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ORIGINAL RESEARCH

Study of polymer flooding and intelligent well technology for improved oil recovery

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Abstract

The application of Intelligent Well Technology (IWT) to improve efficiency of a polymer flooding operation has been studied under three cases using a 3D model implemented in reservoir simulation software. The base case was the simulation study of a polymer flood with a relatively low oil recovery, which led to the least produced water into the producer well. The second case was incorporating IWT into the producer well where production control was achieved via the operation of inflow control valves (ICVs) installed in each productive segment of the wells. The reactive control strategy responded to changes in segment water cut, which led to improved sweep and, hence, oil recovery at 63 %. A third case was considered where injection control was performed via the same conditions as the producer well but, in this instance, the outflow control valves (OCVs) responded to changes in water cut at the injection wells. This oil recovery under injection control also improved to 68 %, but with higher water cuts. The study results showed that a better sweep of oil is possible despite the high water cuts when downhole segment conditions are adequately responded to. Thus, concluding that polymer flooding can be improved by incorporating IWT through production or injection control for a multi-layered heterogeneous reservoir.

Keywords: Polymer Flood, Intelligent Well Technology, Reservoir Simulation, Reactive Control Strategies

Introduction

During the initial production stage, a hydrocarbon reservoir is depleted by primary drive mechanisms such as solution gas drive, water drive, gravity drainage, etc. Primary drive mechanisms mostly recover a small number of recoverable reserves. The water drive mechanism achieves the most effective recovery of the listed primary drive mechanisms, leaving large volumes of recoverable oil in the reservoir. Secondary drive mechanisms harnessed via water or gas injection (i.e., water or gas flooding) provide reservoir pressure maintenance, providing artificial support that improves the oil recovery. However, in some cases, water flooding may not improve the oil recovery due to the fingering of water through the oil during flooding. This phenomenon is referred to as viscous fingering (Kargozarfard *et al.,* 2019). Viscous fingering occurs when the water mobility is higher than oil mobility; hence leads to poor sweep efficiencies since the injected fluid bypasses the mobile oil saturation (Alvarado and Manrique, 2010).

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The polymer flooding as a chemical recovery method provides mobility control of the displacing fluid (i.e., water) (Sorbie, 1991). A stable front of the polymer-water mix would displace oil with minimal fingering effect as observed by various investigators (Needham and Doe, 1987; Wang *et al.,* 2005; Urbissinova and Kuru, 2010; Sheng 2013; Sheng *et al.,* 2015). The polymer increases the water viscosity, which further leads to a reduction in its mobility; hence increasing the sweep efficiency of the flooding operation (Sheng *et al.,* 2015). The flooding process involves adding polymer to the injected water to create a high-viscosity solution to control the mobility of the displacement process (Torrealba and Hoteit, 2019). In high permeability channels found in heterogeneous reservoir layers, irrespective of favourable mobility ratios, there has been observed impairment in the area (Dawson and Lantz, 1972) and vertical sweep efficiencies during the polymer flooding. Early polymer breakthrough is also expected in these high permeability zones. However, the low permeability layers in the same reservoir would yield a delayed polymer breakthrough relative to the early breakthrough experienced in the high permeability zones, leading to a poor sweep (Rhudy *et al.,* 1977).

This problem requires the need for injection and production control systems to minimise the poor sweep efficiencies. In other words, there is a need to optimise the injection and production control via wells to ensure a successful polymer flooding operation. Intelligent well technology (IWT) is a well equipped with special measurement, monitoring and control devices (Camargo *et al.,* 2015) and provides significant advantages for injection and production operations. Typical sensors for monitoring that include pressure and temperature sensors deployed downhole of the well. For measurement, the

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flow rate from individual layers can be made given zonal isolation by packers. To control inflow or outflow, control valves are used to proactively or reactively control fluid flow based on the set bottom hole conditions (Sarkodie *et al.*, 2014).

The proactive control strategy (PCS) involves optimisation algorithms within the IWTs framework to achieve automated inflow control valve (ICV) or outflow control valve (OCV) operation to maximise oil production, net profit and minimise production cost. A set of variables are set to meet an objective function of oil maximisation or net profit generation. These algorithms include adjoint-based optimisation, genetic algorithms, global search methods, rate control theory and gradient-based methods. Several investigators have considered applying production and injection control using IWTs based on a proactive control strategy for mainly water flooding operations (Asadollahi and Naevdal, 2009; Asadollahi, 2012; Carvajal *et al.,* 2013; Pinto *et al.,* 2018). Their focus was to use the IWT to optimise a water flood operation via numerical simulation.

The reactive control strategy (RCS) considers the use of a trial-and-error basis to achieve optimal ICV or OCV settings based on oil's prevailing production and recovery. The control valves are adjusted until an optimal recovery is achieved with net profit maximisation. A reactive control strategy has been considered for a water flooding operation by some investigators (Addiego-Guevara *et al.,* 2008; Sarkodie, *et al.,* 2014). The RCS is easier to implement, though reactive in the framework, and it is most practicable when implemented on field trials. The performance of IWT during field trials and campaigns has encouraged further use. This is because of the improved economic benefits when incremental recoveries are achieved faster (i.e., earlier) than normally considered conventional wells. The application of intelligent completions on injector wells provides the capability to control all cases of water breakthrough and reduce water cycling in reservoir layers, which yield incremental recoveries of 2 – 8 % in net profit and 6 – 9 % in cumulative production (Li *et al.,* 2013; Pinto *et al.,* 2018).

Although, there have been numerous field campaigns on the application of IWT for surveillance, optimal production and fluid mobility control, there have been little or no field campaigns or simulation studies on the application of IWT with polymer flooding for enhance oil recovery. More so, there has been no related studies on production nor injection control strategies by IWT to control a polymer flood. Although, Awan et al. (2014) worked on the application of IWT for horizontal production wells operated under polymer flood, they only considered the IWT for surveillance of the polymer flood for each zone. There was no implementation of any control strategies but rather monitoring applications and measurement of zonal production rates under the polymer flood operation.

The objective of this research, therefore, is to study the effect of production and injection control on oil recovery during a polymer flood via conventional wells (CWs) and Intelligent wells (IWs). This research considers a simulation study using a black oil simulator (Eclipse) to model the performance of intelligent producers and injections wells applied to polymer flooding.

Methodology

To achieve the objectives of this study, a black oil model simulator known as Eclipse Reservoir Simulator by Schlumberger was be used to model a synthetic 3D model with no flow boundaries on all its sides. This model is to mimic a multi-layered reservoir with commingled flow from its layers. The model also aids to properly understand the vertical and areal sweep efficiencies via visualisation of the simulation results. The base case was a polymer flood implemented with a 5-spot pattern (4 injectors and 1 oil producer).

To include the IWT in the simulation and assess its effects on the polymer flooding case, the following cases were incorporated: (i) 4 CW injector wells with 1 IWT producer to study production control, and (ii) 4 IWT injector wells and 1 IWT production well to study the effect of both injection and production control.

Reservoir model description

Figure 1 shows the 3D model built with placement of the injection (INJ1, INJ2, INJ3, INJ4) and producer well (PROD) in a five-spot pattern. The areal grids are made of 25 blocks (NX = 5 and NY = 5) with 3 blocks vertically, representing three (3) production zones of the reservoir; hence, a total of 75 Blocks that make up the model. The reservoir top is 8000 ft deep with a thickness of 500 ft.

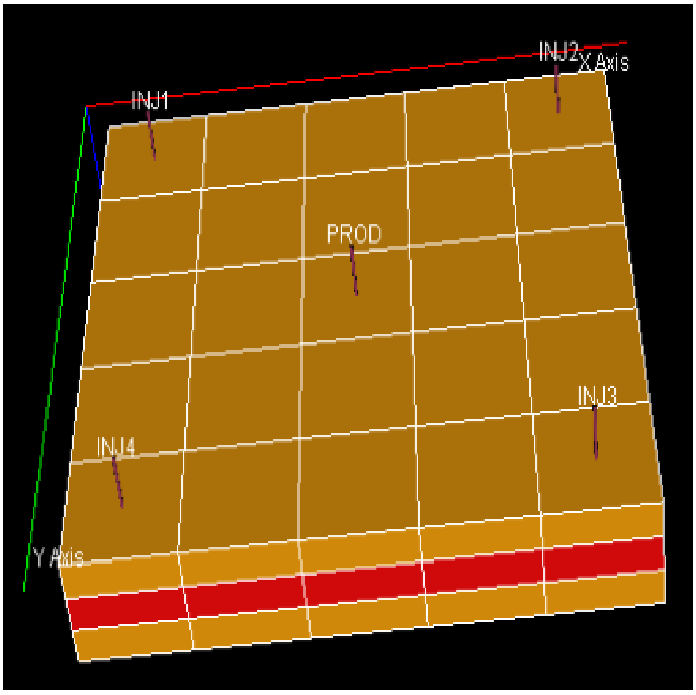

Figure 1 The reservoir model of the 4 injection wells and 1 producer well for a 5-spot pattern

The model is homogeneous based on porosity but heterogeneous based on permeability. The porosity of each block in the model is set to 0.2, while the directional permeabilities are summarised in Table 1 where it can be deduced that production zone 2 has the highest permeability in all directions. This zone, hence, represents the thief zone where the polymer is expected to break through the producer well.

Table 1 Datasets required for the system

Layers	Permeability	Value (md)
	K_X	200
1	K_Y	150
	K_Z	20
	K_X	1000
2	K_Y	800
	K_Z	100
	K_X	200
3	K_Y	150
	K_Z	20

The drainage strategy of the base case is the use of 4 injectors to drain oil and water into the producer well using a polymer flood. In this model, no gas is produced; hence, the reservoir is drained for an under saturated condition.

The polymer model

Eclipse reservoir simulator utilises the same 2 phase flow model to simulate polymer injection. The implementation of the polymer injection in the model is performed by using the POLYMER keyword in Eclipse in the RUNSPEC section. This model includes polymer adsorption effects where the polymer viscosity and rock adsorption effects are specified to affect the viscosity of water using a multiplier. Other relevant keywords in the model include PLYADS, PLYROCK, PLYMAX, and PLYVISC. The well in which the polymer is injected is also specified by concentration using the WPOLYMER keyword.

Mathematically, the effect of polymer addition to the water flood is modelled using the Equations (1) to (3) as fluid flow through porous media, which are then discretised using finite difference and solved based on an implicit scheme of solution. The equations (1-3) assumes no influence or reaction of the polymer solution on the hydrocarbons.

$$\frac{d}{dt}\left(\frac{VS_w}{B_rB_w}\right)=\Sigma\left[\frac{TK_{rw}}{B_w\mu_{w\,off}R_k}(\delta P_w-\rho_w gD_z)\right]+Q_w \tag{1}$$

$$\frac{d}{dt}\left(\frac{V^*S_wC_p}{B_rB_w}\right)+\frac{d}{dt}\left(V\rho_rC_p^a\frac{1-\phi}{\phi}\right)=\Sigma\left[\frac{TK_{rw}}{B_w\mu_{p\,off}R_k}(\delta P_w-\rho_w gD_z)\right]C_p+Q_wC_p \tag{2}$$

$$\frac{d}{dt}\left(\frac{VS_wC_n}{B_rB_w}\right)=\Sigma\left[\frac{TK_{rw}C_n}{B_w\mu_{s\,off}R_k}(\delta P_w-\rho_w gD_z)\right]+Q_wC_n \tag{3}$$

Where:

S_{dpv} is the dead pore space within each grid cell; C_p^a is the polymer adsorption concentration; p_r is the mass density of the rock of the formation; ϕ is the porosity; ρ_w is the water density; $\sum$ is the sum over neighboring cells; R_k is relative permeability reduction factor for the aqueous phase due to polymer retention; C_p, C_n are the polymer and salt concentration respectively in aqueous phase; μ_{aoff} is the effective viscosity of the water (α=w), polymer (α=p) and salt (α=s); D_z is the cell center depth; B_r, B_w are rock and water formation volumes; T is the transmissibility; k_{rw} is the water relative permeability; S_w is the water saturation; V is the block pore volume; Q_w is the water production rate; and P_w is the water pressure.

Reservoir model description

To implement the IWT for both the producer and injector wells, the layers are segmented into three where each ICV or OCR is placed to control production or injection. Figure 2 illustrates the segmentation of the producer and injection wells into three sections. In each of the three segments (equivalent to the number of zones for simplicity), thresholds such as water cut, bottom hole pressure and liquid rate can be set for actions to be implemented on the valves. These actions may be to OPEN or SHUT the valves, given the expected flow conditions.

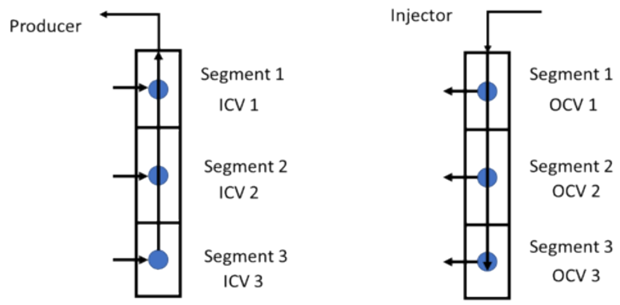

Figure 2 Implementation of the IWT in the simulator

The reactive control strategy (RCS)

Changes in the liquid rate, bottom hole pressure, and water cut may affect oil production; hence, a reactive control strategy is considered in this study to improve oil recovery. The RCSs are based on injection and production criteria where the installed control valves will be SHUT or OPEN when set parameters are met. For Production control, either the WBHP (well bottom hole pressure) is controlled, or the segment water cut SWCT at the producer (PROD) is controlled based on a set value. For injection control, the Segment Injection pressure will be set. The polymer injection will be controlled via the OCV by SHUT or OPEN positions to ensure an overall increase in oil production. The idea is to ensure a stable displacement of fluids where the pressure drawdown will amount to the same saturation of fluids for each layer. These algorithms are achieved by the ACTIONS keyword in the SCHEDULE section of the data file (see Figure 3).

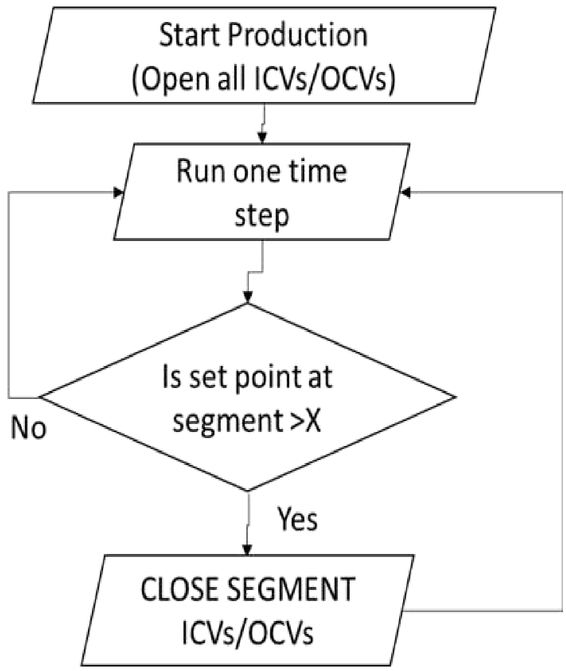

Figure 3 The reactive control strategy for either injection and production control or the injection of polymer using IWT

Results and Discussion

Base case – polymer injection

The base case is described as the simulation of polymer injection through the four injectors on the single production well. The production strategy was to achieve field significant production through the PROD well based on minimum bottom-hole flowing pressure of 2000 psia under maximum injection pressure of 10000 psia and 5500 bopd of polymer flood for each well.

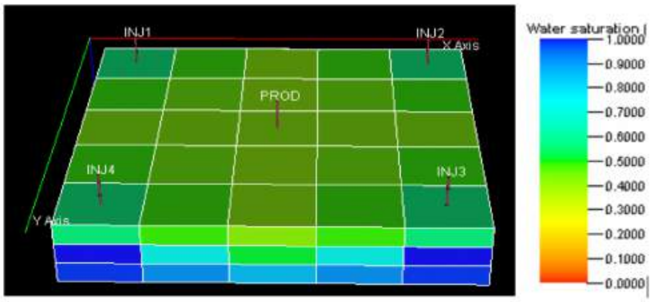

Figure 4 Base case - polymer injection 3D model of remaining saturation of oil after a 55-year run

Figure 4 presents the visualisation of the Eclipse model, showing that there is a relative adequate recovery based on the polymer flood. However, there is a poor areal and vertical sweep, which could be improved by production and injection control. As indicated earlier, the high permeability zone is well swept, leaving behind the upper zones with a lower permeability of 200*mD* upswept properly even with the polymer injection. It can also be observed that the lower zone is well swept over the time step of 55 years since injection of polymer at deeper depths are effective given the presence of higher pressures both from the reservoir and that provided by the injection wells.

Figure 5 also presents the oil recovery of the polymer flood over the period to be about 37 % based on the 22 g/mol of polymer concentration set at a factor of a 40-fold increase in fluid viscosity. This is accompanied by an early polymer breakthrough after four days. This water production increased to 99 % at the end of the simulation period. An early breakthrough is due to the presence of high injection rates of the high concentration polymer per injection well for the four injection wells. The presence of the high permeability layer of 1000mD further dictates the early breakthrough of polymer in the production well, PROD.

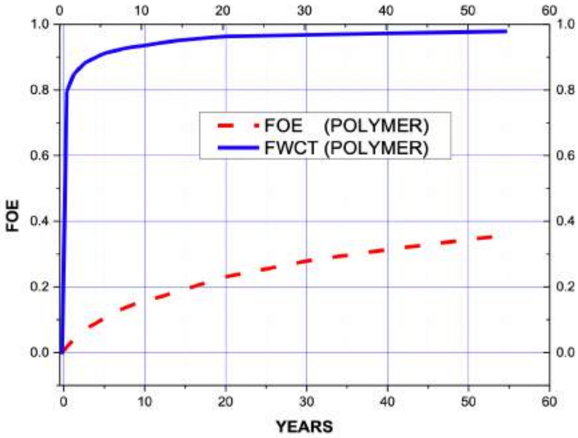

Figure 5 Oil field recovery and field water cut over time using polymer injection

At the early stages of production (Figure 6), the oil production rate peaked at 5767 bopd with a rapid decline over the 55 years. The oil production also follows with a corresponding rise in water production rate that far supersedes the oil production rate based on the cumulative value.

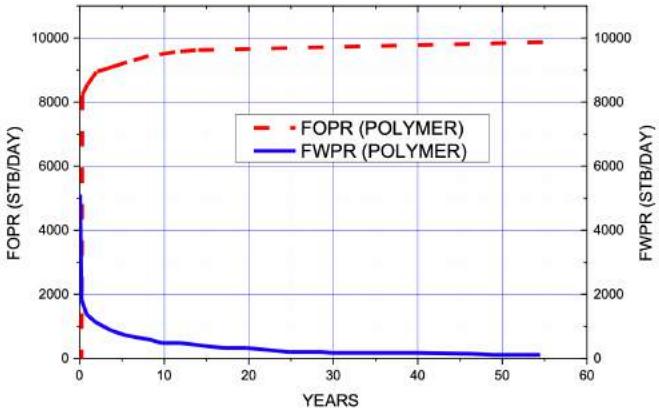

Figure 6 Oil production rate and field water cut over time using polymer injection

As presented in Figure 7, a rise in the field pressure from 4500 psia to around 10000 psia also drove the relative increase in bottom hole pressure of the PROD well to slightly above 9000 psia. It can also be deduced from Figure 7 that the difference between field pressure (average reservoir pressure) and the production well bottom hole pressure is the DRAWDOWN pressure (PR – PWF). This is the pressure difference required for fluids to flow from the reservoir into the production well under the polymer injection. Since the drawdown is directly related to increases in flow rate, there is potential for further improvement in oil recovery if lower bottomhole pressures can be achieved.

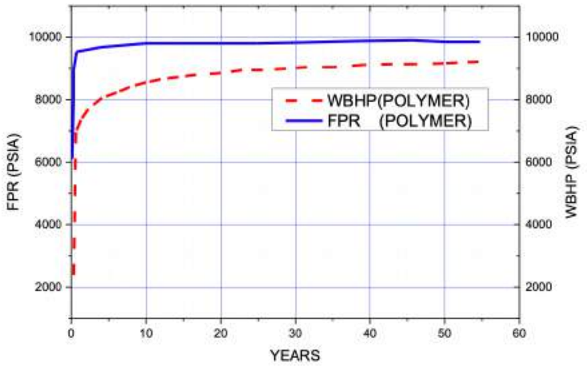

Figure 7 Average pressure and well bottomhole flowing pressure at the production well (PROD)

Given that the reservoir pressure and bottomhole pressures are high, the polymer flooding performance is expected to be improved via smart control of the production and injection of fluids from the modelled reservoir. In this work, only oil and water production were considered; hence, a drop in minimum bottomhole pressure of 2000 psia for the production is chosen to attain a maximum drawdown.

Production control (Case 1)

The production control case focuses on achieving improved recovery from the production well by establishing desirable control of water production into the well segments and sweep efficiency through the whole reservoir (especially in the highest permeability zone). This control is expected to increase oil production.

Under the same flow conditions as the base case, the incorporation of IWT on the PROD well to control segment water cut was implemented. There were three-segment ICVS that acted as binary valves that respond to changes in SWCT. The reactive control strategy is for the production well to shut any segment with the highest SWCT during the simulation run.

If SWCT of segment 2 (high permeable zone) is greater than the SWCT of the top layer and lower layers (low permeability zones), the segment is triggered to shut or close. When its SWCT has dropped below the water cut of other segments, then it opens again. The result of the described reactive control strategy on the sweep efficiency is presented in Figure 8. The 3D model after the simulation of a polymer flood under IWT production well control depicts an improved vertical sweep of oil within each layer of the reservoir. Although the areal sweep could be improved as viewed from the oil saturation on the surface of the model, the bottom layer (200 md zone) shows a complete sweep of oil due to polymer injection under high pressure whereas the top layer (also 200mD) indicates a lower sweep efficiency due to the issue of crossflow into the highest permeability layer of 1000mD. In comparison, the performance of the production control case is relatively better than that of the base case.

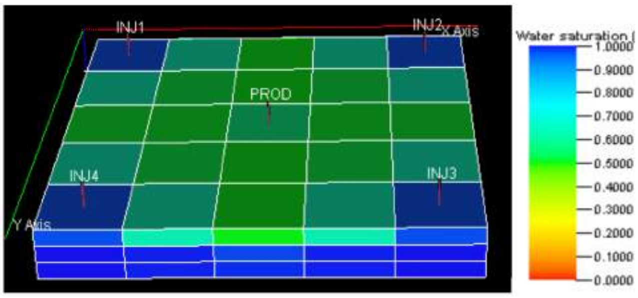

Figure 8 The production control case 3D model of the remaining saturation of oil after a 55-year run

Segment pressures and velocities

Under the production case, the initial segment pressures were set at a limit of 2000 psia including the hydrostatic of the depths of reference. During oil production till year 26, the spiking effect of pressure over time at segments 2 and 3 can be observed in Figure 9. This spiking was due to the shutting and opening of ICV2 and ICV3 at the respective segments when the condition of the highest SWCT is met at each segment. These segment pressures spiked up close to the maximum injection pressure of 10000 psia of the reservoir. The pressure in segment 1 remained within 2000 psia (as observed from Figure 9) since this segment was allocated to be the outlet segment of the production well, which coincided with the bottom hole pressure node of the 2000 psia limit. These results are interesting as expected since the highest permeability zone at segment 2 would suffer a high water cut and, hence, lead to the operation of ICV2 in this segment. Segment 3 is also expected to have high water cuts since it is the deepest layer. The effect of gravity on the flow is expected to impose cross flows from segment 3 into the high permeability zone of segment 2; hence, retaining the polymer water flood saturation over time. There is also considerable stability in segment pressures beyond year 26 since the SWCT are equal till year 55 for all three segments.

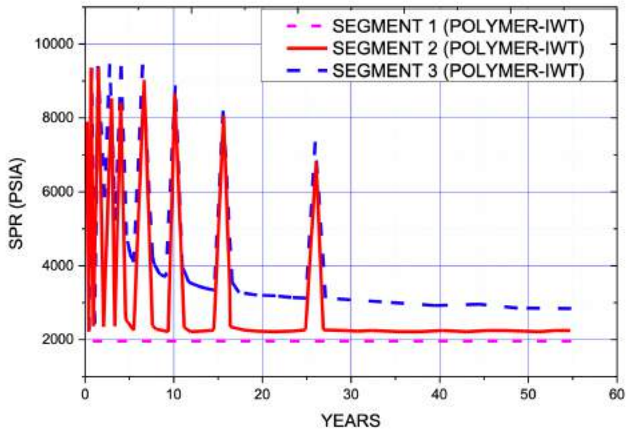

Figure 9 Segment pressure (SPR) of segments 1a, 2 and 3 over time

Further validation to the segment pressure variations as related to the operation of the ICVs is the analysis of segment pressure drops presented in Figure 10. In Figure 10(a), it can be observed that segment 1 has no significant pressure drop since the pressure remained constant at segment 1 (from Figure 9); hence, ICV1 remained open to flow into the production well (PROD). However, segments 2 and 3 indicate alternating pressure drops, given that ICV2 and ICV3 reacted to the SWCT setting. A high pressure drop across segment 2 indicates the closing action of ICV2. This mechanism from Figure 10(a) corresponds to a pressure drop of zero in segment 3, which infers that the ICV3 is fully open within the specified segment at the same time; i.e., practically, the orifice of the valves has a small cross-sectional area. For these reasons, the segment water velocity within segment 1 gives the highest water velocities (ICV1 open all through the time), as presented in Figure 10(b). Segment water velocities peaked at 5 ft/sec in segment 1 since the drawdown was between the injection pressure and the constant segment pressure (2000 psia). The segment water flow velocities in segment 2 also fluctuates given the operation of the ICV2 and gave the maximum flow velocities of around 4 ft/sec. The segment flow velocities of water for segment 3 is close to zero as it presents the deepest section of the reservoir where the effect of crossflow into layer 2 (highest permeability layer) is suspected. It is therefore possible that at wellbore conditions in segment 3, the flow of fluids is near zero since most mobile fluids migrate into the most permeable layer and possibly up until layer 1, where segment 1 is defined.

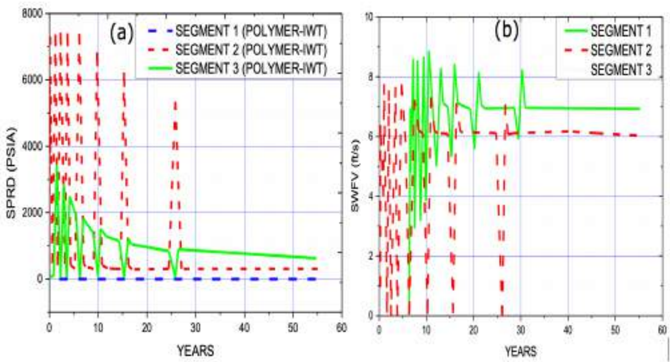

Figure 10 (a) Segment pressure drops, and (b) Segment water flow velocities

Segment water cuts

Figure 11 presents the resulting segment water cuts over the time. It can be observed from the results that an early water cut occurs at all segments from the beginning of production up until year 26, and the water cut from each segment is almost similar given the implemented reactive control strategy. The fluctuations are also because of the ICV operations in each of the segments. It is also worthy of emphasis that though the ICV did not delay water cut, the imposed stability of polymer displacement leads to adequate oil displacement rather than emphasis on a delayed polymer - water breakthrough in the producer well.

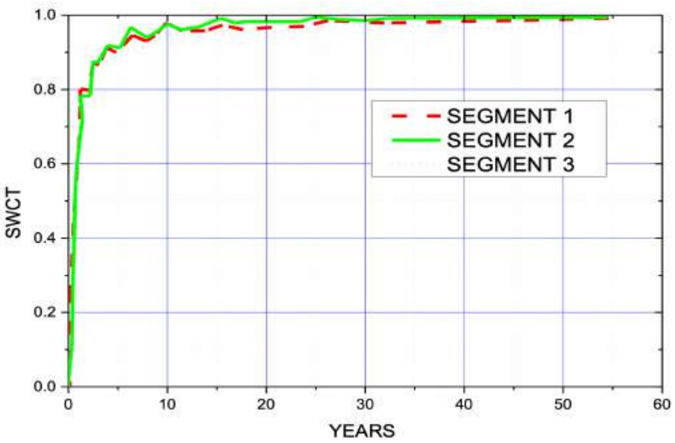

Figure 11 Segment water cuts for segments 1, 2 and 3

Segment oil production rates

Figure 12 presents the corresponding oil production rates for each segment. There is an early peak oil production rate in all segments with a later decline in production. It can be observed from the results that the highest production rates are at segment 1 (around 8000 bopd peak value), where there is maximum drawdown between the reservoir pressure and the segment's stable pressure at 2000 psia. Segment 1 is also set as the outlet segment to the production well where the bottom hole pressure is equal to the segment pressure. Segment 2 follows with a peak production rate of 7000 bopd with a decline over time. Segment 3 seems to produce an insignificant or no amount of oil. This can be explained based on the forced crossflow concept where due to pressure variations between layers such as a lower pressure in layer 2 relative to layers 1 and 3, significant migration of oil occurs from the bottom layer 3 at segment 3 to the high permeability layer of segment 2. The concept of forced cross flow is well detailed for the case of injections into multi-layered heterogeneous reservoirs by Jalali et al. (2016).

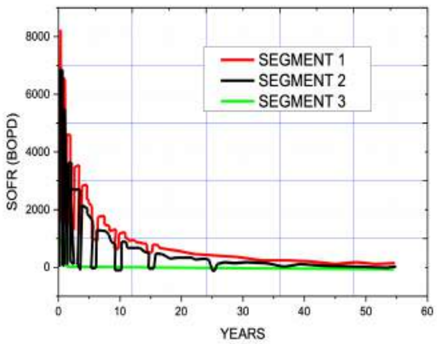

Figure 12 Segment oil production rates for segments 1, 2 and 3

Field and well pressures

Figure 13 presents the field and wellbore pressures over time. It can be observed that the field pressure declines from around 10000 psia (induced by the injectors) to around 3000 psia. The injection well pressures are also seen to fluctuate which corresponds to the response from the production well with ICVs operation in each segment. The overall bottom hole pressure is constant in the IWT producer at 2000 psia. The pressure difference between the reservoir or field pressure and the bottom hole pressure induces a pressure drawdown on the mobile fluid saturation in the reservoir. Therefore, sections with a high-pressure drawdown are expected to correspond to high fluid flow rates relative to low drawdown magnitudes. It can also be observed that all injection wells (INJ1-4) behave similarly and, hence, alter the magnitudes of the overall reservoir pressure under the production control case.

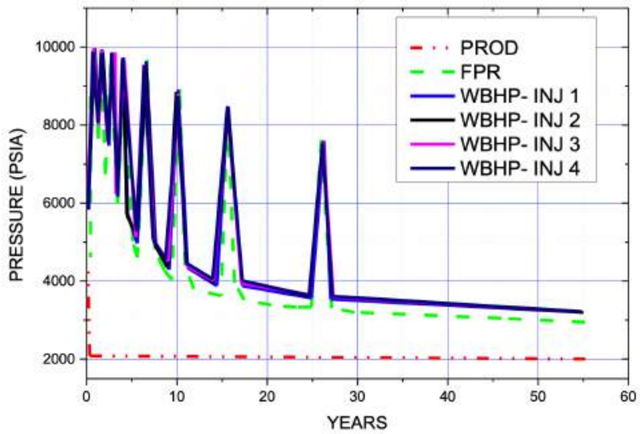

Figure 13 Pressures at the well injectors and producer

Comparison of base case with Case 1

A comparison of the field performance parameters such as the field oil recovery (FOE), field water-cut (FWCT) and production rates are made between the polymer flood (base case) and production control for polymer flooding case (case1). Figure 14(a) presents the results of the field water production (FWPR) rate from the IWT producer well and the conventional well in the base case. There is a higher water production rate from the IWT producer compared to that of the conventional well over time. The fluctuations in water production are clearly due to the valve operations in each segment. Water production rates from the CW stabilises at 10000 bopd compared to the water production of 20000 bopd from the IWT producer well.

Figure 14(b) shows the corresponding field water cuts of the base case and case 1. It can be observed that there are similar water cuts over time for both cases, even though there is a slight decrease in water cut in case 1 compared to the base case between years 1-5. This is due to the overall effect of the valve operation.

The results from Figure 14(c) further validate the improved performance of the production control case (case 1) given the maximum oil recovery of 63 % at the end of the 55 years compared to the oil recovery of 37 % of the base case. Higher oil production rates are also observed for case 1 compared to the base case in Figure 14(d). It can be inferred that the application of IWT in production wells where polymer flooding is considered is beneficial in the case of oil recovery.

Although the IWT based on production control did not reduce water production, it increased oil production and, hence, a higher oil recovery given the control strategy of operating the ICVs based on segment water cut (SWCT).

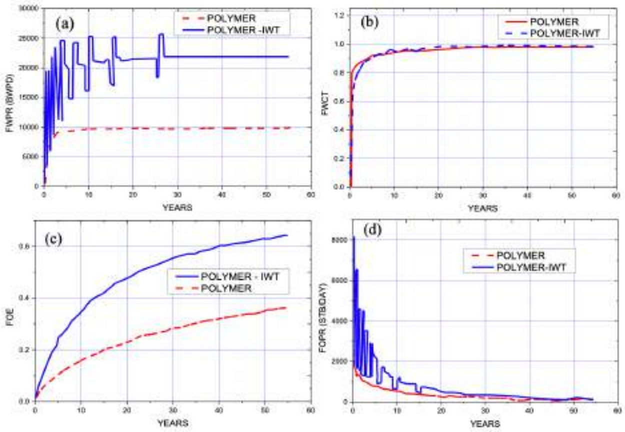

Figure 14: Comparison between the performances of the base case and production control case of the (a) water production rates FWPR, (b) water cuts FWCT, (c) oil recovery FOE, and (d) oil production rates FOPR

Injection control (Case 2)

Injection control of polymer and water floods is focused on maintaining pressure drops across each segment such that there is a steady displacement for improved oil recovery. Lessons learnt from Figure 13, where variation in pressure declines can be manipulated to ensure that frontal stability in the overall fluid displacement process, is considered. The reactive control strategy on the injection control implemented was based on the same criteria as the producer well, where the segment with the highest water cut the segment water cut, which is to shut the outflow control valves. This closing action would increase the segment pressure drop; hence, controlling the injected fluid flow in each segment.

Figure 15 presents the result of the remaining oil saturation after the simulation run. By visual inspection, there seems to be a similar displacement efficiency within the reservoir.

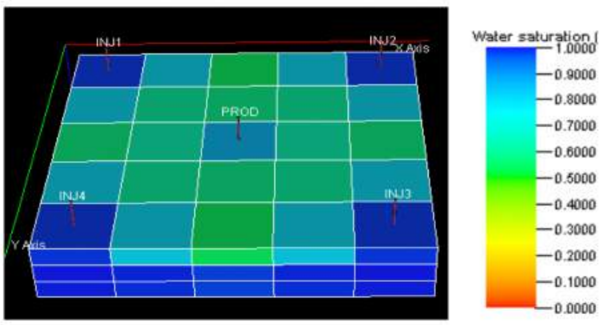

Figure 15 The injection control case 3D model of the remaining saturation of oil after a 55-year run

Injection segment pressure and velocities

Figure 16 further presents results of the segment pressure of injection wells 1 - 4. The vivid fluctuation in segment pressure is due to the closing and opening action of the OCVs. It is also clear that all injection wells are subject to similar fluctuations in segment pressure, which infers asymmetric injection of fluids into the reservoir. This fluctuation in pressure occurs between 10000 psia and 4000 psia.

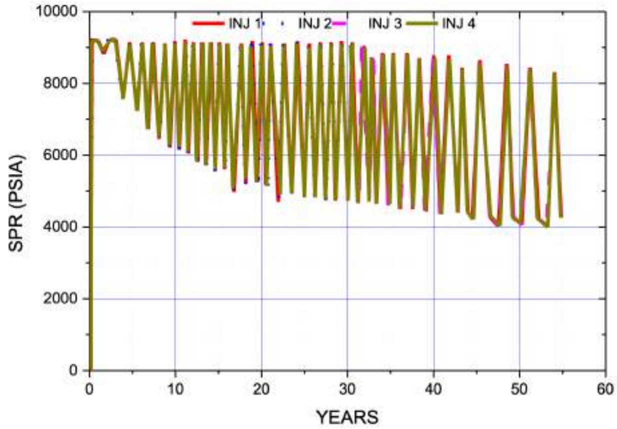

Figure 16 Injection pressures of injector wells 1, 2, 3 and 4

Figure 17 presents the segment oil flow velocities into the production well. Segment 1 reaches a peak flow velocity of 8.5 ft/sec compared to segment 2 with a peak oil flow velocity of 7.8 ft/sec. There is a very low velocity of oil through segment 3 given the earlier discussions in section 4.2, i.e., the crossflow into the high permeability zone above. High oil flow velocities are realised in segment 1 because it shares a similar node with the bottom hole pressure of the producer well; hence, a sufficient drawdown condition for fluid flow into the wells.

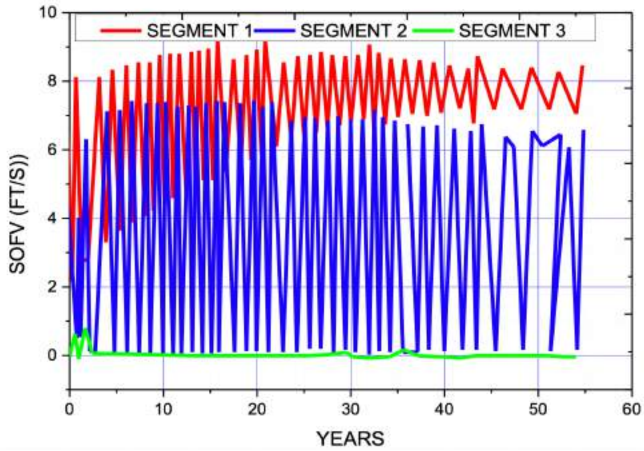

Figure 17 Segment oil flow velocities for the production well

The oil flow velocity also corresponds to the polymer water production at segment 1 as presented in Figure 18, which presents the highest water flow velocity compared to the lower velocities derived at segment 2 and worse off at segment 3 (little or no flow velocity of water). It is necessary to state that the fluid flow velocities are relatively stable compared to those from the production case.

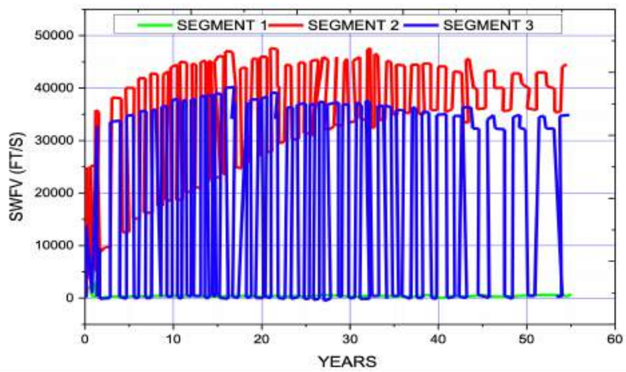

Figure 18 Segment water flow velocities

Field performance indicators

Overall, the impact of the injection control case on-field performance can be deduced from Figure 19(a) where the relatively high oil recovery at 67 %, as can be compared with the production control case, is observed. There is, however, still a high water cut, which peaks at 99 % at the end of the simulation run. Figure 19(b) also presents the oil production and water production rates for the injection control case. It can be observed that the high-water production rates (40000 bwpd), which fluctuate are because of the action of the segment valves. Oil production rates also peaked at about 11000 bopd. Figure 19(c) further elucidates the flow potential of the mobile fluids in the reservoir since it presents the reservoir pressure and production well bottomhole pressure. A general decline is observed in reservoir pressure, although there are fluctuations to a minimum of 4000 psia. The minimum reservoir pressure allows further production from this reservoir since the initial reservoir pressure without fluid injection is at 4500 psia. The reservoir is, thus, presented at a high drive energy. The constant bottom hole pressure in the producer well of 2000 psia will also suffice for sufficient fluid production.

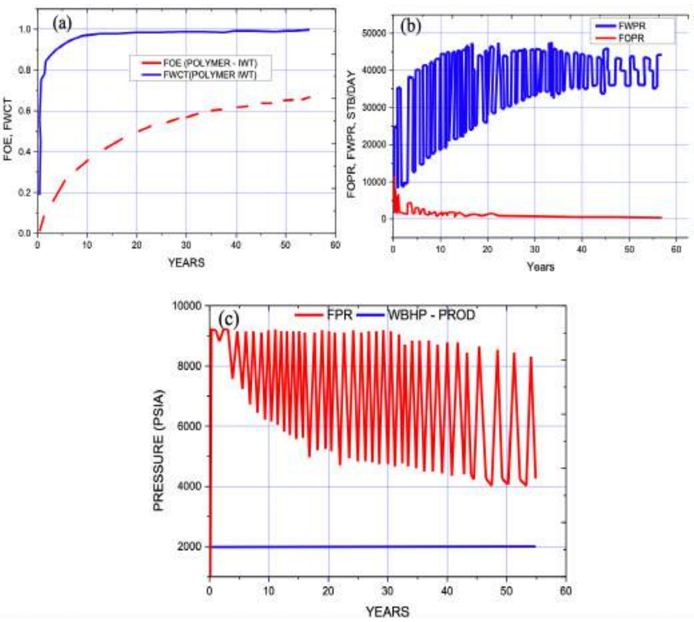

Figure 19 (a) Oil recovery and field water cut versus time, (b) the oil and water production rates over time, and (c) reservoir pressure and production well bottom hole pressure

Conclusions

This study has shed more light on the applicability of IWT combined with polymer injection to improve the recovery of hydrocarbons. The use of a reactive control strategy based on segment water cut thresholds within the modelled segments of production and injection wells provided desirable increments to the recovery of oil initially at 37 % (base case) to around 63 % (case1, production control) and 68% (case 2, injection control) when production and injection controls of the wells are considered separately.

Although the total water production of IWT wells was higher, the key focus was to ensure a stable displacement of the polymer flood deduced from an adequate sweep of oil at the vertical and areal perspectives of the reservoir. It is, hence, recommended to consider the use of IWT in polymer flooding injection where a multi-layered reservoir system of contrasting permeability exist.

Application of proactive control strategies on the use of IWT can be studied for improved recovery using polymer flooding or any form of EOR method. The strategies could include the use of genetic algorithms and artificial intelligence in the form of machine learning methods, etc. An economic evaluation of the implementation of IWT of the considered case in this work can be considered for future studies as well. The analysis of uncertainties such as the effect of changing reservoir conditions on the efficiency of the proposed reactive strategy would be useful to test the robustness of the analysis made. In case water production becomes critical to economic efficacy, a downhole separation of the oil and water can be simulated to further reduce the total produced water from the wells.

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Conflict of Interest Declarations

The authors have no affiliation with any organization with a direct or indirect financial interest in the subject matter discussed.

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