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Well-pattern investigation and selection by surfactant-polymer flooding performance in heterogeneous reservoir consisting of interbedded low-permeability layer

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Abstract–Surfactant-polymer (SP) flooding has been demonstrated to be one of the most efficient methods of recovering the residual oil in the enhanced oil recovery (EOR) stage. However, the uses of SP flooding in horizontal or vertical well patterns are still being disputed from either technical or economic points of view, particularly in complicated reservoir systems. We investigated the successful application of SP flooding for many well-pattern combinations in a heterogeneous reservoir. A quarter five-spot pattern reservoir model is proposed with three different permeable layers; in particular, the interbedded layer has a much lower permeability than the other layers. The combinations of horizontal injectors and producers possess the most successful EOR processes, especially when the wells are interchangeably located in the high-permeability layers. However, the short-length horizontal-well combination is more preferable than the full-length horizontal-well pattern from the results of a comprehensive evaluation.

Keywords: Surfactant Polymer Flooding, Enhanced Oil Recovery, Horizontal Well, Well Patterns, Heterogeneous Reservoir

INTRODUCTION

Chemical flooding has been employed widely as the most effective method to extract oil remaining in a reservoir when water flooding generally can only recover 30-50% of the original oil in place (OOIP) [1]. Among the uses of alkaline-surfactant-polymer (ASP) flooding, single injection or combined injection, which respectively correspond to the injection of only one chemical agent or the use of a solution of more than one agent for the flooding processes, can be utilized. An alkali is suitably employed for acid-oil reservoirs since it can generate an in-situ surfactant as a result of the reaction activities with the natural acid components of oil, thereafter reducing the interfacial tension (IFT) between oil and water. The use of a synthetic surfactant also aims to decrease the IFT to an ultralow value; in particular, the addition of a surfactant to an alkaline solution significantly increases the capillary number to a higher level than that of a single solution [2]. The injection of a polymer solution can considerably improve the mobility ratio between the displacing fluid and the oil as a result of the formation of a viscous solution fluid, thereby improving the sweep efficiency [3]. However, the success of chemical flooding depends on the characteristics of the agents used, the reservoir conditions, and the production/injection strategies. Sheng [4] reviewed ASP flooding and very clearly stated the criteria for chemical injection in a reservoir, such as the temperature, formation water salinity, permeability, and oil viscosity [4]. It was concluded that the chemical enhanced oil recovery (EOR) applications in sandstone reservoirs provide a higher efficiency than carbonate reservoirs owing to the high chemical adsorption of the carbonate rock. In addition, a polymer can be applied with a reservoir temperature up to 120 °C, as indicated by the wide thermal range of polymer utilization. Within the temperature limit, the adsorption level of polymer is inversely correlated with salinity and reservoir temperature [5]. Arabloo et al. [6] investigated the characterized viscous fingering phenomena in multilayered heavy oil systems by using a natural surfactant for various patterns; they observed a decrease in the bypassed oil level according to the increase in the dimensionless distance traveled by the front for all heterogeneous systems [6]. The existence of low-permeability objects also makes the reservoir complicated in terms of the geological conditions and presumably influences the EOR performance. Various shale geometry models in a five-spot well pattern were designed to verify the effects on polymer flooding in heavy oil systems by the experimental and numerical works of Mohammadi et al.; the results illustrated the importance of designing the injector so that the mean direction of the injected fluid flow is parallel to most of the shale barrier objects [7,8]. The layer orientations also impact the flooding project, especially when the permeable levels of the layers are highly deviated. Meybodi et al. [9] used glass micromodels to determine the important effects of different permeable layer orientations on the polymer flooding performance in a five-spot pattern [9]. The results demonstrated the strong influence of the local heterogeneity near the injection regions on the oil recovery; in particular, the best oil recovery performance was achieved when the liquid was injected from a low-permeable portion rather than from a high-permeability layer for polymer flooding. In addition, various numerical works have been carried out to identify special issues that were restricted by experiments. By using the CMG (STARS) simulator, Sinha et al. [10] found that the numerical results agreed with laboratory data for surfactant and polymer flooding; however, a high deviation was observed for ASP flooding owing

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to the complex mechanisms when adding the alkali [10]. Ngoc et al. [11] proposed a new approach for evaluating the uncertainty of a surfactant-polymer (SP) flooding project by using GOCAD in conjunction with CMG's CMOST and STARS software; they identified the most important factors influencing the NPV by a sensitivity analysis including the chemical concentration, polymer slug, and injection schedules [11].

Regarding the well patterns, the utilization of horizontal wells for the recovery of trapped oil in the enhanced oil recovery stage has been developed as the significant well pattern for installation in reservoirs. The improvements in horizontal-well technologies have been demonstrated to be technically and economically attractive compared to the use of only conventional vertical wells [12,13]. Many previous works investigated the success of horizontal-well patterns on water flooding and achieved considerable conclusions. Popa and Turta [14] found that the pressure loss along a horizontal section of the well will influence the sweep efficiency of water flooding, regardless of the well pattern. Popa and Clipea [15] also clarified the uniform degree of the fluid flux within the reservoir by verifying different pressure drawdowns between the heel and the toe of the horizontal section for either injectors or producers. Algharaib and Ertekin [16], on water-flooding processes, concluded that an increase in the length of a horizontal well does not cause the additional oil recovery to increase linearly, whereas it is unnecessary to have a long horizontal well for recovering the oil trapped in a heterogeneous reservoir [17]. Hadia et al. [18] concluded the unimportant placement of horizontal producer on the oil production performance; however, the results of this work might be more applicable in a homogeneous reservoir than in the heterogeneous system. AI-Abbas and Shedid [19] pointed out the successful applications of steam associated with surfactant flooding on the heavy crude oil by horizontal wells, enlarging the feasibility of the combination of chemical with other methods to recover residual oil in unconventional reservoirs.

This work focuses on the utilization of horizontal wells for SP flooding in a complicated three-layered sandstone reservoir, in which a less permeable layer is interbedded between highly permeable ones. The proposed heterogeneous reservoirs will complicate the EOR processes owing to the unstable and unpredictable performance [20,21]. Many well combinations will be suggested for installation, including altering the horizontal-section length and the locations of the horizontal sections of the wells. It is known that two apposed horizontal wells are the most favorable configuration [22-24]; however, the length of the well and, obviously, the long project life caused by the long horizontal well and injectivity reduction (when injecting a polymer) need to be involved in consideration since they significantly affect the overall evaluation of the project [25].

RESERVOIR DESCRIPTION

Table 1. Reservoir description and input parameters

Grid	15×15×8
Porosity	0.2
Horizontal permeability	
- Layer 1	800 md
- Layer 2	100 md
- Layer 3	500 md
Initial oil saturation	0.5
Depth	396.34 m
Reservoir pressure	4.13 MPa
Reservoir temperature	38 °C
Oil gravity	32.4 °API
Oil viscosity (under reservoir conditions)	4.5 cp

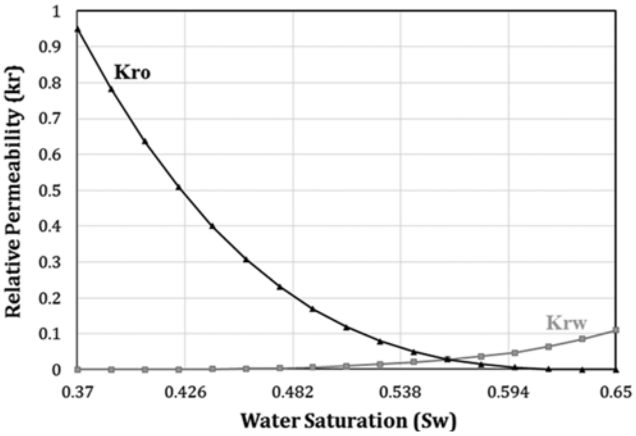


Fig. 1. Relative permeability curves.

A quarter five-spot pattern sandstone reservoir model was built in the STARS black-oil simulator for a field scale of 183×183×21 m^3 with 15×15×8 grid blocks in Cartesian coordinates. The reservoir porosity was assumed to be constant throughout the reservoir; however, the permeability changed vertically, corresponding to different layers. The reservoir consists of three layers in total, as presented in Table 1, where two highly permeable layers (500 and 800 md) are interbedded by a less permeable layer (100 md). The ratio of the vertical to horizontal permeability is also equal between layers and set to 0.1 uniformly throughout the entire reservoir.

A reservoir temperature of 38 °C was proposed following the normal thermal gradient of the earth and remains within the range of the polymer utilization threshold [4]. At the start of the simulation, the oil saturation was set to 50% of the pore volume with a water-flooding residual-oil saturation as high as 35% for the entire reservoir. The rock was described as water-wet rock condition. Fig. 1 shows the relative permeability curves of the reservoir as a presentation of the water-wet rock reservoir characteristic. The reservoir conditions and input parameters used for the simulation are partially taken from the previous work of Najafabadi et al. [26].

The application of a quarter five-spot pattern has been regularly proved to be effective on enhancing oil recovery, even being much more suitable than the line-drive pattern [27]. In regard to the experimental processes, the uses of this pattern have become more popular and effective in terms of visual observation compared to the conventional core flooding displacement [28]. Therefore, the deployments of different well configurations in a quarter five-spot pattern as in this work will promisingly result in the efficient EOR processes as well as the applicable conclusions compared to other patterns.

WELL COMBINATIONS: CASE STUDIES

1. Base Case (V-V)

The combination of a conventional vertical injector and producer wells is proposed as the base case, with two wells fully perforated throughout the reservoir thickness. The distance between the two wells is approximately 241.5 m, and the well radius is 0.15 m and the same for both wells. The wellhead locations of the injector and producer are fixed for the other cases.

2. Vertical-horizontal (V-H) and Horizontal-vertical (H-V) Cases

In the V-H case, the producer is installed as a horizontal well, whereas the injector is still a vertical well. The horizontal producer is located in layers 1 and 3, and the corresponding well combinations are denoted as V-H1 and V-H3, respectively. The horizontal section is designed to reach nearly the end of the Y axis in the grid — namely, full-length horizontal (to distinguish it from short-length horizontal discussed later).

In contrast to the V-H case, the producer in the H-V case is vertical, and the injector is a full-length horizontal well. However, the horizontal section of the injector in the H-V case will be located in layers 1, 2, and 3, corresponding to well combinations H1-V, H2-V, and H3-V, respectively.

Fig. 2 illustrates the V-H1 and H3-V well configurations as representatives of the V-H and H-V cases.

3. Horizontal-horizontal Case

In this case, both the injector and producer are horizontal wells. The well combinations are divided into four groups on the basis of the alterations in the lengths of the horizontal sections as follows:

- H-H: Full-length horizontal injector and producer. The installed well combinations are created by interchanging the locations of the injector and producer, where the horizontal section of the injector is located in layers 1, 2, and 3, whereas that of the producer is only located in layers 1 and 3, as summarized in Table 2.

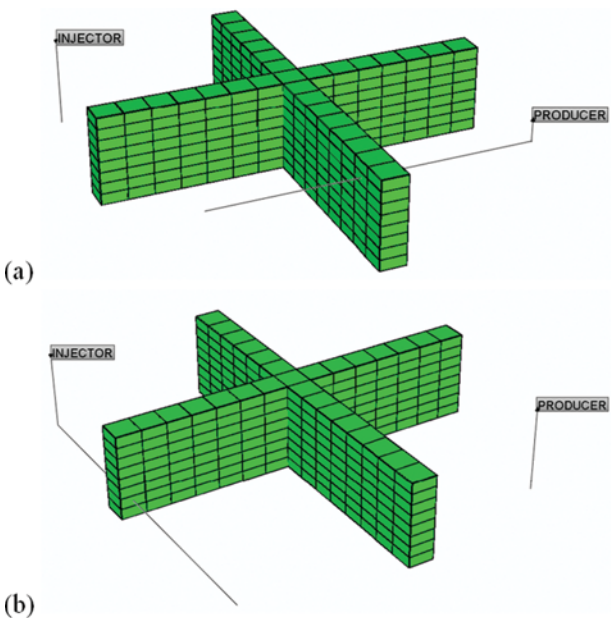


Fig. 2. (a) V-H1 and (b) H3-V well combinations.

Table 2. Well combinations of the H-H group

Producer Injector	Layer 1	Layer 3
Layer 1	H1-H1	H1-H3
Layer 2	H2-H1	H2-H3
Layer 3	H3-H1	H3-H3

Table 3. Well combinations of the H-HS group

Producer Injector	Layer 1	Layer 3
Layer 1	H1-HS1	H1-HS3
Layer 2	H2-HS1	H2-HS3
Layer 3	H3-HS1	H3-HS3

- H-HS: Full-length horizontal injector and short-length horizontal producer. A "short" length means that the length of the horizontal section is half of the "full" length. Similar to H-H, the various combinations of this group are created by interchanging the well locations (Table 3).
- HS-H: Opposite to the H-HS group. The horizontal producer is full-length. The well combinations of this group are HS1-H1, HS1-H3, HS2-H1, HS2-H3, HS3-H1, and HS3-H3.
- HS-HS: Both the horizontal injector and producer are short-length. The well-pattern combinations belonging to this group are

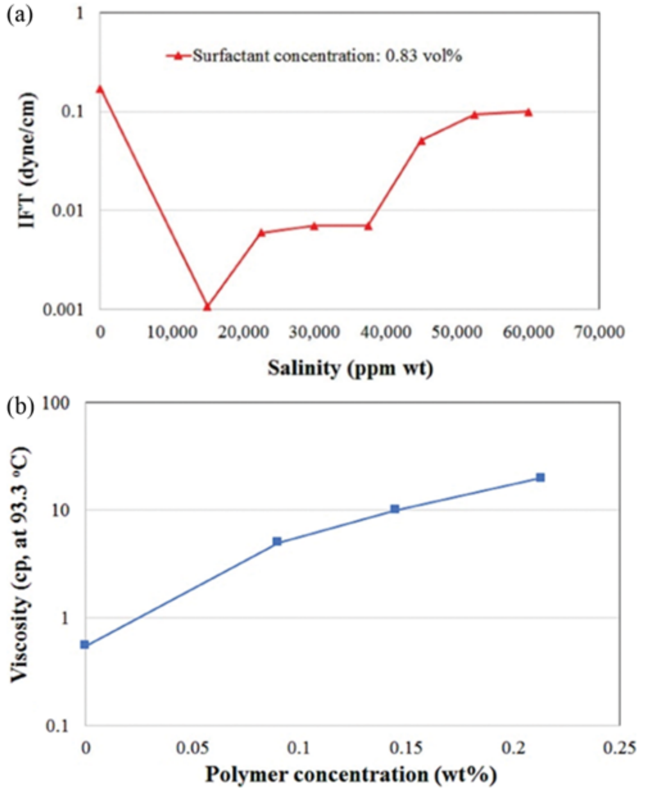


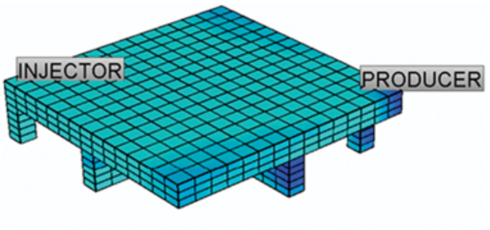
Fig. 3. Chemical characteristics used for simulation: (a) IFT relationship and (b) viscosity behavior of the polymer.

HS1-HS1, HS1-HS3, HS2-HS1, HS2-HS3, HS3-HS1, and HS3-HS3.

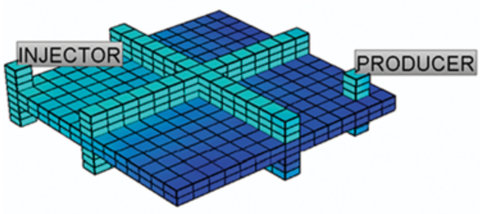
RESULTS AND DISCUSSION

The same flooding strategy is applied for all simulations, in which the reservoir is flooded with water since January 1^{st} of 2000 without any solvent agents. After one year, 0.83 vol% surfactant was injected with make-up water as the pre-flushing agent to reduce the capillary forces between the oil and the water in the pores [29,30]. The same amount of surfactant and 400 ppm water-soluble polymer were contemporarily added to the make-up water on the first day of 2002 and added for two years. After that, the EOR processes ceased the addition of polymer to the displacing fluids. The utilization of a soluble polymer helped to increase the viscosity of the injected liquids considerably; hence, there was an improvement in the mobility ratio between the displacing and displaced fluids in the reservoir and the extraction of drastically trapped oil in the pore spaces [31-33]. The designed chemical concentrations were screened for simulation on the basis of the characteristics of the chemical solution, such as the IFT reduction and solution mobility ratio. Fig. 3 illustrates the IFT relationship and viscosity behavior that were applied in this study. The maximum liquid rate of both the injector and producer was set to be 477 m^3/day, the maximum bottom-hole pressure (BHP) of the injector was 6.9 MPa, and the minimum BHP of the producer was 0.69 MPa.

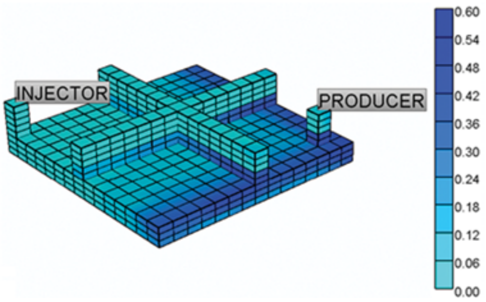
The simulation results for the base case were considered first and used to evaluate the other combinations. In total, 3.1 PV of liquids was injected after 1658 simulation days for the V-V well patterns, and 74.45% of the oil in place (OIP) was recovered. As can be seen in Fig. 4, the oil in layer 1 was swept nearly throughout the reservoir at the end of the project life, and the uniformly swept area in layer 3 also describes the sweep efficiency of SP flooding. However, despite the efficient coverage of the pre-flushed surfactant, there remains a large area in layer 2 that has not been perfectly covered owing to the failure of viscous fluids to propagate caused by the low permeability despite the improvement of crossflow by polymer injection. This result indicates the evident impact of the less permeable zone on the oil production performance, as demonstrated by the V-V combination, where almost all of the oil has been extracted from layers 1 and 3 rather than layer 2 of the reservoir. Furthermore, the use of a vertical injector is not suitable for pushing the oil bank into the producer in points of either sweep efficiency or injectivity while an interbedded poor permeable zone existed. The chemical propagation profiles after injecting 0.62 PV of liquids for three layers are presented in Fig. 5 in terms of the IFT. As presented, the swept regions are relatively uniform in each layer, indicating the proper mobility control of the injected viscous solution. Furthermore, the IFT in the covered area has been reduced



(a) Layer 1

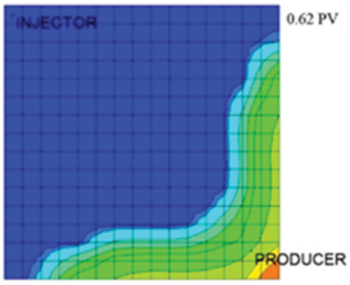


(b) Layer 2

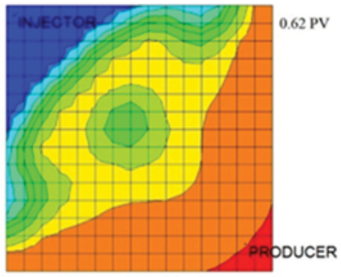


(c) Layer 3

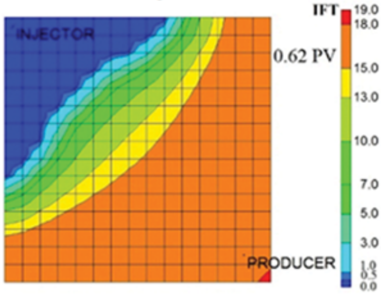
Fig. 4. Oil saturation profiles for the three layers after 1658 simulation days for the base case.



(a) Layer 1



(b) Layer 2



(c) Layer 3

Fig. 5. IFT profiles of the base case after injecting 0.62 PV of fluids.

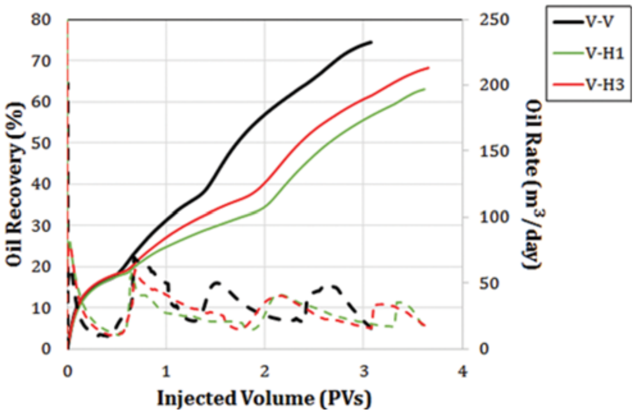


Fig. 6. Oil production for the V-H case compared to the base case.

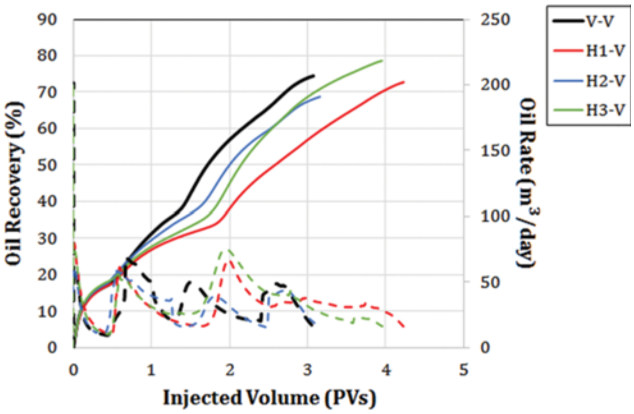
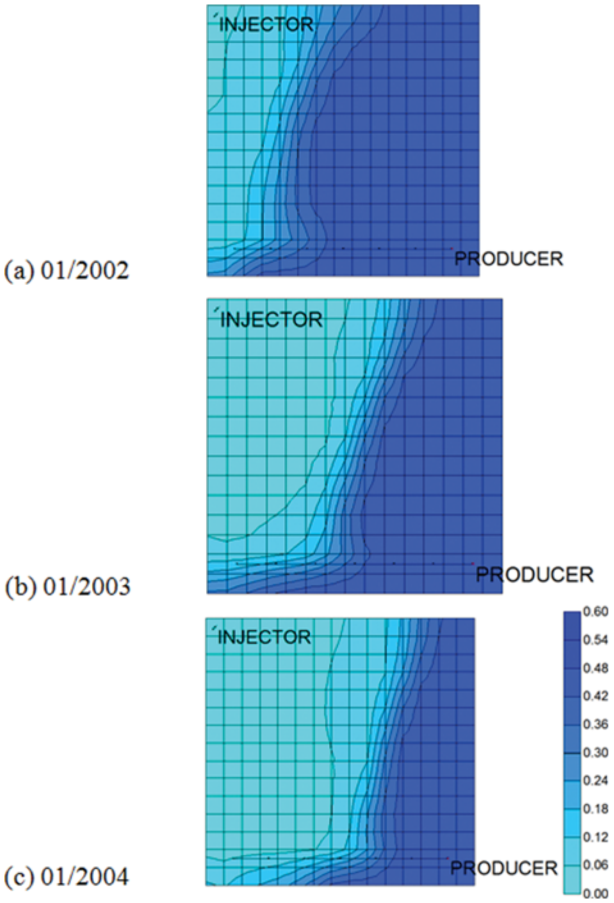


Fig. 8. Oil production for the combinations of the H-V case compared to the base case.

to an ultralow value, as evidently indicated by the effective surfactant and salinity designs corresponding to the reservoir fluid properties and wetting conditions.

The well combinations of V-H case show unsuccessful EOR performance despite the use of a horizontal producer instead of a vertical producer. As presented in Fig. 6, a maximum of 68.22% of the OIP was recovered after injecting 3.7 PV of liquids by the V-H3 well configuration, whereas the oil recovery is 63.01% for the V-H1 combination. The flow patterns of the fluids in the reservoir are also diverse in comparison with the base case, as illustrated in Fig. 7. The moveable fluids in the layer in which the producing well is located tend to converge to the toe of the horizontal section from the vertical injector rather than the upper point oriented towards the heel, and the flow still uniformly pervades throughout the rest of the layers.



(a) 01/2002

(b) 01/2003

(c) 01/2004

Fig. 7. Oil saturation profiles in 2002, 2003, and 2004 for V-H3 combination, demonstrating the convergence of fluids oriented towards the toe of the horizontal producer.

The argument is similar for the H-V case, in which the fluids flow towards the vertical producing well via fluid channels from the toe of the injection well, as easily visualized from 2001 to 2002 for all combinations. Nevertheless, alteration of the well pattern for the injector results in better EOR performance than that of the V-H case. In detail, H3-V resulted a higher injectivity than V-H3, with 4 PV of fluids injected in 1569 simulation days and 76.65% of the OIP recovered. Although H2-V exhibited the worst performance, it was still better than a couple of combinations of the V-H case with an oil recovery of 68.72%, as shown in Fig. 8. These simulation results evidently show the advantage of a horizontal injector for the improvement of EOR performance rather than the horizontal production well.

The oil production performance is greatly improved when conjugating both the injector and producer to be the horizontal wells, as in the horizontal-horizontal case. However, the increase in the oil extracted depends on the relationship between the placement of the injector and producer. Presumably, installing both horizontal wells in the same layer just effectively recovers the oil trapped in that layer; however, placing a producing well in a different layer with an injection well might result in better performance as a consequence of fully propagating the displacing fluids throughout the reservoir. Further, the areas of swept regions principally depend on the crossflow of the fluids, especially when injecting viscous liquids, featured by the shear-thinning behavior of polymer solution [34,35].

As evidently illustrated in Fig. 9, relatively high oil recoveries were mostly achieved when the injector was placed in layer 1 and the producer was located in layer 3, and vice-versa, for all groups. For instance, H1-H3 gives the highest produced oil volume with 85.88% of the OIP, whereas the recovery factor of H3-HS1 is 83.76%,

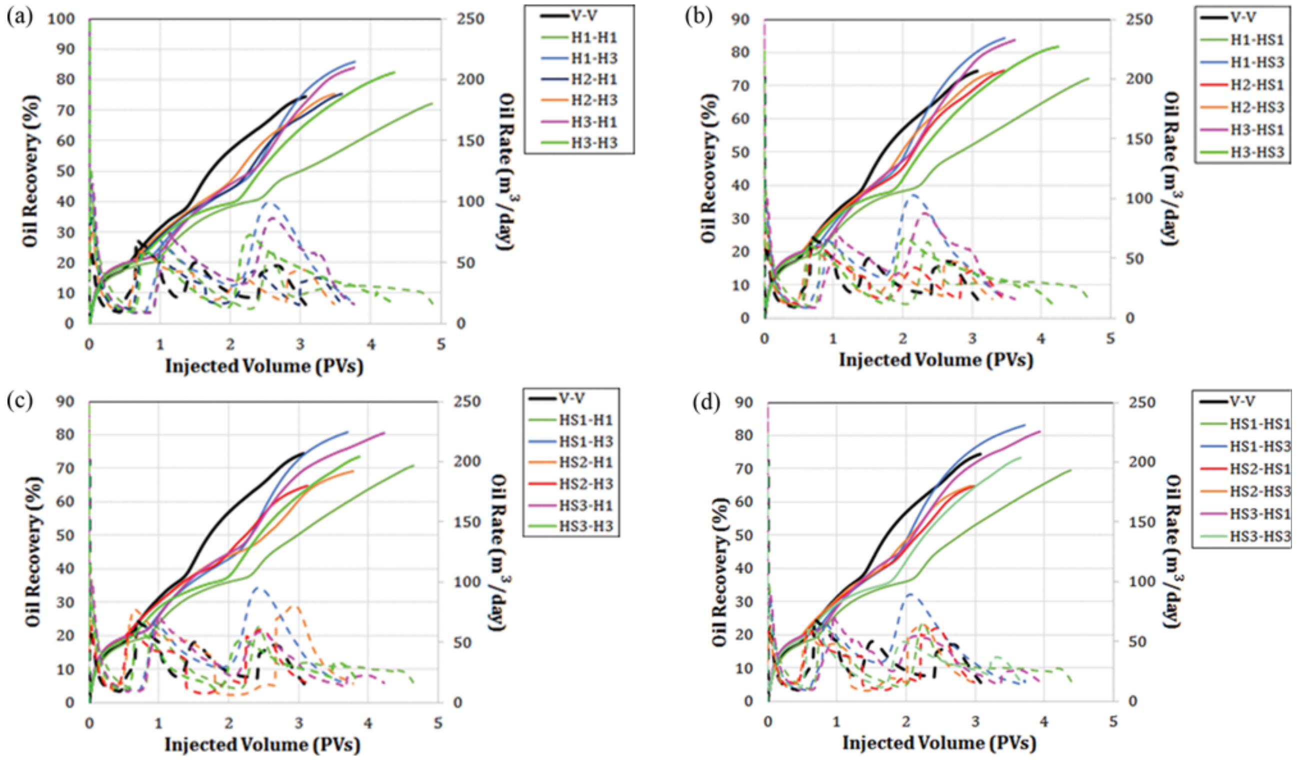


Fig. 9. Oil production performance for combinations belonging to the horizontal–horizontal case compared to that of the V-V case: (a) H-H, (b) H-HS, (c) HS-H, and (d) HS-HS.

nearly higher 10% than that of the base case. Similar to the H-V and V-H cases, a flow channel still occurs when two horizontal wells are placed in the same layer, particularly at the time before injecting the viscous liquids, as presented in Fig. 10.

The installation of two wells in the same layer dramatically restricts the propagation of the displacing fluids to the other layers because of the interbedded layer. As observed in Fig. 11, the injected solution can effectively sweep oil within the injector regions in HS1-HS1; however, at a farther distance, the oil is just predominantly swept in layer 1 compared to the other locations. In contrast, when the producer is located in layer 3, the swept oil regions are broader than the other layers in the HS1-HS3 combination, and as the consequence, the injectivity is lower than that of HS1-HS3. This absolutely confirms the relevance of the installation of horizontal wells in different layers rather than in the same layer in order to enhance the sweep efficiency by SP flooding.

Obviously, in comparison with the other cases, the installation of horizontal injector and producer wells is absolutely the most attractive configuration for the deployment of an EOR project for this type of reservoir. In general, full-length horizontal wells achieve the highest oil production; however, the deviations between H-H and the other groups are not very high to take biased. As can be seen from Fig. 9, the HS1-HS3 combination recovered approximately 2% less of the OIP than that of the highest combination, even though both horizontal wells are half of the length of the H-H configuration, which demonstrates that it is unnecessary to lengthen very long horizontal wells. Therefore, the short-horizontal-well combination seems to be the best selection, as comprehensively evaluated in terms of either technical or economic points of view.

To validate the simulated results, the grid dimensions are also examined since they might significantly affect to the running data in the case of an inappropriate grid design. A test grid with dimensions of 30×30×8 was designed and substituted for the old structure while retaining the same reservoir model size and well distances. Fig. 12 presents the simulation results for the HS1-HS3 and H1-HS3 combinations for two different grid dimensions. As shown, there are small deviations in the oil rates for both combinations for the two grid dimensions; however, the final oil recoveries are approximately equal for each of the well combinations. The difference in the oil recovery factors of both combinations is approximately 0.3%, demonstrating that the first design with grid dimensions of 15×15×8 is valid compared to the tested grid structure with the new dimensions.

The operational parameters of the initial well designs are also taken into account as factors that affect the flooding performance. This work investigates the effects of different perforation intervals by simply changing the block numbers of the perforation. Presumably, a higher perforation density will generate a more uniform fluid flow profile; therefore, a better sweep efficiency will be attained. However, the improvement in the EOR performance depends on the reservoir fluid properties, particularly in the region adjacent to the injector. In this work, three cases were redesigned for simulation with perforation intervals of 24.4 m, 12.2 m, and 6.1 m for the HS1-HS3 well combination. Owing to the good agreement of the results for the 15×15×8 and 30×30×8 grid dimensions, the denser grid will be applied for the different well completion conditions.

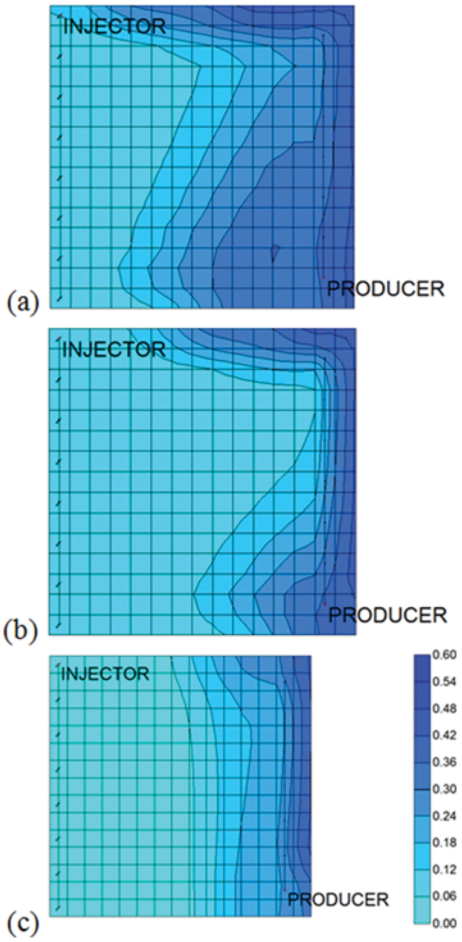


Fig. 10. Oil saturation profiles of the H1-H1 combination after (a) 547, (b) 670, and (c) 790 simulation days.

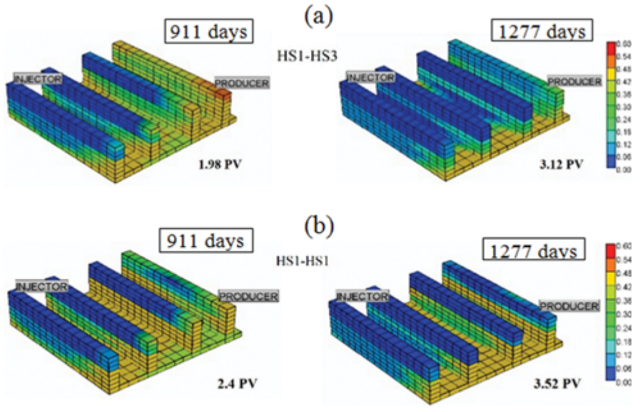


Fig. 11. Oil saturation profiles after 911 and 1277 simulation days for (a) HS1-HS3 and (b) HS1-HS1.

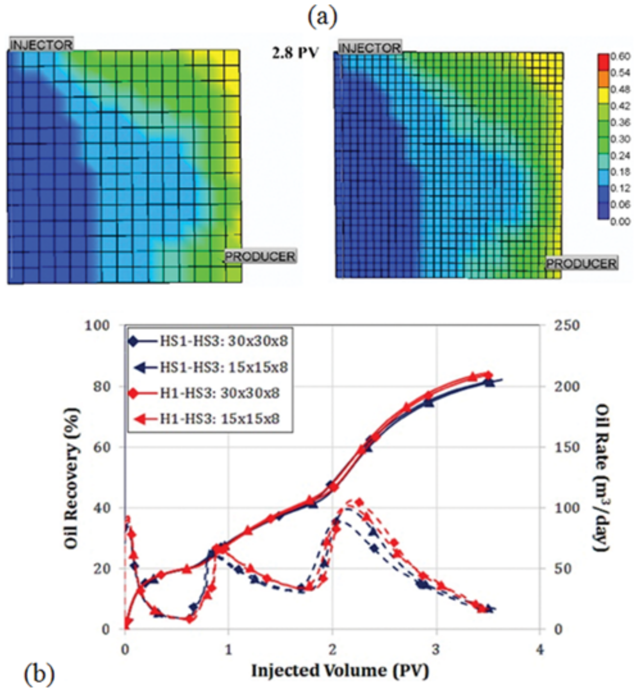


Fig. 12. A comparison of the effects of different grid dimensions on the simulation results: (a) oil saturation profiles of H1-HS3 after injecting 2.8 PV of fluids and (b) oil production performance of HS1-HS3 and H1-HS3.

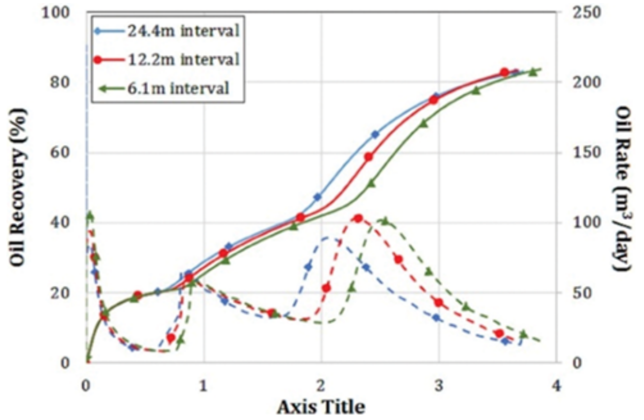


Fig. 13. Oil production performance of HS1-HS3 for three different perforation intervals.

The results in Fig. 13 show the effects of different perforation intervals on the oil rate; however, the ultimate oil recoveries at the final rate of 15.9 m^3/day for the three cases are relatively similar. A large deviation between the oil rate curves begins after approximately 1.6 PV of injected volume; this is approximately the time at which the polymer is beginning to be added to the injected solution. As the perforation density increases, the increase in the oil rate after improving the mobility ratio is postponed to the peak. The improvement in the uniform fluid flow profile generated by the denser perforation sweeps the oil more thoroughly, especially at the region near the injector, thereby resulting in a slower response at the producing well. Nevertheless, from the nearly equal ultimate oil recoveries of three cases, it is not necessary to design a very close perforation interval for the purpose of improving the EOR performance. This implies that various manners of the production performance for proposing the well perforation interval should be considered since the injected liquids have been appropriately designed according to the reservoir condition.

It is extremely important to investigate fully the impacts of the reservoir structure on the EOR performance, particularly when the heterogeneity determines many aspects of a project, such as the well installation, completion design, and injection strategies. Since numerical studies have demonstrated mostly validated results for SP flooding processes, the results and conclusions of this work promise to contribute significantly in terms of considering and selecting the possible well patterns for the deployment of a chemical flooding project in complicated heterogeneous reservoir systems.

CONCLUSION

Various well-pattern combinations have been investigated to determine the most effective configuration for deploying the EOR project of SP flooding. The novelty of this work involves a heterogeneous reservoir that consists of a less permeable interbedded layer. Even though the crossflow of fluids has been improved as a result of the injection of a polymer solution, the profiles of the fluid flows are still not uniform, and therefore cause varied EOR performance for different well configurations.

In the H-V and V-H cases, the utilization of a horizontal injector results in a significant improvement in the EOR performance rather than the utilization of a vertical injector with an existing interbedded low-permeability layer. However, fluid channels always occur from/to the toe of the horizontal section due to the pressure drawdown and ineffective crossflow, thereby causing a failed EOR process with a large remaining unswept area.

The employment of two horizontal wells has given predominant results, compared to the other cases, especially when two facing wells are installed in different layers excluding the interbedded layer. In addition, two short-length horizontal wells are more preferable for deployment than full-length horizontal wells from an economic point of view, since these two combinations have a very low deviation in the ultimate oil recovery.

Simulation results have also been obtained with different denser grid dimensions, demonstrating the proper grid structure design for obtaining accurate results. After investigating the effects of the change in the perforation interval, it is not necessary to utilize a design with a high perforation density to obtain better EOR performance, even though the closer interval results in a more uniform fluid profile in the region near the injection well.

Understanding the impacts of the specific complicated reservoir on the efficiency of EOR significantly contributes to the decision-making for well-pattern installation and optimizing the project.

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