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Application of Chemical EOR in Viscous, Heavy Crude in Thin Stacked Heterogeneous Reservoirs Using CMG Simulator

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Abstract

Recovery of viscous, heavy oil from thin stacked reservoirs with heterogeneity is very difficult from sandstone formations. Thermal enhance oil recovery method fails in recovering incremental oil over water flooding. Because of highly viscous crude oil, it becomes difficult to carry out water flooding successfully. Water flooding leads to fingering effect and effective sweep is unable to achieve. Chemical flooding proves to be successful in bringing oil adhere to rock into the production well bore. Alkali reacts with acid components present in crude oil to form natural surfactants; it reduces interfacial tension (IFT). Polymer solution facilitates in increasing the sweep efficiency and improving the mobility ratio. Surfactant flooding helps in further lowering the IFT. It also helps in altering wettability from oil-wet rock to water wet. Thus making more oil flow able from the rock surface. Core flood experimental runs were performed in laboratory to understand the effect of polymer flooding (PF) and alkali-surfactant-polymer (ASP) flooding on the recovery of viscous heavy oil at reservoir temperature. In this paper, the modeling for core flooding was performed using CMG simulator. CMG STARS was used for modeling the ASP flood. CMG CMOST was used for history matching and forecasting the oil production for ASP flooding. Chemical EOR method proved to be successful in recovering the viscous, heavy oil.

Keywords: *Enhanced oil recovery; Chemical EOR; ASP flooding; CMG STARS; CMG CMOST; Polymer flooding.*

1. Introduction

Recovery of oil by natural mean is around 15% during the initial primary recovery phase for conventional reservoirs. With the help of secondary recovery, around 30% of the OOIP (original oil in place) can be recovered using water flooding technique. Oil recovery mainly depends on the reservoir rock properties as well as the property of oil inside the rock. It is very difficult to produce the remaining percentage of oil economically because of low sweep efficiency. During 1960 the oil prices were high and the recovery cost was low which forms the basis for the enhanced oil recovery (EOR) to produce the remaining oil, which is available in the trapped formation [1-2].

Petroleum industry faces tremendous challenges in the recovering heavy oil which is viscous in nature from thin stacked payzones [3]. There is a rapid decline in production rate because of heavy viscous crude oil which create the adverse mobility ratio effect in the primary recovery method [4-6]. The recovery rate of oil is between 10-20% or it can be less than 20% as the recovery of heavy viscous crude oil is very difficult [7]. Thermal recovery methods are used mostly for recovery of viscous heavy crude oil [8]. In the reservoirs where there are pay zones which contains highly viscous heavy crude oil, chemical flooding is the best option for increasing the incremental oil recovery effectively by the means of enhanced oil recovery method [9]. If the crude oil has 200 cP viscosity and has a specific gravity of less than 20 degree then it is termed as heavy oil [10]. If there is a significant difference between water viscosity and crude oil viscosity, water fingering effect arises. Water fingering can be caused due to water encroachment, it leaves back a large amount of oil and ultimately oil recovery is reduced [11].

With the help of chemical flooding recovery of oil can be more than 47 % as in case of (ASP) alkali-surfactant-polymer flooding initially surfactant-polymer (SP) flooding solution is injected after water is pre flushed [12]. After the surfactant polymer solution is injected in the formation in order to improve the performance of oil production and increase the recovery of oil a buffer solution is injected in the reservoir apart from using water flooding [13-14]. Water flooding can help to recover an incremental oil of around 10% from the OOIP for heavy oil recovery [15-16]. Highly viscous heavy oil present in the payzone, where recovery of oil from water flooding is very limited [17]. Potential to produce the heavy oil from such reservoir is very good but because of the ineffectiveness caused by the water flooding there is a need to use other EOR methods. In order to increase the recovery from the reservoir in such cases thermal EOR methods have limitations [18]. Need for chemical flooding specially alkali surfactant polymer flooding is well understood in the reserves having thickness less than 10m in thickness [19]. If the reservoir rock contains heavy crude oil, thermal recovery methods fail to get the incremental oil gain. From the result it’s easy to conclude that along with ASP flooding, even the polymer flooding is very effective at low oil saturation levels in recovering oil [20].

1.1. Reservoir heterogeneity

Heterogeneity in the reservoir or in the formation, then it gives birth to several problem related to recovery of oil. If there is clay present in the formation and if we use water flooding method then it may lead to swelling of clay. Swelling of clay will create problems related to recovery of oil. Also there might be some problems related to heterogeneity which may lead to poor permeability of the formation, which also may lead to reduced recovery of oil. Now in case when we focus mainly on the recovery of heavy oil, then pay zone formation must have good permeability [24]. The pay zone must have zero or minimum heterogeneity for good recovery of oil, as permeability also depends on heterogeneity of the pay zone formation. For heavy oil, where viscosity is very high, permeability of the pay zone must be very good for easily making the viscous crude to flow through the pay zone. If the permeability of pay zone is poor due to heterogeneity, then the recovery of heavy oil won’t be very good. In case where recovery of heavy oil is not good due to permeability related problems, then application of EOR methods can be done for increasing the oil recovery. But in case of stacked pay zones with heavy oil, having heterogeneity problems, it becomes difficult to use thermal EOR methods for the recovery of heavy crude. Hence in such cases other EOR methods can be used such as chemical flooding, which includes alkali- surfactant (A-S) or alkali- polymer (A-P) or surfactant- polymer (S-P) or even (ASP) flooding can applied. Now amongst these various chemical flooding methods which will be best suited depends upon the rock and fluid conditions and their characteristics, which varies from case to case.

1.2. Thin stacked payzones

Recovery of maximum amount of heavy oil from pay zone is a task for the petroleum companies. Water flooding fails as water breaks through the heavy oil due difference in the density and viscosity [25]. Also water flooding becomes ineffective as water is not able push the heavy oil in the production wells. Hence, there comes the need for the tertiary recovery. But tertiary recovery application methods are relatively much costlier than the secondary recovery methods. Important and conventional tertiary methods applied for recovery of viscous oil are SAGD (steam assisted gravity drainage), Steam flooding, Insitu combustion. Even these methods of thermal EOR of tertiary recovery fails to recovery heavy oil with thin stacked reservoirs. Hence there is need to find some alternative methods of tertiary recovery which will not cause problems to thin stacked pay zones. Hence Chemical EOR methods are used in such cases.

2. Geological description

Reservoir pay zone thickness of 3-19m with a water contact of 900m, reservoir was initially producing through the assistance of a bottom water drive mechanism wherein the oil was driven by an active aquifer. Reservoir is dealing with a thin stacked reservoir where the initial pressure was 97.3 Ksc, API gravity of oil being 15°, viscosity of the concerned oil is 270 cP, the pressure and temperature condition at which the first bubble of gas comes out in oil solution is 36.4°.From this moment forth the production rate kept deteriorating, subsequently reservoir was subjugated by waterflooding, that too turned out to be not sufficient economically. Before the well is to be subjected for EOR methods some compatibility screening criteria eventuated and a decision of commencing EOR technique with (ASP) flooding.

Prior to the implementation of ASP on actual field, core flooding analysis was incorporated. On the concerned core, eight core flooding experimental runs were carried out, three ASP flooding and five polymer flooding experimental runs were performed successfully. one successful job was simulated on CMG Stars.

This paper articulates the simulation of a thin stacked reservoir on CMG Stars regarding ASP flooding. It also verbalizes about the consequences of upscaling the results obtained from CMG Stars to the fully functioning field. As well as the author has tried to demonstrate how lab and simulation data plays a vital role in determining the optimal EOR method for any desired field.

3. Experimental procedure

a. Prepare core – 2 types of core i) original (bariea) ii) synthetic
b. Dry the core to remove moisture and get dry weight (note: temp of drying and time required)
c. Put the core in core holder and put molten metal to fix the core
d. Send it for machining.
e. Flood the core with (saturate with water) – I) ETP water/sea water ii) TWW- tube well water, iii) treated produced water.
f. Basic data of core like porosity, permeability, saturation, pore volume, dry weight is known.
g. Displace water with oil with: I) alkali ii) surfactant iii) polymer.
h. Maintain the hot air oven / core holder temperature at reservoir temp and pressure is to be recorded for displacement.
i. Final removal of oil / displacement of oil is measured and pore volume (PV) is calculated
j. After finding the volume then AS volume is found
k. Polymer volume in terms of displacement is found as per PV
l. No of days/hrs/ time must be recorded
m. After collecting the oil/water/displaced fluids then experimentation starts from viscosity, adsorption, polymer trace etc. is carried out.

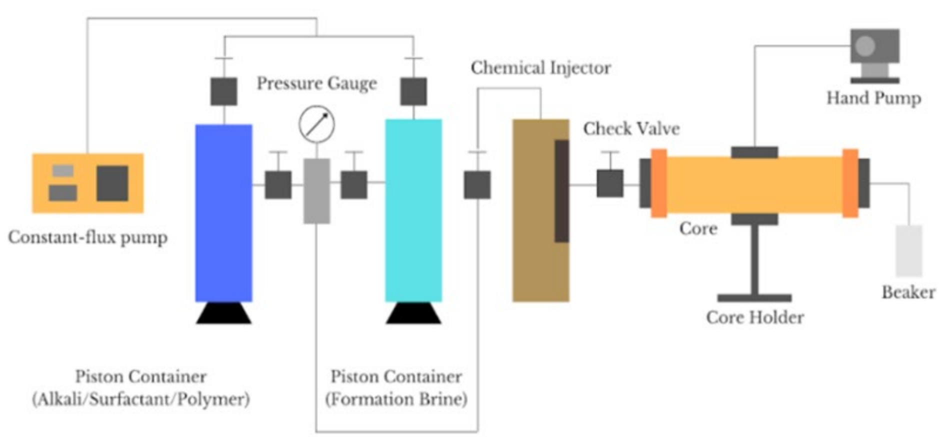


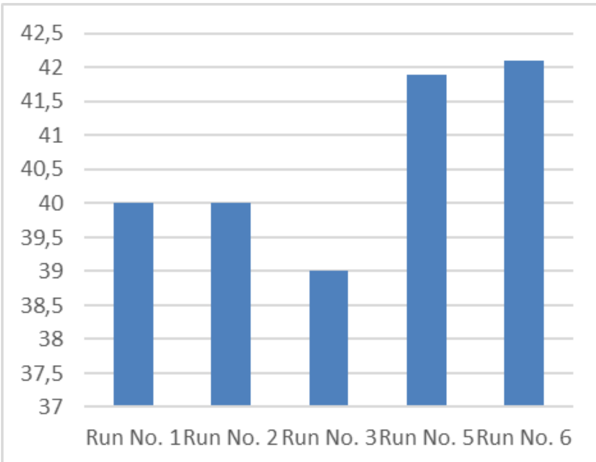
Figure 1. Process flow diagram of core flooding

4. Analysis of experiments

This section instantiates few lab results and explains the consequence of polymer & ASP flooding.

a) Polymer flooding

Remaining oil saturation with respect to water flooding and polymer flooding



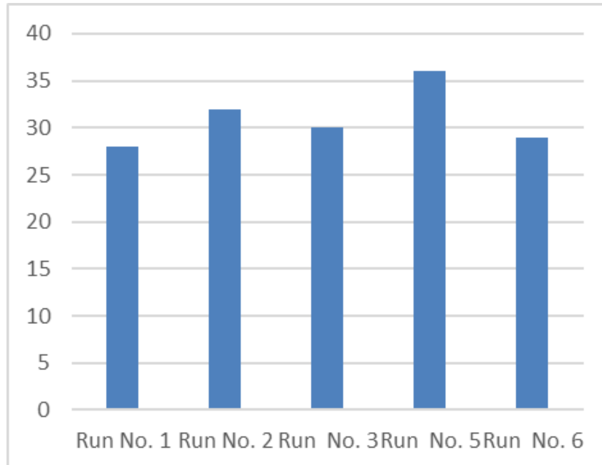


Figure 2. Remaining oil saturation Sor, after waterflood & polymer flood for all experimental runs

The histogram on the left illustrates after succeeding water flooding in the consecutive 5 Experiments Y axis demonstrates higher values of remaining oil saturation obtained in experiment No.6 i.e., 42.1%. But after conducting polymer flooding amongst the 5 cores, analyst came to know that even after having larger quantity of oil left in the reservoir after water flooding the amount of oil produced from experiment No. 6 is not as efficient as the amount of oil produced from experiment No.1 therefore implying polymer flooding on experiment No.1 instead of 6 is economically as well as practically feasible.

5. Polymer displacement efficiency

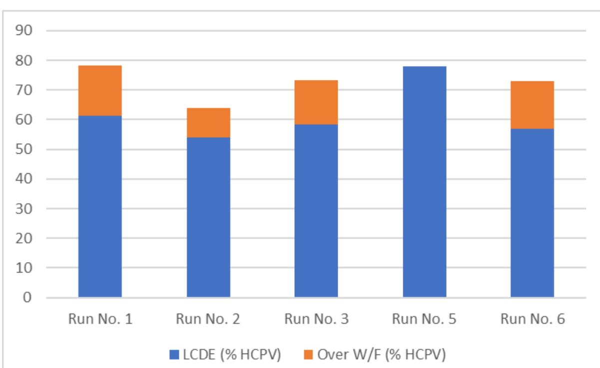


Figure 3. Polymer displacement efficiency of all experimental runs for LCDE over waterflood

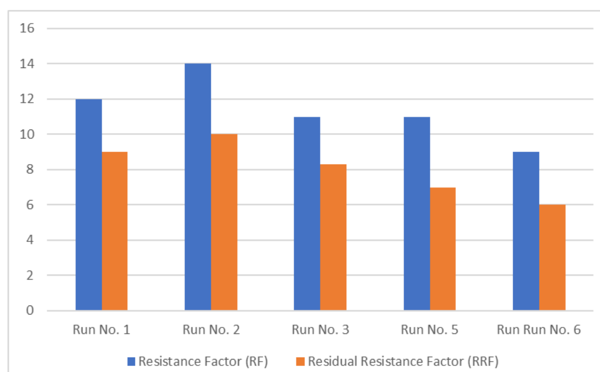


Figure 4. RF & RRF for all experimental runs

Fig.3 illustrates displacement efficiency of polymer over and above waterflooding. Waterflooding job is incorporated with polymer flooding to minimize cost and effectively enhance productivity of oil. Experimental run No. 1 satisfies the above statement since it gives maximum efficiency by the application of both polymer and waterflood.

6. RF and RFF comparison for polymer flooding runs

The relationship between RF and RRF of polymer flooding goes hand in hand because as the polymer adsorption increases the mobility ratio decreases. As the polymer adsorption reduces permeability of the core, the above 5 experimental runs justify the effects of polymer adsorption in terms of RF and RRF. In experimental run No. 6 the RF & RRF is significantly less than the other 4 experimental runs. This states that the polymer used in experimental run no.6 is considered to be reliant one compared to the other four as its adsorption properties are less affective to core.

b) ASP Flooding

Remaining oil saturation with respect to water flooding and ASP flooding

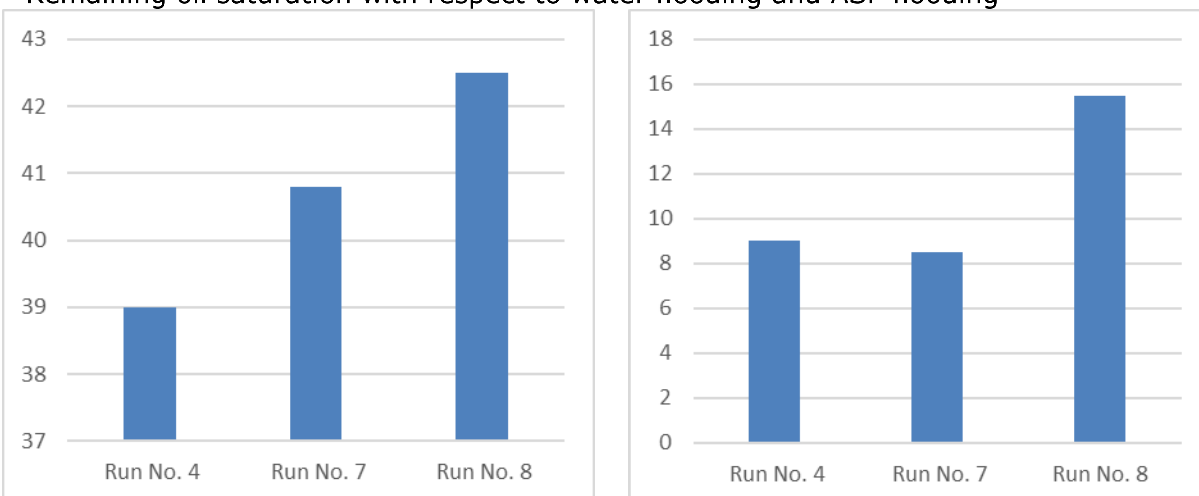


Figure 5. Remaining oil saturation Sor, after waterflood & ASP flood for all experimental runs

In the Fig.5 remaining oil saturation afte waterflooding and ASP flooding is shown. Remaining oil saturation after waterflooding of experimental run no.4 is 39% while the Sor for ASP flooding is 9% similarly for experimental run no. 7 Sor for waterflooding is 40.8% and for ASP flooding 8.5%. therefore experimental run no.7 for ASP flooding in comparison with waterflooding is more efficient.

7. ASP displacement efficiency

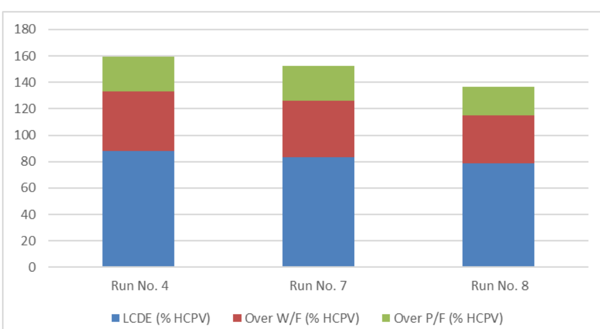


Figure 6. ASP Displacement efficiency for LCDE over waterflood & polymer flood

Fig.6 justifies displacement efficiency of ASP flooding over and above waterflooding and Polymer flooding. Experimental run no. 7 shows effective displacement efficiency compared to the other experimental runs since in experimental run no. 7 the Sor after Waterflood was more than that of experimental run no.4 therefore even though experimental run no.4 shows more effective displacement efficiency than Experimental run no. 7 but after considering the above-mentioned parameters experimental run No. 7 turns out to be the successful ASP flooded core.

8. Remaining oil saturation for all experimental runs

Since there are 8 cores from which experiment run no. 1,2,3,5,6 was polymer flooded and the rest were ASP flooded. The above fig. illustrates the remaining oil saturation over and above waterflood as well as ASP/ Polymer flood. Experimental run no.1 which incorporates polymer flooding gives higher efficiency i.e., has less remaining oil saturation compared to experimental run no. 2,3,5,6. On the other hand experimental run no.7 has left less remaining oil saturation compared to experimental run no.4 & 8.

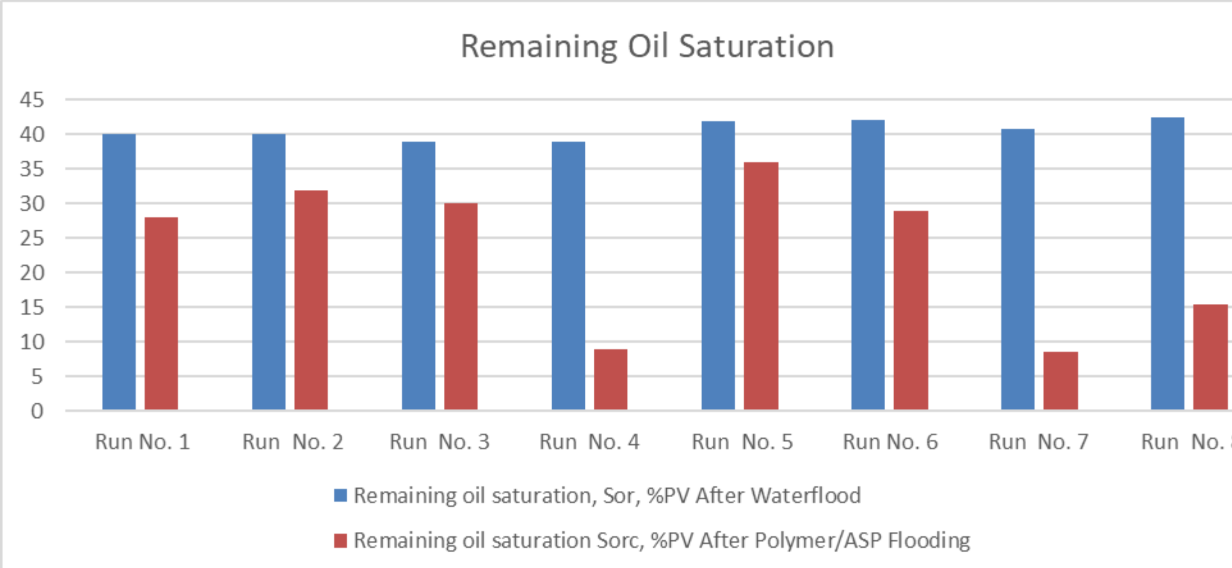


Figure 7. Remaining oil saturation for all experimental runs of polymer & ASP flooding

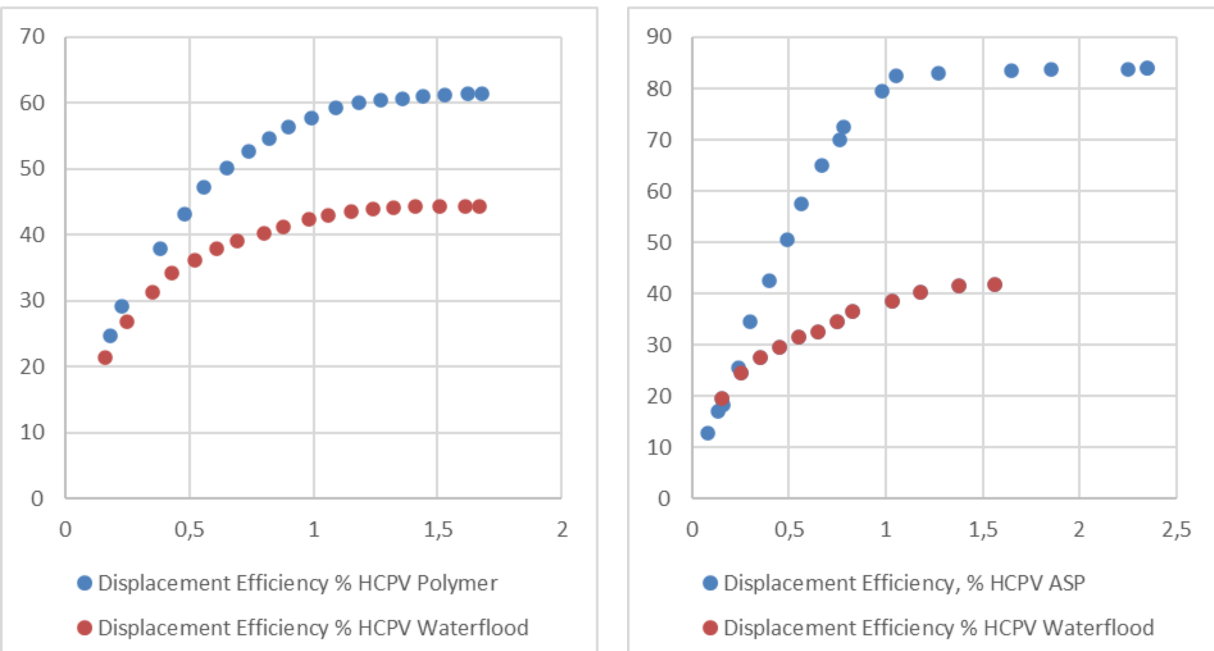


Figure 8. Total volume injected vs displacement efficiency of experimental run no. 1 & 7.

As the fig.8 illustrates the amount of volume injected with respect to the displacement efficiency, for experimental run no.1 the amount of polymer injected is more than the displacement efficiency received (above 60%). While on the other hand the amount of ASP volume injected is kept equal to that of polymer injection (experimental run no.1) with increase in displacement efficiency (above 80%).

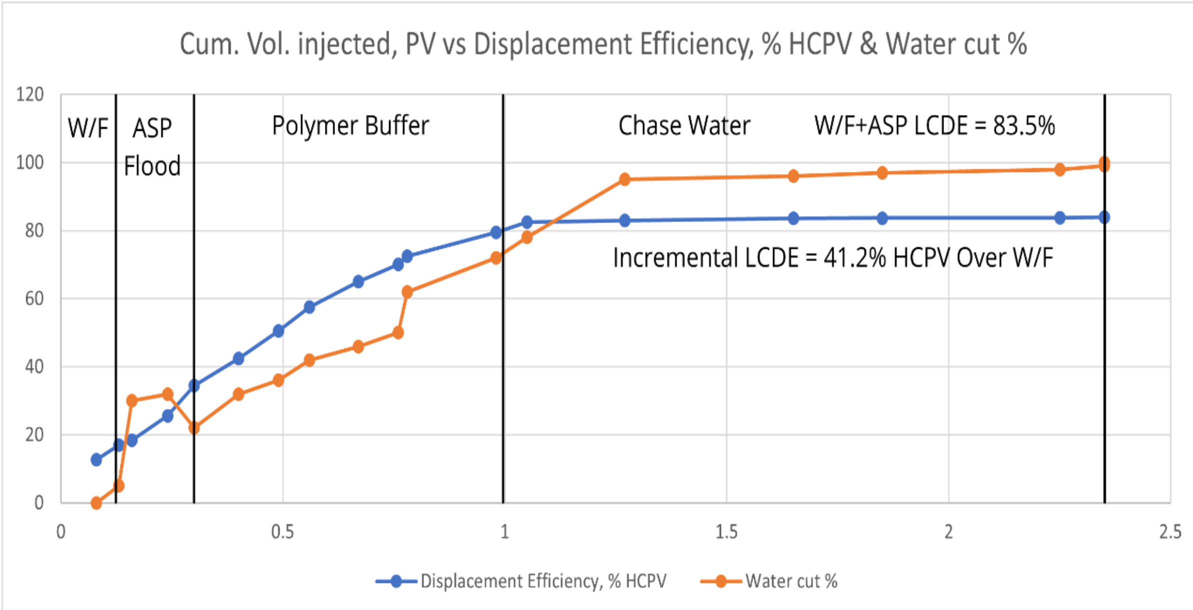


Figure 9. cumulative oil production & water cut for ASP flooding.

Fig.9, ASP Flooding experimental run no.7 is segregated into four contiguous results. In the first Part I.e. W/f wherein waterflooding was conducted, watercut was found to be less than oil productivity. This waterflooding formulated a smooth path for ASP flooding, the flooding was proceeded which gave a higher watercut than the water flooding done earlies which is a sign of successful areal displacement efficiency subsequently after receiving a little less water cut during asp flooding polymer buffer was introduced to the core where appreciable oil production rate was obtained with decrease in watercut followed by this chase water was flooded which gave a constant production rate of oil as well as water.Therefore, ASP Flooding experimental run no.7 is simulated on CMG STARS.

9. Reservoir Simulation using CMG

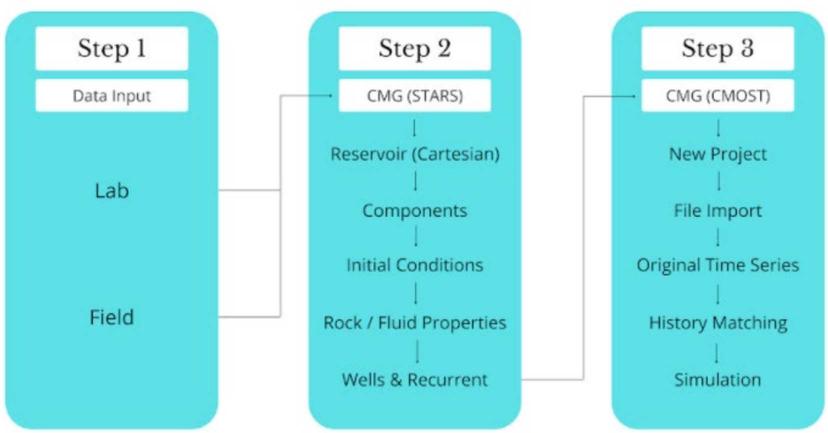


Figure 10. Process flow chart of ASP flooding simulation on CMG STARS

As Lab results were commendable for flood job no 07, it was simulated on CMG Stars. In order to forecast reservoir's productivity as a resultant of lab experiment i.e. coreflooding, a model was created on CMG STARS. As shown in Fig.3 there were 3 major steps involved for simulating a reservoir. In 1st step the data was generated via lab as well as field, relying on the data given by respective offset wells in the reservoir and lab step 2 was commenced, this step took place in CMG STARS Builder module wherein a reservoir grid was created on Cartesian lines it was considered as foundation subsequently reservoir components, Rock/Fluid properties, types and number of wells their initial conditions were specified. Following this sequence, the model was out-turned which was proceeded to the contiguous step i.e. step 3. In step 3 the lab and field and the model prepared in CMG STARS was scrutinized in CMOST for history matching. In there, CMOST verified and interpreted the condition of reservoir and determined its forecast productivity.

10. Results and discussion

As CMG STARS verified the data for both cases (lab & field) and compared the efficiency of Waterflood, polymer flood and ASP flood. CMG proposed several Graphs in order to determine a suitable flooding process for the desired reservoir.

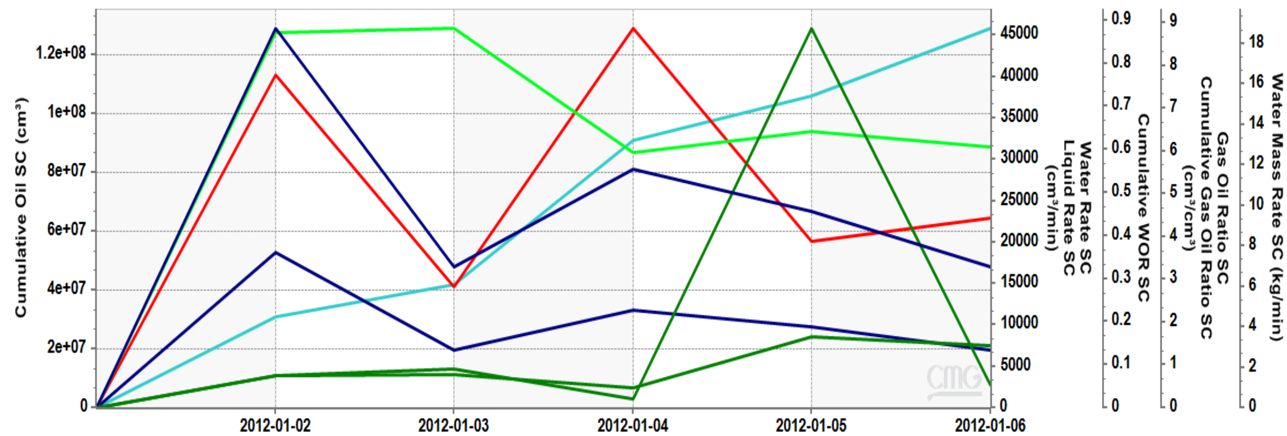


Figure 11.Cummulative oil SC and water rate SC, liquid rate SC, GOR SC, cumulative GOR & WOR SC, water mass rate SC vs time. cumulative oil SC; water rate SC & Water mass rate SC; liquid rate SC; cumulative WOR SC; cumulative GOR SC

Figure 11. Shows the Cumulative oil produced after implementing ASP flooding on the desired reservoir, it also demonstrate the production of water, liquid and gas simultaneously on Y2 axis. As the process cycle of ASP flood reaches towards the end there is significant increase in cumulative oil production with decrease in water, liquid and gas production is observed.While comparing both the EOR Processes (ASP & Polymer flooding) CMG has yield a graph representing the effective process for reservoir.

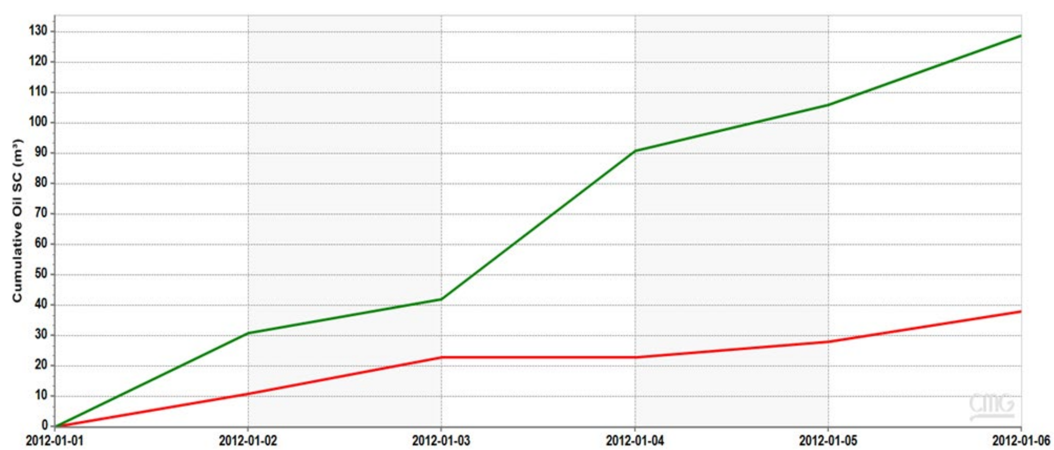


Figure 12. Comparison between ASP and polymer flooding; green-oil produced by ASP flooding, red cum. oil produced by polymer flooding

Figure 12 illustrates that the application of ASP flooding for this reservoir is most effective and feasible, whereas use of polymer flooding gives less oil production and adds up to the total cost of process. CMG has also verified the mechanism and flow pattern of ASP flooding obtained in lab (Figure 9) by producing a graph of the same trend in STARS i.e. Figure 13.

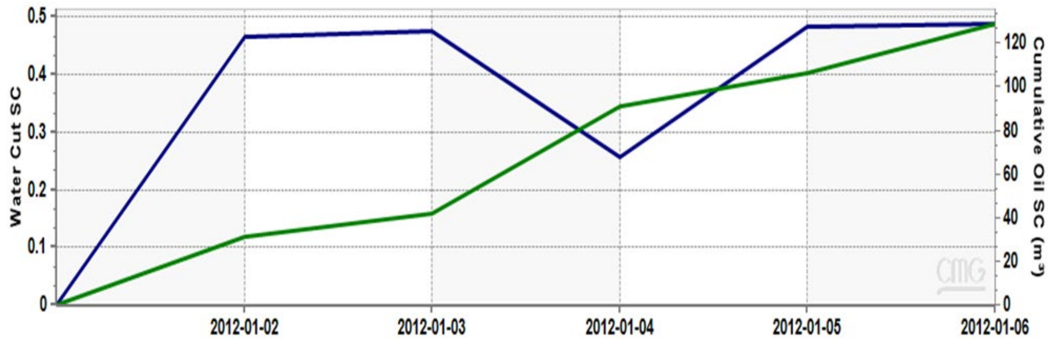


Figure 13. Cumulative oil SC and water cut vs time using ASP flooding; green-cum. oil SC, Blue-water cut SC

The viscous nature of oil caused undesired mobility ratio due to which despite having good permeability and hydrostatic pressure, water cut increased sharply in the early phase of production resulting in low (10%) primary recovery. With the objective to improve recovery, application of EOR was conceptualized. After detailed laboratory investigation on feasibility of chemical EOR processes, ASP was found to be the most feasible chemical EOR technique. ASP flooding is quite effective in thin, stacked payzones with highly viscous heavy oil, where it's difficult to use thermal EOR techniques. Further, as is the common practice pilot project of ASP flooding is recommended in the field for three years followed by polymer buffer for two years.

This work has lead in advancement of knowledge where heavy oil pay zones with heterogeneity creates problems in recovery of heavy oil. Hence, ASP/polymer flooding is applicable to this payzone in the field for recovery of heavy oil from all production wells present in this region. The overall percentage recovery of hydrocarbon was increased from selected chemicals used for ASP flooding. In case of a heavy oil bearing sand-shale reservoir laboratory core studies and simulation studies were carried out for water flood, PF and ASP flood with various combinations. In general, above studies are recommended to decide flood plan for improving recovery of oil. The optimized concentration of fluids in injection water could be decided only after that.

11. Conclusion

This paper anticipated the cumulative production of oil over and above waterflooding, by application of EOR method. It also aimed to determine effective EOR method for thin stacked reservoir. This paper investigated both operations .i.e. polymer as well as ASP flooding, which was evaluated in CMG STARS in coordination with CMOST.

1) According to CMG, the cumulative oil to be produced over and above waterflooding for ASP method is 40 % whereas for polymer flooding it was just 15% raise in cumulative oil production after waterflooding.
2) The remaining oil saturation after ASP flood was 9% while on the contrary (S_{or}) for polymer flooding was found to be 29%.
3) ASP flooding had less resistance factor as well as less residual resistance factor compared to polymer flooding.
4) The watercut in ASP flooding is significantly less than that of polymer flood.

These results enable us to state that the ASP flooding for thin stacked reservoir has proved to be more effective and will ultimately increase oil recovery in oil wet sandstone reservoir.

Further following recommendations are made for possible future work based on the present study:

1. Upscaling of the core flood model to field scale needs to be done using CMG for ASP and Polymer flood, for understanding the effect of total cumulative recovery of oil with more data.
2. Based on the recommended doses for ASP flooding, there must be further implementation of the pilot project on field scale for ASP flooding, to understand the benefit of ASP on incremental oil recovery.

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