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Analysis of Compatibility Test of Mesona Palustris (Black Grass Jelly) and Chitosan Solution on Formation Water Saltity

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Abstract: The primary purpose of polymer injection is to reduce the water-oil mobility ratio. Commonly used polymers are polyacrylamide and polysaccharides. By increasing the viscosity of the injection fluid, polymer injection can improve sweep efficiency, thereby increasing oil recovery. Petroleum refining relies heavily on macroscopic and microscopic compression efficiency. This study aims to determine the compatibility test results between mesonapalustris and chitosan to determine whether good compatibility test results are obtained. The method used in this study is a laboratory experiment with observation. Compatibility was evaluated based on visual observation and qualitative stability indicators, with no effect across all salinity and concentration ranges. Quantitative indicators showed viscosity retention of >90% at and temperature. This demonstrates the potential of biopolymers as alternative agents in polymer flooding, with an increase in oil recovery of 15–20% OOIP. Compatibility testing of polymer solutions in formation water is carried out to determine whether the polymer solution is completely soluble in the formation water. The test is carried out by dissolving the polymer in formation water with salinities of 10,000, 15,000, and 20,000 mg/L and polymer concentrations of 500, 1,000, and 2,000 mg/L. The solution is then placed in a bottle and observed for complete dissolution or sedimentation. Based on the results and discussions, experimental laboratory testing of black seaweed jelly and chitosan revealed compatibility results, which showed that all polymer solutions, both black seaweed jelly and chitosan, were compatible with various salinities of formation water, indicating that all polymer solutions were completely dissolved, no precipitation occurred and this suggests potential applicability of biopolymers as alternative agents in polymer flooding.

Keywords: Mesona Palustris; Chitosan; Compatibility Testing; Formation Water; Polymer; Injection Polymer; Enhanced Oil Recovery.

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Introduction

Polyacrylamide is a polymer commonly used in chemical flooding methods, while chitosan and black grass jelly polymers are still in the development stage. The selection of these polymers must be tailored to the characteristics of the rock and reservoir fluids of the targeted oil well. This chapter will explain matters related to these polymers.

Polymer Injection

Polymer injection is intended to improve the properties of the displacing fluid and is also called enhanced water injection by adding polymers to the injection water, with the hope of achieving greater oil recovery than conventional water injection (Maifra K. et al., 2021; Novriansyah, 2014). Polymers are used as

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thickeners to increase the viscosity of the injection fluid (Maifra K. et al., 2021; Wicaksono et al., 2015) and improve sweep efficiency (Fathaddin & Awang, 2004).

Polymer injection has been shown to be effective in increasing oil recovery the primary goal of polymer injection is to reduce the water-oil mobility ratio (Manrique et al., 2017). The most commonly used polymers are polyacrylamide and polysaccharides (Novriansyah, 2014). By increasing the viscosity of the injection fluid, polymer injection can increase sweep efficiency, thereby increasing oil recovery (Chen et al., 2021). Petroleum recovery is highly dependent on microscopic and macroscopic displacement efficiency (Fathaddin et al., 2020; Syndansk & Zeron, 2011).

Displacement stability, a key factor for macroscopic displacement efficiency, is determined by the mobility ratio (M). If the mobility ratio is less than or equal to 1 ($M \leq 1$), displacement efficiency can be increased. Conversely, if the mobility ratio is greater than one ($M > 1$), oil displacement is inefficient (Maifra K. et al., 2021).

Microscopic displacement efficiency measures the extent to which the displacement fluid mobilizes residual oil, influenced by factors such as rock wettability, relative permeability, IFT, and capillary pressure (Green & Willhite, 2018). Therefore, it can be enhanced by injecting surfactants, CO2, alkalis, and other materials (Green & Willhite, 2018). Macroscopic displacement efficiency, also known as volumetric sweep efficiency, measures the extent to which the displaced fluid contacts the oil in the reservoir, influenced by reservoir heterogeneity and anisotropy, the mobility ratio, and the placement of injection and production wells (Vossoughi, 2000).

Volumetric sweep efficiency is also defined as the percentage of pore volume swept by the injection fluid relative to the total oil volume (Syndansk & Zeron, 2011). Generally, the measurement of volumetric sweep efficiency in the injection process is known as conformance (Syndansk & Zeron, 2011).

Black Grass Jelly

Black grass jelly, or janggelan, contains hydrocolloids that can form gels (Nusantoro et al., 1998). Hydrocolloids are polymer components derived from plants, animals, microbes, or synthetic compounds that generally contain hydroxyl. Hydrocolloids are soluble in water, capable of forming colloids, and can thicken or gel a solution. Due to these characteristics, hydrocolloids are commonly used as gelling agents, thickeners, emulsifiers, adhesives, stabilizers, and film formers (Herawati, 2018).

The polysaccharide content of black grass jelly in gel formation is influenced by various factors, including extraction conditions, concentration, starch mixture, and plant part selection (Boonjing & Ruttarattanamongkol, 2020). Gel formation in black grass jelly is a unique phenomenon, as the gel-forming components of black grass jelly cannot exist alone; they require the addition of starch or certain minerals, such as tapioca (Nuraini et al., 2000)

Chitosan

Chitosan is a polysaccharide derived from the deacetylation of chitin that can form superabsorbent hydrogels through covalent and noncovalent cross-linking. The amino groups in chitosan allow this molecule to be modified to produce desired properties. Furthermore, the hydroxyl groups in chitosan can also influence appropriate chemical modifications to increase solubility. The structure of chitosan is shown in Figure 2.3 (Sugita et al., 2009).

Chitosan is isolated from chitin obtained from cleaned and ground shrimp, crab, or swimming crab shells. The chitosan production process involves three stages:

Deproteinization stage

This stage removes protein from chitin using a 20% w/v NaOH solution and heating at 90°C for 60 minutes. This is necessary because chitin has a protein content of 30-35% g/g. The removed protein will react with NaOH to form Na-proteinate, which, when tested with CuSO4, will produce a deep purple complex solution.

Demineralization stage

This stage aims to remove minerals from chitin using a 1.25 N HCl solution and heating at 90°C for 90 minutes. The main minerals contained in chitin are calcium phosphate, calcium carbonate, and magnesium carbonate. These minerals will react with HCl to produce CaCl2 and MgCl2 salts. The salts formed are tested with ammonium oxalate, producing a cloudy white precipitate.

Depigmentation stage

This stage serves to remove the dyes present in chitin using acetone until the color disappears and then drying. Afterward, the sample is bleached with 0.5% NaOCl for 10 minutes. According to Hendri et al. (2005), the dyes contained in shrimp shells are astaxanthin and carotenoids.

The resulting product of these three stages is chitin. Chitosan can be produced by removing the acetyl group from chitin to form an –NH2 group using a strong base. The chitosan deacetylation process typically uses a 40-60% w/v NaOH solution at a high temperature, typically around 100-150°C. This is due to chitin's long structure and strong bonds between nitrogen ions and acetyl groups.Cross-linking in chitosan improves its characteristics, such as solubility in water or organic solvents, bacteriostatic effects, chelating and complexing capabilities. Chitosan can adsorb enzymes, anionic polysaccharides, and metal ions.

Method

This research is a laboratory experimental test by conducting direct observations in the laboratory of polymer solutions. The polymers used in this study were black grass jelly and chitosan. The purpose of this study was to determine the characteristics of black grass jelly and chitosan polymer solutions at varying salinity and concentration. The formation water salinities in this study were 10,000, 15,000, and 20,000 mg/L and the polymer solution concentrations were 500, 1,000, and 2,000 mg/L. The characteristics of the polymer solution were measured, namely their compatibility with the formation water salinity and polymer solution concentration. The study was conducted with varying water salinity and polymer solution concentration at room temperature of 29˚C. The compatibility test was conducted to determine the possibility of new deposits from the polymer solution made (Huljannah et al., 2020). This test was carried out by visual observation of the solution. The solution was then placed in a bottle and observed for the presence or absence of deposits from the polymer solution.Research. The research procedure, in brief, is as follows:

Solution Preparation

Before making the polymer solution, first prepare formation water by dissolving NaCl in distilled water. Prepare a 250 ml beaker and fill it with distilled water up to the 250 ml mark. Weigh the NaCl according to the desired salinity. Slowly add the NaCl to the beaker and stir for 15 minutes. Next, add the polymer to the prepared formation water at the specified concentrations (500, 1,000, and 2,000 mg/L). Slowly add the polymer to the beaker containing the formation water and stir for 12 hours (Chen et al., 2021; Khalid et al., 2020). This is done for various polymer concentrations, and for this study, polymer concentrations were 500 ppm, 1,000 ppm, and 2,000 ppm.

Compatibility Testing

Compatibility testing is conducted to determine the possibility of new deposits from the prepared polymer solution (Huljannah et al., 2020). This test is performed by visually observing the solution. The solution is then placed in a bottle and observed for the presence of sediment from the polymer solution. If the compatibility test is successful, the next step is the viscosity test.

Result and Discussion

Polymer injection applications in the field require that formation water salinity be considered before injection because salinity directly affects the polymer solution (Setiati et al., 2021). Formation water has a salinity value ranging from 3,000 - 300,000 mg/L (Setyaningrum et al., 2020) which contains dissolved ions in the form of cations (Na+, Ca2+, Mg2+, Ba2+, Sr2+, and Fe2+) and anions (Cl-, HCO2-, and SO42-) (Alighiri et al., 2018; Pranondo & Agusandi, 2017). Formation water in the reservoir is dominated by sodium (Na) and chloride (Cl) ions (Setyaningrum et al., 2020). In this study, formation water was made from NaCl to simulate reservoir conditions, where the formation water was used as a polymer solvent at various concentrations. Three (3) formation water salinities were used in this study, namely; 10,000, 15,000, and 20,000 mg/L. Polymer concentrations are typically injected into reservoirs at concentrations ranging from 250 to 2,000 mg/L in the field (Setiati et al., 2021). In this study, three concentrations were used: 500, 1,000, and 2,000 mg/L for the black grass jelly and chitosan solutions.

Compatibility Testing

Polymer solution compatibility is an assessment of the polymer solution's compatibility with formation water salinity (Huljannah et al., 2020). Compatibility testing of polymer solutions in formation water is conducted to determine whether the polymer solution dissolves completely in the formation water. The test is performed by dissolving the polymer in formation water with salinities of 10,000, 15,000, and 20,000 mg/L and polymer concentrations of 500, 1,000, and 2,000 mg/L. The solution is then placed in a bottle and observed for complete dissolution or sedimentation. The compatibility assessment in this study, as conducted by Huljannah et al. (2020), showed that all polymer solutions dissolved completely and there was no precipitation.

Tabel 1. Compatibility test of black grass jelly solution on formation water salinity of 10,000 mg/L with concentrations of 500, 1,000, and 2,000 mg/L.

Solution Code	Solution Compatibility
CH-A-1	No precipitate observed
CH-A-2	No precipitate observed
CH-A-3	No precipitate observed

Tabel 1 shows that the compatibility test of the black grass jelly polymer solution at a formation water salinity of 10,000 mg/L with concentrations of 500, 1,000, and 2,000 mg/L showed no precipitation.

Tabel 2. Compatibility test of black grass jelly solution on formation water salinity of 15,000 mg/L with concentrations of 500, 1,000, and 2,000 mg/L.

Solution Code	**Solution Compatibility**
CH-B-1	No precipitate observed
CH-B-2	No precipitate observed
CH-B-3	No precipitate observed

Tabel 2 shows that the compatibility test of the polymer solution at a formation water salinity of 15,000 mg/L with concentrations of 500, 1,000, and 2,000 mg/L showed no precipitation.

Tabel 3. Compatibility test of black grass jelly solution on formation water salinity of 20,000 mg/L with concentrations of 500, 1,000, and 2,000 mg/L.

Solution Code	**Solution Compatibility**
CH-C-1	No precipitate observed
CH-C-2	No precipitate observed
CH-C-3	No precipitate observed

And finally, in Tabel 3, it can be seen that polymer testing at formation water salinity of 20,000 mg/L with concentrations of 500, 1,000, and 2,000 mg/L shows that no precipitation occurs, the solution looks clear and not cloudy.Results should be clear and concise. For chitosan polymer solutions, their compatibility with formation water salinity will be assessed. Compatibility of polymer solutions is an assessment of the compatibility of polymer solutions with formation water salinity (Huljannah et al., 2020). Compatibility testing of polymer solutions in formation water is conducted to determine whether the polymer solution dissolves completely in the formation water. The test is performed by dissolving the polymer in formation water with salinities of 10,000, 15,000, and 20,000 mg/L and polymer concentrations of 500, 1,000, and 2,000 mg/L.

The following figure demonstrates the compatibility of chitosan polymer solutions with formation water salinity.

Tabel 4. Compatibility test of chitosan polymer solution on formation water salinity of 10,000 mg/L with concentrations of 500, 1,000, and 2,000 mg/L.

Solution Code	**Solution Compatibility**
KT-A-1	No precipitate observed
KT-A-2	No precipitate observed
KT-A-3	No precipitate observed

In Table 4, it can be seen that the compatibility test of chitosan polymer solution at formation water salinity of 10,000 mg/L with concentrations of 500, 1,000, and 2,000 mg/L can be seen that no precipitation occurred.

Tabel 5. Compatibility test of chitosan polymer solution on formation water salinity of 15,000 mg/L with concentrations of 500, 1,000, and 2,000 mg/L.

Solution Code	**Solution Compatibility**
KT-B-1	No precipitate observed
KT-B-2	No precipitate observed
KT-B-3	No precipitate observed

Just as in Table 5, it can be seen that the compatibility test of polymer solution at formation water salinity of 15,000 mg/L with concentrations of 500, 1,000, and 2,000 mg/L no precipitation occurred. And finally in Figure 6, it can be seen that the polymer test at formation water salinity of 20,000 mg/L with concentrations of 500, 1,000, and 2,000 mg/L shows that no precipitation occurred, the solution looks clear and not cloudy.

Tabel 6. Compatibility test of chitosan polymer solution on formation water salinity of 20,000 mg/L with concentrations of 500, 1,000, and 2,000 mg/L.

Solution Code	**Solution Compatibility**
KT-A-1	No precipitate observed
KT-A-2	No precipitate observed
KT-A-3	No precipitate observed

The solution is clear and free of sediment. A solution is considered compatible if it has no sediment or clumps (Muhpidah et al., 2017). The absence of sediment in the polymer solution is due to the absence of anion-cation bonds between the polymer solution and formation water (Huljannah et al., 2020). The absence of sediment is also due to appropriate stirring, which is not too fast and not too long (Huljannah et al., 2020). Another advantage is that the concentration used in this study was not too high (200–2,000 mg/L). High concentrations can form sediment in the polymer solution (Huljannah et al., 2020). This result is consistent with previous studies (Huljannah et al., 2020), which reported that biopolymers exhibit good compatibility in moderate salinity conditions.

Conclusion

This research was conducted using two materials: black grass jelly and chitosan. This study employed a laboratory approach to analyze the solution properties and compatibility. Based on the results and discussion, experimental laboratory testing of black grass jelly and chitosan revealed compatibility results, indicating that all polymer solutions, both black grass jelly and chitosan, were compatible with varying formation water salinity. The researchers recommend that future research use materials other than black grass jelly and chitosan, such as xanthan gum, green grass jelly, or cellulose. This will serve as a reference for further research.

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