.87

Core 1 exhibited slightly higher permeability, while Core 2 demonstrated marginally higher porosity. These attributes were instrumental in evaluating polymer injectivity and retention under reservoir-like conditions.

## 3.2 Experiments Methodology

### 3.2.1 Polymer Preparation Procedure

The polymer preparation followed API RP 63 standard to create reliable experimental results. Polymers were dissolved into brine solutions using FW as the base medium.

To get the desired concentration, the necessary polymer powder was first carefully weighed using an analytical balance. We slowly added the polymer into the brine solution using a stirring device impelled by magnets. Stirring the brine carefully prevented the polymer from bunching up and made the mixing work more even as it can be seen in Figure 16. Our stirring process followed API RP 63 rules with gentle speeds (150-200 rpm) for 6 to 8 hours to achieve complete chain hydration of the polymer.

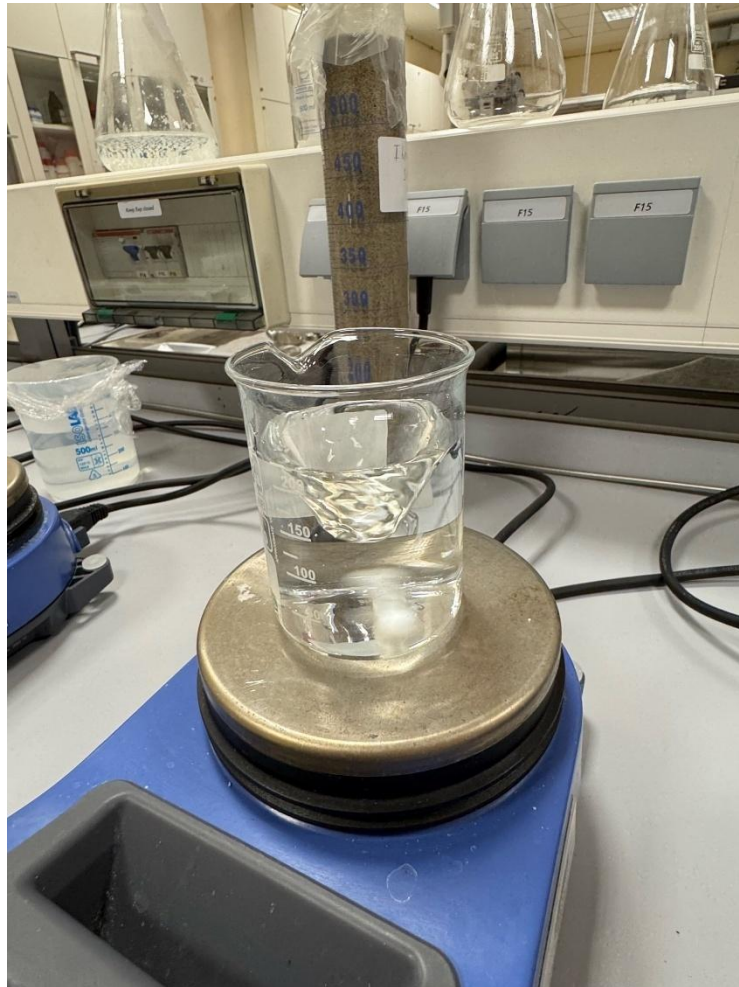


Figure 16. Polymer solution preparation procedure

After dissolving, the mixture was allowed to settle for a full day and stabilize the polymer molecules. The polymer solutions were filtered through fine membranes to guarantee homogeneity and avoid any pore blockage during core flooding studies. Before being used in tests, the produced solutions were kept at regulated temperatures in sealed, contamination-free containers. The concentration range in which polymer solutions were prepared was between 500 and 3000 ppm.

### 3.2.2 Rheology test

The rheology test was conducted to evaluate the viscosity behavior of polymer solutions under shear conditions that mimic reservoir operations. The test employed a Modular Compact Rheometer (MCR 302) by Anton Paar, equipped with both cone-and-plate and double-wall concentric cylinder geometries as can be seen in Figure 17. The double-wall concentric cylinder shape was used for tests at high temperatures in order to avoid evaporation and guarantee accurate viscosity results. This setup was critical for accurately simulating the high-temperature and high-salinity conditions of the Uzen Field reservoir.



Figure 17. MCR 302 apparatus and its application

For all polymers we measured rheology between 500 and 3000 ppm concentrations. Before testing, the rheometer was calibrated, and the appropriate measurement geometry was installed. In accordance with API RP 63, the polymer solutions were made in FW, guaranteeing constant hydration and stability. Following preparation, the solutions were allowed to settle for a full day in order to remove air bubbles and attain consistent hydration. Approximately 2–3 mL of the polymer solution was applied to the cone plate for room temperature evaluations, while 50 mL was used in the cylindrical cell for elevated temperature tests.

The viscosity measurements were conducted over a range of shear rates, from 1 s<sup>-1</sup> to 100 s<sup>-1</sup>, replicating the flow velocities encountered during polymer injection and displacement in porous media. The test temperature was maintained at 63°C, reflecting the reservoir conditions of the Uzen Field. The MCR 302 rheometer collected viscosity data in real-time, which was saved for subsequent analysis to assess shear-thinning behavior and the polymers' ability to achieve target viscosities under reservoir conditions.

To avoid cross-contamination, the rheometer and related equipment were meticulously cleaned after each test was finished. This entailed rinsing with hot household water, then cleaning with solvents to get rid of any remaining polymer, and then rinsing with distilled water.

### **3.2.3 Thermal Stability Test**

The thermal stability tests were conducted to evaluate the ability of polymer solutions to retain their viscosity under prolonged exposure to reservoir temperature conditions. The testing process aimed to simulate the thermal degradation of polymers over time, using FW as the base medium for solution preparation. The polymer concentrations were selected based on the optimum results obtained from the rheology tests, ensuring relevance to the reservoir's operating conditions.

The polymer solutions were prepared in FW at the desired concentrations and then subjected to thermal aging in a controlled environment set at 63°C. To reduce oxidation and evaporation during the testing period, the solutions were kept in sealed vials. The total duration of the thermal stability tests was two months, with a strategic schedule for viscosity measurements.

Ten measurements of viscosity were made within the first two weeks in order to track any early deterioration patterns and track any initial alterations. The measures were taken twice a week for the next two weeks, and once a week for the last month was considered optimal. This method preserved data collecting efficiency while enabling thorough tracking of viscosity trends over time.

All polymers were prepared in FW at a concentration of 2000 ppm. In Figure 18, it can be seen how polymer solutions were placed in heat oven.



Figure 18. The placement of polymer solutions in vials inside of the heat oven with temperature of 63°C.

Viscosity measurements were performed using the MCR 302 with the double-wall concentric cylinder geometry, ensuring precision under high-temperature conditions. The information gathered from these experiments shed light on the polymer solutions' thermal stability and demonstrated their ability to endure extended exposure to reservoir conditions without suffering appreciable degradation.

### 3.2.4 Static adsorption test

A static adsorption test was conducted to determine the maximum level of polymer adsorption on reservoir rock samples from the Uzen Field. The test evaluated the adsorption behavior of polymers, which were prepared in FW following the API RP 63 standard. Before testing we filtered the FW through a filter press to remove potential interfering materials. The study focused on the effect of polymer concentration, with solutions prepared in a range of 1000 to 3000 ppm.

To accurately measure polymer adsorption, a calibration curve was established using a UV-Vis spectrophotometer (Figure 19). Polymer solutions at known concentrations (100 ppm, 200

ppm, 300 ppm, 400 ppm, and 500 ppm) were analyzed to determine their absorbance values. These absorbance values were used to construct the calibration curve, which served as the basis for calculating polymer adsorption in subsequent tests.



Figure 19. UV-Vis spectrophotometer device.

Polymer solutions were mixed with crushed Uzen sandstone at a mass ratio of 4:1, a proportion chosen to ensure complete adsorption of polymers onto the sandstone particles. Before setting it in an oven, we kept the mixture at room temperature in a rotary oven for 36 hours. This aging process facilitated equilibrium adsorption and closely simulated reservoir conditions.

A UV-Vis spectrophotometer was used to evaluate the absorbance of the polymer-sandstone combination following the aging process. The previously defined calibration curve was used to translate the obtained absorbance values into adsorption values. This method provided a quantitative understanding of the polymers' adsorption behavior in FW and on sandstone surfaces under reservoir-relevant conditions.

### **3.2.5 Ion modification**

The ion modification test was designed to assess the effects of additional ions on the rheology of polymer solutions prepared in FW. The primary objective was to understand how variations in ion concentrations influence polymer viscosity, with a target viscosity of 5 cP under a shear rate of  $10 \text{ s}^{-1}$ . Numerous studies have established that the composition of brine solution

greatly influences polymer performance through its ion content especially with respect to divalent ions and sulfates. The introduction of divalent cations including  $\text{Ca}^{2+}$  and  $\text{Mg}^{2+}$  into solution leads to dramatic reduction in polymer viscosity according to Lee et al. (2019) because they neutralize polymer chain negative charges while forcing chains to contract. The presence of sulfate ions from  $\text{Na}_2\text{SO}_4$  controls polymer chain interactions through hydrolysis modifications which affect both viscosity properties and stability behavior.

According to Hu et al. (2024) and Saha et al. (2021) the modification of ion composition in high-salinity solutions decreases polymer degradation yet optimal formulation adjustments both enhance heat resistance and minimize surface binding between polymer and rock materials. Consequently, three salts—  $\text{Na}_2\text{SO}_4$ ,  $\text{CaCl}_2$ , and  $\text{MgCl}_2$ —were chosen for our investigation because they represent the key ionic species that control polymer behavior under challenging reservoir conditions. All experiments were conducted at the Uzen Field reservoir temperature of  $63^\circ\text{C}$ , and polymer solutions were prepared following API RP 63 standards to ensure consistency and reliability.

The process started by determining the base case polymer solution's viscosity in the absence of any extra ions. Table 5 and 6 show the composition of all brines used compared to FW.

Table 5. Composition of brines modified by  $\text{Na}_2\text{SO}_4$  compared to FW.

<b>Component</b>	<b>FW (ppm)</b>	<b>1.5× <math>\text{SO}_4^{2-}</math></b>	<b>2× <math>\text{SO}_4^{2-}</math></b>	<b>3× <math>\text{SO}_4^{2-}</math></b>	<b>4× <math>\text{SO}_4^{2-}</math></b>
$\text{Na}^+$	18902	18920	18938	18975	19011
$\text{Ca}^{2+}$	3307	3307	3307	3307	3307
$\text{Mg}^{2+}$	972.8	972.8	972.8	972.8	972.8
$\text{Cl}^-$	36159	36159	36159	36159	36159
$\text{SO}_4^{2-}$	75.8	113.7	151.6	227.4	303.2
$\text{HCO}_3^-$	390.4	390.4	390.4	390.4	390.4
$\text{K}^+$	276.0	276.0	276.0	276.0	276.0
$\text{CO}_3^{2-}$	390.4	390.4	390.4	390.4	390.4
<b>Total</b>	<b>60083.0</b>	<b>60138.9</b>	<b>60194.8</b>	<b>60307.6</b>	<b>60419.4</b>

Table 6. Composition of brines modified by MgCl<sub>2</sub> and CaCl<sub>2</sub> compared to FW

Component	FW (ppm)	2× MgCl <sub>2</sub>	4× MgCl <sub>2</sub>	2× CaCl <sub>2</sub>	4× CaCl <sub>2</sub>
Na <sup>+</sup>	18902	18902	18902	18902	18902
Ca <sup>2+</sup>	3307	3307	3307	6614	13228
Mg <sup>2+</sup>	972.8	1,945.6	3,891.2	972.8	972.8
Cl <sup>-</sup>	36159	38992	44666	42007	53711
SO <sub>4</sub> <sup>2-</sup>	75.8	113.7	151.6	227.4	303.2
HCO <sub>3</sub> <sup>-</sup>	390.4	390.4	390.4	390.4	390.4
K <sup>+</sup>	276.0	276.0	276.0	276.0	276.0
CO <sub>3</sub> <sup>2-</sup>	390.4	390.4	390.4	390.4	390.4
Total	60083.0	63888.8	71508.4	69238	87556

The base case served as a control and was prepared at the optimal concentration determined during rheology tests. The viscosity of this solution was measured using a MCR 302 with cone-and-plate geometry, which provided precise control over shear rate and temperature. For the calcium ion modification, calculated amounts of CaCl<sub>2</sub> were added to the FW to double and then quadruple the concentration of Ca<sup>2+</sup> ions. To guarantee even ion dispersion, the polymer solution was well combined following each addition. After allowing the solution to stabilize, its viscosity was measured at the same shear rate and temperature conditions. Similarly, for magnesium ion modification, MgCl<sub>2</sub> was added to double and quadruple the Mg<sup>2+</sup> ion concentration. Magnesium ions were of particular interest due to their potential to enhance polymer-ion interactions, leading to increased viscosity.

In the case of sulfate ion modification, Na<sub>2</sub>SO<sub>4</sub> was added to the FW to double and quadruple the SO<sub>4</sub><sup>2-</sup> ion concentration. After each concentration adjustment, the viscosity of the solution was measured under consistent conditions to observe the effects of sulfate ions on the polymer rheology.

Due to the unavailability of fresh water in the Uzen Field, formation water is used as the basis for all polymer solutions. This operational constraint means that we cannot dilute the inherent high salinity of the reservoir fluids. Our approach involves specific modifications of formation water salt content through Na<sub>2</sub>SO<sub>4</sub>, CaCl<sub>2</sub>, and MgCl<sub>2</sub> addition to enhance the performance of the polymer system. We modify the concentration of specified ions to improve stability and viscosity

retention when dealing with rock surface adsorption without changing the solution salinity. This approach enables us to leverage the existing formation water while mitigating its adverse effects on polymer flooding efficiency.

### **3.2.6 Injectivity test**

The injectivity test was conducted to evaluate the flow behavior of polymer solutions and their impact on the permeability of Uzen Field core samples under reservoir conditions. A realistic simulation of how polymer solutions interact with formation water during dynamic processes within porous media occurred during this test. The FW, with a salinity of around 60000 ppm, was first filtered to remove any solids or contaminants that could obstruct the pore network in the core. The polymer solution was prepared at the desired concentration following API RP 63 standards.

A key objective of this test was to compare the performance of polymer solutions modified by selective ion additions, without altering the overall salinity and to compare it with the best polymer in FW. The introduction of  $\text{Na}_2\text{SO}_4$ ,  $\text{CaCl}_2$ , and  $\text{MgCl}_2$  in the polymer solution enabled us to achieve better performance for maintaining viscosity and stability when under high-salinity conditions. The testing method enabled us to examine how modified ions affect injectability and fluid movement characteristics of unmodified polymers when injected into high-salinity conditions.

Before the test, the cylindrical core samples, which were 3.81 cm in diameter and 6 cm in length, were manually saturated with FW. The CFS 700 Core Flooding System was utilized to perform the injectivity test under controlled reservoir conditions, including a temperature of 63°C, a confining pressure of 1500 psi, and a back pressure of 300 psi during brine and polymer injection. The setup for CFS 700 can be seen in Figure 20 and Figure 21.



Figure 20. CFS 700 Coreflooding System

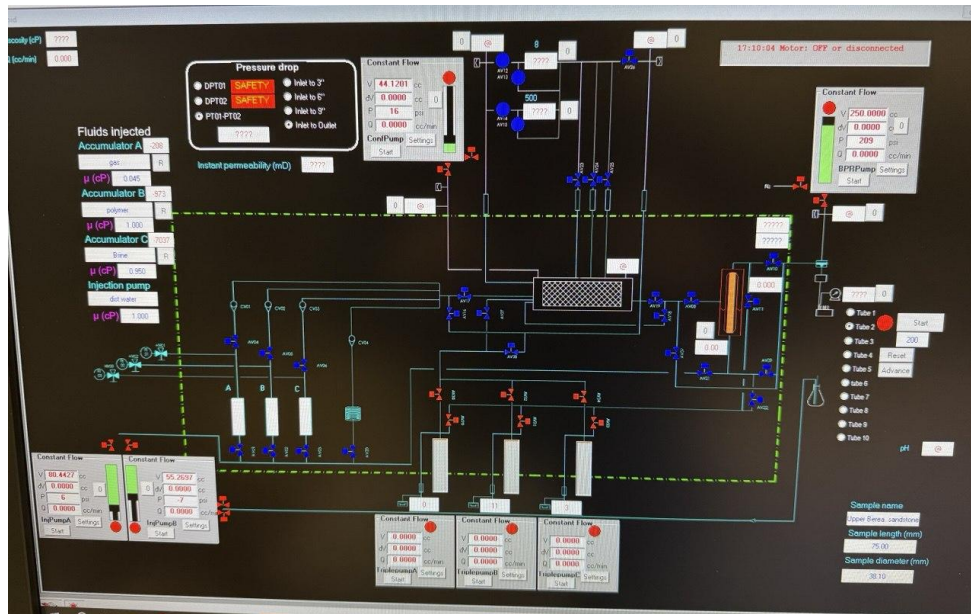


Figure 21. Schematic of the CFS 700 Coreflooding System

The test began with the saturation of the core using FW. FW was injected at incremental flow rates of 0.5, 1.0, 1.5, and 2.0 cc/min to establish baseline permeability and observe the pressure drop across the core. These measurements provided an initial understanding of the flow properties and core permeability under reservoir conditions.

Following the FW saturation step, the best polymer solution was injected into the core. Beginning with a flow rate of 0.5 cc/min, the polymer injection rate was progressively raised to 1.0, 1.5, and 2.0 cc/min. The reason behind changing the flow rate was to measure the resistivity factor and the degradation at different shear rate. During polymer injection, the back pressure was set to 0 psi to avoid degradation of the polymer as it exited the core. The pressure drop across the core was recorded at each flow rate to assess the injectivity and compatibility of the polymer solution with the porous medium.

After polymer injection, the core was flushed with FW at similar incremental flow rates. The purpose of this post-flush step was to measure the decrease in permeability brought on by polymer retention in the core pores to determine the RRF. This step also ensured the displacement of unadsorbed polymer from the system.

The injectivity test provided a comprehensive assessment of the flow behavior of polymer in FW-saturated cores under reservoir-like conditions. By evaluating pressure responses and permeability changes during each stage, the test contributed valuable insights into the performance and suitability of polymer flooding for EOR in the Uzen Field.

### 3.2.7 Workflow

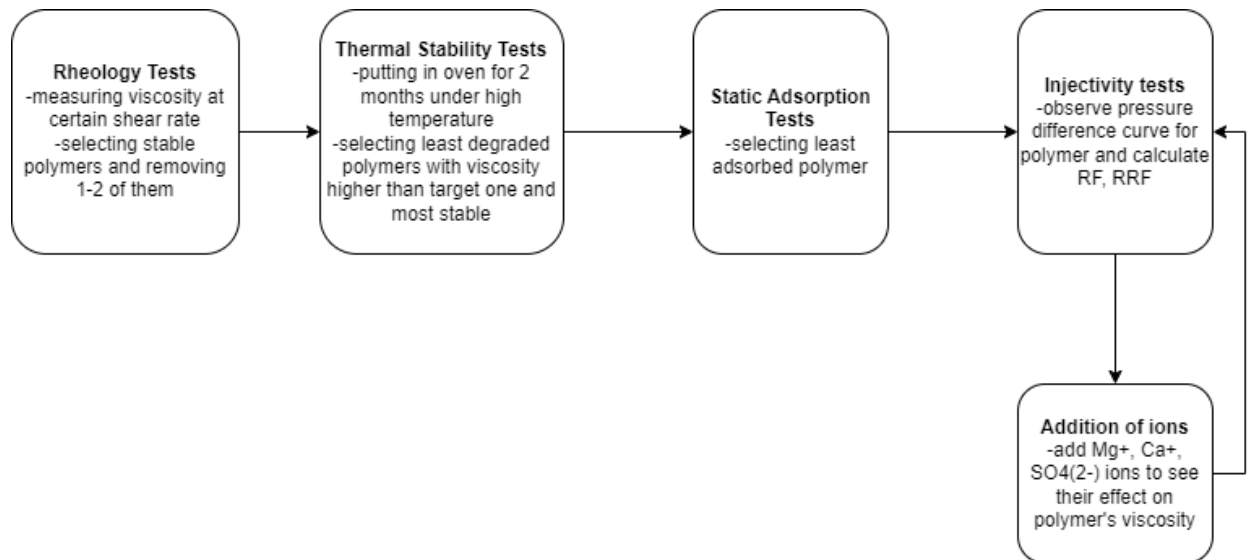


Figure 22. Experimental Workflow

Based on Figure 22, the experimental workflow was systematically designed to evaluate the performance and suitability of polymer solutions for EOR under the conditions of the Uzen

Field. Rheology experiments were used to determine the viscosity of polymer solutions at different shear rates at the start of the operation. The discovery of stable polymers that could preserve desired rheological characteristics in the face of dynamic flow circumstances was guaranteed by this procedure. Based on the results, 1–2 polymers exhibiting consistent performance were selected for further evaluation.

The capacity of the polymers to maintain their viscosity over time at the reservoir temperature of 63°C was then evaluated using thermal stability tests. The polymers were placed in an oven for two months, and periodic viscosity measurements were taken to monitor degradation. In order to ensure long-term performance under high-temperature circumstances, this stage sought to select the polymers that showed the least degradation and maintained viscosities above the required threshold.

Following thermal stability testing, static adsorption tests were performed to evaluate the interaction of the polymers with the reservoir rock. A UV-Vis spectrophotometer was used to evaluate the adsorption levels after the polymer solutions were combined with crushed Uzen sandstone. Since little adsorption lowers chemical losses and improves economic viability during field application, the polymer with the lowest adsorption was given priority.

Injectivity experiments were the next step, which evaluated how well the chosen polymers interacted with the reservoir rock. Pressure decreases across the core were measured by core flooding experiments, and metrics including the resistance factor (RF) and residual resistance factor (RRF) were computed. These experiments shed light on the effects of the polymer solutions on injectivity and permeability in reservoir simulations.

Finally, ion modification tests were conducted to optimize the performance of the polymer solutions further. To investigate their impacts on polymer rheology, several ions, such as  $Mg^{2+}$ ,  $Ca^{2+}$ , and  $SO_4^{2-}$ , were introduced to the solutions at different quantities. In order to improve viscosity retention in the high-salinity environment of the Uzen Field and get a better knowledge of how ionic interactions affect polymer behavior, these ions were added.

The selection of the best option for increased oil recovery activities was made possible by this approach, which guaranteed a thorough evaluation of polymer solutions. Each stage improved on the outcomes of the one before it, resulting in a solid and trustworthy method for assessing polymer performance.

## 4. RESULTS AND DISCUSSION

The evaluation of polymer flooding effectiveness under Uzen Field high-salinity situations is presented in this chapter. The assessment of polymer solutions behavior and ion modification effects required a series of extensive laboratory tests which included rheology, thermal stability, static adsorption, and injectivity experiments. The experimental data gathered through these tests delivers quantitative measurements about viscosity changes combined with degradation patterns as well as absorption trends. The following sections evaluate the outcomes of the optimized polymer flooding strategy for EOR along with its potential and constraints.

### 4.1 Rheology Test

The rheology test was conducted to evaluate the viscosity behavior of six polymer samples under varying concentrations. The target viscosity for the test was set at 5 cP under a shear rate of  $10 \text{ s}^{-1}$ , which aligns with the optimal mobility control requirements for EOR in Uzen field. Figure 23 illustrates the viscosity versus polymer concentration curves for the tested polymers (ASP 2, ASP 3, ASP 5, ASP 6, ASP 7, and ASP 8) in FW at reservoir conditions.

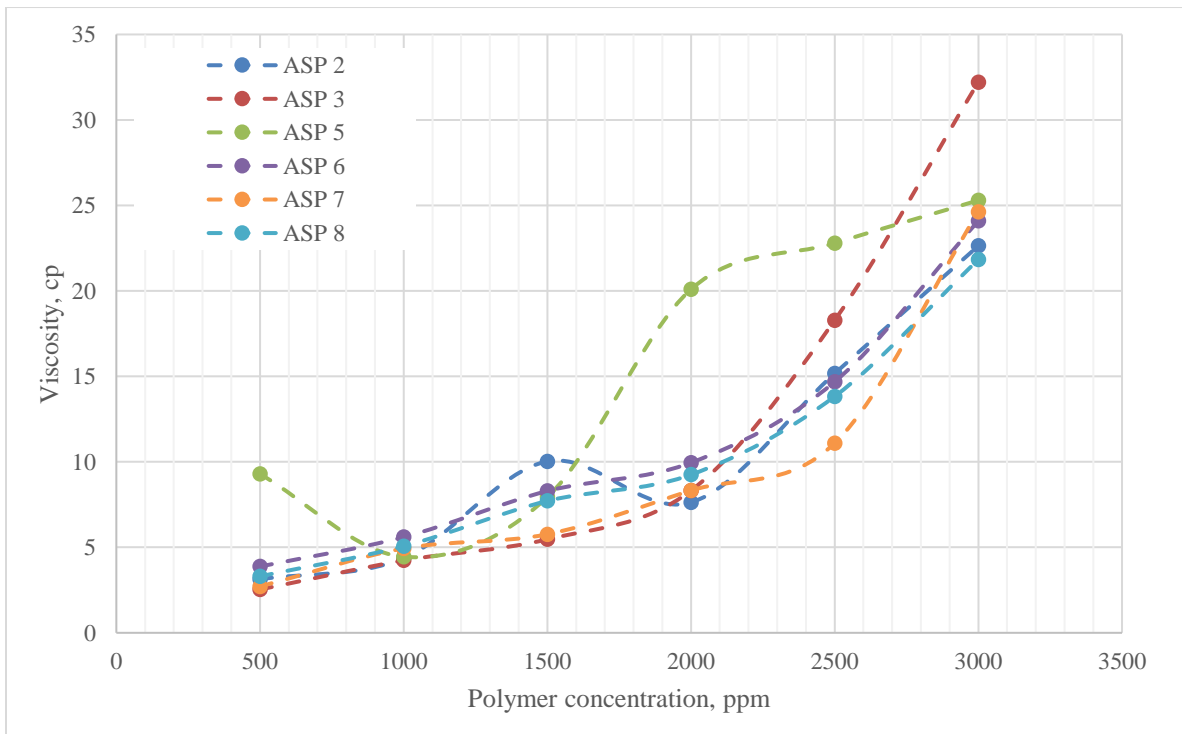


Figure 23. Rheology of 6 polymers in FW solution at reservoir temperature

Figure 24 was shown as an example to show the shear thinning behavior of all samples, where viscosity decreased when shear rate increased for all polymer concentrations. This property is favorable for maintaining mobility control in reservoir conditions.

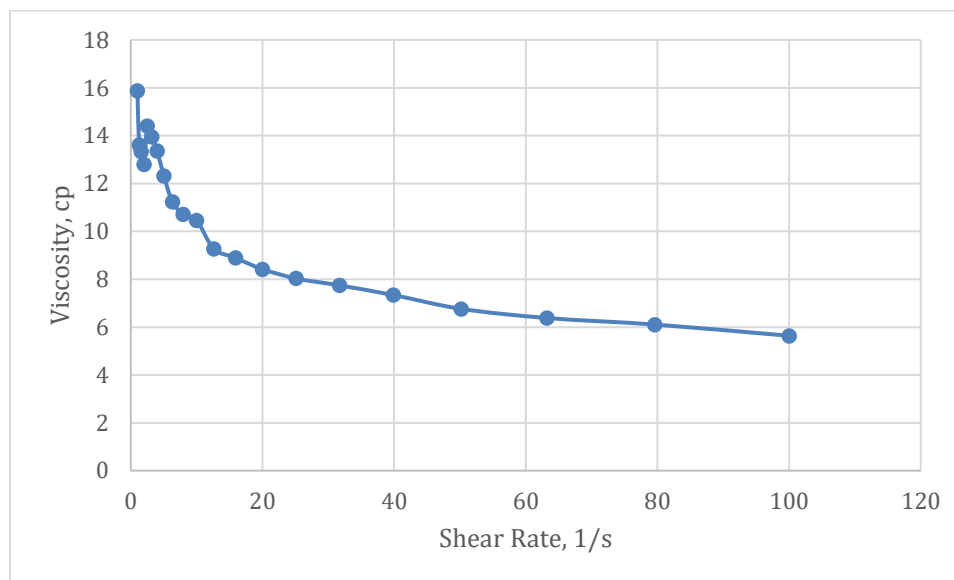


Figure 24. Viscosity under shear rate for ASP6 in FW with concentration of 2000 ppm in reservoir temperature

After detailed analysis, ASP 2 and ASP 5 were removed from further testing. ASP 2 was excluded due to its similarity to ASP 6 in both chemical composition and rheological behavior, as evident from overlapping trends in Figure 23. To expedite the experimental procedure and concentrate resources on unique samples, redundancy in testing comparable polymers was avoided.

ASP 5 was removed because of its unstable behavior in FW salinity. At low concentrations (below 1500 ppm), ASP 5 demonstrated disproportionately high viscosity values, which could lead to injectivity issues in porous media. Because of this behavior, ASP 5 is not appropriate for reservoir applications when saline levels surpass 60000 ppm. These results are consistent with previous research that emphasizes the crucial role that salinity plays in affecting the stability and flow characteristics of polymers (e.g., Lee et al., 2019; Wang et al., 2018).

The remaining polymers (ASP 3, ASP 6, ASP 7, and ASP 8) demonstrated stable rheological properties, achieving or exceeding the target viscosity of 5 cP within the range of tested concentrations. To further assess these polymers' performance under reservoir-like circumstances, they will undergo adsorption and thermal stability experiments.

## 4.2 Thermal Stability Test

The thermal stability of polymer solutions was evaluated over a duration of two months at a constant temperature of 63°C. All polymers were prepared in FW at a concentration of 2000 ppm, which was selected based on the rheology test results as a representative low concentration. Measurements were conducted using an optimized schedule: ten measurements in the first two weeks, two measurements per week in the next two weeks, and one measurement per week for the remaining month. Figures 25 and 26 illustrate the viscosity behavior and degradation curves for 4 polymers performance in FW.

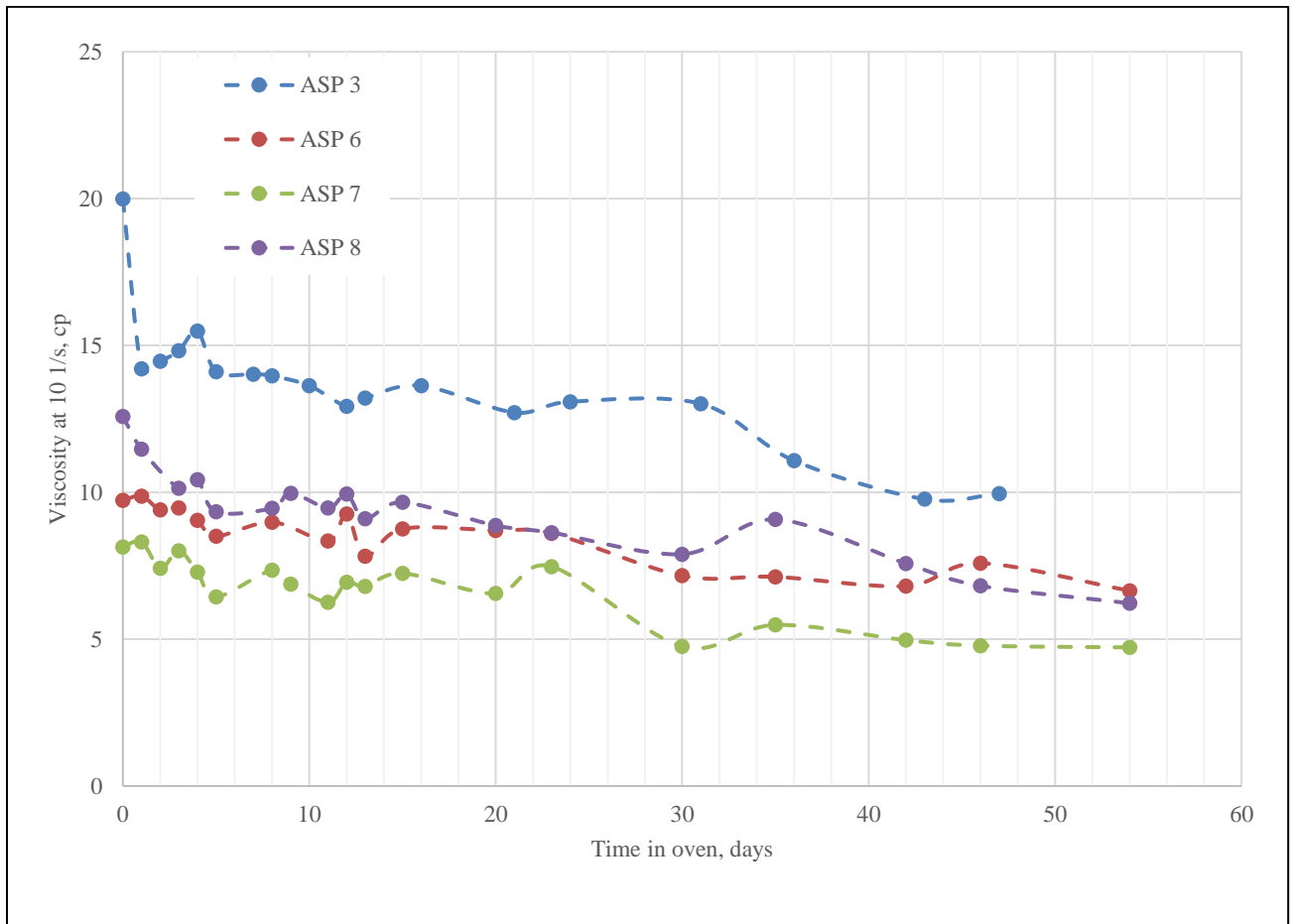


Figure 25. Viscosity over time for 4 polymers at 2000 ppm at reservoir temperature

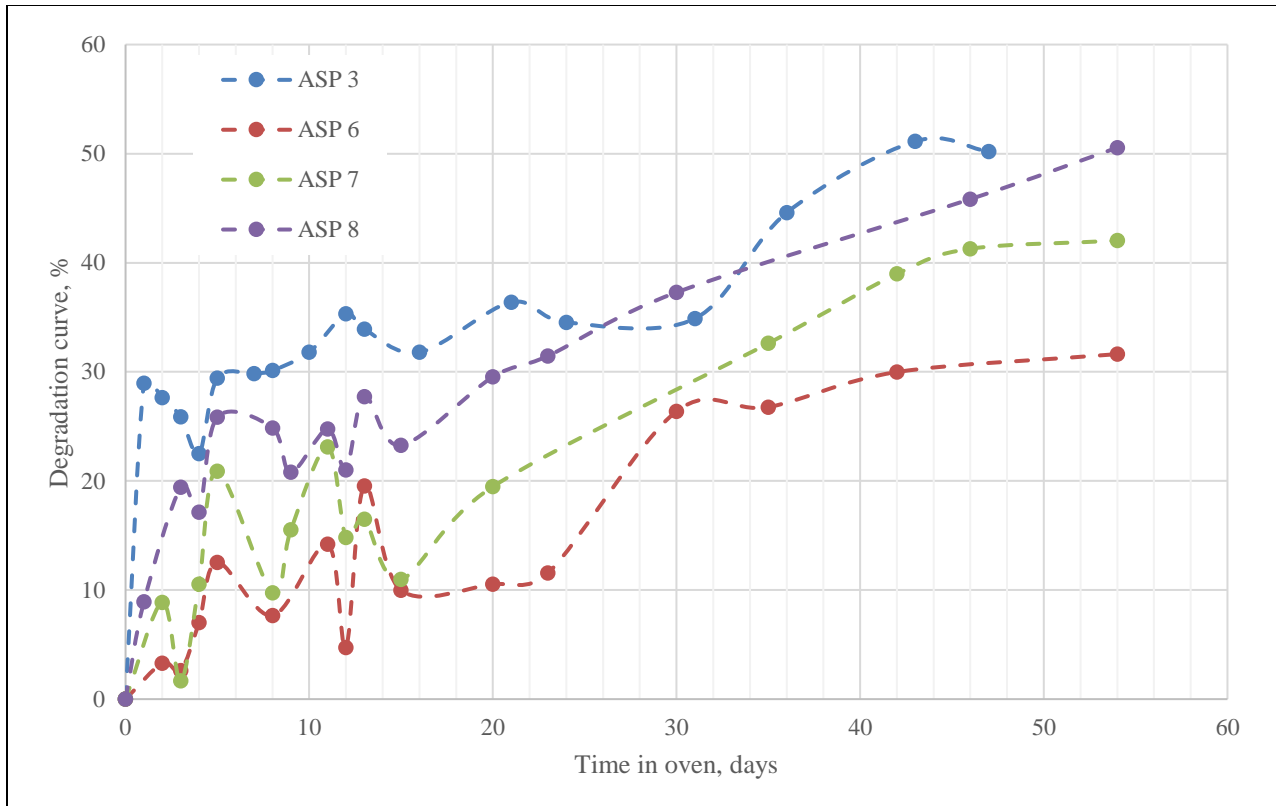


Figure 26. Degradation curve for 4 polymers at 2000 ppm at reservoir temperature

As shown in Figure 25, all polymers experienced viscosity reduction over time due to thermal degradation, but their stability varied significantly. ASP 3 started at an initial viscosity of 20 cP and reduced to 13 cP by the end of the test, showing a steady decrease after a pronounced drop during the initial two days. A similar pattern was seen by ASP 8, which began at 12.5 cP and ended at 8.6 cP. ASP 6 and ASP 7 demonstrated better thermal stability with relatively smaller reductions in viscosity; ASP 6 decreased from 9.7 cP to 8.6 cP, while ASP 7 reduced from 8.1 cP to 7.4 cP.

While all polymers retained viscosities above the target of 5 cP for most of the test period, ASP 7 failed to meet this requirement during the second month, making it unsuitable for further evaluation.

The degradation curves in Figure 26 provide additional insights into polymer stability. After 24 days in FW, ASP 3 showed a breakdown rate of about 34%, suggesting superior thermal stability in comparison to the other polymers examined. The deterioration curves for ASP 6 and

ASP 8 were mild, while ASP 7 showed the most degradation of all the polymers, which further supported its rejection from additional testing.

The comparison of ASP 3 in CSW and FW, as shown in Figure 27, reveals significant differences in thermal stability. In FW, at the beginning of thermal degradation test, the viscosity of ASP3 was 19.99 cP. When put in the oven for about 47 days, the viscosity dropped till 9.95 cP. In comparison with SW, ASP3 viscosity before the test was 25.81 cP and decreased till the value of 5.17 cP after 70 days in heat oven. In contrast to 50% in FW, ASP 3 shown more noticeable degradation in CSW, reaching almost 80% by the conclusion of the test. This indicates that ASP 3 is thermally more stable at higher salinity levels, such as those in FW, despite the lower initial viscosity due to the challenging ionic composition. ASP 3 in FW maintained a viscosity of 9.96 cP after 50 days, indicating that it is appropriate for additional testing.

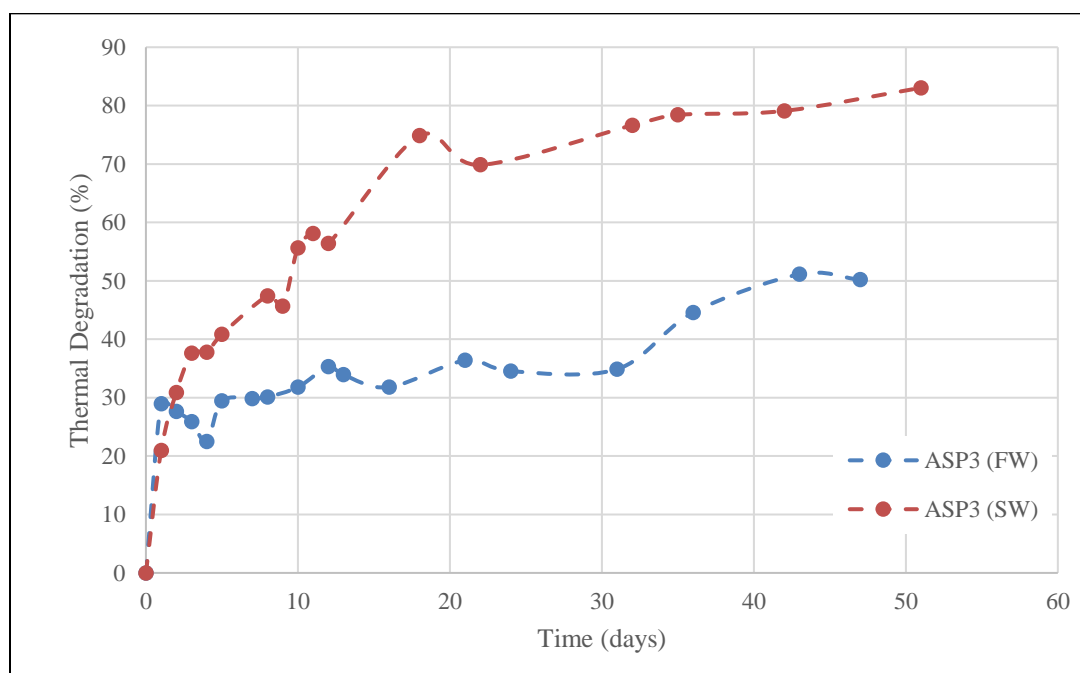


Figure 27. Thermal stability comparison of ASP3 in CSW and FW at 2000 ppm

By the end of the two-month thermal stability test, ASP 3, ASP 6, and ASP 8 demonstrated sufficient viscosity retention and thermal stability to qualify for subsequent evaluations. Because of its improved performance in FW over CSW and its capacity to sustain greater viscosities over time, ASP 3 stood up as the most viable contender. ASP 8 and ASP 6 also showed acceptable

thermal stability and will be further tested. ASP 7, however, was excluded from further testing due to its inability to maintain the target viscosity beyond the first month.

The thermal stability test confirmed the critical role of brine salinity and polymer composition in influencing viscosity retention under high-temperature conditions. The performance of ASP 3, ASP 6, and ASP 8 was satisfactory; even at lower concentrations, ASP 3 was very effective in FW.

### **4.3 Static Adsorption test**

The static adsorption test was conducted to evaluate the adsorption behavior of polymers ASP 3, ASP 6, and ASP 8 under FW conditions. The polymers were prepared following API RP 63 standards, and FW was filtered to eliminate impurities that might interfere with adsorption results. Uzen sandstone was used as the reservoir rock, and the polymer solutions were mixed with crushed sandstone in a rotary oven at room temperature for 36 hours. Adsorption values were determined using a UV-Vis spectrophotometer and calibration curves.

Figure 28 illustrates the adsorption of ASP 3, ASP 6, and ASP 8 as a function of polymer concentration (1000–3000 ppm) in FW. According to the screening criteria, ASP 6 was the best choice since it showed the lowest adsorption at all doses. Its adsorption values remained significantly lower than those of ASP 3 and ASP 8, which is critical for minimizing polymer loss in reservoir rock and ensuring cost-effectiveness during chemical flooding. For example, at 2500 ppm, ASP6 showed 48% less adsorption compared to ASP8 and 67% less adsorption compared to ASP3. The similar trend can be observed for all other concentrations.

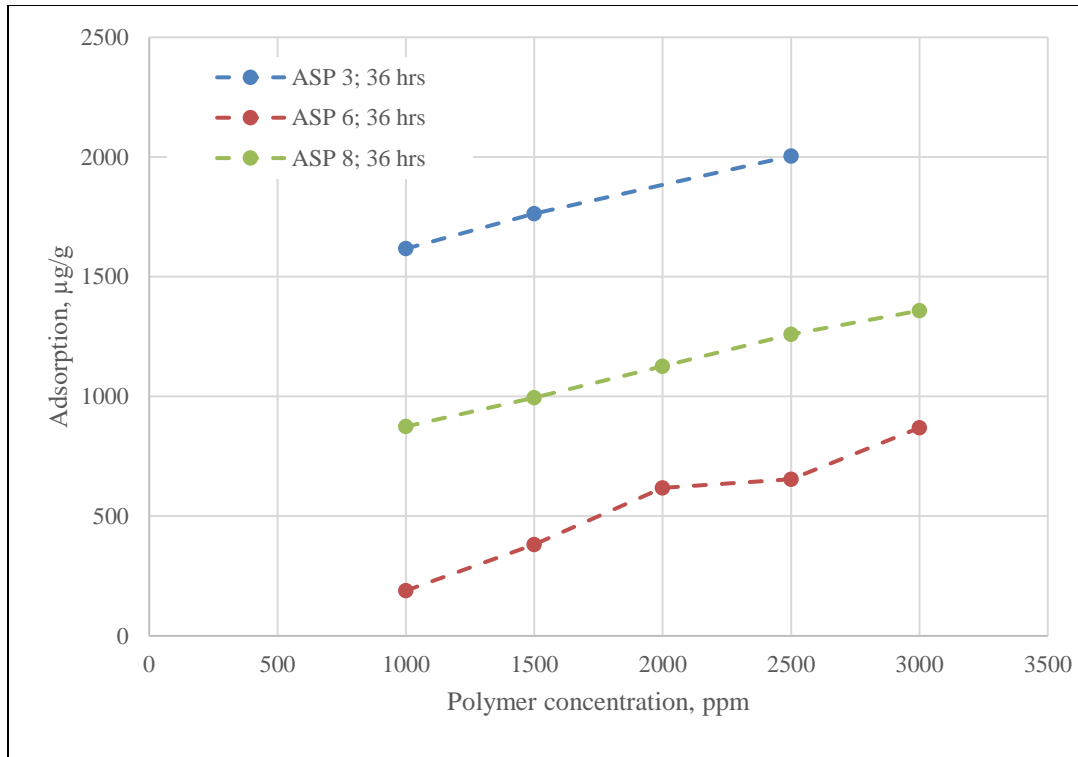


Figure 28. Adsorption values for three polymers in FW after 36 hours

ASP 3, while maintaining higher adsorption values, showed a consistent increase with concentration, highlighting its interaction with the sandstone surface. ASP 8 displayed moderate adsorption levels but was less effective compared to ASP 6 at retaining low adsorption values at higher concentrations. These results suggest that ASP 6 is the most practical polymer for FW applications, as it minimizes adsorption losses.

Figures 29 and 30 compare the adsorption behavior of ASP 3 and ASP 6 in FW and SW. For ASP 3, higher salinity significantly increased adsorption levels, as shown in Figure 32. For example, at 1500 ppm, ASP 3 in SW reached adsorption values of approximately 1047 µg/g, while in FW, the adsorption remained around 1764 µg/g, meaning 40% difference in adsorption values. At 2500 ppm, the difference was minimal, around 2.2%. This trend indicates that ASP 3 is more suitable for applications in SW environments, where its adsorption is higher and can potentially improve interaction with the reservoir rock.

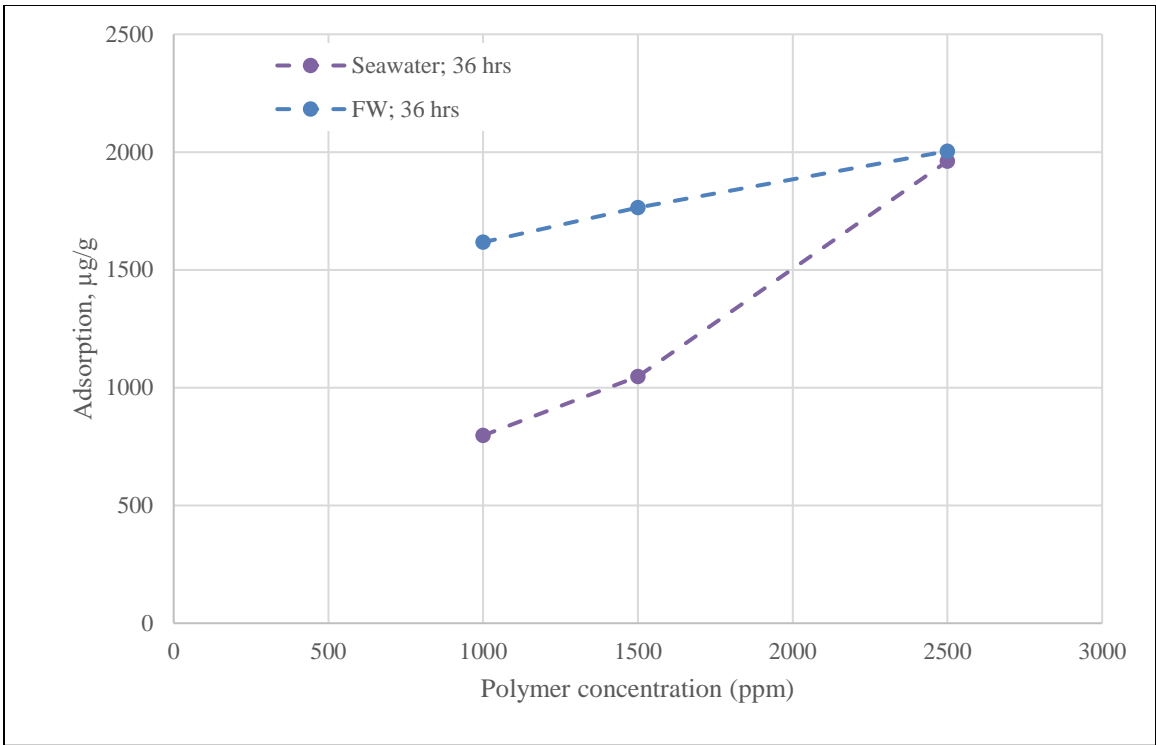


Figure 29. Adsorption for ASP3 in FW and CSW after 36 hours

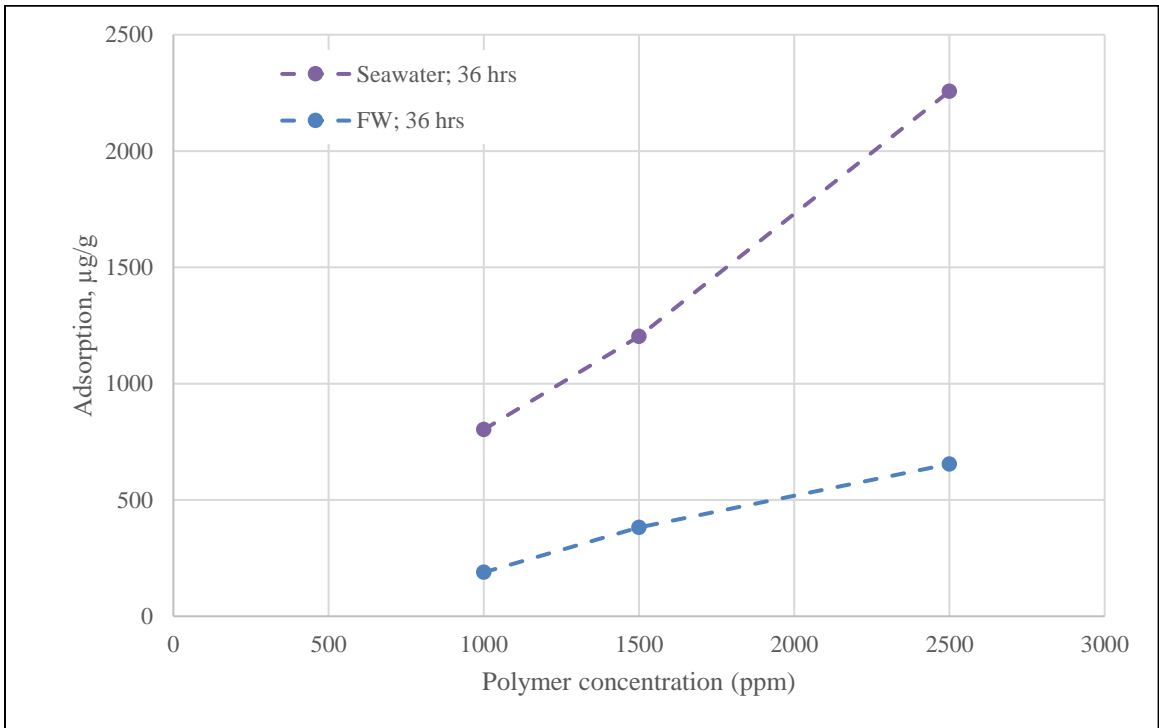


Figure 30. Adsorption for ASP6 in FW and CSW after 36 hours

In contrast, ASP 6, shown in Figure 30, displayed an opposite trend. Adsorption values in SW were consistently lower than those in FW, indicating that ASP6 works better in solutions with greater salinity, such as FW. At 2500 ppm, the adsorption of ASP6 in FW was approximately 654  $\mu\text{g/g}$ , while in SW, it was around 2256  $\mu\text{g/g}$ , meaning 72% difference in adsorption values. At 1500 ppm, the difference was around 69%. By comparing polymer behavior in SW and FW by adsorption we are looking for a polymer works better at high salinity. This behavior highlights the practical advantages of ASP6 for applications in high-salinity reservoirs such as the Uzen Field.

The static adsorption test provided critical insights into the suitability of polymers for different salinity environments. According to the findings, ASP 6 was the most economical and effective option for high-salinity applications since it showed the lowest adsorption levels in FW. Because of its increased adsorption, ASP 3 performs well in SW situations but is less useful in FW settings. ASP 8 showed moderate adsorption values but did not outperform ASP 6 under FW conditions.

The chemistry of ASP 6, which is Aspiro P 5411, should also be considered to understand why it outperformed other polymers that were tested during screening. Firstly, its sulfonated polyacrylamide backbone gives rise to a stronger ionic shielding around the polymer chains to minimise their affinity to the negatively charged sandstone surfaces. This is also endorsed by BASF's own viscosity studies where they had stipulated that in the case of presence of the divalent  $\text{Ca}^{2+}$  ions, standard HPAM grades tend to lose as much as 69 % of its viscosity whereas Aspiro P 5411 loses up to 56 %, which shows better performance in high salinity conditions.

Advantages of the Aspiro P 5411 go beyond its excellent tolerance to calcium and include the superior shear stability, prompt dissolution, and wide applicability with regards to geochemical conditions. Its molecular architecture gives resilience against the high level of shear forces experienced close to the wellbore and within narrow pore throats, hence reduced mechanical degradation during injection. Its neutral pH ( $\approx 7$ ) also ensures that it does not cause the unwanted reactions with reservoir minerals or fluids. The major cost is a slightly poorer intrinsic viscosifying power relative to ultra-high-molecular-weight HPAMs, which will necessitate a higher polymer concentration to achieve the same mobility control in the reservoir.

In conclusion, because of its better performance in FW, ASP 6 is suggested for more testing and field applications in the Uzen Field. Its capacity to sustain low adsorption levels in high-

salinity conditions guarantees little chemical losses, which is consistent with the goals of economical and efficient polymer flooding.

#### 4.4 Ion management

The ion management study was conducted to evaluate the effect of altering ion concentrations in FW on the rheological performance of ASP6 polymer solutions. Due to the unavailability of fresh water for salinity reduction, FW was used for polymer preparation. To optimize polymer rheology, the concentrations of key ions— $\text{Ca}^{2+}$ ,  $\text{Mg}^{2+}$ , and  $\text{SO}_4^{2-}$ —were adjusted using salts such as  $\text{CaCl}_2$ ,  $\text{MgCl}_2$ , and  $\text{Na}_2\text{SO}_4$ , respectively. Each ion was tested separately by doubling and quadrupling its concentration to observe its influence on polymer viscosity under reservoir conditions ( $63^\circ\text{C}$ ).

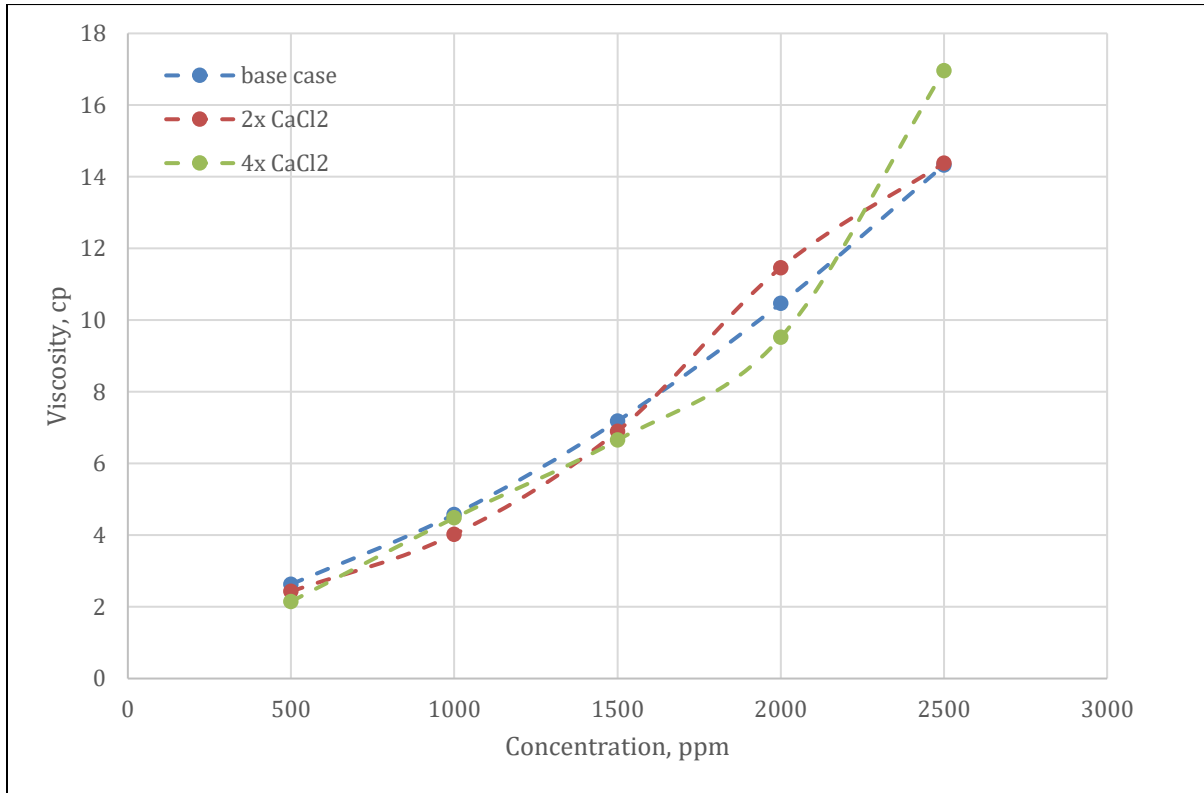


Figure 31.  $\text{Ca}^{2+}$  ions modification and its effect on ASP6 viscosity

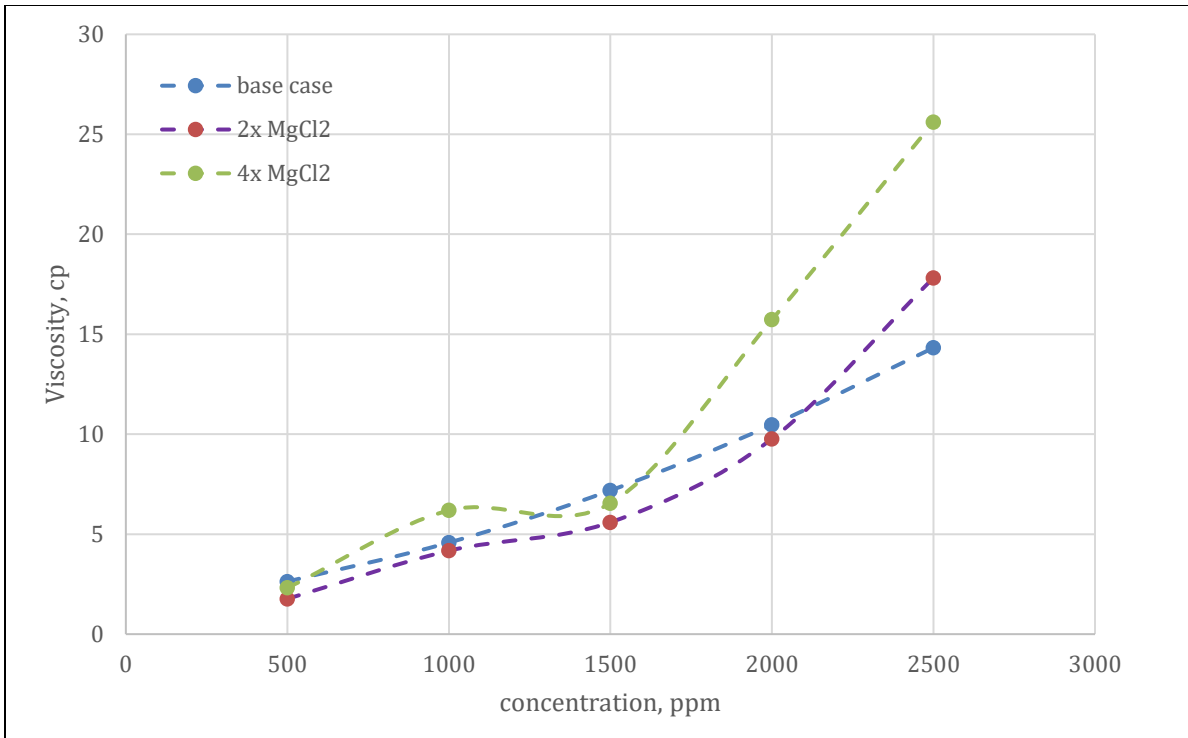


Figure 32. Mg<sup>2+</sup> ions modification and its effect on ASP6 viscosity

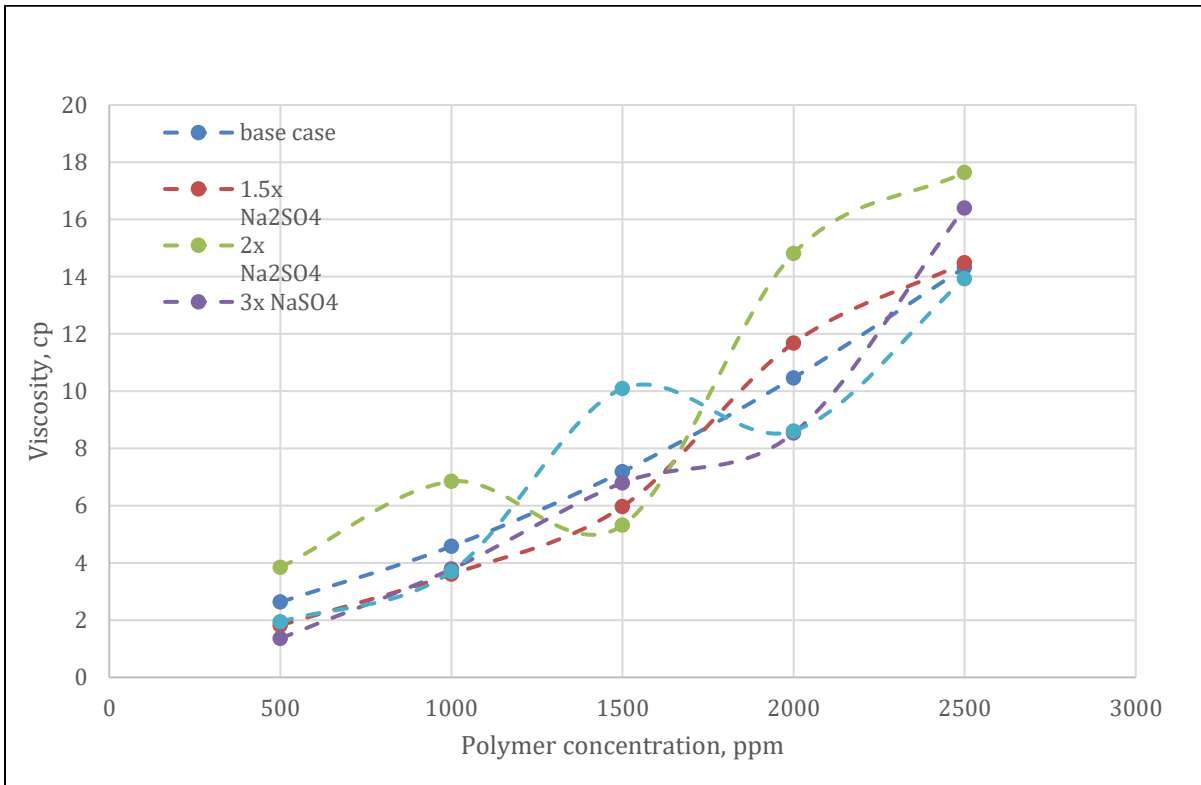


Figure 33. SO<sub>4</sub><sup>2-</sup> ions modification and its effect on ASP6 viscosity

Table 7. Results for ASP6 viscosity changes from ion modification

<b>ASP6 Polymer Concentration (ppm)</b>	<b>500 ppm</b>	<b>1000 ppm</b>	<b>1500 ppm</b>	<b>2000 ppm</b>	<b>2500 ppm</b>
Base Case	2.63	4.58	7.18	10.46	14.32
CaCl <sub>2</sub> (2×)	2.43	4.02	6.9	11.46	14.38
CaCl <sub>2</sub> (4×)	2.15	4.48	6.65	9.52	16.95
MgCl <sub>2</sub> (2×)	1.77	4.17	5.59	9.77	17.82
MgCl <sub>2</sub> (4×)	2.32	6.12	6.55	15.73	25.61
Na <sub>2</sub> SO <sub>4</sub> (1.5×)	2.39	4.45	6.68	10.74	15.09
Na <sub>2</sub> SO <sub>4</sub> (2×)	4.53	5.96	6.46	11.14	15.99
Na <sub>2</sub> SO <sub>4</sub> (3×)	2.26	4.59	6.94	9.66	16.54
Na <sub>2</sub> SO <sub>4</sub> (4×)	2.72	5.03	8.38	11.05	12.48

Figure 31 shows that increasing the concentration of Ca<sup>2+</sup> ions through the addition of CaCl<sub>2</sub> negatively affected polymer viscosity across all tested concentrations. In the base case, the polymer solution at 2000 ppm achieved a viscosity of 10.46 cP. The viscosity increased slightly to 11.46 cP when the Ca<sup>2+</sup> ion concentration was doubled (CaCl<sub>2</sub> 2×); however, it decreased to 9.52 cP when the concentration was quadrupled (CaCl<sub>2</sub> 4×). According to these findings, too many calcium ions disrupt the polymer chains, making it harder for them to create a stable, viscous solution. The findings of Lee et al. (2019) show that rising calcium concentration levels trigger extensive HPAM chain contractions which ultimately causes substantial viscosity reduction in solution. Oliviera et al. (2019) discovered that elevated Ca<sup>2+</sup> levels trigger rapid polymer decomposition which leads to decreased effective viscosity and impaired mobility control. High-ionic environments promote significant degradation through divalent cations according to Hasiri et al. (2023) who measured the sensitivity of polymer gels towards these particles. The findings from these research studies strongly indicate that reserve lifespan depends on keeping control of Ca<sup>2+</sup> salt levels for sustaining polymer stability within saline environments.

According to Figure 32, the addition of Mg<sup>2+</sup> ions through MgCl<sub>2</sub> produced mixed results, with a significant positive effect observed at higher concentrations. Doubling the Mg<sup>2+</sup> ion concentration yielded a viscosity of 9.77 cP, slightly lower than the base case. However, as seen

in the table, a significant rise in viscosity to 15.73 cP was obtained by quadrupling the  $Mg^{2+}$  ion concentration. This significant improvement implies that  $Mg^{2+}$  ions increase viscosity retention by strengthening the contact between water molecules and polymer chains. Lee et al. (2019) demonstrated that medium concentrations of  $Mg^{2+}$  improve both hydration of polymers and their structural stability which optimizes viscosity maintenance. A significant number of reports demonstrate that applying high concentrations of divalent ions results in polymer gelation and precipitation phenomena that decrease injectivity abilities and sweep performance levels. The research by Hu et al. (2024) demonstrates that moderately controlled magnesium addition reduces polymer degradation, but this efficacy is extremely sensitive to correct ionic ratio maintenance. Based on their research Aguiar et al. (2021) found that the beneficial impact of  $Mg^{2+}$  ions on polymer rheology depends heavily on both the composition of solution ions and the formulation used for the polymer. The results support the theory that  $Mg^{2+}$  ions are a good option for ion management as they can improve polymer performance in high salinity environments.

The addition of  $SO_4^{2-}$  ions via  $Na_2SO_4$  demonstrated varying effects depending on the concentration as it can be seen in Figure 33. Doubling the  $SO_4^{2-}$  ion concentration ( $Na_2SO_4$  2 $\times$ ) produced stable and positive results, with a viscosity of 11.14 cP at 2000 ppm. But when the concentration was quadrupled ( $Na_2SO_4$  4 $\times$ ), the viscosity dropped to 11.05 cP, suggesting that too many sulfate ions might compromise the structural integrity of the polymer. The results suggest that moderate increases in sulfate concentration are beneficial, but over-concentration can negatively impact polymer performance. The moderate sulfate level enhancements improve fluid performance through balanced hydrate chain growth yet high salt amounts lead to chain reduction and strength interference which decreases viscosity. Li et al. (2019) showed nonlinear degradation of polymer solution intrinsic viscosity when sulfate and NaCl concentrations elevate. Jouenne (2020) also stressed that a properly regulated ionic atmosphere ensures stable polymer chains function correctly in difficult reservoir environments. Furthermore, Hasiri et al. (2023) observed that an optimal level of sulfate is crucial to minimize polymer adsorption on rock surfaces, thereby sustaining viscosity and injectivity.

The rheology results indicate that ion management can significantly influence polymer performance in FW. While  $CaCl_2$  consistently exhibited a negative impact,  $MgCl_2$  at 4 $\times$  concentration (15.73 cP) and  $Na_2SO_4$  at 2 $\times$  concentration (11.14 cP) showed the most positive effects. For FW, ASP6 with concentration of 2000 ppm is recommended as a base case. The

viscosity was 10.46 cp. As  $4\times \text{Mg}^{2+}$  was added to the solution, the viscosity changed to 15.73 cp at 2000 ppm of ASP6 concentration. This was chosen as the most effective enhanced case by ions management.

Error analysis is shown in Figure 34 for sulfate ions case as an example to see the range of error of data reported in Table 7. This was done to validate the repeatability of the tests. The measurements were repeated three times at least to see the change in trends or conclusions that can be drawn from the ion management. The error bars on this graph suggest some variability in the results, but the trend is clear despite the inherent experimental uncertainties.

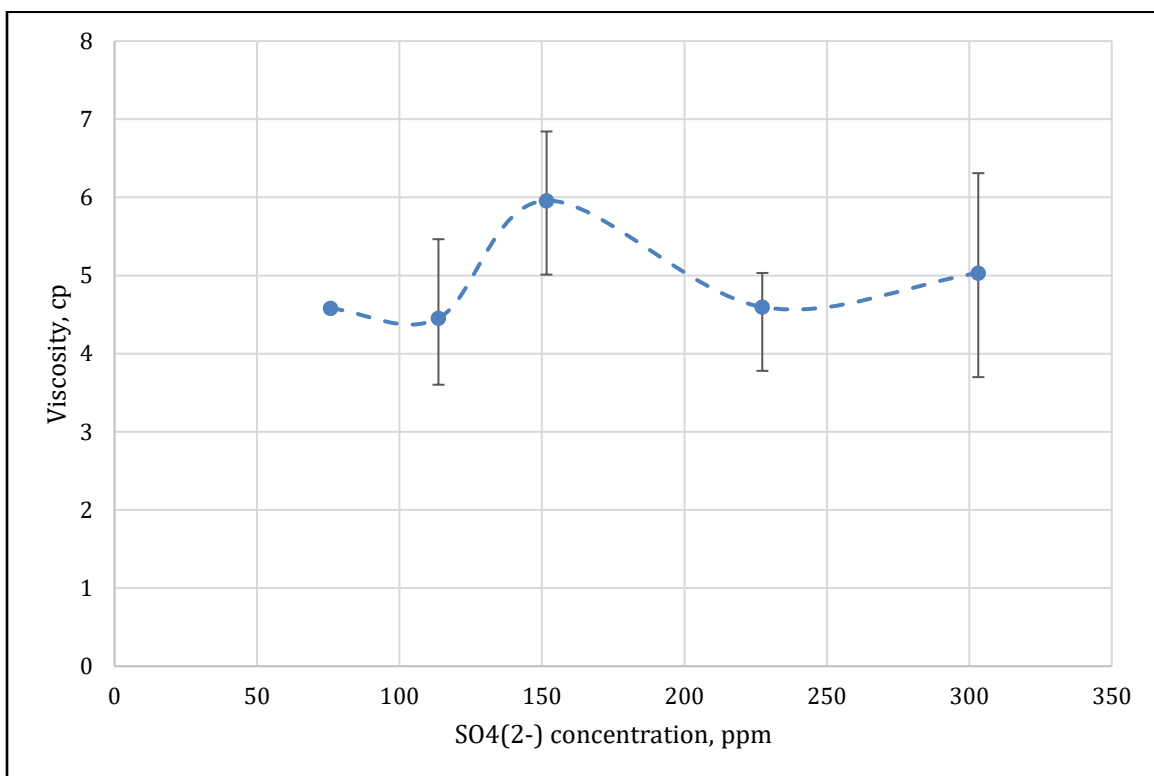


Figure 34. Effect of  $\text{SO}_4^{2-}$  ions on ASP6 at 1000 ppm with error bars

#### 4.5 Injectivity test

The injectivity test was conducted to evaluate the performance of ASP6 polymer solutions under two scenarios: a base case, where the polymer was prepared in FW at a concentration of 2000 ppm, and an enhanced modified case, where the FW was supplemented with  $4\times \text{Mg}^{2+}$  ions. The test assessed the RF and RRF at varying flow rates, providing insights into polymer behavior under dynamic flow conditions.

The performance of the two cases is illustrated by the trends in the pressure differential ( $\Delta P$ ) observed in Figures 35 and 36. In the base case,  $\Delta P$  rises sharply during polymer flooding but declines significantly during the post-flush stage, indicating reduced flow resistance as the polymer is flushed out. Conversely, the enhanced case shows consistently higher  $\Delta P$  values during polymer flooding, especially at low flow rates, reflecting the higher viscosity and improved ionic interactions. These characteristics are further supported by the more stable RF values across increasing flow rates, making the enhanced case more adaptable to varying injection conditions. For each step we continued for 2 PV to achieve a stable pressure to measure RF and RRF.

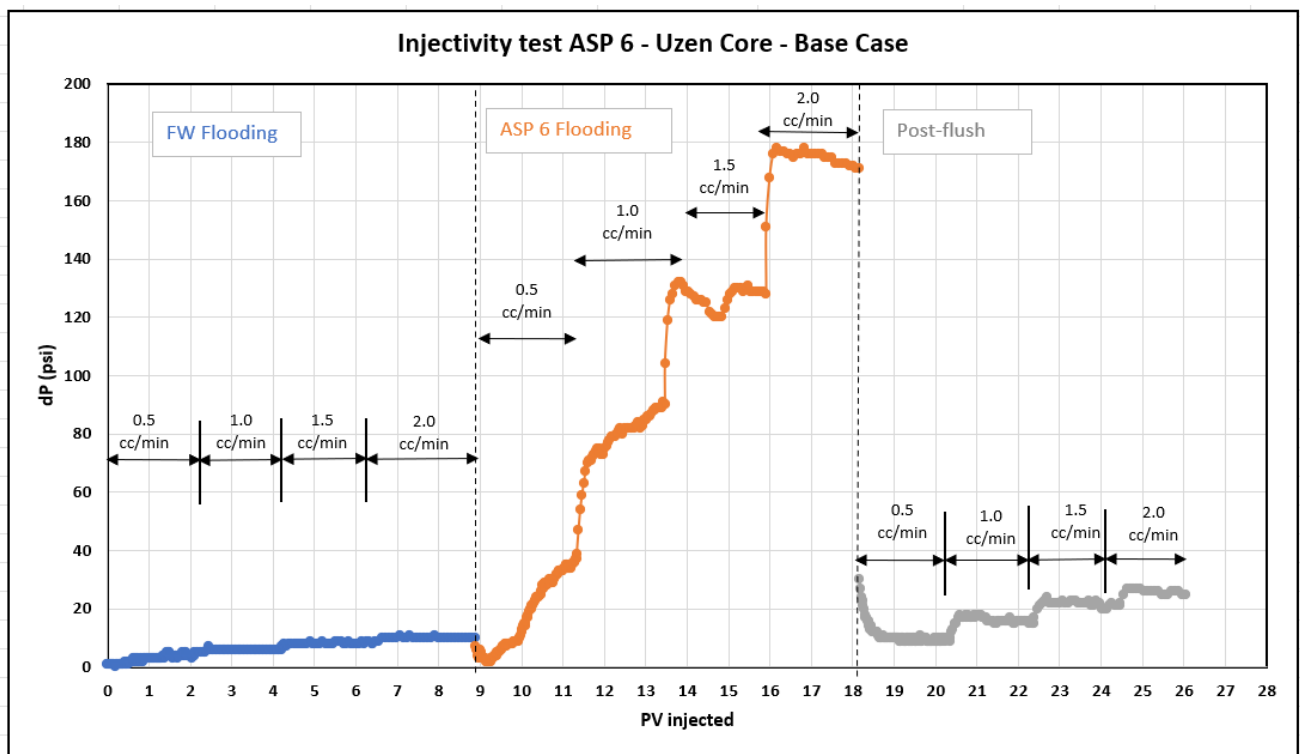


Figure 35. Injectivity test for ASP6 base case

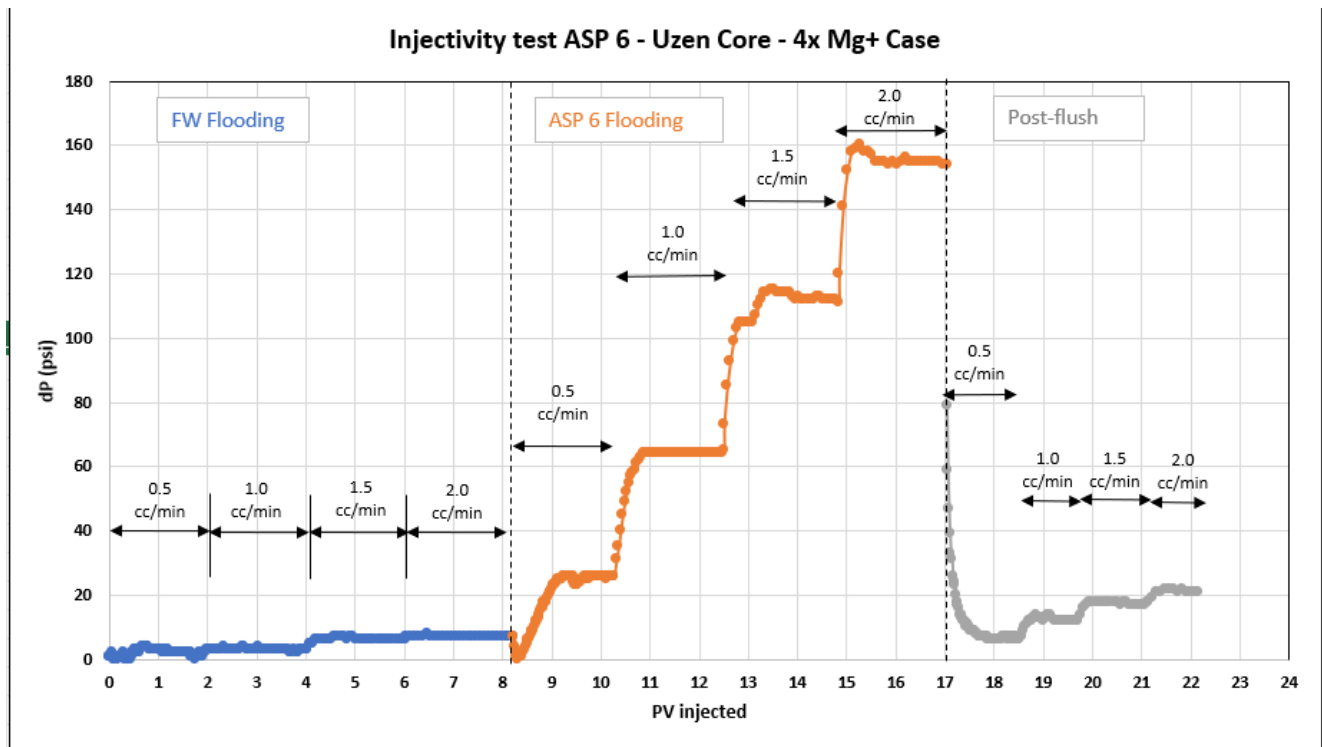


Figure 36. Injectivity test for ASP6 with 4× Mg<sup>2+</sup> ions

Table 8. RF and RRF for ASP6 base case and for ASP6 with 4× Mg<sup>2+</sup> ions

q (cc/min)	FW Flooding		Polymer Flooding		Postflush		RF		RRF	
	Base case dP (psi)	4× Mg+ case (psi)	Base case dP (psi)	4× Mg+ case (psi)	Base case dP (psi)	4× Mg+ case (psi)	Base case dP (psi)	4× Mg+ case (psi)	Base case dP (psi)	4× Mg+ case (psi)
0.5	2.83	1.89	17.80	19.28	11.1	12.34	6.28	10.18	3.92	6.52
1	5.86	2.98	77.92	60.26	16.04	11.83	13.29	20.22	2.74	3.97
1.5	8.19	6.03	126.38	108.68	21.68	17.17	15.43	18.02	2.65	2.85
2	9.97	7.04	173.82	153.70	25.75	20.92	17.43	21.83	2.58	2.97

In the base case, the pore volume of the core was 11.97 cc, with a porosity of 20% and a permeability of 228.8 mD. The polymer solution's viscosity decreased from 10.46 cP before the

test to 7.07 cP after the test, indicating significant mechanical degradation as the polymer traversed the porous medium. From Table 8 the RF and RRF values decreased as the flow rate increased, which is characteristic of shear-thinning behavior often observed in polymer flooding. At a flow rate of 0.5 cc/min, the RF was 6.28, decreasing to 2.58 at 2.0 cc/min. Likewise, throughout the same timeframe, RRF levels decreased from 3.92 to 2.58. This pattern implies that the polymer's resistance to flow decreases with increasing injection rates, most likely because of decreased viscosity and polymer retention.

The core's pore volume in the enhanced scenario was 11.87 cc, and its porosity and permeability were 21% and 224 mD, respectively. Following the test, the viscosity of the polymer solution dropped from 15.70 cP to 9.48 cP, indicating polymer breakdown once more. In contrast, the RF and RRF values in this instance were greater at all flow rates, rising from 10.18 at 0.5 cc/min to 21.83 at 2.0 cc/min (Table 9). The increased resistance factors imply that the injection of Mg<sup>+</sup> ions has enhanced injectivity control. The lower viscosity drop (32.4% drop) in comparison to the basic scenario (39.6% drop) suggests that the ionic interactions probably enhanced the stability and resilience to mechanical degradation of the polymer solution. (Figure 37)

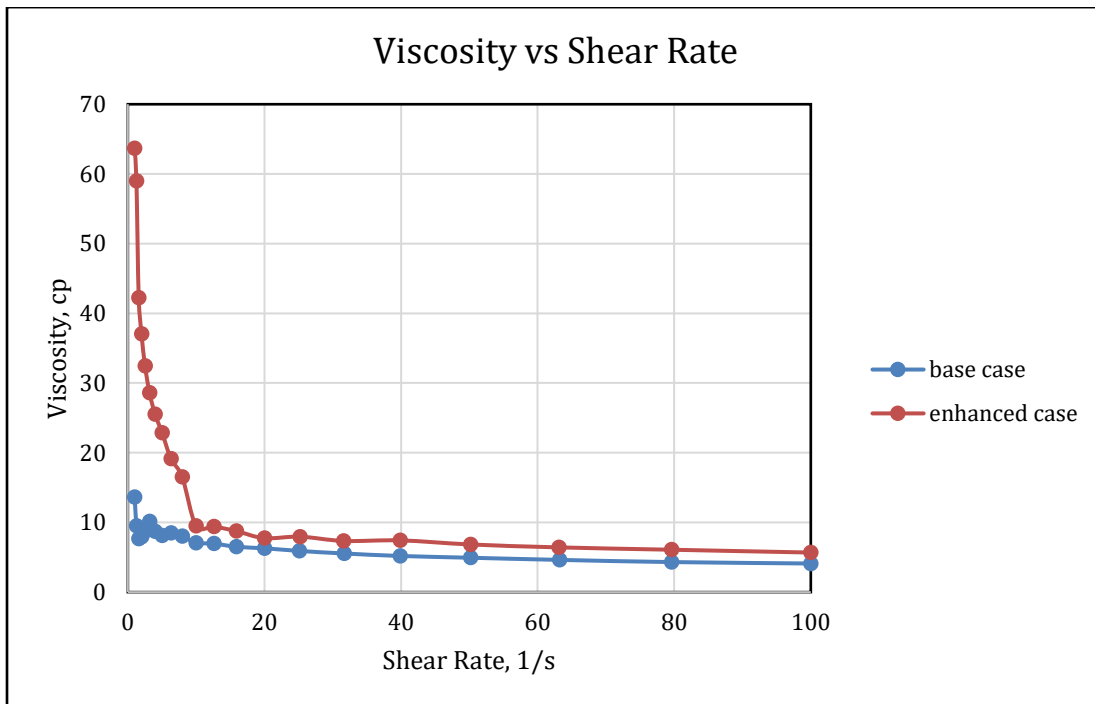


Figure 37. Viscosity vs Shear rate for both cases

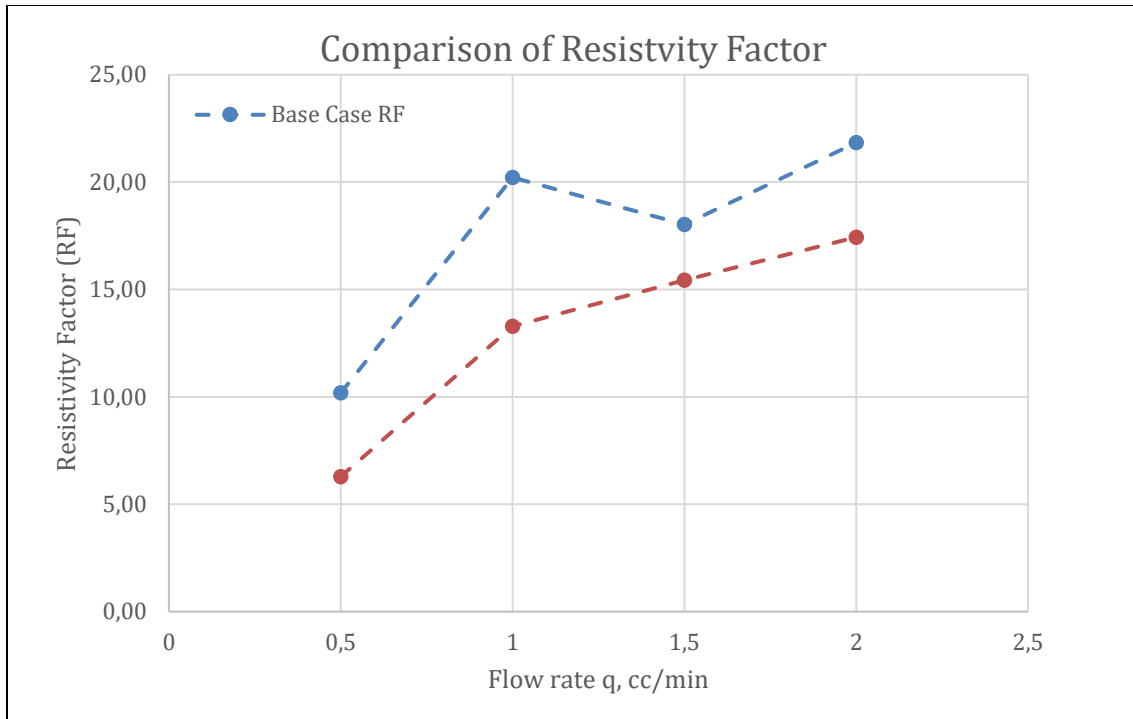


Figure 38. Comparison of RF of base case and enhanced case

Figure 38 illustrates the comparison of RF values for the base and enhanced cases across various flow rates. In the base case, RF values decreased from 6.28 at 0.5 cc/min to 2.58 at 2.0 cc/min, reflecting significant mechanical degradation and reduced flow resistance at higher flow rates. Conversely, the enhanced case demonstrated significantly higher RF values, ranging from 10.18 at 0.5 cc/min to 21.83 at 2.0 cc/min. These results indicate superior injectivity control in the enhanced case, as the higher RF values represent increased resistance to flow, which is essential for effective polymer flooding operations.

The advantage of the enhanced example is demonstrated by comparing the two injectivity tests. Higher RF and RRF values were obtained with the addition of  $Mg^{2+}$  ions, suggesting improved injectivity control and resistance to breakthrough. Additionally, the improved casing retained viscosity better, indicating less mechanical deterioration. In polymer flooding operations, this enhanced stability is essential for guaranteeing efficient mobility control. The basic case, on the other hand, was limited in its efficacy under difficult flow circumstances due to substantial viscosity loss and decreasing RF values at higher flow rates.

The injectivity test demonstrated that ion management through the addition of  $Mg^{2+}$  ions significantly enhance the performance of polymer flooding operations. The enhanced modified

case outperformed the base case, achieving higher RF and RRF values and better viscosity retention. These findings suggest that incorporating  $4\times \text{Mg}^{2+}$  ions into FW is an effective strategy for improving injectivity control and maintaining polymer stability under dynamic reservoir conditions. For future applications, the enhanced case is recommended for achieving superior mobility control and efficiency in polymer flooding.

Overall, the injectivity tests confirmed that the polymer flooding target was achieved using the available formation water. Injectivity control of this process significantly improved after adding  $4\times \text{Mg}^{2+}$  ions because it led to enhanced resistance factors and better viscosity maintenance. These findings demonstrate that changing the ionic content slightly enhances polymers' stability alongside better mobility control which creates potential for more efficient EOR operations in high-salinity reservoirs.

## 5. CONCLUSION AND RECOMMENDATIONS

This study was conducted to evaluate the performance of polymers in FW from the Uzen Field under reservoir conditions and to optimize their properties for EOR applications. The experimental framework included rheology tests, thermal stability tests, static adsorption tests, ion management studies, and injectivity tests. Each step systematically contributed to identifying and recommending the most suitable polymer and conditions for field deployment. The results emphasize the significance of making strategic adjustments to enhance polymer performance and offer insightful information on how polymers behave in high-salinity, high-temperature environments.

Six polymer samples' viscosity behavior was determined by the rheology test; the most promising candidates for additional testing were ASP2, ASP3, ASP6, ASP7, and ASP8.

The target viscosity of 5 cP under a shear rate of  $10 \text{ s}^{-1}$  was achieved by most polymers, except for ASP5, which exhibited unstable behavior and excessive viscosity at low concentrations. Because of its resemblance to ASP6, ASP2 was eliminated to simplify the experimental emphasis.

The thermal stability test demonstrated significant differences in polymer performance under prolonged exposure to reservoir temperature ( $63^\circ\text{C}$ ). ASP3, ASP6, and ASP8 exhibited good thermal stability, retaining viscosities above the target level, while ASP7 failed to meet the required viscosity threshold in the second month. With less thermal deterioration shown in FW than in SW, ASP 3 fared especially well in FW, underscoring the stabilizing benefits of increased salinity. These results underscore the suitability of ASP3, ASP6, and ASP8 for high-temperature, high-salinity reservoirs.

The static adsorption test evaluated the interaction between polymers and Uzen sandstone. ASP6 showed the lowest adsorption levels across all tested concentrations, making it the most cost-effective and efficient polymer for minimizing chemical losses in FW. Despite showing greater adsorption levels, ASP3 fared better in SW, indicating that it might work well in less salinized reservoirs. The results confirm that ASP6 is the best candidate for FW environments due to its minimal adsorption and stable performance.

The ion management study explored the effects of modifying the concentrations of  $\text{Ca}^{2+}$ ,  $\text{Mg}^{2+}$ , and  $\text{SO}_4^{2-}$  ions on polymer rheology. Among the tested ions, the addition of  $4\times \text{Mg}^{2+}$  ions (via  $\text{MgCl}_2$ ) had the most positive effect, increasing the viscosity of ASP6 from 10.46 cP in the base case to 15.73 cP. This demonstrates the potential of  $\text{Mg}^{2+}$  ions to enhance polymer

performance by reinforcing the ionic interactions between polymer chains. Conversely, excessive  $\text{Ca}^{2+}$  ions reduced viscosity, and while  $\text{SO}_4^{2-}$  ions showed positive effects at moderate concentrations ( $2\times$ ), higher concentrations led to viscosity reductions. These results highlight how crucial customized ion management techniques are to enhancing the results of polymer flooding.

The injectivity tests further validated the improved performance of polymers under enhanced ion management conditions. The enhanced modified case, prepared with  $4\times \text{Mg}^{2+}$  ions, exhibited higher RF and better viscosity retention compared to the base case. RF values increased significantly, ranging from 10.18 to 21.83, compared to the base case values of 6.28 to 2.58. These results highlight the superior injectivity control and flow resistance provided by the enhanced case, making it a more efficient option for field applications. Despite slightly higher viscosity loss in the enhanced case, the stronger ionic interactions stabilized the polymer structure, ensuring better performance under dynamic flow conditions.

Based on the comprehensive evaluation of polymer behavior in FW, ASP6 and ASP3 are recommended for further field-scale testing. With low adsorption, strong thermal stability, and compatibility with ion management techniques, ASP6 showed the greatest overall performance in FW. ASP3 may be taken into consideration for reservoirs with reduced salinity because it demonstrated potential in SW conditions. Furthermore, adding  $4\times \text{Mg}^{2+}$  ions is highly advised for enhancing injectivity control and polymer viscosity optimization. Future research should concentrate on assessing polymer performance in various reservoir conditions, integrating economic feasibility calculations, and scaling these findings to field applications.

The research outlines a thorough method to achieve optimal polymer efficiency in difficult reservoir conditions through unification of several key assessment tests including rheology testing along with thermal stability and adsorption screening and ion balancing and injectivity performance evaluation. The study identified ion management as a vital factor because intentional formation water ionic composition adjustments produce protective effects toward polymer viscosities when operating under high salinity conditions. Research results show that targeted changes of  $\text{Na}_2\text{SO}_4$ ,  $\text{CaCl}_2$ , and  $\text{MgCl}_2$  salt concentrations optimize polymer stability and results in effective mobility control across the entire salinity range. Substantial knowledge advancement about polymer flooding in high-salinity reservoirs combined with more sustainable EOR operations become possible in fields like the Uzen Field after these discoveries.

This thesis proposes recommendations to optimize polymer flooding operations in Uzen Field high salinity reservoirs considering the experimental data outcomes:

**Conduct Additional Field Pilot Tests:**

The optimized polymer flooding strategy must undergo pilot field tests to verify laboratory results. Laboratory tests should be scaled up into pilot field tests for operational parameter optimization and polymer performance evaluation in real reservoir conditions.

**Refine Polymer Formulations:**

Develop innovative research on advanced polymers and hybrid copolymer solutions to enhance performance stability in high-salinity reservoirs. Laboratory tests investigating alterations in molecular weight distribution and stable chemical components will help reduce degradation and absorbance-related performance losses.

**Optimize Ion Management Strategies:**

Future research needs to adjust the key ion concentrations such as  $\text{Na}_2\text{SO}_4$ ,  $\text{CaCl}_2$ , and  $\text{MgCl}_2$  until the intended ionic environment is achieved without changing the total solution salinity. Additional research on experimental investigation combined with simulation modeling should optimize polymer performance through adjustments that have already demonstrated improved results.

**The application of advanced monitoring and simulation tools should be implemented.**

Monitoring solutions must be created for simultaneous tracking of polymer injectivity alongside resistance factors and reservoir condition transformations during the polymer flooding operations. Simulations integrated with real-time data allow for dynamic process optimization which enables rapid detection of problems while ensuring peak performance.

**Perform Economic Evaluations:**

A complete economic assessment must be performed to determine how the optimized polymer flooding process compares financially between oil recovery benefits and all expenses from preparation to modification and deployment activities.

**Future Evaluation of SAV10 in High-Salinity Conditions:**

Based on the pH-insensitive and thermally efficient performance of SAV10 evidenced (Jouenne, 2020), we suggest performing special coreflood and field-pilot tests for SAV10 in the Uzen Field high salinity formation water. Considering the low sensitivity of the SAV10 to the divalent cations, an investigation of its injectivity, viscosity retention, and incremental recovery in

the Uzen field's specific ion composition can confirm its compatibility with HPAM based polymers as a substitute in even harsher surroundings.

These recommendations leverage research findings to keep polymer flooding effective and efficient as an enhanced oil recovery strategy in demanding reservoirs.

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