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Insights into oil recovery mechanism by Nothing-Alternating-Polymer (NAP) concept

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ABSTRACT

This paper introduces new oil recovery mechanisms for oil recovery by polymer injection in heavy oil reservoirs with strong bottom aquifers. Due to unfavorable mobility ratio between aquifer water and oil and the development of the sharp cones significant amount of oil remains unswept. To overcome these issues, for the case demonstrated in this paper, a polymer injection pilot was executed with three horizontal injectors, located a few meters above the oil/water contact. The injectivity issues resulted in frequent shutdowns of the injectors. Interestingly, the water cut reversal and oil gain continued during the shut-in periods. This observation has led to the development of a new cyclic polymer injection strategy, in which the injection of polymer is alternated with intentional well shut-ins. The strategy is referred to as Nothing-Alternating-Polymer (NAP).

It was found that during polymer injection, the oil is recovered by conventional mobility and sweep enhancement mechanisms ahead of the polymer front. Additionally, during this stage the injected polymer squeezes the existing cones and creates a barrier between the aquifer and the oil column, suppressing the aquifer flux and hence the negative effect of the cones or water channels (blanketing mechanism). Moreover, injection of polymer pushes the oil to the depleted water cones, which is then produced by the water coming from the aquifer during shut-in period (recharge mechanism). During the shut-in or NAP period, the aquifer water also pushes the existing polymer bank and hence leads to extra oil production. The resistance caused by polymer adsorption reduces the extent of fingering of water into polymer bank. The NAP strategy reduces polymer loss into aquifer and improves the polymer utilization factor expressed in kg-polymer/bbl of oil, resulting in a favorable economic outcome.

1. Introduction

Polymer flooding is a mature technology, which involves injection of a viscous solution to reduce the mobility ratio between the displacing phase and oil (Bedrikovetsky, 1993; Lake et al., 2014). This leads to extra oil gain from the reservoirs. Moreover, polymer injection into heterogeneous reservoirs can create viscous-driven pressure drop between layers (Sorbie and Skauge, 2019; Zhang and Seright, 2007), which can eventually divert fluids from already-swept high-permeability layers to lower-permeability layers with high oil saturation. In comparison with the conventional waterflooding, polymer injection results in a more efficient utilization of water in oil fields, leading to significant reduction in the CO_2 intensity (kg-CO_2/bbl) of the produced oil (Farajzadeh et al., 2021).

The recovery of oil by injection of polymer in heavy oil reservoirs (>100 cP) has gained more attention in recent years. Several successful field applications of the technology have been reported (Seright et al., 2018a, 2018b; Eric Delamaide et al., 2014). The results of these applications suggest that enhancing oil recovery from heavy oil reservoirs might not require high polymer viscosities. For example, for Canadian fields with oil viscosities of 1000–3000 cP, injection of polymer solutions with viscosities of 15–30 cP has resulted in significant oil gains (Seright et al., 2018a). Several mechanisms have been proposed to explain these better-than-expected results. Seright et al. (2018a) argue

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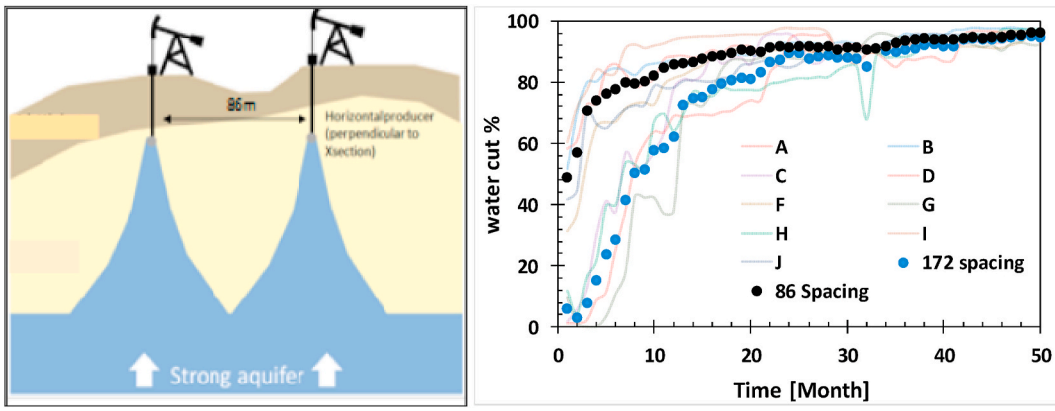

Fig. 1. From left (a) schematic of development of cones, (b) water breakthrough behavior in the producers. Dotted lines represent the average well response for a spacing of 172 m (blue dots) and 86 m(black dots). (For interpretation of the references to color in this figure legend, the reader is referred to the Web version of this article.)

that the end point relative permeability of the heavy oil reservoirs is very low, and therefore, only a small amount of polymer is required to improve the mobility ratio between the displacing phase and oil. For reservoirs with multiple zones or different permeability layers, injection of more viscous polymers might be required to take advantage of the crossflow between layers and in-depth conformance control. Water injection in heavy oil reservoirs creates fingers, and therefore, large volumes of oil remain untouched by water. Injection of polymer can extract the "by-passed oil" which is the main target of polymer enhanced oil recovery (EOR) (Sorbie and Skauge, 2019). For reservoirs with an active bottom-up aquifer, like the case in this study, the situation is more complicated. The adverse mobility ratio between the oil and water and the pressure drawdown imposed by the off-take rate in the horizontal producers results in the rapid development of water cones. Therefore, large amounts of oil remain unswept between the cones. It is believed that polymer EOR is a viable technology for heavy oil reservoirs with an active aquifer and can help mitigate the negative impacts of aquifer influx on oil recovery (Li et al., 2014; Lotfollahi et al., 2016; Mjeni et al., ; Poulsen et al., 2018). However, the exact contributions of oil recovery mechanisms are not yet fully understood.

This paper discusses the application of polymer injection in a heavy oil reservoir with oil viscosity of 300–800 cP supported by a strong bottom-up aquifer in the South of the Sultanate of Oman. To overcome the aforementioned issues, a polymer injection pilot was started in 2013 with three horizontal injectors located few meters above the oil/water contact (Mjeni et al.,). An observation well was placed at the oil-water contact to monitor polymer losses into the aquifer. The initial assumption was to continuously inject a 100 cP polymer solution at 500 m^3/d of injection rate. However, it was challenging to sustain the injectivity mainly due to issues related to surface facilities, water and polymer quality (Lotfollahi et al., 2016; Mjeni et al.,). This resulted in frequent shutdowns of the injectors. Interestingly, the water cut reversal and oil gain continued during the shut-in periods. This strategy of injecting polymer and then shutting-in the injectors is now referred to as Nothing-Altering-Polymer (NAP), or cyclic polymer injection. The objective of this paper is to explore the mechanisms that contributed to oil production during the polymer pilot. The results of this paper can be used to extend and optimize the implementation of polymer flooding in different parts of the field and other reservoirs with similar characteristics. The structure of the paper is as follows: first, a brief description of the reservoir and the results of the pilot will be given. Then, the constructed simulation and the modeling strategy used to explain the field behavior (aquifer drive and polymer trial) will be discussed in detail. The outcome of the numerical simulations will be used to explain the behavior observed in the pilot. The model results will be used to shed light on the physics of the NAP process. Finally, the concluding remarks will be provided.

2. Field overview

The field discussed in this paper is located in the South of the Sultanate of Oman and was initially developed by drilling vertical wells targeting the main oil-bearing sandstone reservoir. The reservoir rock has a multi-Darcy (4–5 Darcy) permeability with an average porosity of 0.25. The average oil column thickness of the main reservoir is ~40 m attached to a strong aquifer. The reservoir contains oil with viscosity of 300–800 cP. The water salinity is around 7000 ppm. The unfavorable water/oil mobility ratio leads to rapid water breakthrough due to the establishment of sharp cones, limiting the oil recovery via the vertical producers (see Fig. 1a). Therefore, the drilling of long horizontal wells placed at the top of the reservoir was commenced. Initially, the wells were drilled at the spacing of 172 m, which was later followed by the infill-drilling of horizontal wells (with the length of 400–1000 m) at 86 m spacing. However, once more due the adverse mobility ratio and relatively high off-take rates, large water cuts (fraction of water in the produced liquids) are observed in the producers in relatively short times, as shown in Fig. 1b. This leaves significant amount of oil unswept in between the cones, as illustrated schematically (yellow area) in Fig. 1a.

To overcome these issues and extract the bypassed oil, injection of (viscous) polymer solutions was proposed by EOR screening and dynamic modeling studies. A key risk in the implementation of chemical EOR in reservoirs with an active aquifer is the loss of injected chemicals into the aquifer, which can limit the economic success of the project. To test the efficiency of polymer in recovering oil and to quantify the possible loss of polymer into the aquifer, a field trial was designed consisting of four existing oil producers and three polymer injectors drilled midway (43 m horizontal spacing) and placed few meters above the oil-water contact (OWC). The pilot injection started in 2013 and was concluded in 2016.

3. Pilot results

The objective of the polymer injection pilot was to (1) evaluate the efficiency of polymer in sweeping the remaining oil trapped in between the existing cones, and (2) quantify the amount of polymer loss to the underlying aquifer. Therefore, three horizontal polymer injectors with an average length of 500 m were drilled in between the four existing horizontal oil producers and placed few meters above the oil-water contact (OWC). An observation well (O-1) was placed at the OWC to monitor polymer loss to the aquifer. To monitor the lateral polymer movement and to measure the oil saturation, a vertical observation well (O-2) was placed adjacent to the middle injector (BC). Also, to monitor

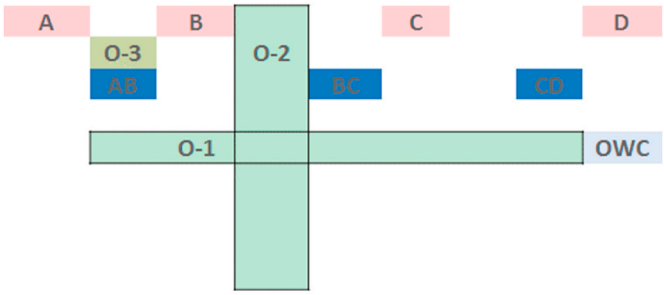

Fig. 2. Pilot configuration. A, B, C, and D are the producers; AB, BC, and CD are injectors, O1, O2 and O3 are observations/sampling wells.

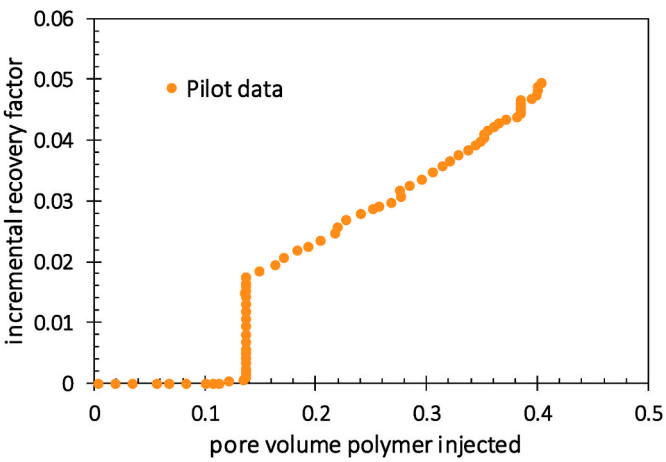

Fig. 3. Observed incremental oil gain from the polymer pilot in the field.

the vertical advancement of the injected polymer, a horizontal observation well (O-3) was placed few meters above the injector (AB). A simplistic configuration of the pilot is shown in Fig. 2.

The initial pilot design proposed to continuously inject a 100 cP viscosity polymer solution at the rate of 500 m^3/d under matrix conditions. A partially hydrolyzed polyacrylamide (HPAM) polymer with an average molecular weight of 18–20 MM Da was used. More information on the polymer type, concentration and relating issues can be found in ref. 10 and 11. However, it proved challenging to sustain such injectivity due to issues mainly related to surface facilities, and water and polymer quality. To resolve the problems caused by injectivity decline, the injectors were frequently shut down while producer wells were still working as a result of the strong aquifer support. Subsequently, acid stimulation jobs were conducted in all injectors to restore the injectivity; however, the initial injectivity was never restored. As a result, the injectors initially maintained a high injection rate and high polymer viscosity of 100 cP for several months only. Then, injected polymer viscosity was reduced to 30 cP, and the injection rate was reduced to 300 m^3/d. This improved the uptime of the injection facilities and the wells.

Between high-viscosity high-injection rate and low-viscosity low-injection rate stages, the injection was stopped for almost a year. During this period, a comprehensive research program was initiated to understand and address the causes of the injectivity decline. As mentioned, the producing wells were still operational, and interestingly, the producers continued to produce incremental oil even when no polymer was injected for a relatively long period. An incremental oil recovery of 2% was achieved during the injection shut in period and after only 0.14 pore volume of polymer injected, as shown in Fig. 3. Furthermore, the analysis of water samples from O-1 showed that only a small portion of the injection polymer made its way to the aquifer. The loss of polymer to aquifer was estimated to be less than 5% of the total injected polymer.

The observations of continued incremental oil recovery during no polymer injection period and lower than expected polymer losses to aquifer have led to the development of a new cyclic polymer injection strategy here referred to as Nothing-Altering-Polymer (NAP).

4. 3D dynamic model

The mechanics of polymer flow in the presence of a strong aquifer is sketched in Fig. 4. There are two interfaces or fronts that play important roles during this process: an oil/polymer front where the mobility control provided by the polymer enhances the oil displacement, and an aquifer/polymer front where the aquifer drive is affected the residual resistance factor (RRF) due to polymer adsorption/retention. Residual resistance factor (RRF) is defined as the ratio of the rock permeability to water before and after polymer injection. The RRF induced by polymer adsorption reduces the water relative permeability thereby slowing down and spreading the aquifer flux. In addition, part of the oil is pushed towards the cones. We refer to this as "recharging mechanism". The recharged oil is produced by aquifer water during the shut-in period, which will be explained later.

To better evaluate and understand the oil recovery mechanism during NAP, a 3D model of the target reservoir was constructed. A major

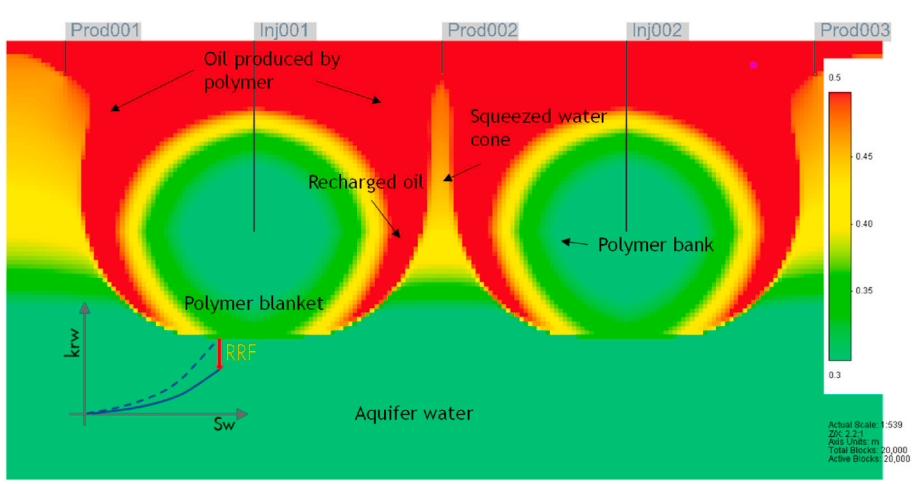

Fig. 4. Illustration of the flow mechanics of polymer in the presence of an active aquifer. At the polymer/oil front the polymer viscosity is providing a better mobility ratio than water. The created polymer bank reduces the water flux from aquifer to the reservoir. Part of the mobilized oil by polymer is pushed towards the water cones, which will later be produced during shut-in period by aquifer drive.

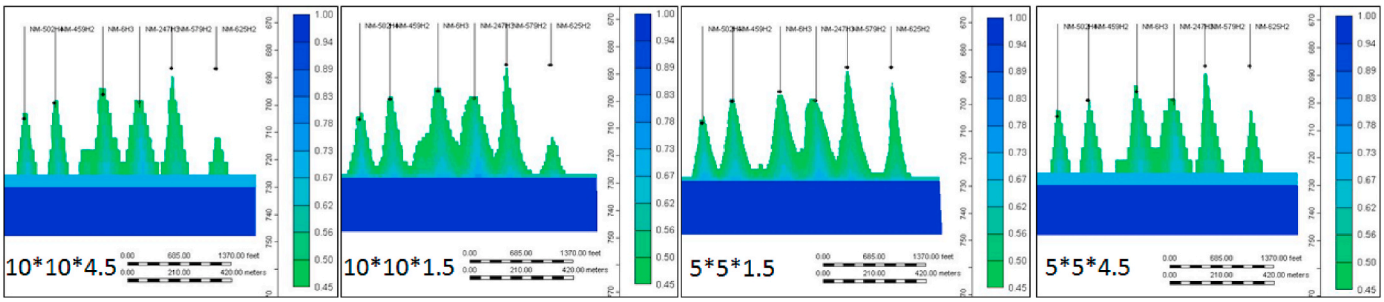

Fig. 5. Impact of the grid resolution on the numerical representation of the water cones developed by the water flux from the underlying strong aquifer.

challenge in simulating heavy-oil reservoirs with a strong aquifer is the grid resolution required for reproducing the sharp water cones. Another challenge in this field is the presence of small flow baffles whose extent and frequency is not certain. A well-by-well match with the data is usually required for obtaining a reasonable distribution of the remaining oil saturation, which is essential for quantifying the potential of future technologies, such as polymer EOR in this field. Here, we briefly describe the approach adapted to history match the field data, which was used to match the performance of the polymer injection in the field trial.

As mentioned previously, the main drive mechanism in this field is due to the strong bottom aquifer support. Because of the dominance of the destabilizing viscous forces over the stabilizing gravity forces exacerbated by the adverse mobility ratio between the oil and water, sharp cones are rapidly formed once the production was started. In essence, water cones can be considered as large and narrow immiscible fingers. To model the fingering behavior, grid block sizes smaller than the wavelength of the fingers are needed. Such grid resolution becomes computationally expensive and impractical in field case simulations. Both lateral and vertical grid resolutions matter; however, lateral grid resolution appears to be more important in our simulations. In the case of this reservoir, the lateral and vertical grid size of 2–5 m and <5 m resulted in acceptable outcomes, as shown in Fig. 5. Improving the vertical resolution from 4.5 m to 1.5 m, did not have a significant impact on the shape of the cones, but increased the run time by three times. At the same time, improving the lateral resolution from 10 × 10 m to 5 × 5 m resulted in a better representation of the cones, but the run time increased by four times. Finally, the vertical and lateral resolutions were set to 4.5 m and 5 m, respectively, as a compromise between the run time and the acceptable quality of the results.

The obtained cores from the target reservoir indicated the existence of discrete and randomly distributed thin-cemented streaks. The geometry, frequency, and location of such reservoir baffles are highly uncertain. The analysis of the well open-hole logs and production data suggests that the baffles do not extend across the reservoir and have no significant impact on the flow. Water filters through the baffles with no observed delays on the breakthrough behavior.

Table 1
Parameters of the Corey-type relative permeability.

Parameter	k_{roe}	k_{rwe}	n_o	n_w	S_{wc}	S_{orw}	*RRF*
value	0.85	0.22	2.7	3	0.2	0.17	1

To fully quantify the impact of the baffles on the production behavior of the reservoir, the sensitivity analysis was performed by changing the frequency and location of the baffles. The impact of the baffles on the overall oil recovery performance was found to be less than 3%. However, they exhibited a significant impact on the well-by-well level performance. On the well group level, the reduction in the oil production in one well surrounded by the baffles was compensated by another well located far from the baffles. Given the high uncertainty of the size and location of the baffles and their small impact on the overall oil production, it was decided to exclude the explicit modeling of the baffles from the dynamic modelling. It is sufficient to model the baffles implicitly i.e., by modifying the average or effective k_v/k_h (k_v and k_h stand for the vertical and horizontal permeability, respectively). Change of k_v/k_h ratio alters the mobility of all fluids; however, coning in heavy oil reservoirs is largely influenced by water-related properties. Consequently, to model the cones mainly water relative permeability parameters (particularly end-point water relative permeability was altered. With these modifications, a good agreement was achieved for cumulative liquid, cumulative oil, oil rate, and down-hole pressure of the pre-polymer production period. The results are shown in Fig. 6. The

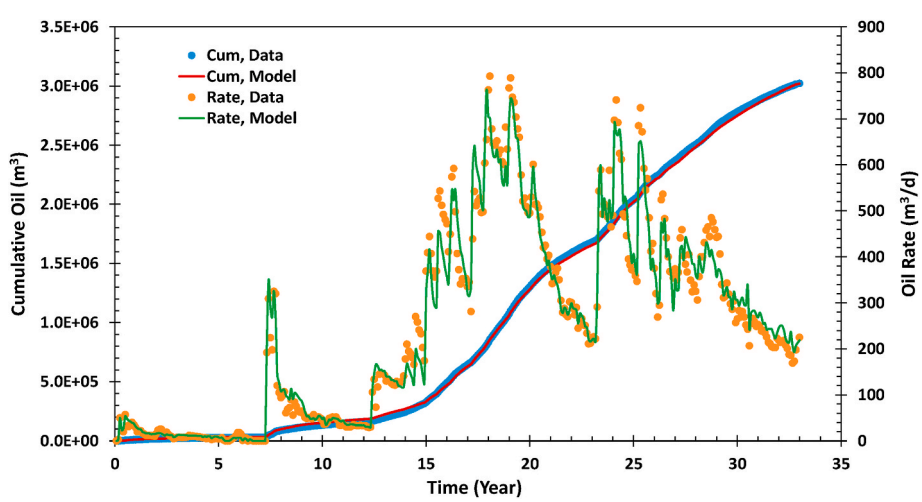

Fig. 6. The comparison between the simulation results and the field data.

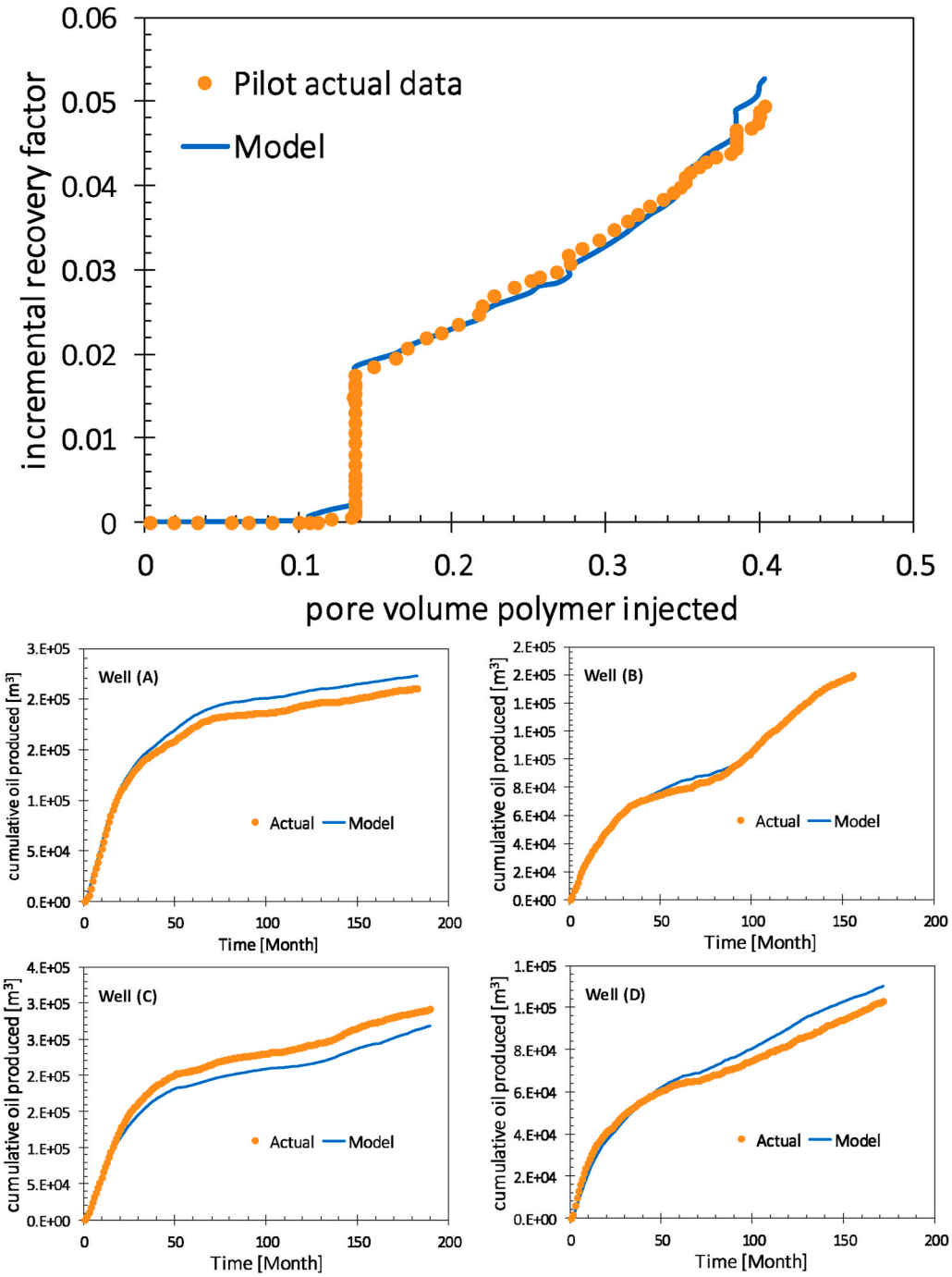

Fig. 7. History matching of the oil production from the polymer pilot on field and well level.

relative permeability and polymer-related parameters used to obtain the match are also provided in Table 1.

Once the dynamic model was fine-tuned to match the production data from the aquifer drive period, the historical polymer injection profiles were introduced to simulate the pilot data. Polymer rheology parameters were imported based on the lab measurements. However, in order to match the production data, with the reservoir simulator used in this study, the viscosity of the injected solution had to be reduced to 1/3 of its reported surface value, implying a severe viscosity degradation in the wells or the reservoir. This could be either due to thermal/chemical stability of the polymer or dilution of the polymer solution due to mixing with the aquifer water. Also, it could be due to the alteration of relative permeability in the presence of polymer and the significant hysteresis effects during NAP. Although both theories result in a similar outcome, their underlying physics is different. For instance, the polymer degradation component can be improved through well-design surface surveillance and operational measures; however, the change of relative permeability or hysteresis behavior is given by nature and cannot be mitigated. At this moment, it is difficult to assess which approach is the closest to the reality and in fact both mechanisms could play a role.

The 3D model can simulate the continued incremental oil gain during the polymer injection shut-in periods. The model can also adequately match the oil gain by the individual wells in the pilot area, as shown in Fig. 7. These results show that polymer injection creates a blanket over the aquifer significantly reducing the water flow through the cones and other water channels. During the shut-in period, the strong aquifer

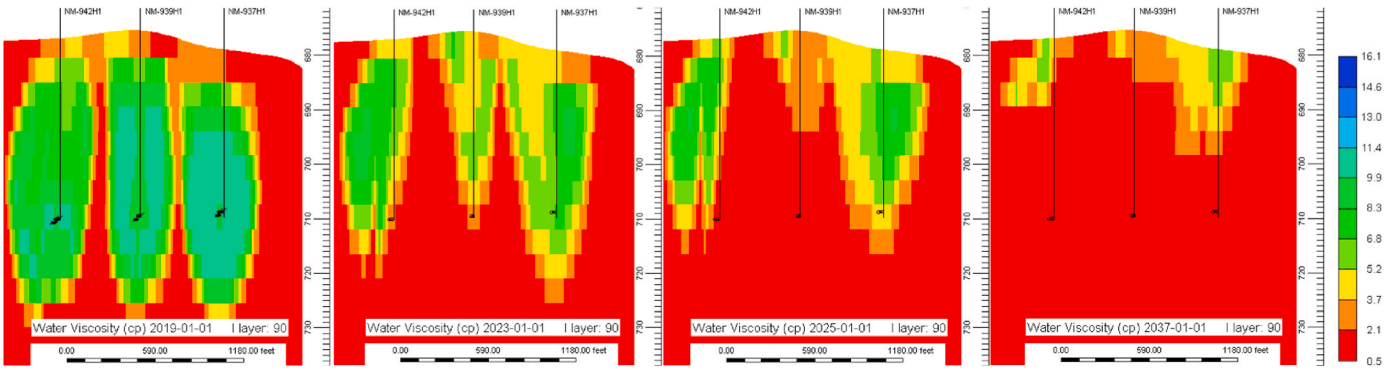

Fig. 8. During shut-in or NAP period water coming from aquifer pushes the polymer bank, which results in extra oil production. The polymer solution is diluted due to dispersion and mixing with the aquifer water, shown by yellow color. (For interpretation of the references to color in this figure legend, the reader is referred to the Web version of this article.)

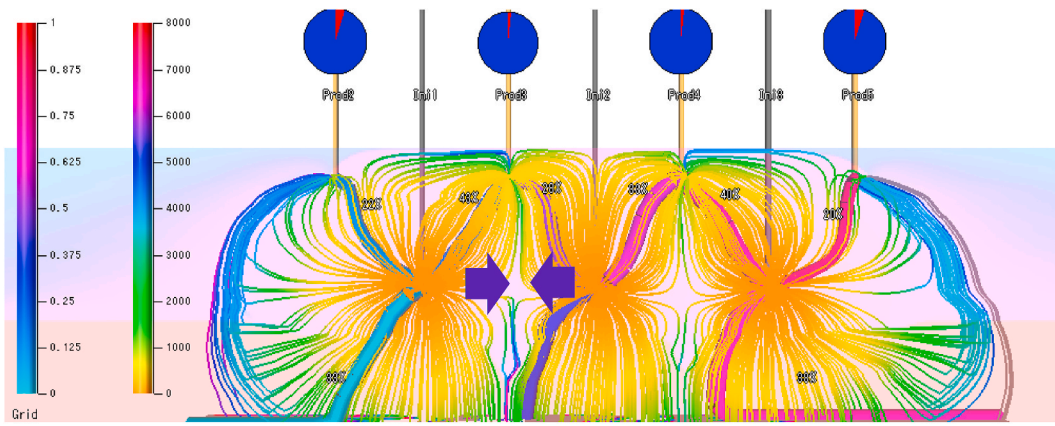

Fig. 9. 2D cross sections showing the streamlines from the injectors to the producers (top) and the oil bank size and shape (bottom). Polymer saturated area areas shown by green, aquifer by orange and oil saturated areas by purple. (For interpretation of the references to color in this figure legend, the reader is referred to the Web version of this article.)

pushes the injected polymer slug towards the producers, hereby changing the sweep and leading to extra oil gain. Naturally, after a certain time, as shown in Fig. 8, the aquifer water fingers through the polymer slug as it advances towards the producers. However, there are at least two mechanisms opposing the severe fingering behavior. Firstly, mixing of polymer solution with the aquifer water results in formation of a zone between the polymer bank and the aquifer whose mobility is less than water. The degree of mixing depends on the polymer concentration, local heterogeneity of the reservoir or variations in the pore-scale flow field. Secondly, the water mobility upstream of the polymer bank is also reduced through the resistance induced by the polymer adsorption or the RRF mechanism. The mixing of the aquifer water with the polymer solution leads to polymer dilution, which could be the reason for measuring tiny concentrations of the back-produced polymer over the pilot duration.

The effectiveness of the created polymer blanket, apart from the petrophysical properties of the reservoir (see eq. (4) in the next section) depends on the polymer viscosity and magnitude of the residual resistance factor (RRF). The value of RRF increases (exponentially) with decreasing permeability and increasing water saturation. Within the polymer bank shown in Fig. 4 the water saturation is larger than or close to 1-S_{orw} (S_{orw} is the residual oil saturation to water) and RRF can become large. Although a large RRF is beneficial for reducing the mobility of the aquifer water, it can also lead to high pressures in the injectors and can possibly impede the well injectivity.

Another important mechanism is the “recharge” mechanism. During injection of polymer, an oil bank is created, part of which is pushed towards the desaturated water cones, i.e., the cones are recharged with oil as illustrated in Fig. 4 and in Fig. 9 with a snapshots of the streamlines and oil bank formation. Consequently, the oil saturation in the water cones increases and the oil becomes more mobile. During the shut-in period, the aquifer drive pushes the recharged oil to the producer, as there is no horizontal pressure gradient in the absence of injection. As the oil bank movement corresponds to a drainage process with respect to water, modeling of this mechanism should include hysteresis in the relative permeability function. This is expected to accelerate the oil bank breakthrough. The response from the central wells is significantly higher than the wells on the side (edge wells) as shown by the streamlines. Indeed, the polymer blanket does shut-off the water influx and aquifer keeps feeding the edge wells from the outside. The large arrows below the producer in Fig. 9 show the oil recharge sites. This oil is produced during the shut-in period by water flux from the aquifer.

It also appears that the shutdowns of the polymer injectors reduce the amount of polymer loss to the aquifer that would not otherwise contribute to oil recovery. This in turn improves the polymer utilization factor, defined as the mass of polymer required to produce a unit volume of oil (kg-polymer/bbl). Therefore, the NAP process could be optimized to minimize the polymer losses and water fingering from the aquifer and obtain similar but slightly lower oil recovery efficiency as in continuous polymer injection. Fig. 10 illustrates that, for reservoirs with a strong bottom aquifer, continuous polymer injection would lead to a significant loss of polymer to the aquifer. Due to practice of NAP, in the right plot the polymer front barely travels past the water/oil contact depicted by a solid. This agrees well with the finding of the field trial, where no

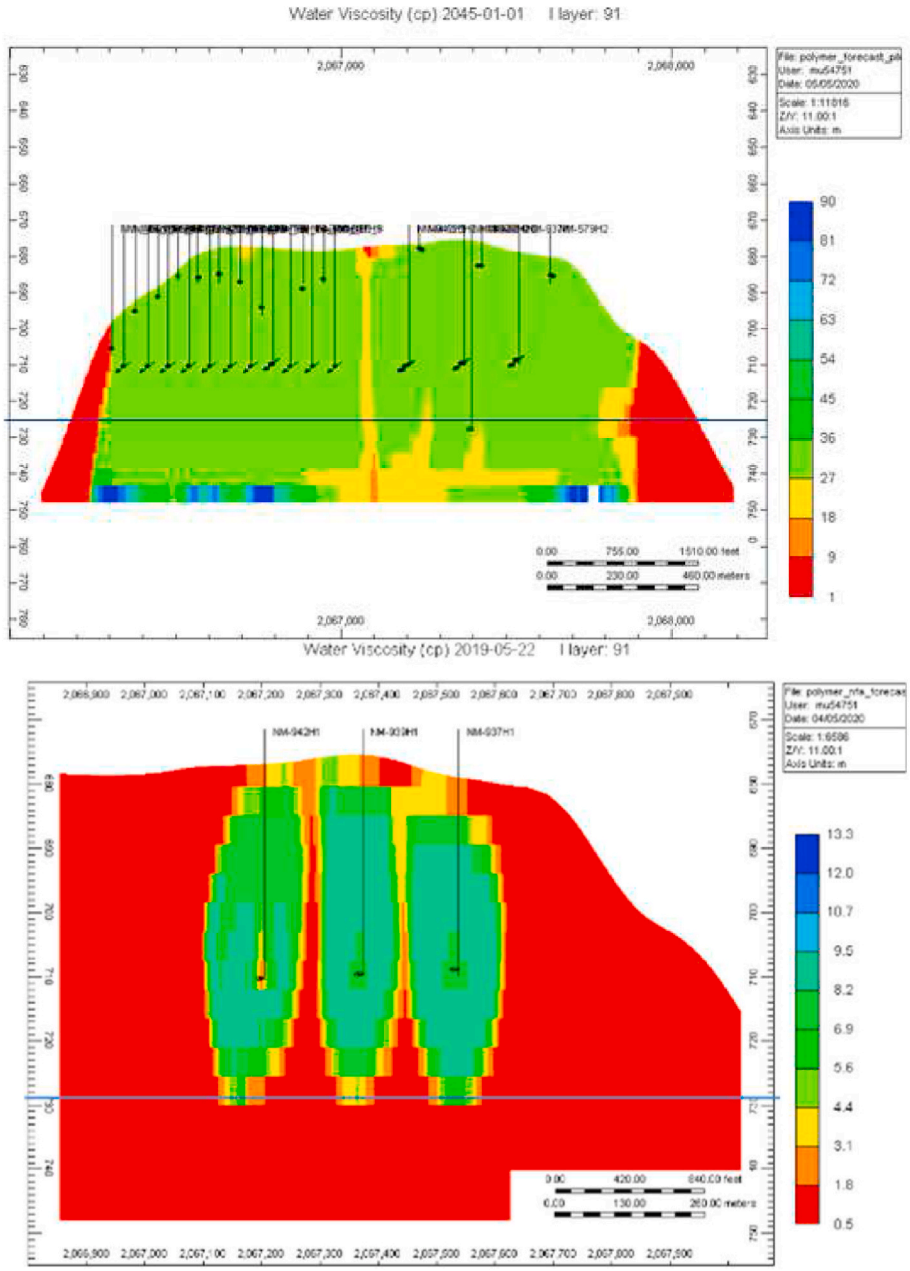

Fig. 10. Comparison of the polymer loss to aquifer for continuous polymer injection (left) and the NAP process (right). Polymer saturated areas are shown with green color. (For interpretation of the references to color in this figure legend, the reader is referred to the Web version of this article.)

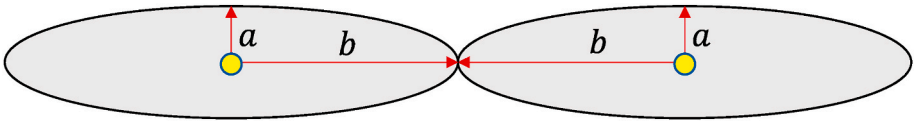

Fig. 11. Schematic of polymer blanket creation by injection of polymer in horizontal wells.

significant amounts of polymer were measured in the sampling well drilled at the aquifer interface (well O1 in Fig. 2).

5. Design of the NAP process

To suppress the water influx from the aquifer into the cones and hence reduce the water circulation, the injected polymer is expected to create a viscous blanket above the aquifer using horizontal wells. This is schematically shown in Fig. 11, where b is the half of the injector-injector distance. Since the reservoir vertical permeability is usually less than the horizontal permeability the shape of the polymer blanket will be elliptical. Note that the derivations of this section only indirectly consider the role of "recharge" mechanism explained in the previous section. In a more realistic scenario, because the aquifer is always active, it is difficult (within realistic injection volumes) to fully squeeze the water cones, i.e., the advancing front of the two oval-shaped blankets

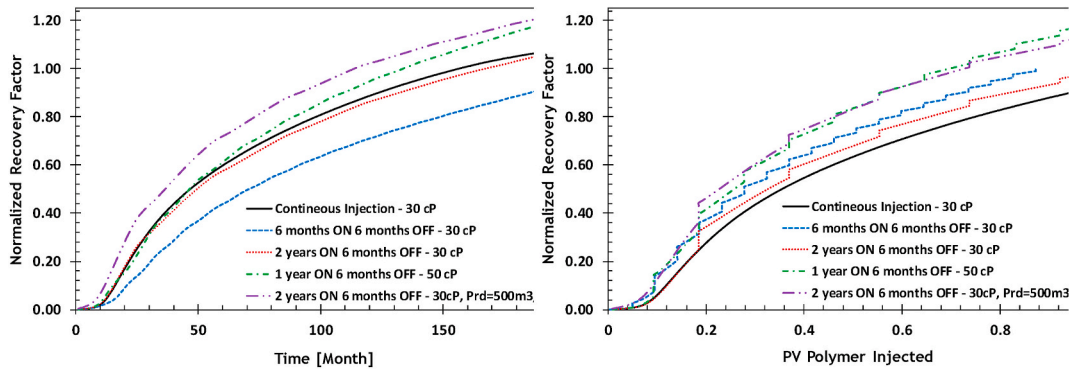

Fig. 12. Normalized recovery factor as a function of time and pore volume polymer injected for different scenarios. The recovery factor is normalized to an arbitrary number.

will not meet each other (see the streamlines in Fig. 9). Instead, during the shut-in period, the recharged oil or the oil pushed by the polymer into the water cones will be produced by the water flux from aquifer. This is especially the case when there is a large drawdown pressure and the oil column or injector/producer distance is short. However, to be able to calculate the minimum polymer slug size required to block the cones this assumption is made. Assuming an average oil saturation behind the polymer front, the volume of required polymer solution in one of the injectors is equal to the volume of the ellipse, i.e.,

$$V_{pol} = \pi\varphi abL_{well}(1 - S_{or}) \tag{1}$$

L_{well} is the length of the horizontal well and φ is the porosity. For a reservoir with a uniform permeability,

$$\frac{a}{b} = \frac{k_v}{k_h} \tag{2}$$

where, k_v and k_h are the vertical and horizontal permeabilities, respectively. Replacing Eq. (2) in Eq. (1) leads to

$$V_{pol} = \pi\varphi\left(\frac{k_v}{k_h}\right)b^2L_{well}(1 - S_{or}) \tag{3}$$

Therefore, an approximation of the minimum slug size or duration is given by

$$t_{pol,slug} = \frac{\pi\varphi\left(\frac{k_v}{k_h}\right)b^2L_{well}(1 - S_{or})}{Q_{inj}} \tag{4}$$

Equation (4) indicates that for heavy oil reservoirs with strong bottom-up aquifer, the minimum polymer slug size to (partially) block the aquifer flow, depends on the ratio of the k_v/k_h, the injector-injector spacing, length of the well, remaining oil saturation before polymer flood, and the injection rate. During the project operation, the main parameter to adjust the time is the injection rate. As mentioned earlier, the extent of the reduction in the water influx (water relative permeability or relative mobility) is largely influenced by the polymer viscosity and the magnitude of the residual resistant factor.

During the NAP or polymer shut-in period, the influx from the aquifer can result in fingering of water through the created bank. Therefore, the NAP period should be designed to minimize the negative impact of these fingers. The extent of fingering depends on the viscosity of the injected polymer; the higher the polymer viscosity the more severe the fingering behavior is. However, dispersion and flow resistance induced by polymer adsorption will reduce the extent of water fingering behavior. The maximum NAP period depends on the heterogeneity degree of the reservoir (especially the vertical permeability), the size of the polymer slug (or the magnitude of a in Fig. 11), and the rate of water flux from the aquifer. A coarse estimate of the maximum NAP period can be obtained from

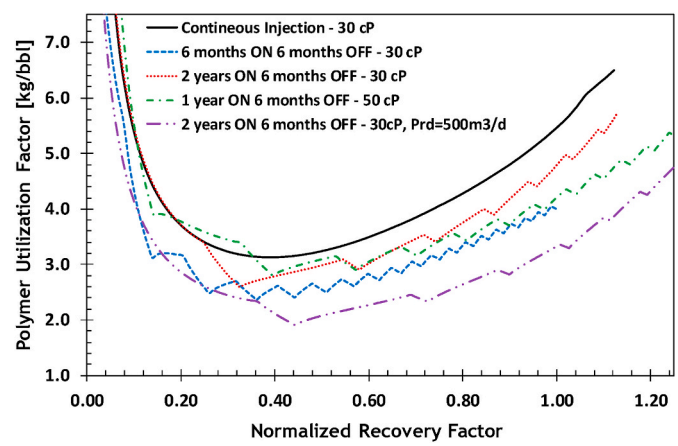

Fig. 13. Polymer utilization factor as a function of the normalized recovery factor for different scenarios. The recovery factor is normalized to an arbitrary number.

$$t_{D,NAP} = \frac{t_{D,polymer}}{K} \tag{5}$$

t_D is expressed in dimensionless pore volume unit. K is Koval heterogeneity factor (Koval, 1963) and it is a product of rock heterogeneity, H_k (measured by Dykstra- Parson coefficient, V_{DP}) and the effective viscosity of the solution in the mixing region between water and polymer:

$$K = H_kE \tag{6}$$

$$\log_{10}H_k = \frac{V_{DP}}{(1 - V_{DP})^{0.2}} \tag{7}$$

$$E = \left((1 - c_e) + c_e\left(\frac{\mu_p}{\mu_w}\right)^{\frac{1}{4}}\right)^4 \tag{8}$$

The water mobility in the mixing zone will still be larger than the mobility of the polymer bank; however, the contrast will be less compared to water only. On the hand, the mobility of the aquifer water is reduced by resistance caused by the polymer adsorption (RRF), which will further reduce the instability at the water/mixing zone interface. In summary there is no sharp interface between aquifer water and polymer (see Fig. 4). The mixing zone is shown by yellow color ahead of the polymer bank (green color) in this figure.

6. Effect of viscosity and offtake rate on the NAP process

Fig. 12 shows the simulation results for different scenarios

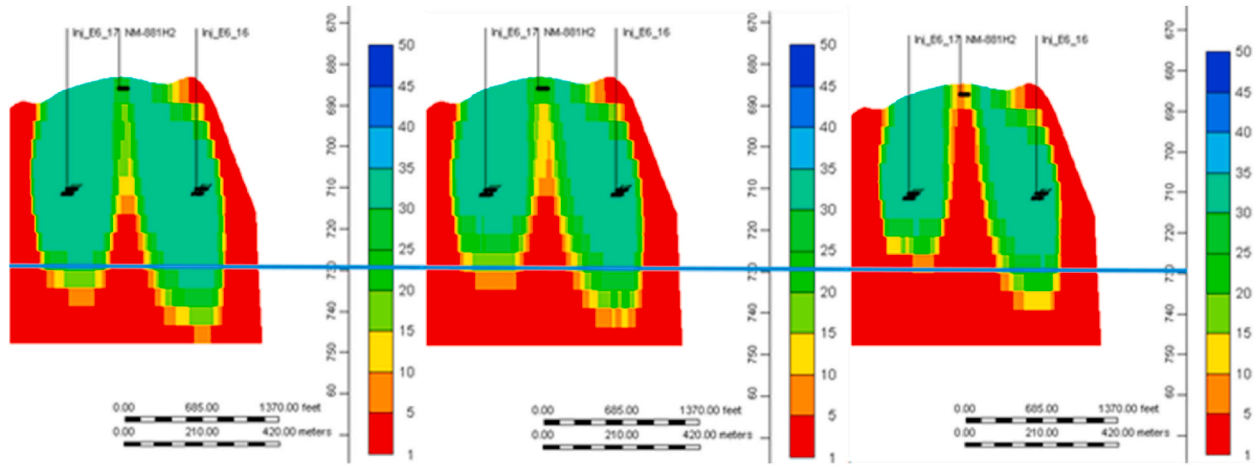

Fig. 14. Comparison of the polymer loss to aquifer for the NAP cases shown in Fig. 13.

considered in this study. The NAP process is compared to the continuous polymer injection. For the parameters of the studied reservoir, $t_{D,NAP}$ (Eq. (5)) is estimated to be around 6 months. The scenario with 2 years of polymer injection and 6 months of injection shut-in produces the same amount of oil as the continuous polymer injection (injection viscosity of 30 cP). At the same time NAP case has a better PUF as shown in Fig. 13. NAP design could be further optimized to improve the oil recovery and PUF by increasing the drawdown and/or increasing the viscosity of the injected polymer as shown in figures below. Increase of polymer viscosity leads to an increase in the oil recovery; however, in terms of PUF the impact is hardly significant. Interestingly, the most favorable PUF corresponds to the least polymer loss to aquifer, as shown in Fig. 14. The highest oil recovery factor with the lowest PUF is obtained for the case with an increased offtake rate of 500 m^3/d in the producers. This is due to fact that during the polymer injection and the shut-in periods, significant amount of oil is mobilized which can only be produced faster if the production rate in the producers are enhanced.

7. Conclusions

The injectivity decline caused by low water and polymer quality in the field trial resulted in shut-down of the injectors, while the producers were kept open. Interestingly, the water cut reversal and oil gain continued during the shut-in periods. This observation has led to the development of a new cyclic polymer injection strategy referred to as Nothing-Altering-Polymer (NAP). This paper discusses the oil recovery mechanism from the NAP strategy. A 3D model was constructed to match the actual pilot results and to capture the observed behavior. During polymer injection, the oil is recovered by conventional mobility and sweep enhancement mechanisms ahead of the polymer front. Additionally, during this stage the injected polymer creates a barrier between the aquifer and the oil column, suppressing the aquifer flux and hence the negative effect of the cones or water channels (blanketing mechanism). The relative contribution of this mechanism to oil production depends on the parameters in Eq. (4) as well as the injected polymer viscosity and the residual resistant factor. Moreover, injection of polymer pushes the oil to the depleted water cones, which is then is produced by the water coming from the aquifer during shut-in period (recharge mechanism). During the shut-in or NAP period, the aquifer water also pushes the existing polymer bank and hence leads to extra oil production. The mixing zone and resistance induced by polymer adsorption prevent severe fingering of water through polymer bank. It was demonstrated that the initial assumption of continuous injection would have resulted in significant polymer losses into the aquifer, limiting the oil recovery and affecting the polymer utilization factor. Using NAP, the slugs of polymer can be designed to minimize polymer loss into the aquifer and extract similar amounts of oil compared to the continuous polymer injection. The NAP strategy improves the polymer utilization factor expressed in kg-polymer/bbl of oil, resulting in a favorable economic outcome. The findings of this study can help with optimization of the future polymer EOR projects in heavy oil reservoirs with a strong bottom aquifer.

Credit author statement

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Declaration of competing interest

Authors declare no conflict of interest.

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