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Preliminary Study by Reservoir Simulation of Field Trial Polymer Injection in SBR Field Using Silica-Modified HPAM

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Abstract

Polyacrylamide (PAM) is the most inorganic polymer type which is usually used in injection for enhanced oil recovery. Furthermore, hydrolyzed polyacrylamide (HPAM) is a common polymer used in polymer injection, but it has the sensitivity towards salinity and temperature. Thus, the experiment modified PAM and HPAM with silica aims to improve the performance of polymer toward temperature and salinity. This experiment included polymer synthesis, polymer modification, rheological measurement of the product and reservoir modeling study. Some experiments were performed to assess the feasibility of the product. In the polymer injection simulation, the properties of a polymer are referred to as product properties. The best outcome is selected to be implemented in SBR field. Prior to do trial in the real SBR field, the study by simulation is needed. The simulation predicts the incremental oil recovery and helps to determine an optimum injection rate and the best injection well location. The SBR field temperature, the salinity and the oil viscosity were about 60˚C, 10,000 ppm and 2.64 cp, respectively. From the viscosity measurement, it was concluded that HPAM-Si was qualified to become a displacing agent because it had the highest viscosity among other product which was about 9.8 cp. The simulator used in this study was black oil IMEX-CMG simulator. The three scenarios applied were the base case, water injection and polymer injection. The base case gained recovery about 15.26%, whereas the water injection with a rate of about 2000 bbl/day gained oil recovery about 21.33%. The best scenario is polymer injection, where the optimum polymer injection rate is about 2000 bbl/day and the highest recovery is approximately 30.73%.

Keywords

Polyacrylamide, Silica, Polymer, Injection, EOR

1. Introduction

The function of polymer is improving the mobility ratio between water and oil [1] [2] [3]. Polyacrylamide (PAM) and hydrolyzed polyacrylamide (HPAM) are the common materials used for polymer injection [4] [5]. HPAM has a serious viscosity reduction in the high temperature and salinity reservoir, in which the temperature is about 60˚C to 120˚C [6]. In temperature above 60˚C, the acrylamide will be hydrolyzed to form acrylate and carboxylic groups that are sensitive to salinity in the reservoir. By those weaknesses, this study aims to improve polyacrylamide performance in higher temperature and salinity condition by adding Tetraethyl orthosilicate (TEOS). The unique of this study is the method and material composition that differ from previous research of polyacrylamide modification by nanoparticle of silica [7].

SBR oilfield is a sandstone reservoir and located in Indonesia. The average of porosity and permeability are about 20% and 180 mD, respectively. This study used the reservoir model of this field as a field trial for polymer injection. The drive mechanism of this field is a solution drive, which has a low water rate and a high gas rate. Polymer injection can improve oil displacement because the water has not been made a "water highway" which will lead polymer to pass through it. The model is a Southern part of whole reservoir model which is bordered by sealing-fault. In this case, the oil viscosity is about 2.64 cp and the initial pressure is about 1600 psi.

The injectivity (injection rate and pressure) is observed by the simulation. The polymer should be high rate injected to improve oil production [8] [9] [10] [11]. On the other hand, the injectivity must be limited by the fracture pressure in the reservoir. By using reservoir simulation, the polymer injection field trial is modeled in SBR reservoir, in which the property of synthesized polymer will be used as inputted polymer data. Simulation results can be used in EOR project plan to achieve the optimum recovery [12]. So, the oil recovery can be predicted before field application.

2. Methodology

There are three stages in this experiment. Those are polymer synthesis and modification, rheological measurement and recovery estimation by using reservoir simulation study.

2.1. Polymer Synthesis

Polymer synthesis is done by modifying the polyacrylamide with Tetraethyl orthosilicate (TEOS). Varies of temperature, material's combined ratio and reaction time were tried. The processes are detailed below:

1) PAM; It was started by mixing 7.5 gram acrylamides with 120 ml pure water and NaOH (until pH 8) in the three-necked bottle using hot magnetic stirrer plate with speed of 200 rpm and temperature about 55˚C. After that, potassium persulfate about 0.4 gram was added and then, it was mixed for 105 minutes. After the temperature of the mixture decrease to room temperature, it was added again with 240 ml methanol to separate product from the liquid. Finally, the product was dried with temperature 80˚C in the oven.

2) PAM-Si; A 10 gram dried of PAM was mixed with 150 ml of pure water, TEOS and HCl (until pH 4 - 5) in the three-necked bottle using hot magnetic stirrer plate with speed of 200 rpm and temperature about 60˚C. It was mixed for 60 minutes. Then, it was cooled to the room temperature, prior it was added 407 ml methanol to separate product from liquid. Finally, the product was dried with temperature 80˚C in the oven.

3) HPAM; The dried PAM was mixed with 240 ml of NaOH 0.5 N in the three-necked bottle using hot magnetic stirrer plate with speed of 200 rpm and temperature about 55˚C for 90 minutes. After the temperature dropped to ambient temperature, the mixture was added 480 ml of methanol to separate product from liquid. Eventually, the product was dried with temperature of 80˚C in the oven.

4) HPAM-Si; The dried HPAM about 10 grams was mixed with 150 ml pure water, 5 grams of TEOS and HCl (until pH 4 - 5) in the three-necked bottle using hot magnetic stirrer plate with speed of 200 rpm and temperature about 60˚C for 60 minutes. After the temperature dropped to ambient temperature, the mixture was added 630 ml methanol to separate product from liquid. Lastly, the product was dried with temperature of 80˚C in the oven.

2.2. Rheological Measurements

After synthesizing polymer with some modifications, the product needs to be examined the feasibility of polymer as EOR agent. The feasibility test of polymer produced is performed by measuring the viscosity with varies temperatures, polymer concentration and salinity. The salinity modifier used was NaCl. Viscosity measurement was analyzed by viscometer Brookfield DV3TLV with rotational speed of about 8 rpm (11 s^{-1}). This speed was chosen because it represented the speed of polymer injection in the reservoir rocks. Therefore, the results showed some correlation graphs between the polymer viscosity with type of the polymer solution, salinity, and temperature. Those graphs were utilized as a reanalyze type of reservoir which fitted with the polymer limitation. Polymer products were mixed for 16 hours to homogenize the polymer solution. The measurements were performed with 1000; 5000; 10,000 ppm of the polymer concentrations. The temperatures vary from room temperature to 80˚C with 10˚C interval.

3. Simulation Study

The obtained polymer's properties by rheology measurement were inputted into a simulation study in order to delve the pilot project polymer in this field. The model was built up by cutting the SBR Field reservoir. There are some criteria of reservoir characteristics to become a candidate for polymer flooding that is issued by Indonesia' government institution as shown in **Table 1**.

Table 1. Polymer injection criteria [13].

Reservoir Parameter	Criteria	Parameter Reservoir	Criteria
Rock Type	Sandstone	Salinity (ppm)	<50,000
Depth (ft)	<9000	Permeability (mD)	>40
Reservoir Temperature (˚F)	<200	Porosity (%)	20
Oil Viscosity (cp)	<200	Water saturation (%)	>40
Oil Gravity (˚API)	>25	Wettability	Water wet

Reservoir properties of SBR field are shown in **Table 2**. Reservoir grids were made up by 12i × 16j × 3k, which every layer thickness was about 41 ft. This concerned part of the SBR field was bordered by a sealed fault. This reservoir rock type is sandstone. In this part, there are four production wells which have been producing since 2013. The production history data is until 2019. The SBR relative permeability data is shown in **Figure 1**.

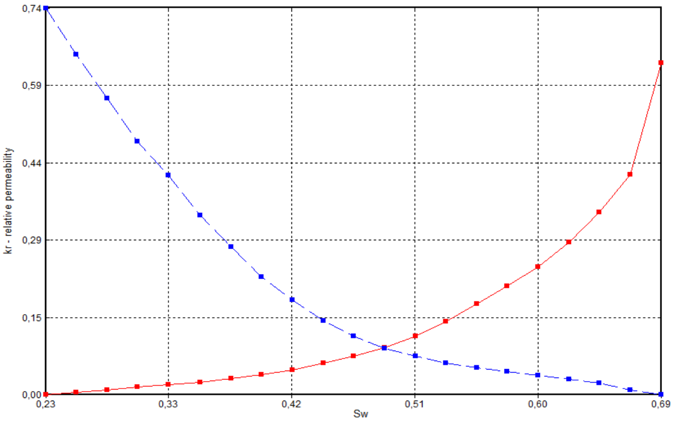


Figure 1. Relative permeability of SBR field.

Table 2. SBR reservoir properties.

Parameter	value
Grid (i × j × k)	12 × 16 × 3
Initial Pressure (psi)	1600
Tr (˚F)	60
ϕ (%)	0.2
Permeability (mD)	80 - 280
Oil viscosity (cp)	2.64
Polymer viscosity (cp)	9.8
Oil Gravity (API)	24
Sw (fraction)	0.21
Salinity (ppm)	10,000
OOIP (MMSTB)	41.845

Black oil simulation used in this experiment with assumptions was isothermal and there was no change in the composition. Production for a base scenario runs for 35 years and 67 years. Scenario 1 was the base case and water injection, while Scenario 2 was a base case and polymer injection. Further, both scenarios used an injection well with inverted five spot patterns in 2025. In Scenario 2, polymer data was based on the best performance polymer laboratory data. **Table 3** shows the scenario details.

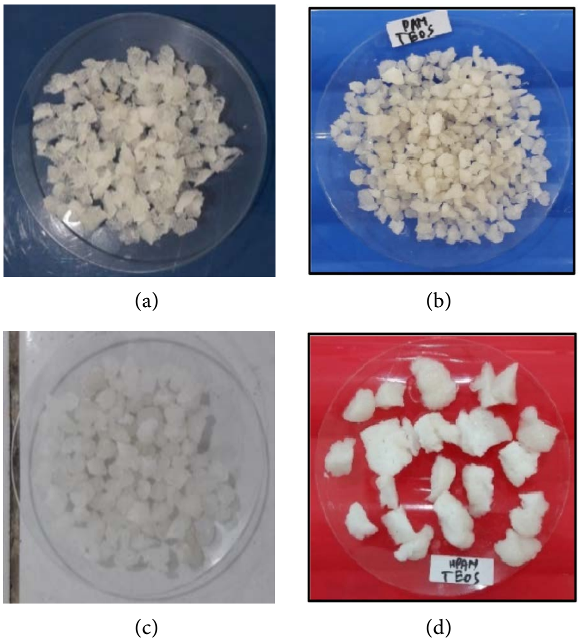
Table 3. Simulation scenario description.

Scenario	Description
Base case	Four existing production wells
Water injection	Four existing production wells + one injector
Polymer injection	Four existing production wells + one injector

4. Result and Discussions

4.1. Polymer Synthesis Results

By quantity of composition and synthesized method, polymer product from the synthesis process of a dry PAM (a), a dry PAM-Si (b), a dry HPAM (c), and a dry HPAM-Si were about 7.7 gram, 8.6 gram, 6.5 gram, and 3.9 gram, respectively. The products were in the dried solid from as shown in **Figure 2**.



(a) (b)

(c) (d)

Figure 2. Solid polymer product. (a) PAM; (b) PAM-Si; (c) HPAM; (d) HPAM-Si.

Adding TEOS intended to improve polymer resistance toward temperature increases. Theoretically, the silica attachment process is described in **Figure 3**. To prove that silica has been attached in HPAM backbone, the product was examined by FTIR (**Figure 4** and **Figure 5**).

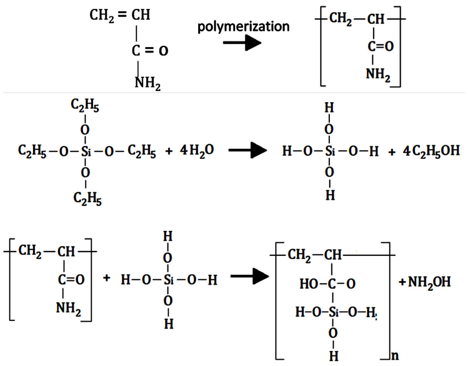


Figure 3. Silica attachment process.

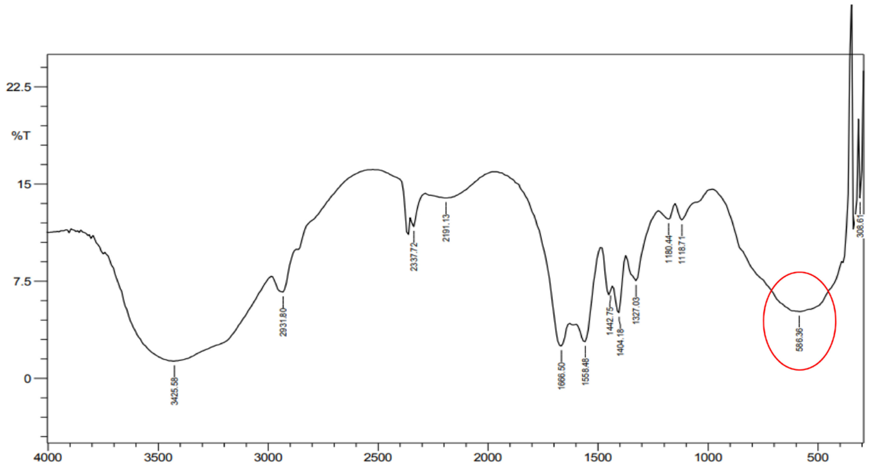


Figure 4. FTIR analysis results of HPAM.

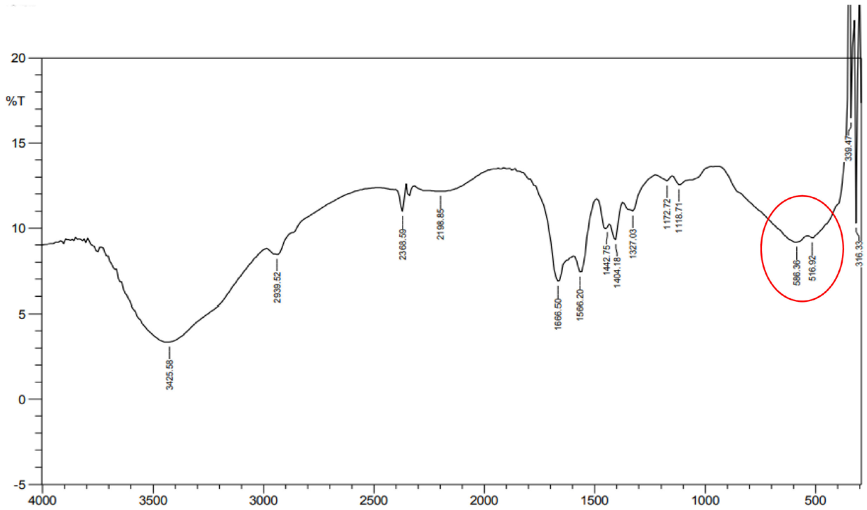


Figure 5. FTIR analysis results of HPAM-Si.

Figure 4 shows FTIR Analysis of HPAM and Figure 5 shows FTIR Analysis of HPAM-Si product. Comparing between Figure 4 and Figure 5, it indicates that silica has been success attaching to HPAM chain. It shows that the different peak exists in Figure 5 compared to Figure 4.

4.2. Rheological Measurements

Synthesized polymer products were PAM, PAM-Si, HPAM and HPAM-Si. The feasibility test of polymer solutions was conducted by diluting this polymer with brine water until its salinity attained about 30,000 ppm. The polymer product diluted with water generated a clear solution as shown in Figure 6. It evidences the precipitation tendency of this solution when injection in reservoir is very small. On the other hand, it exhibits that these polymers are feasible to become polymer injection agents.

Figure 6. Polymer solution.

After the feasibility test, polymers were tested for rheological properties with temperature and salinity sensitivities. Viscometer Brookfield DV3TLV was used with rotational speed about 8 rpm. As known, that increasing temperature and salinity will lower the viscosity of the polymer. So, those sensitivities were needed to show the capability of polymer to hold the temperature and salinity. The polymer solution concentrations were 1000 ppm; 5000 ppm; 10,000 ppm with varying the NaCl concentration 0, 10,000 ppm, and 30,000 ppm. The temperature conditions in the measurement were 30˚C, 40˚C, 50˚C, 60˚C, 70˚C, 80˚C. Results of viscosity measurement with varies conditions are shown in Figure 7-18.

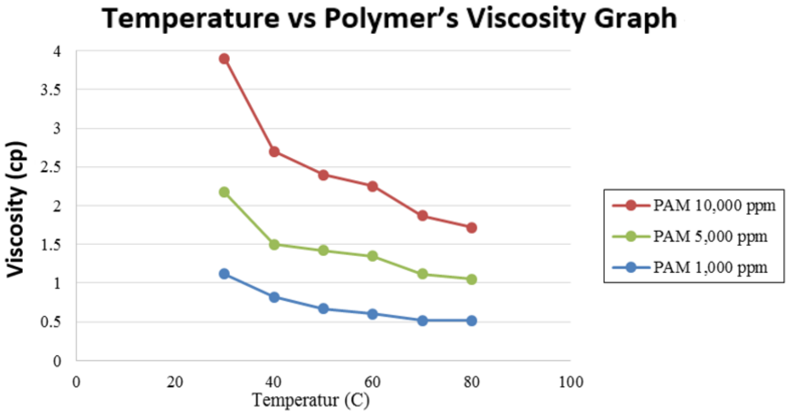


Figure 7. Viscosity PAM @ salinity 0.

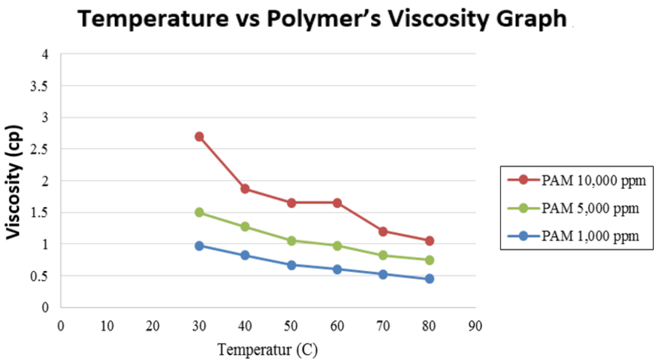


Figure 8. Viscosity PAM @ salinity 10,000 ppm.

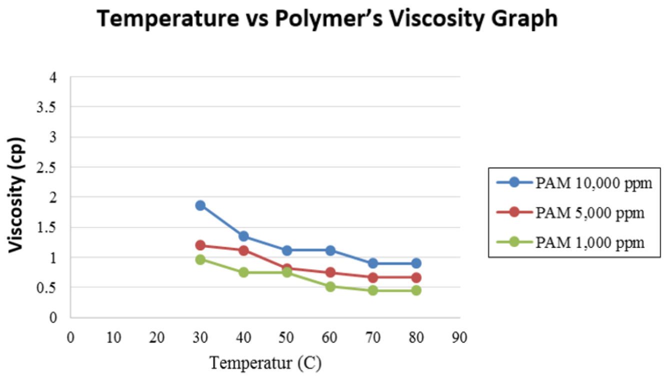


Figure 9. Viscosity PAM @ salinity 30,000 ppm.

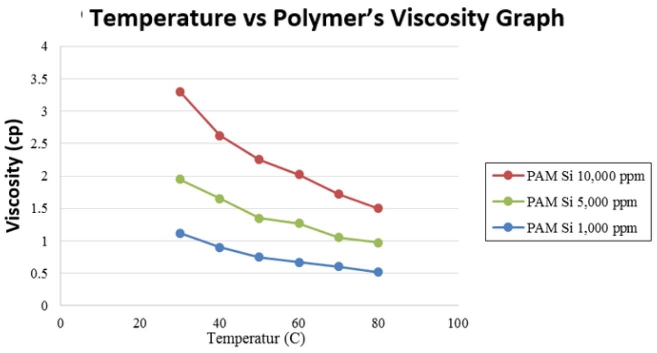


Figure 10. Viscosity PAMSi @ salinity 0 ppm.

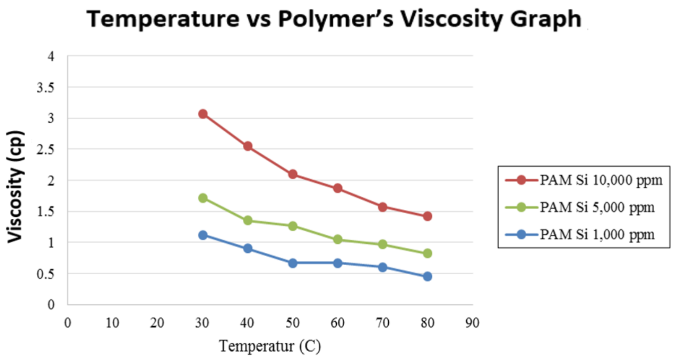


Figure 11. Viscosity PAMSi @ salinity 10,000 ppm.

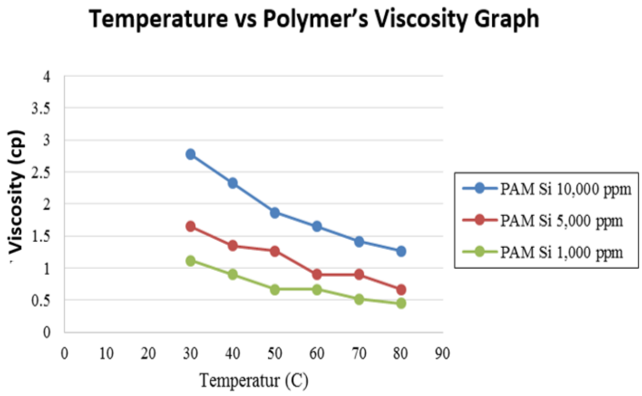


Figure 12. Viscosity PAMSi @ salinity 30,000 ppm.

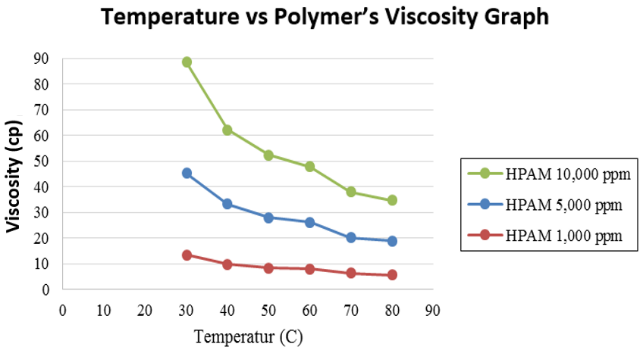


Figure 13. Viscosity HPAM @ salinity 0 ppm.

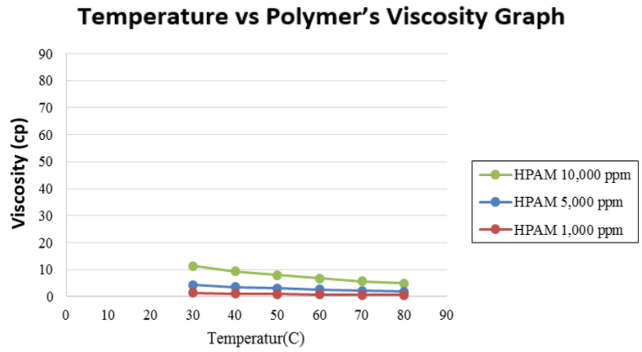


Figure 14. Viscosity HPAM @ salinity 10,000 ppm.

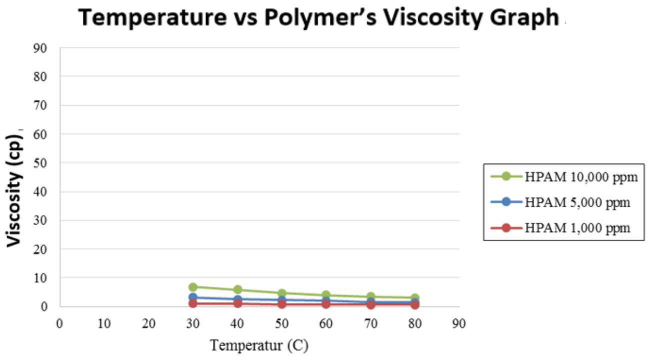


Figure 15. Viscosity HPAM @ salinity 30,000 ppm.

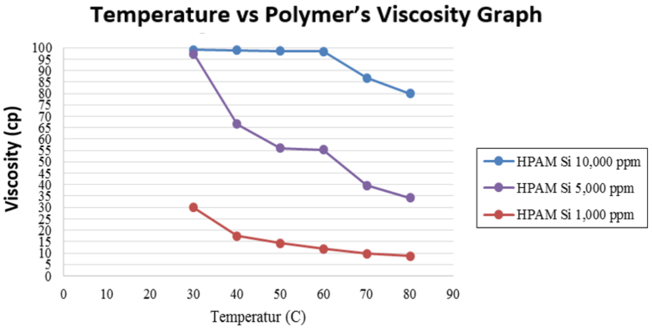


Figure 16. Viscosity HPAMSi @ salinity 0 ppm.

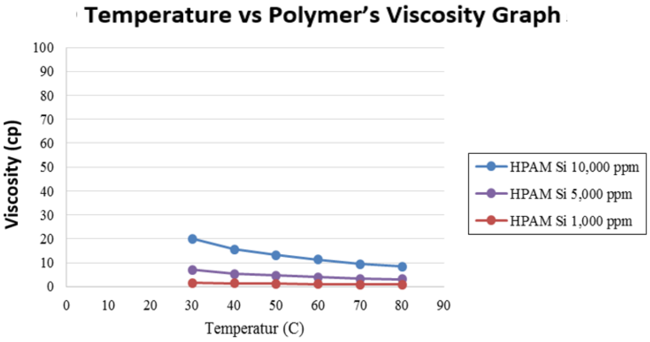


Figure 17. Viscosity HPAMSi @ salinity 10,000 ppm.

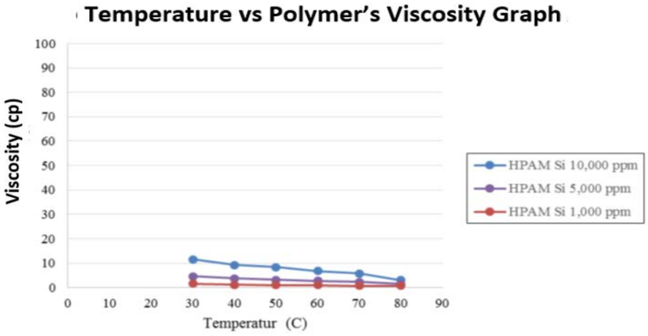


Figure 18. Viscosity HPAMSi @ salinity 30,000 ppm.

From measurement results, the PAM and the PAM-Si give lower viscosity than HPAM and HPAM-Si. The viscosities of PAM, PAM-Si, HPAM-Si were about 0.5 cp to 3cp, 0.5 to 3.3 cp, and 3 cp to 100 cp, respectively. When the salinity and temperature are increasing, the viscosities of PAM and PAM-Si are decreasing. HPAM-Si gives the highest viscosity among other products even in the highest temperature and salinity.

4.3. Polymer Injection Simulation

Reservoir model was built from the partition of SBR oilfield. This preliminary study aims to predict the incremental oil recovery by polymer injection. The initialization results original oil in place (OOIP) was about 41.85 MMTSB. From the laboratory data, it showed that HPAM-Si product had the best performance among the other products. Refer to reservoir condition which has temperature about 60˚C and salinity about 10,000 ppm, the viscosity of polymer (HPAM-Si) inputted was about 9.82 cp according to HPAM-Si properties. Permeability distribution in the model is shown in **Figure 19**. Based on **Table 1**, this SBR field is eligible to apply polymer injection.

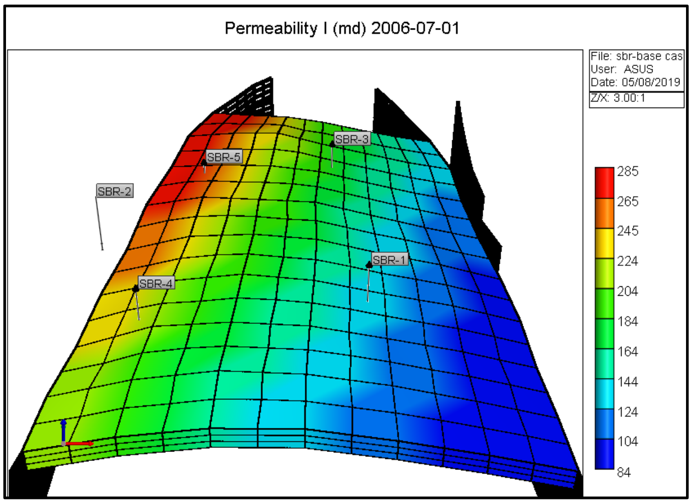


Figure 19. 3D model of permeability distribution.

There are three scenarios that are discussed in this paper. Those are the base case, Scenario 1 (water injection), Scenario 2 (polymer injection). On base case, the oil has been produced for six years from 4 production wells and continues running prediction until 2048 and 2080. On Scenario 1, existing production wells and adding a water injection well, which has a rate about 2000 bbl/day. On Scenario 2, existing production wells and adding a polymer injection well. Polymer injected is about 0.41 PV. In the Scenario 1 and 2, adding an injection well is occurred in 2035 with an inverted five spot pattern. The production and injection wells locations are shown in **Figure 20**.

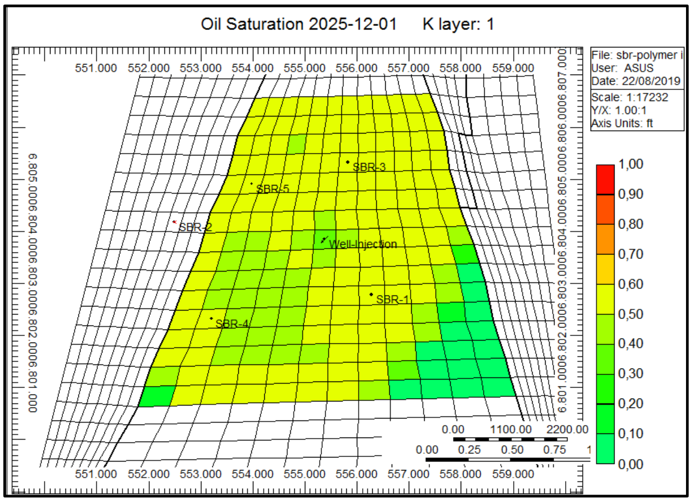


Figure 20. 3D model of oil saturation before injection.

The oil saturation distribution is displayed in **Figure 21**. Production History SBR Field is shown in **Figure 22**. In this field, the water production is smallest. This is indicating that the drive mechanism in this reservoir is depletion drive and weak water drive.

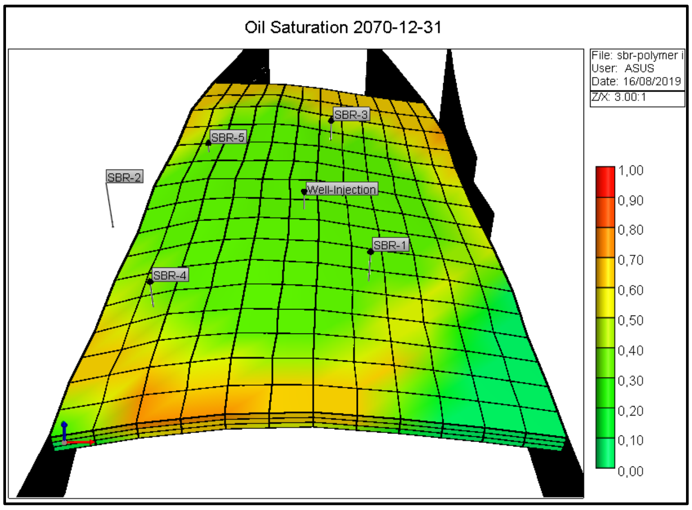


Figure 21. 3D Model of oil saturation distribution after polymer injection.

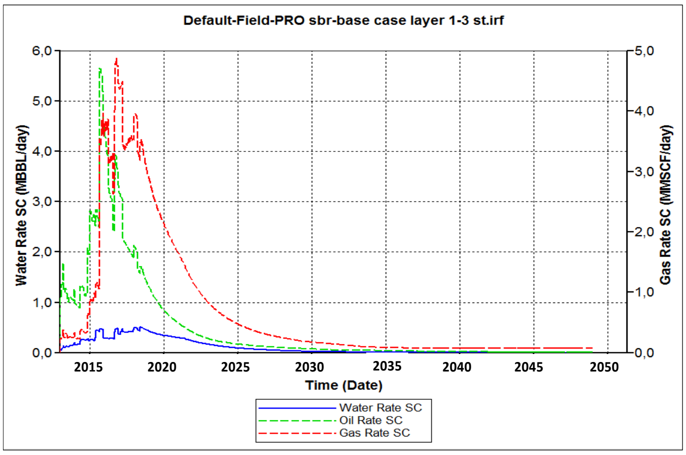


Figure 22. SBR field production history.

The first running for the base case is only until December 2038. It gives oil cumulative of about 6.38 MMbbl. Meanwhile, if the simulation prediction is until 2080, the incremental is only 12 Mbbl. So that, it gives small incremental oil recovery is about 0.02%. **Figure 23** shows that the oil cumulative is almost plateau. This is caused by the dominant reservoir drive mechanism that gives less support reservoir pressure. On Scenario 2, water injection well is added at the center among production well on January 2035. It gives incremental oil about 986.1 Mbbl (recovery factor incremental is approximately 2.35%) in 2038 and 2540.71 Mbbl (recovery factor incremental is approximately 6.07%) in 2080. In polymer injection Scenario 2, the result is about 8196.42 Mbbl (recovery factor incremental is about 19.58%) in 2038 and 12860.71 Mbbl (recovery factor incremental is about 30.73%) in 2070. The simulation results are shown in Table 4.

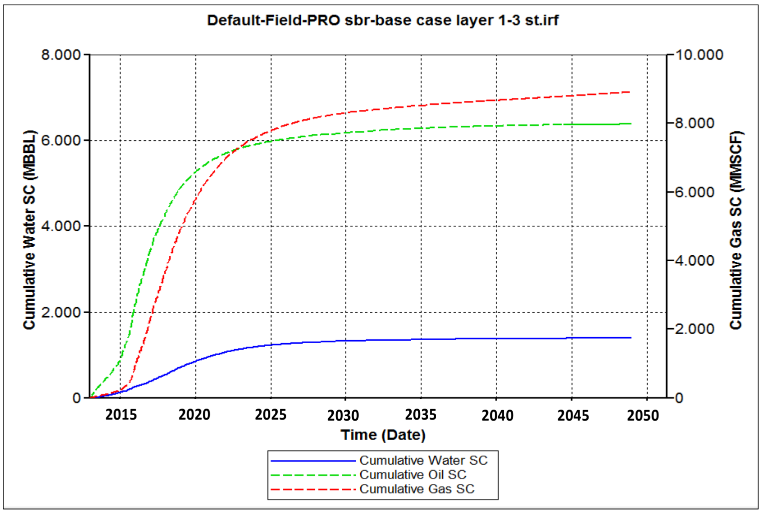


Figure 23. Prediction until 2048.

Table 4. Simulation results of SBR field.

Scenario	Description	2038		2070	
		Np (Mbbl)	Wp (Mbbl)	Np (Mbbl)	Wp (Mbbl)
Base case	Four existing production wells	6376.93 (15.24%)	1394.14	6388.35 (15.26%)	1420.71
Water injection	Four existing production wells + one injector	7363.03 (17.59%)	12468.15	8929.06 (21.33%)	41629.87
Polymer injection	Four existing production wells + one injector	8196.42 (19.58%)	4036.27	12860.71 (30.73%)	30087.67

Scenario 1 and 2 starts from 2035, the cumulative oil and water production performance are shown in Figure 24 and Figure 25, respectively. In the base case scenario, the incremental oil is almost plateau. Within 2035 to 2046, the oil production by polymer injection is lower compared to the oil production by water injection. It is caused by polymer displacement has not been reached the water displacement distance. In 2046, the amount of polymer injected is about 0.2 PV. Since the polymer fluid is more viscous than water, therefore, it will move slower than water. Its slower movement and more viscous property will give better oil displacement. After 2046, the oil production by polymer overtakes the oil production by water injection. Figure 25 shows that water production by water injection is higher than by polymer injection. It is caused by polymer viscosity will reduce the mobility of water so that it reduces water cut without lowering oil production. Polymer injection has a visible impact when it is injected in a longer period. By predicting the trend of oil production rate by polymer injection, it will still increase even after 2080.

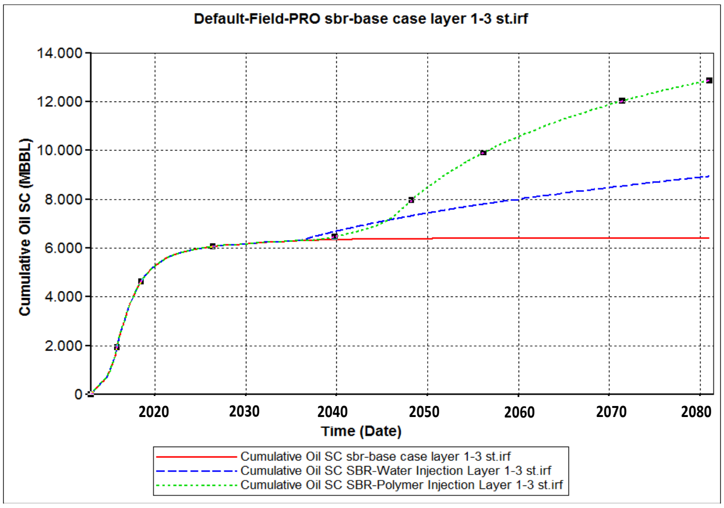


Figure 24. Cumulative oil.

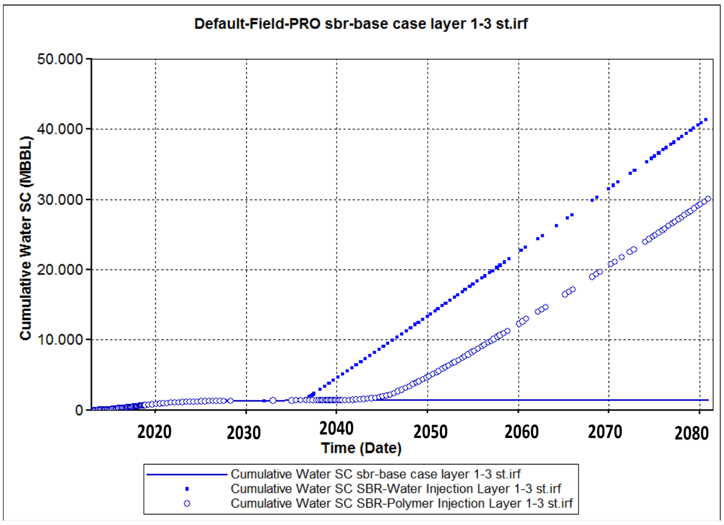


Figure 25. Water production performance.

The maximum pressure response is about 1500 psi, which is still below the Pi (1600 psi). It implies that the injection rate is safe to use in this scenario. Because the fracture pressure is unknown, the initial pressure becomes reference pressure that should not be exceeded. Raising the injection rate above 2000 bbl/day increases oil gained, but the average reservoir pressure exceeds the initial pressure, so it is not recommended to operate the injection with the rate above it.

5. Conclusion

Adding TEOS (silica) into HPAM is a success to gain the highest viscosity among PAM, PAM-Si and HPAM. In the field case study, the optimum injection operation is achieved when the rate is about 2000 bbl/day and the maximum pressure response is about 1500 psi. Polymer injection scenario provides the highest oil recovery, which is about 30.73%. In this case, the best scenario in polymer injection is able to reduce a significant water production for about 11,542 Mbbl.

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Conflicts of Interest

The authors declare no conflicts of interest regarding the publication of this paper.

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