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Simulation Study of Sodium 4-Vinylbenzene Sulfonate as a Surfactant for Enhanced Oil Recovery in the North of Thailand

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Owing to the increasing energy demand, producing more oil from the residual in the old reservoir by water flooding and enhanced oil recovery (EOR) methods should be considered. Water flooding has become the most widely used process by injecting water into the reservoir to displace oil. The chemical EOR is a chemical injection into the reservoir. When water flooding becomes uneconomical, the chemical especially surfactant, has been applied in the flooding process like sodium 4-vinylbenzene sulfonate (SVBS). This study aims to simulate and evaluate the surfactant flooding by using SVBS with various conditions such as surfactant concentration, injection rate, and injection period in Northern oilfield of Thailand. The concentration of SVBS varies from 0 to 4,000 ppm and the injection rate is from 7.95 to 47.7 m^3/d. The period of chemical injection is from 0 to 12 y. This technique will be compared with conventional water flooding. From the results, the surfactant EOR can obtain higher recovery factor compared to water flooding. The suitable concentration is 2,000 ppm. For the injection rate, the recovery factor (RF) is higher at higher injection rate, The highest RF is up to 56.92 % from all cases of a parameter change. The period of surfactant injection to enhance oil production is 12 y. RF can be improved up to 4.2 % compared with applying water flooding for the same period. The results from this study can contribute to further EOR application in the actual field at the Northern oilfield in Thailand as a reference in the future.

1. Introduction

A large portion of the current world oil creation originates from the developed fields. A significant concern for oil organizations nowadays is an expanding oil recovery from the maturing resources. The secondary stage, like water flooding and the tertiary stage or enhanced oil recovery (EOR) such as chemical EOR (CEOR), will be the fundamental method to satisfy the expansion of the increase in oil production or recovery factors (RF) from the developing fields (Kaiser, 2019).

By injecting water underground, water flooding is a secondary recovery technology to increase oil recovery in Thailand (Maneeintr et al., 2020a). For the water flooding process, residual oil in reservoir formation is displaced by water from injection wells to production wells. The various permeability and early water breakthrough time may cause the potential problems associated with water flooding techniques (Li et al., 2016). Waterflooding is the typical EOR method when it is applied in the tight oil reservoirs by interfracture water injection (Liu et al., 2020). EOR is the method by which the gases or chemicals and/or thermal energy are injected into the reservoir (Husein et al., 2018). There are 2 classifications of the EOR processes: thermal and non-thermal recoveries (Thomas, 2008). The mechanism of the thermal method is the decline of viscosity by adding heat to heavy oil to gain its mobility improved. The conventional non-thermal methods are the miscible gas method by gas injection (Li et al., 2016) or alkaline, surfactant, polymer flooding to light oil (Maneeintr et al., 2020b). In the Northern oil field in Thailand, the type of oil is light oil and this is suitable to apply the CEOR in this field (Maneeintr et al., 2020b).

In the case of CEOR, its mechanisms include the decrease in the interfacial tension (IFT) and an increase in the mobility ratio (Druetta et al., 2019). The main mechanism of polymer is to increase mobility ratio (Mejía et al., 2021), alkaline and surfactant are to reduce IFT and change the wettability of reservoir rocks from oil-wet to water-wet or ultra water-wet depending on the kind of surfactant is injected (Rellegadla et al., 2021). However,

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due to the adsorption, the surfactant and alkali lose their efficiency along their stream in the permeable media (Fink, 2012).

The surfactant flooding is obtained by adding chemicals to boost oil production. Surfactants may be classified according to the ionic nature of the head group as anionic, cationic, nonionic, and zwitterionic. Each type possesses certain characteristics depending on how the surfactant molecules ionize in aqueous solutions (Dong et al., 2018). The basic principles for surfactant flooding are lowering the interfacial tension and improving the flow of residual oil inside the reservoir (Gbadamosi et al., 2019). During surfactant flooding, the complex system to form microemulsions with the residual oil is required because it supports the decrease in the IFT and the growth of mobility (Massarweh and Abushaikha, 2020). The liquid surfactant injected into the reservoir is usually a complex chemical system so that it creates a so-called micelle solution (Sheng, 2015). The importance of emulsification is not only in surfactant but also shown in combination methods between the surfactant and other chemicals like alkaline or polymer. Wang et al., (2021) concluded that emulsification played an important role in the heterogeneous model and increased swept efficiency and adsorption in the surfactant polymer (SP) flooding technique. Besides the conventional CEOR methods, a nanofluid is a new technology applied in recent years to improve the oil production process (Kumar et al., 2020).

The oilfield in the North of Thailand has produced oil for over 60 y of natural flow and recently it has low oil recovery with natural production. Currently, water injection has been applied in this field at the beginning stage. However, the new techniques are required to enhance oil production for this oil field (Settakul, 2009). Yoosook and Maneeintr (2018) have shown the effects of total injected hydrocarbon pore volume, water alternating gas ratio on oil production, other techniques such as CO_2 EOR; including consumption and storage in this field.

The surfactant flooding is obtained by adding the chemicals such as sodium 4-vinylbenzene sulfonate (SVBS) to improve the oil recovery factor (Chuaicham and Maneeintr, 2017). In this study, CEOR especially surfactant flooding with SVBS will be studied by using simulation. SVBS is cheap and available. And it has the properties to be advantageous as a surfactant like IFT reduction. SVBS has not been applied and evaluated in any EOR work before in Thailand. The objective of this study is to simulate the surfactant flooding by using SVBS and to compare the efficiency of this technique with conventional method. The simulation is conducted under various conditions such as chemical concentration, injection rate, and period of surfactant injection. This work will apply the potential surfactant for EOR in Thailand. The results of this study can be contributed for further EOR application in the area as a reference in the future.

2. Simulation

2.1 Reservoir data

The geological data for this study is obtained from the Defense Energy Department (DED) and the previous study (Yoosook and Maneeintr, 2018). This studied area has geological data with depth from 300 to 1,200 m and sand thickness from 1 to 7 m. The detail of geological data is presented in Table 1. Moreover, its oil viscosity is ranged from approximately 10-120 cP and 20 - 40 °API for the gravity of oil.

Table 1: Characteristics of Northern oilfield in Thailand

Parameter	Values
Grid dimension (block)	50 x 50 x 30
Reservoir size (m)	381 x 381 x 9.144
Top of reservoir (m)	1,347.216
Reservoir thickness (m)	9.144
Porosity (fraction)	0.2 - 0.3
Horizontal permeability (mD)	48.02 – 779.97
Vertical permeability (mD)	4.802 – 77.997
Reservoir pressure (kPa)	6550
Reservoir temperature (C^o)	62.2
Reservoir type	Sandstone

Based on the ECLIPSE software program developed by Schlumberger, 3D pore-scale models of a porous medium have been created. All grids in the reservoir are set at porosity ranging from 0.2 to 0.3 and the horizontal permeability of the formation range from 48.02 to 779.97 mD. All required input data are from the experiment of the previous works (Chuaicham, 2016). The software will simulate these properties. Figure 1 shows the heterogeneous model of the reservoir built with the injection well and production well. These wells are located at 2 corners of the reservoir and perforated from the top layer to the bottom layer as shown below. With all porosity and permeability data at all grids, this reservoir is heterogeneous with the Lorenz coefficient at 0.3023.

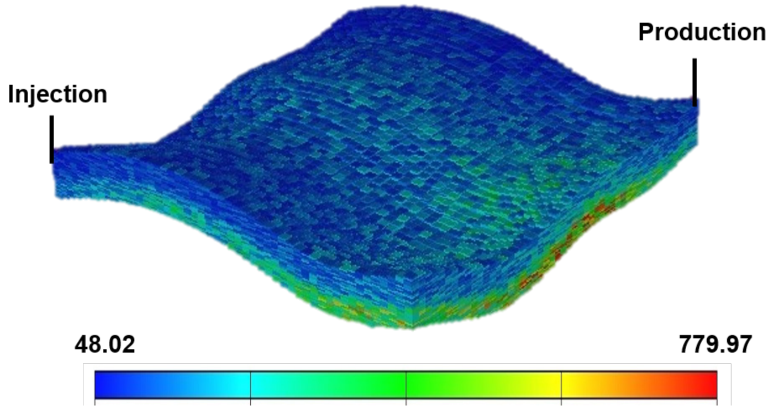

Figure 1: Permeability distribution in heterogeneous reservoir model

2.2 Methodology

The widespread use of the surfactant technique allows it to improve the oilfield performance after the water flooding process. The analysis of the chemical injection strategy is necessary for the operation's success which plays a major role in the efficiency of the recovery process, including the order and the time gap between each chemical slug injection.

This study simulates two main technologies which are water flooding and SVBS surfactant flooding. Also, the effects of the injection rates at 7.95, 15.9, 31.8, and 47.7 m^3/d (50, 100, 200, and 300 barrels/d) and the surfactant concentration at 1,000, 2,000, 3,000, and 4,000 ppm have been studied. In addition, the surfactant will not be injected throughout the production time. The plan is that the SVBS surfactant flooding will be injected for 6 cases such as 2, 4, 6, 8, 10, and 12 y; then water flooding will be processed. The total time for injection is 12 years and more details are presented in Table 2. The injection periods are not operated with all injection rates and surfactant concentrations. The optimum value of 2 these parameters have been chosen under consideration in Section 3.1 and 3.2. Later, Section 3.3 will show the effect of the different injection periods. The RF is the main result to be focused on throughout this study.

Table 2: Injection plan for surfactant flooding in EOR

Parameter	Strategies
Surfactant concentration	1,000, 2,000, 3,000, and 4,000 ppm
Injection rate	7.95, 15.9, 31.8, and 47.7 m^3/d
Injection period (y)	2 y SVBS – 10 y water
	4 y SVBS – 8 y water
	6 y SVBS – 6 y water
	8 y SVBS – 4 y water
	10 y SVBS – 2 y water
	12 y SVBS

3. Results and discussion

3.1 Comparison of concentration for oil recovery factor

The surfactant concentration is always a concern when the EOR method with surfactant is applied, as the surfactant adsorption or chemical loss affects the benefit of surfactant injection for production. Therefore, an optimum surfactant concentration is one of the main considerations in this research. Figure 2 shows the result of the recovery factor versus surfactant concentration in 4 cases of injection rate are 7.95 m^3/d, 15.9 m^3/d, 31.8 m^3/d, and 47.7 m^3/d. The recovery factor increases as an increase in surfactant concentration from 0 ppm to 2,000 ppm. However, injecting more surfactant at 3,000 ppm and 4,000 ppm can slightly increase RF for 0.01 to 0.03 %. The reason is that the critical micelle concentration can be formed and it may not help to reduce IFT. Therefore, the amount of oil cannot be produced more. For this case, the optimum surfactant concentration should be 2,000 ppm.

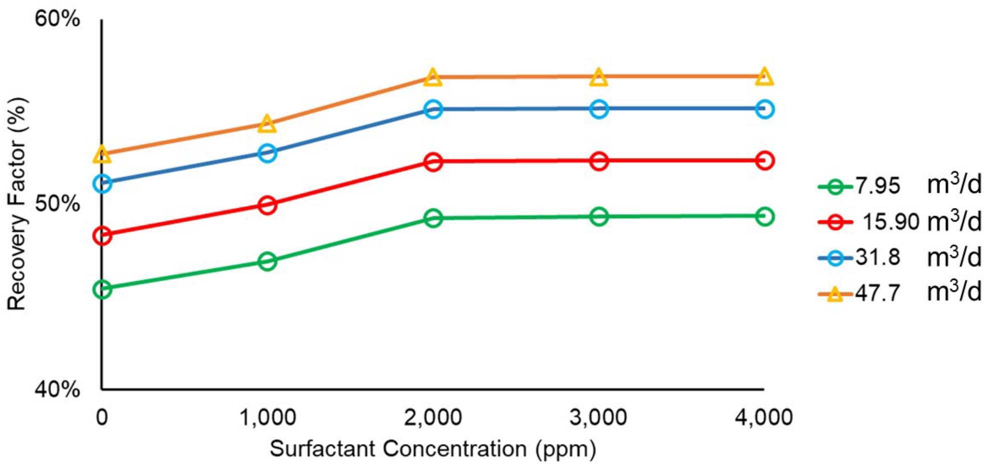

Figure 2: Comparison of concentration in oil recovery factor

3.2 Comparison of injection rate for oil recovery factor

The injection rate is an important parameter needed to consider because an operating cost will depend on the amount of the fluid injected into the reservoir. Figure 3 illustrates the RF versus injection rate result in 5 cases of surfactant concentrations, 0 ppm (water flooding), 1,000 ppm, 2,000 ppm, 3,000 ppm, and 4,000 ppm. Figure 3 shows that the higher injection rate of surfactant flooding, the higher oil recovery factor can be obtained because more oil can be pushed to the production well and produced there at higher injection rate.

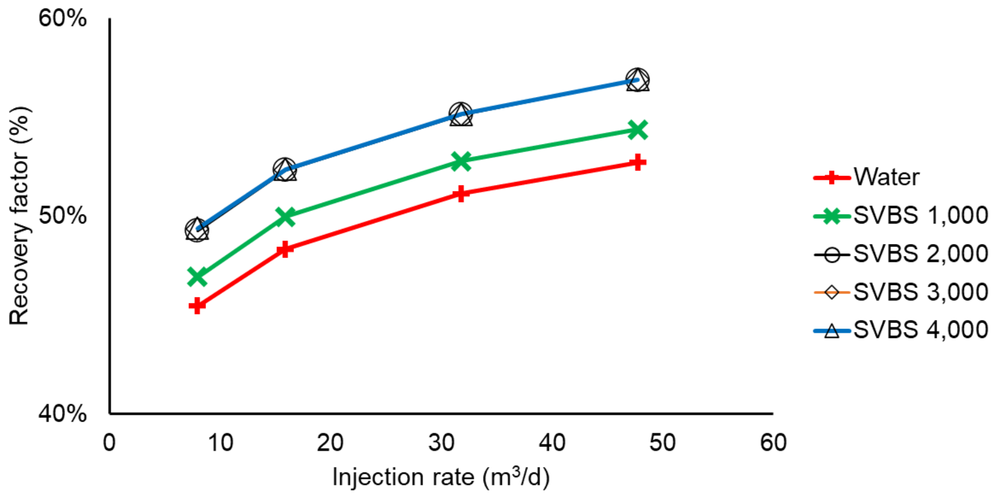

Figure 3: Comparison of injection rate in oil recovery factor

The highest oil RF is 56.92 %, that means when SVBS is injected surfactant, 56.92 % of the oil volume underground can be produced to the surface. Water flooding has the lowest RF compare with surfactant flooding at all injection rates and the highest different is 4.2 % at surfactant 4,000 ppm and injection rate at 47.7 m^3/d. At the same surfactant concentration, when the injection rate change from 7.95 to 47.7 m^3/d, the RF can increase over 7 % for all the cases and the highest change of RF is 7.62 % in SVBS at 2,000 ppm. It can be confirmed that 2,000 ppm is the optimum surfactant concentration for injection. In this section, it can be concluded that the ratio of RF factor change is not the same as the ratio of the injection rate change. In other words, when the injection rate increases 6 times, the recovery factor cannot change 6 times corresponding. This point has meant that the designed facilities should be based on the economic research after the technical evaluation because a higher injection rate is not always certainly tended to obtain the higher profit.

3.3 Effect of injection period in oil recovery factor

For the injection period, 6 cases of 2, 4, 6, 8, 10, and 12 y of surfactant injection followed by water injection until the end of 12 y with surfactant concentration at 2,000 ppm and injection rate at 31.8 m^3/d are applied. The results are presented in Figure 4. In this section, the water flooding is not considered as it does not show the effect of surfactant. Figure 4 shows that the longer injection period of surfactant flooding, the higher oil recovery factor can be achieved. The highest RF is 55.15 % when surfactant is injected in the whole period of 12 y. From these results, with the change of injection time for 2 y, the rate of RF change is not the same amount. From 2 y to 4 y, the RF changes 0.75 %, but this change becomes smaller from 4 y to 6 y and smallest from 10 to 12 y with 0.49 %. It demonstrates that surfactant injection will bring a higher effect in the early time of EOR.
For the environmental concern, based on the MSDS of SVBS, no hazardous effect or environmental impacts has been informed. However, it is informed that this chemical can be harmful if swallowed, causes skin irritation, eye damage or respiratory irritation.

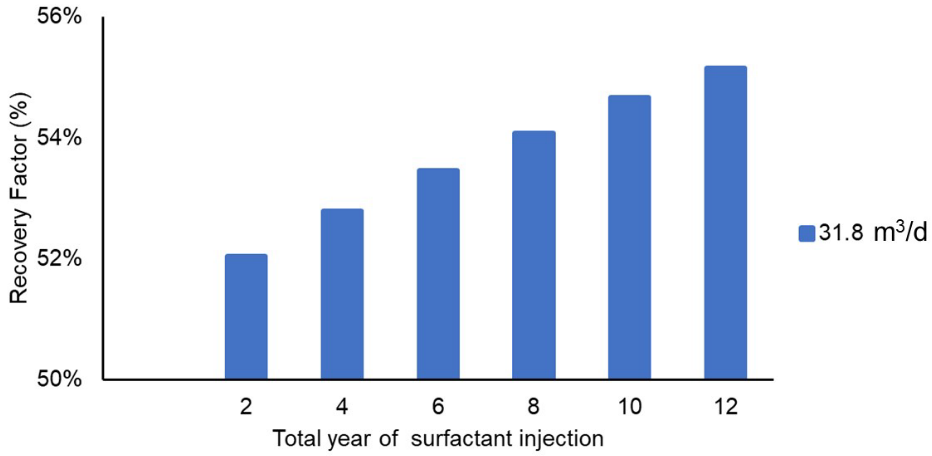

Figure 4: Comparison of different surfactant injection time in oil recovery factor

Therefore, from this study, the longer surfactant injection time can provide the higher RF. Further study on economic study is recommended. This result can be used as a database for the SVBS injection development plan in the real field for the future.

4. Conclusions

Oilfields in Thailand have produced oil with natural flow for over 60 y. Water flooding and the EOR methods are the way to increase the recovery factor in the present and the future work. The surfactant concentration and the injection rate are the two most important parameters affecting the oil production. In this research, from the results of SVBS as a surfactant, the EOR can obtain the higher recovery factor than water flooding. The suitable concentration of SVBS is 2,000 ppm because at higher concentration, RF has been slightly improved. For the injection rate, the RF becomes higher at higher injection rate, the highest RF is 56.92 %. Furthermore, the period of surfactant injection to enhance oil production is 12 y and RF can be improved up to 4.2 % in compared with applying water flooding for the same period. It can be concluded that the ratio of RF factor change is not the same as the ratio of the injection rate change, and the longer surfactant injection time provides a higher RF. The further study is recommended. The results from this study can contribute to further EOR application in the real field at the Northern oilfield in Thailand as a reference in the future. This article is only worked under the technical point of view. For the further study, the economic point of view is recommended to assess the surfactant flooding in the actual process.

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