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Numerical study for continuous surfactant flooding considering adsorption in heterogeneous reservoir

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ABSTRACT

Surfactant flooding is a proven Enhanced Oil Recovery (EOR) technique used for mobilizing residual oil trapped in the reservoir. The mechanism of surfactant injection into reservoirs for improving oil recovery factor is to alter the fluid/fluid interaction by reducing interfacial tension between oil and brine. Besides, they alter fluid/rock properties via wettability alteration of the porous medium. Surfactant flooding has been applied on several field pilot projects. This research mainly focuses on investigating the continuous surfactant flooding for Bentiu oil reservoir in Sudan. The main method used in this study is numerical analysis of compositional flow using STARS software provided by the Computer Modelling Group Company (CMG-STARS). The research also proposed new surfactant for the continuous flooding. Moreover, the surfactant ability to increase the recovery factor was studied and compared to the traditional water flooding recovery method. Furthermore, for accuracy purposes, the risk of surfactant adsorption in the typical heterogeneous field was studied. The surfactant adsorption was calculated from static batch adsorption test by the surface tension method. The simulation results showed that the newly proposed surfactant improved total oil recovery by ~70%. The surfactant flooding showed lower water cut when compared to conventional water flooding. The improvement in the oil recovery and water cut was a good indication for the suitability of surfactant flood in the heterogeneous reservoir.

1. Introduction

Since its discovery, oil has remained the world's major energy source and the demand has always been increasing. The main reason behind the high demand of oil is the rapid industrialisation of the world (Krane, 2015). Under pressure of demand, the two issues of recovering trapped hydrocarbons and increasing oil production became the major concerns of petroleum engineers. Increasing oil production seems easy; however, the new oil discoveries have been declined constantly. Thus, passing the era of abundant oil production, we reached a new time when there is not enough oil to fulfil the oil demands. As a consequence, developing mature fields is a step that needs to be taken by oil companies. However, the difficulties appeared because the available data show that the majority of unrecovered oil is under challenging environments. As a result, the unconventional oil recovery strategic plan becomes very necessary (Clemens and Posch, 2017).

The production of oil from reservoirs is basically classified into three stages namely primary, secondary and tertiary stages. During the primary stage, oil is produced from the reservoir due to its initial pressure known as natural energy (Liu, 2015). After the depletion of the natural energy of the reservoir, production of oil is achieved by applying external pressures such as seawater. The secondary recovery method is commonly called water flooding. The possibility of using water flooding results is because of its ability to maintain the pressure depletion for continuous oil production (Yuan et al., 2016, Glasbergen et al., 2014). Overall, the application of primary and secondary recovery techniques can only recover about 30% of the original oil in place (OOIP). The remaining oil is bypassed or trapped within the reservoir. Due to the above

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mentioned reasons, numerous Enhanced Oil Recovery (EOR) methods were devised (Agi et al., 2018).

Among the numerous EOR methods, chemical EOR is the most promising method to recover residual or the remaining oil in the reservoir (Sabzabadi et al., 2014). Chemical EOR methods increase the amount of the recovered oil by several ways. One of them is improving the mobility of the injected water flood, Polymer flooding .The other method is aiding selective diversion of injected fluid from the thief zones to lower permeability regions, Foam flooding (Almaqbali et al., 2017). The other way is by lowering the interfacial tension between the imbibing fluid and oil, Surfactant flooding (Kamal et al., 2017) which results in enhancing the sweep efficiency. In addition to lowering the interfacial tension, surfactant flooding influences the amount of residual oil recovered through other mechanisms such as altering the wettability of the rock surface, improving the interfacial rheological properties, and microemulsification of the trapped residual oil (Kamal et al., 2017).

Surfactant molecules or surface active agents are organic compounds containing two functional groups namely hydrophilic head and hydrophobic tail (Bera and Mandal, 2015). The charge on the hydrophilic group attached to the head of the surfactant determines its classification into anionic surfactants (negative charge), cationic surfactants (positive charge), amphoteric surfactants (positive and negative charge) and non-ionic (no charge) surfactants.

Most of the commercial surfactants that were examined and evaluated on the laboratory scale or were tested in the field for EOR are the anionic surfactant or sodium dodecyl sulphate (SDS) which are the most commonly used surfactant for field application (Olajire, 2014, Negin et al., 2017). However, most surfactants have limitation in harsh environment of high temperature and high salinity, HTHS (Benzagouta et al., 2013, Dahbag and Hossain, 2016). In addition, surfactant adsorption on rock surfaces and their concentration reduce efficiency. Today, research focuses on cost effective and efficient surfactants to withstand HTHS conditions with minimum adsorption. Aerosol-OT surfactant is a surfactant constitute of double chain group which is proposed for surfactant flooding (Gao and Sharma, 2012) and it shows good ability to reduce the Interfacial tension with low concentration compared to other surfactants (Wesson et al., 2012). Moreover, the micellar and adsorption behaviour of Aerosol-OT surfactant in sandstone and shale at HTHS revealed to be tolerable for EOR activities (Abbas et al., 2017a, Abbas et al., 2017b).

As most Sudanese oil fields enter into the brown stage of production, most operators of Sudanese oil fields have conducted the baseline for economic and technical feasibility of surfactant flooding to improve oil production in 2011. An additional 5–15% oil recovery over the previous recovery rate was observed to be the economic target for EOR projects (Ali, 2011). Furthermore, Yeow et al., (2013) used eclipse simulation software to devise chemical EOR screening criteria for Sudanese oil fields with focus on Surfactant-Polymer (SP) and Alkaline-Surfactant-Polymer (ASP) floods. They reported an estimated recovery factor of 4–18%. However, detailed information of the surfactant active group or polymer was not provided. In 2015, ASP pilot test and design were studied to select the suitable area and wells to be used for the pilot test. However, the difficulty still occurs due to the heterogeneity and well condition in the selected area (Ali et al., 2015). In 2016, research showed the laboratory basic analysis for Alkaline, surfactant and polymer flooding. This study was mainly focused on East Africa formation; however, the main issues were early water breakthrough and high water cut present. The main used surfactant was mixed with a tailor-made zwitteronic surfactant and in their findings; the recovery factor was estimated by 54% (Foo et al., 2016).

The objective of this study is to evaluate the recovery factor for continuous Aerosol-OT surfactant injection on sandstone reservoir in Sudan by the numerical model. The motivation behind this study is to facilitate the result in comparison to the previous studies in Sudan. The results of this study will help in predicting the full field flooding performance by checking the main results. Furthermore, the surfactant static adsorption is experimentally estimated to avoid over estimation of the recovery factor and misleading future calculations which might mostly have been ignored in previous studies. The sensitivity of adsorption has an essential contribution to the study. The main tool to estimate the recovery is STARS-CMG software. Moreover, the oil recovery factor from continuous surfactant injection is compared to the base scenario of continuous water flooding. This research also discusses the effect of both water and surfactant floods on water cut ratio.

2. Methodology

In this study, the continuous surfactant flooding performance is described by using several steps. These steps are field data collection, model initialization and numerical analysis run. In addition, the static adsorption experiment test is used instead of default Langmuir isotherm. The data from oil field reports including geological description and reservoir characteristics are also studied extensively. All data in this study are collected from Higleig oil field. Heglieg structure map is in Fig. 1.

Hegleig field is a part of the Cretaceous-Tertiary Muglad Basin. Muglad basin initiated as the extensional tectonics led to rapid subsidence and lacustrine basin fills comprising the rich source rocks of the Lower Cretaceous. The targeted formation is Bentiu which is in vertical sequence deposited in continental fluvial channel. Bentiu is described as thick beds of amalgamated sandstone with lateral thin mud rock intervals (Tewari et al., 2006).

The pressure volume temperature (PVT) reports, X-ray diffraction (XRD), and petrophysical data are presented in Tables 1, 2, and 3 respectively.

The PVT table describes the oil and fluid properties as it has been used in the black oil model in previous studies (Tewari et al., 2006, Ali et al., 2015). The XRD results in Table 2 show the presence of several clay minerals in the core and reservoir. However, the clay mineral in the used simulated cores is handled as the total content based on the crashed rock. The effect of clay minerals cannot be ignored as it has a major impact on the core-up scaling to the field in the future. Moreover, the petrophysical results in Table 3 show several important parameters related to the reservoir rock description of the zone where the core extracted. The data are used as input for the rock-fluid option and initial condition description.

2.1. Experiments

The surfactant used in this study is Aerosol-OT (sodium bis (2-ethylhexyl) sulfosuccinate, AOT) which is a versatile anionic surfactant. The Aerosol-OT was purchased from Acros Organics BVBA (Geel, Belgium) at 96% purity. The chemical formula of Aerosol-OT is $C_{20}H_{37}NaO_7S$ with a molecular weight of 444.55 g/mol. Several surfactant concentrations were prepared at the initial salinity of Bentiu reservoir, which is lower than the previous salinity criteria that the surfactant was endorsed for.

The core was crashed into fine grains using a crusher machine (PULVERIZER Type from BICO, Inc.). The core was sieved between 90 and 175 μm to ease multi-selection for the test process. The static adsorption was conducted by adding 10 g of the crashed samples to 60 ml of several surfactant concentrations. The samples placed on the magnetic plate and stirred for 18 h. The adsorption test was carried out using surface tension method and checked by UV-vis spectroscopy. The surface tension measurement for each

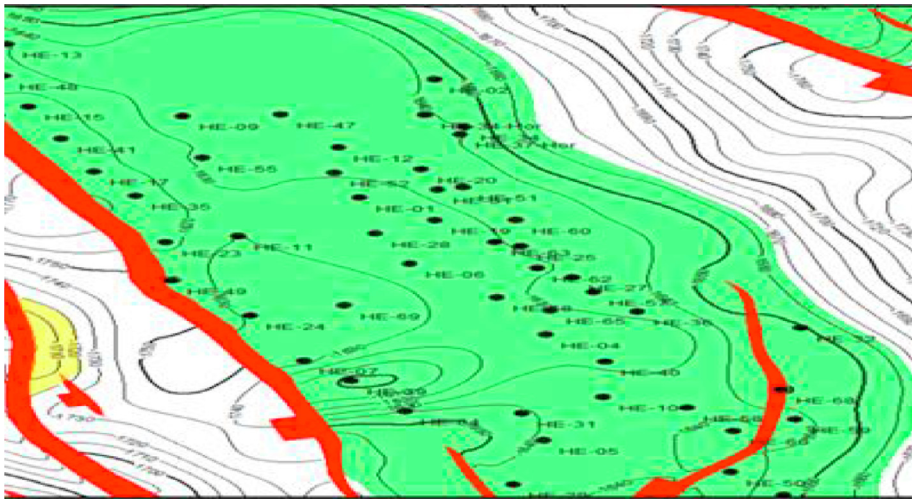

Fig. 1. Heglig-main structure.

Table 1
PVT results from Heglieg Field.

API	29°
Formation Volume Factor (rb/stb)	1.05
Reservoir Temperature	167
Gas Oil Ratio	2
Bottom hole Pressure	47
Oil viscosity (*cP*)	19
Oil density (lb/ft2)	54.5
Gas specific gravity	1.048
Water Salinity (ppm)	1087

Table 2
Clay XRD results.

Formation	Bentiu
Illite	3.1
Kaolinte	81.8
Chlorite	8.3

Table 3
Petrophysical result.

Formation	Bentiu
Top Depth (M)	1615.50
Bottom Depth (M)	1639.20
Interval (M)	23.70
Gross Sand (M)	7.00
Net Sand (M)	6.10
NTG	0.87
Net Pay (M)	6.10
Sw	0.16
Porosity%	0.25
Permeability md	655
VCL%	0.33

sample was reported after liquid filtration process. Since the core had variety of minerals as shown in the petrophysical report, the adsorption test was repeated for five times for the sake of accuracy (Abbas et al., 2017a). The static adsorption test values were averaged by arithmetic mean method in order to ease the calculation. The adsorption was calculated by subtracting the critical micelle concentration of the surfactant before and after the equilibrium. The adsorption values were converted to the equivalent adsorption in g/kg to be used in the simulation. This approach had been used earlier in several studies and the accuracy was well-grounded (Sánchez-Martín et al., 2008, Junin et al., 2012, Muherei and Junin, 2009).

2.2. Simulation and model selection

In order to understand the oil reservoir, four main physical laws were considered namely fluid mass conservation, momentum conservation, thermodynamic equilibrium, and energy phases and composition. In general, the four physical concepts were used in forming varieties in mathematical models describing different cases. In fact, creating mathematical model for fluid flow in porous media is time consuming and needs solving many equations and therefore many numerical solving ways. Moreover, introducing new components to the existing phases is a difficult task. The mathematical equation basics were used as elemental compositional for accuracy reasons. Accordingly, for EOR purposes, numerical software are needed to generate large numbers of results based on flow composition (Russell and Wheeler, 2014). CMG–STARS software was used to study the water flood and surfactant flood in this study. STARS was highly endorsed for all type of cores and it is valuable in matching the results in both experimental and numerical tests (Rai et al., 2015, Dahbag et al., 2016). STARS uses the numerical equation and the solving procedures are for equations of state and compositional analysis. The simulation has an ability to use data correlation for fitting and lumping pure components. In general, the component physical properties are introduced by their original phases.

STARS generates fluid component data using Builder correlation to modify unwanted data for up-scaling with high efficiency of running time. The fluid data include the rock fluid properties, endpoint scaling of the relative permeability curve, temperature dependent relative permeability curve and modifying relative permeability curve based on compositional dependence. The core was modelled by assuming the cubic shape instead of cylindrical shape in order to simplify the initial flow difficulties. The assumed cubic shape had the same properties of the original cores. The simulation cube was divided into 11 blocks with the initial information described in Table 4.

Moreover, the software provided input related options either to the adsorption dependency to rock or salinity. In particular, adsorption component default uses the correlation of Langmuir model (Keshtkar et al., 2016). The correlation used either for the temperature or the concentration independence to assign the rock

Table 4
Model basic description.

Grid Top (m)	Grid thickness (m)	porosity	KI (md)	kJ (md)	KK (md)
1615	0.033375	0.25	655	655	234

type or the grid number. However, in this study the experimental results are used without correlation to avoid errors of underestimation. In general, this approach is suggested because Higlieg reservoir is heterogeneous with high vertical anisotropy direction and the Aerosol-OT has a high adsorption nature. The detailed description in the model follows the real field data for practical purposes.

The first scenario was created to represent the water flooding as a Do-Nothing case. The main concept for water flooding was a continuous injection of water till no more oil could be produced. The water flooding in this case is the injection of the brine without any chemical addition. The time step taken in this run is 0.01 day counted from the start point. In this study, the continuous surfactant flooding evaluation is one of the targets. Accordingly, the second model basically assumes continuous use of surfactant from the step of 0.01 day.

3. Result and discussion

The results of this study are based on numerical analysis using CMG-STARS software. In addition, the adsorption experimental results are included in the numerical model calculation. The generated results help in understanding the surfactant flood capability to produce the trapped oil.

3.1. Adsorption results

Surfactant adsorption occurs instantaneously and it differs based on the surfactant property and the mineralogical composition of the rock. The result of this experiment is specific for the discussed condition and it is used further as the input in the STAR. The results of average surface tension versus surfactant concentration are presented in Table 5. The experimental adsorption at the CMC point for the given core is 2.8 g/kg during static test at the room temperature. In comparison to previous studies (Lv et al., 2011), the anionic surfactant Alkylbenzene sulfonate (ABS) adsorption on sandstone reservoir is in the range of 2.4–1.7 g/kg, which considered lower than finding of the current study. Moreover, Aerosol-OT adsorption in this study is higher than the finding on sand quartz surface and lower than the shale surface (Abbas et al., 2017a). The study findings may be attributed to the significant impact of the rock clay minerals content. Additionally, the obtained results match the previous data about the impact of high molecular weight surfactant on increasing the adsorption (Atay et al., 2002). The surfactant adsorption resulted from the strong hydrophobic nature of the surfactant (Sánchez-Martín et al., 2008, Amirianshoja et al., 2013). The ability of surfactant to accumulate on the crushed core surface is also influenced by the salinity and temperature factors. The reservoir salinity is responsible for lowering the repulsion forces between the surfactant head groups, thus surfactant tendency to adsorb is higher (Abbas et al., 2017b, Puerto et al., 2012).

Table 5
Surface tension results.

Surfactant concentration wt%	mN/m
0.0002	43.9
0.01	41.7
0.05	33.3
0.1	26
0.15	25
0.2	25
0.3	25

3.2. Model initialization

As the model describes a core scale with insight to the field-scale, the model initialized the average properties of the coarser grid in the targeted reservoir. The detailed description in the model is matched to the default interpolation method. Fig. 2 provides the 3D view for the model based on grid thickness property. The oil saturation and water values are provided from the previous field development plan as presented in Figs. 3 and 4 respectively.

In the initialization finding, the model was initialized successfully to represent the field. The process is similar to previous studies in North Sudan basin (Foo et al., 2016). Fig. 5 shows the saturation relative permeability generated by CMG-STARS.

The initialization of the model also includes the match between the viscosity and numerical correlation as shown in Fig. 6. The uploaded initial water viscosity also matches to the numerical result as seen in Fig. 7.

3.3. Simulation results

The flooding simulations were performed by STARS numerical simulation. The numerical solution of the flow helps in estimating the recovery factor and water cut. The results of the base scenario (Water flooding) are shown in Fig. 8.

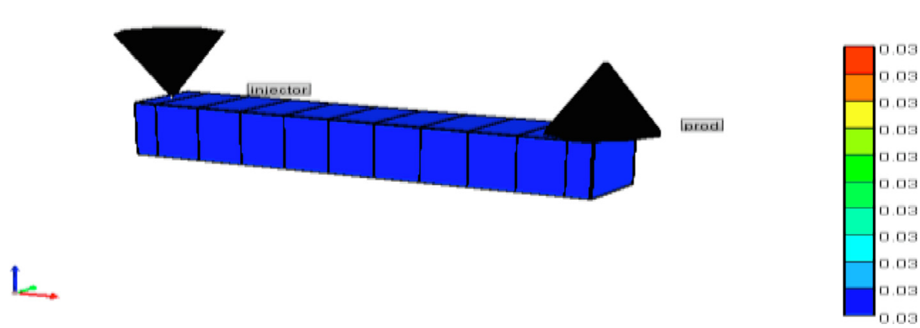

Fig. 2. 3D-grid view.

Fig. 3. Oil saturation.

Fig. 4. Water saturation.

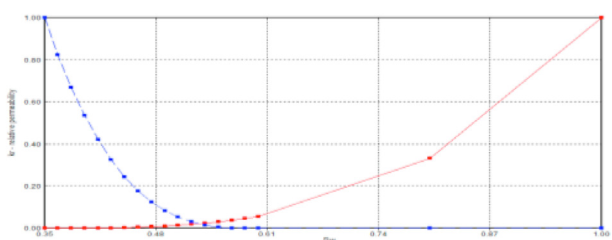

Fig. 5. Initial numerical match for relative permeability curve.

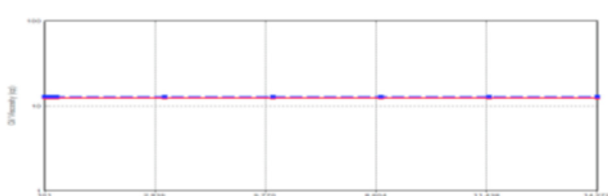

Fig. 6. Oil viscosity match.

Fig. 7. Water viscosity match.

The oil recovery reaches only 33% after 96 min of continuous flooding while the water cut almost reaches 95% at the same duration of flooding. The result shows significant difference to the previous development plan. Previously, the water cut reached 85% while the recovery factor was about 31% (Zhao et al., 2010). Remarkably, the challenge of water flooding process becomes risky as the water cut recorded is close to the economic limit of 97%. Thus, the water flooding recovery process may be technically accepted in terms of recovery factor but its limitation is the water cut. The considerable amount of water production associated with the water flooding is mainly because of the low ability of water to replace the oil trapped in the pores which leads to producing the displaced formation water (Ligthelm et al., 2009). Studies confirm that water flooding maintains the reservoir pressure while water production rate increases (Bidhendi et al., 2018, Mogollón et al., 2017, Shakiba et al., 2017). However in this study, the target is to maximize the trapped oil production. Meanwhile, continuous surfactant flooding process in this study is limited to the initial concentration which was 0.09 mol fraction in the slug. The water/surfactant was mainly injected as a single phase. Furthermore, the fluid slug had not been followed with the chase water. The continuous surfactant flooding results presented in Fig. 9 show that the recovery factor increased by 42% at 0.0669 day which is equivalent to 96 min of surfactant flood and 4 PV.

The highest recovery factor was 71% at 0.345 day equivalent to 500 min of continuous injection to the core. This result indicates very good behaviour of the surfactant for oil production. In addition, it shows that the recovery factor improved more than the report of other studies (Ali et al., 2015, Foo et al., 2016). The reasons behind improving the recovery factor of the oil are due to the ability on Aerosol-OT to reduce the IFT to a good extent. Moreover, the ability of Aerosol-OT surfactant to solubilize oil is proved (Abbas et al., 2018, Wesson et al., 2012, Nave et al., 2000).

Additionally, the water cut percentage in Fig. 9 is one of the major concerns of Sudanese oil fields with the simulation results. It shows an increase in percentage of water cut from 20% at 0.0664 day to 70% at 0.11 day (96 min). At the same time, it is equivalent to injection of 4 PV of surfactant flood in the experimental condition. The results show that all the targeted parameters improve in comparison to the base case. Moreover, the increase in water cut reduction in surfactant flooding compared to water flooding resulted from the residual oil mobilization which is greater and leads to decrease the water passage. Another reason is that as the surfactant pushes oil to flow through the empty pores, they would be occupied by water and consequently the water cut would reduce (Emegwalu, 2009). Moreover, the ability of surfactant to provide homogeneous stable phase is proved

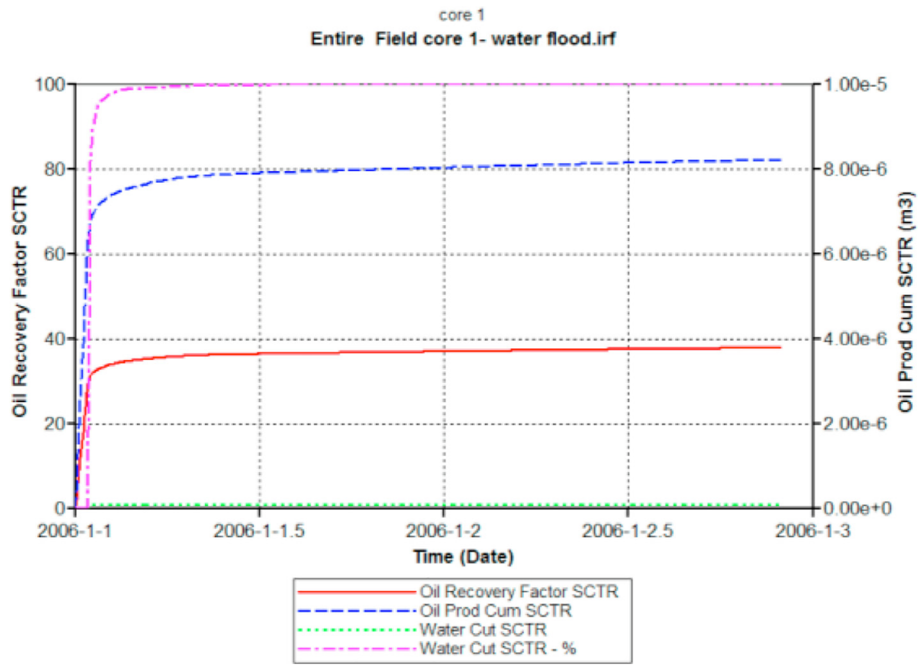

Fig. 8. Waterflooding results.

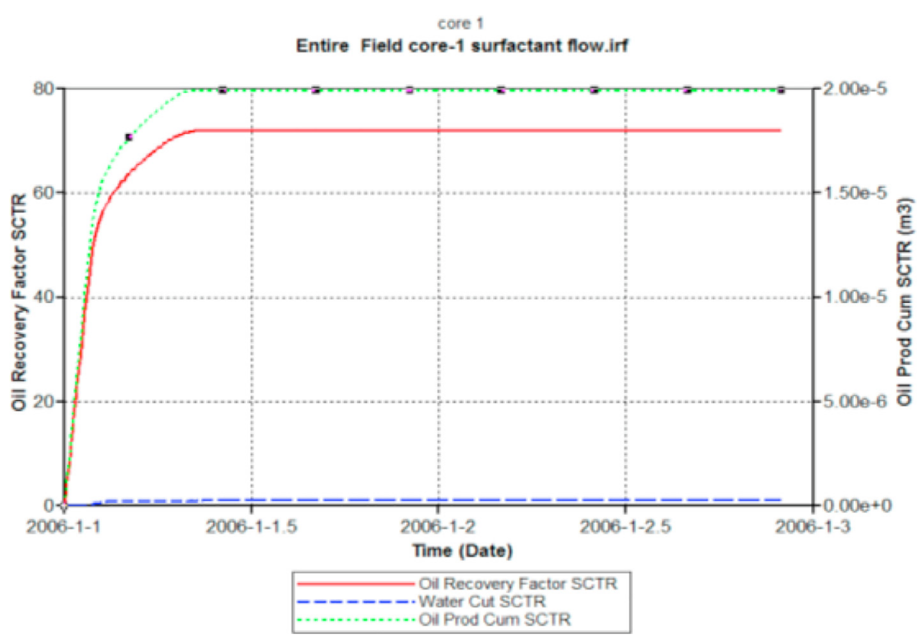

Fig. 9. surfactant flood results.

(Wesson et al., 2012). the variation of the oil/water composition during the flow in the core sections increased in presence of surfactant, which indicates more mixing has occurred. Similar scenario has been proved in multiphase studies in horizontal pipes with lower velocities (Shi et al., 1999).

The movement of oil and water phases within the core illustrates simultaneous flow of two immiscible fluids in a porous media. As surfactant flood starts, the ability of surfactant to create very low interfacial tensions in the core permits the viscous forces fluid to overcome the capillary forces holding the oil in place. Consequently, the flow of the two fluids has changed.

In Fig. 10, the core scale numerical simulation shows that continuous injection of surfactant results in reducing the oil saturation which is associated with mobilization of oil towards the producer outlet. The simulation results in Fig. 10 shows that during the surfactant passage in core, the oil saturation reduces as the injected surfactant moves. The finding of this study reveals that the surfactant injection does not achieve threshold targeted residual oil saturation and that the remaining residual oil saturation is in the range of 0.1–0.3.

As surfactant was injected, the slug classified as a parabolic and hyperbolic partial differential equation and only could be solved by numerical expressions. Most likely the numerical solution uses quasi-linear implicit to calculate the surfactant flow concentration (Völcker et al., 2010, Capolei et al., 2017). For surfactants, the dispersive transport was influenced by the adsorption on reservoir

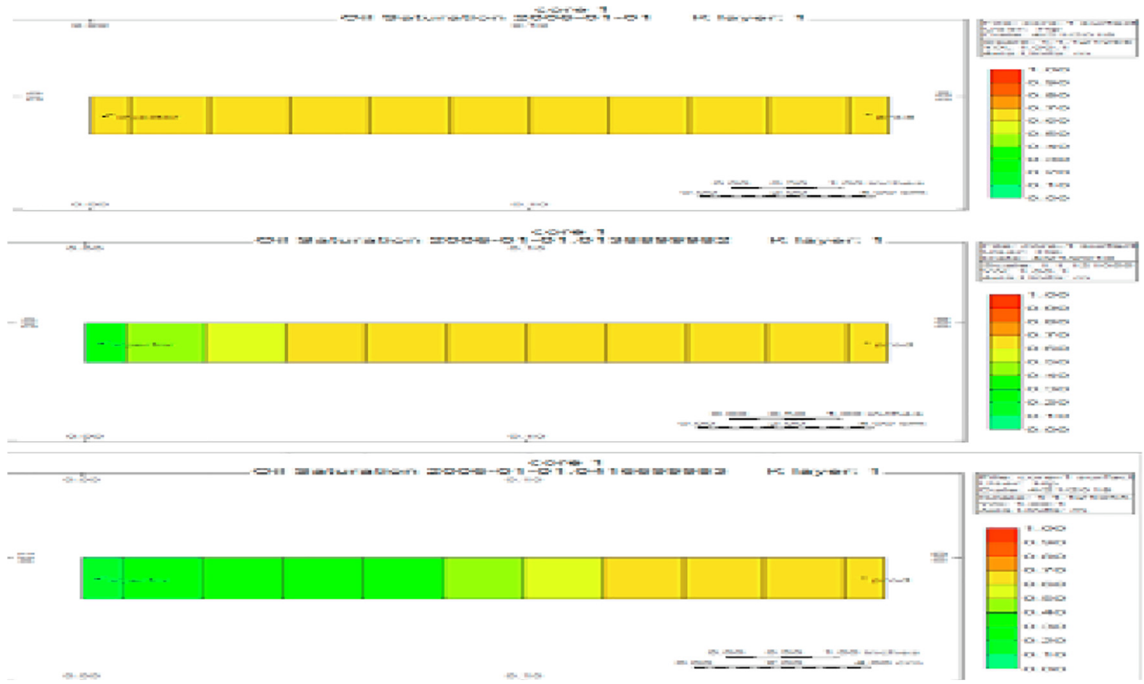

Fig. 10. Oil saturation changes during surfactant flood.

rock, which usually was solved by langmuir equilibrium isotherm (Fathi and Ramirez, 1986, Babadagli, 2007). The approach used in this study for optimizing the sensitivity by including the adsorption data is critical. Accordingly, the available surfactant influences the flow and the redistribution of oil saturation around the injector area. As shown in Fig. 11, the scheme of surfactant concentration reduction because of adsorption indicates surfactant concentration loss around the injector is higher than near by the producer.

Furthermore, the results of surfactant adsorption mass density is around 0.0078 kg/m^3 after 96 min of continuous injection and the adsorption process ceases to occur after 130 min of injection equivalent to 6 PV injected. The critical values represent the effect of surfactant adsorption on the flow and consequently affecting the recovery efficiency at each time. Furthermore, it indicates that during field operation continuous injection will be needed to overcome the adsorption problem. Despite the amount of adsorption,

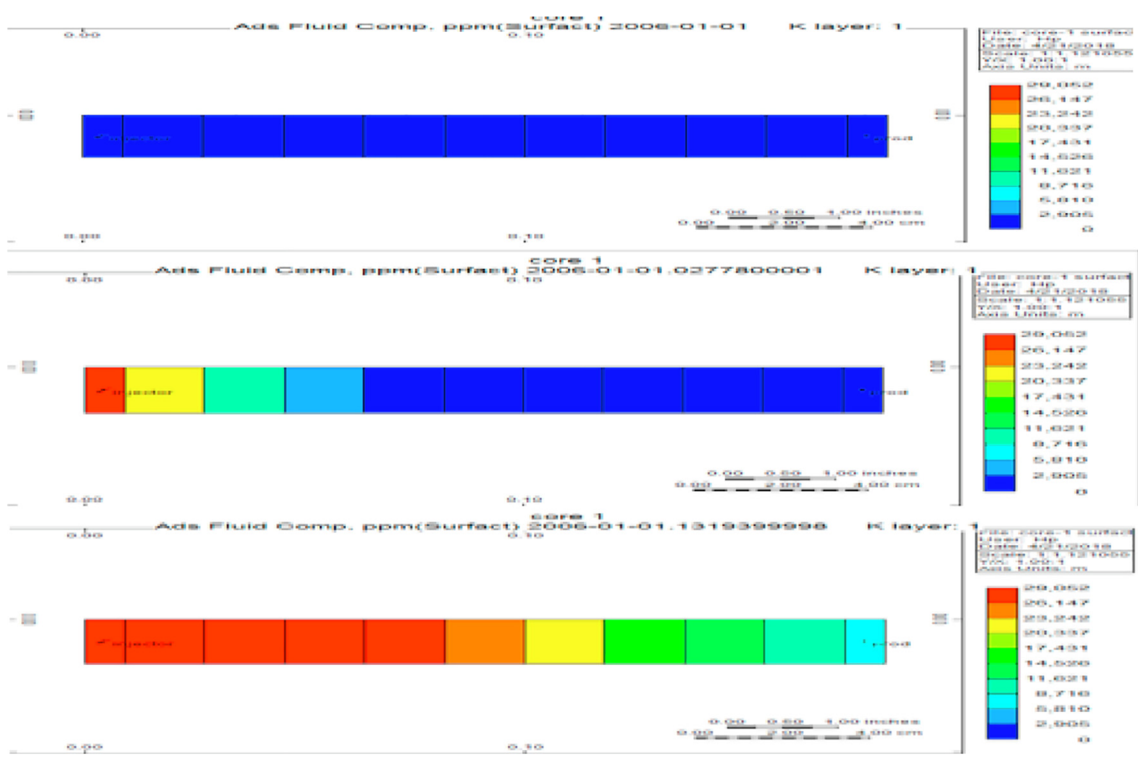

Fig. 11. Surfactant adsorption in core scale.

Aerosol-OT initial concentration (CMC) is lower than conventional surfactant. For example, SDS surfactant has a CMC between 1.5 wt% and 2 wt% (Amirianshoja et al., 2013, Muherei and Junin, 2009), while Aerosol-OT has 0.09 wt% which reflects that the amount of surfactant required is lower, even after adsorption.

4. Conclusion

The current study highlights the possibility of using continuous surfactant flooding for recovering oil from Bentiu reservoir as well as comparison to water flooding process. The surfactant used is Aerosol-OT, which is considerably needed in low concentration. The numerical analysis gives satisfactory results for the process implication. Few observations deduced from the experimental and numerical analysis are as follows:

1- The results show that applying water flooding result in a recovery factor of only 33%, while the use of continuous surfactant flooding led to a higher recovery of up to 70%. The recovery factor improved to 42% for the given core.
2- The water cut percentage reaches 95% and lowered after using continuous surfactant flooding to 70%.
3- An insight is gained with regard to the effect of surfactant adsorption during the continuous surfactant flooding. By including the experimental result instead of langmuir default, the study concludes the dominant effect of adsorption through the process in the first injection which is mainly near the injector. The results show that adsorption can be neglected after 4 PV injection overall the core.
4- The gained information help in predicting the limits of surfactant flooding process if the injector nearby contain hazardous adsorbent mineral.
5- Moreover, the estimated recovery results are promising especially for a strong hydrophobic nature surfactant like Aerosol-OT.
6- The results are considered very positive for further investigation on Aerosol-OT surfactant continuous flooding for Bentiu reservoir.

The experimental approach considered in this study provides a starting point for understanding the effect of reservoir minerals heterogeneity on the surfactant adsorption during the flow and consequently the produced oil and the recovery factor. For future works, the researcher recommends adsorption minimization technique since the adsorption will affect the required surfactant quantities for the full field even though the needed concentration is low. Moreover, more core simulation research would be required to estimate the losses of the surfactant near the injectors. Moreover, more laboratory core flooding validation is recommended to understand the surfactant flow of behaviours in heterogeneous reservoirs.

Appendix A. Supplementary data

Supplementary data associated with this article can be found, in the online version, at https://doi.org/10.1016/j.jksues.2018.06.001.

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