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Studying the Integration of Steam Injection/Polymer and Surfactant and their Effect on Heavy Oil Recovery

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***** *EPRI-ASRT EOR Project*

Abstract

In this work, the steam injection, polymer, and surfactant were used to recover heavy crude oil API 18(American Petroleum Institute) production at 150, 200,250, and 300 °C individually. The results showed that the best recovery was at 300 °C. Three sets of experiments were carried out to integrate steam injection with polymer, surfactant, and polymer/surfactant solutions at the same temperatures to investigate the effectiveness of the integration mechanism for improving oil recovery. The obtained results indicated that, the steam is a promising method for the EOR (Enhanced Oil Recovery) of heavy crude oil. It was found that the final recovery for water flooding ranges from 39.9% to 41.86%. When the core was proceeded by polymer/surfactant injection, additional oil production was recovered. The flooding experiments showed that the maximum oil recovery was obtained using steam integrated with polymer/surfactant solution (64.3 %). In comparison, steam exhibited oil recovery equal to 59.2 % with surfactant and 58.1% with polymer at the same temperature (300 °C). The maximum integration process was pronounced by steam with polymer/surfactant solution. This finding may be due to reducing the viscosity by steam which enhances the sweeping process by polymer, in the presence of surfactant, which reduces the interfacial tension and increases wettability alteration. As a result, the emulsion formed, and the heavy oil recovery increased.

Keywords: Enhanced Oil Recovery, Steam Flooding, Polymer Flooding, Surfactant Flooding.

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Introduction

Crude oil that does not flow smoothly is considered heavy or super heavy oil. The name "heavy" is applied to this type of oil because it has a higher density than light oil. Heavy oil usually has an API of less than 20. (i.e., relative density higher than 0.933) [1]. Heavy oil is more difficult to produce, transport, and refine than light oil. The essential physical qualities distinguishing heavy and light oils are high viscosity and relative density and the presence of molecular components heavier than crude oil [2,12-19]. Due to the temperature of the reservoir, the methods for predicting heavy oil are separated into two groups: cold and hot production methods. The reason for this is the main attribute of fluids, viscosity, which is highly reliant on heat [3]. One of the most common ways of extracting heavy oils is steam injection. Steam injection has been used numerous times in Alberta, Canada, as well as Venezuela and California, America; a series of injective wells and production wells are used in this strategy (steam flooding). The steam injection can improve oil recovery by two mechanisms: (1) heating the oil and lowering its viscosity, and (2) forcing the oil into productive wells after transferring its heat to the ground and condensing, acting as a flooding mechanism. This technology has the potential to produce more than 50% oil on-site. As a result, continuous steam injection is a procedure that involves the utilization of numerous wells to prepare the way for a high rate of oil production. Steam is injected into wells under various conditions, such as location and construction, and oil is retrieved from productive wells. Significant recovery may be achieved if the reservoir was built in such a way that steam had a high motion capability. Simulating a process can help greatly with process optimization in this way [3-4].

Steam flooding processes have different mechanisms; it was defined by China as follows: steam drive, in-situ solvent drive, viscosity reduction, thermal permeability and capillary pressure fluctuations, thermal expansion, gravity segregation solution-gas drive, and emulsion drive. Although steam flood has higher productivity, it has some disadvantages, such as (1) steam channeling through high permeability zones and (2) gravity override, which causes early breakthrough and lowers displacement efficiency. Injection of water-

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soluble or alkaline into the steam used in cyclic steam stimulation operations [5]. often improved oil production, according to previous laboratory and fieldwork. Tiab et al. examined the use of caustic (sodium soda) in a steam flood to reduce the residual oil saturation in the lower portion of the reservoir (which is usually overridden by steam). The results of this study revealed that the use of sodium soda with the steam improves flow efficiency and, as a result, increases oil recovery when compared to conventional steam flood [6,7]. Blair et al., tested the injection of some interfacially active chemicals into some wells In Kern County, CA, before and during the huff and puff steaming cycle. This chemical steam treatment has been shown to increase oil production significantly [8]. Al-Khafaji et al. carried out two experiments, one static, and the other dynamic [9-11].

The dynamic experiment investigated heat transfer through porous media and surfactant steam flood mobility. When surfactant was used, the results showed that steam mobility was reduced. As a result, the goal of this research is to look into oil recovery using various chemical steam methods (such as surfactant steam, alkaline steam, and surfactant alkaline steam). Wu et al. used a sensitivity analysis to design and optimize a low-cost-chemical flooding system that included chemical concentration and permeability field realization (vertical and horizontal permeability ratio). The results showed that by combining current EOR processes, the process of designing chemical floods could be improved [18]. This Chemical flooding is defined by two mechanisms: (1) altering oleic rate in comparison to aqueous rate through the rock (including lowering of interfacial tension, wettability alteration, viscosity alteration, and pore-clogging) and (2) changing phase composition (including miscibility, swelling, and solubilization) [19-25]. For heavy oil reservoirs, steam injection is currently one of the most successful enhanced oil recovery procedures. However, the thermal energy efficiency of steam injection decreases as oil production progresses due to steam flooding [26]. At the same time, the production of steam requires a large amount of water, and the combustion of fossil fuels releases a large amount of greenhouse gases, causing environmental issues. When the solvent is injected into a reservoir, however, it dissolves in the crude oil and reduces its viscosity, improving oil recovery [27-29]. The Solvent-assisted steam flooding method was offered as a way to reduce the environmental impact of steam generation, save water, and improve oil recovery [30]. The solvent injection can widen the temperature range in the reservoir, allowing the solvent to break through the front of the steam displacement and enter the reservoir at a lower temperature. Furthermore, due to the action of mass transfer, solvents can be miscible with oil, reducing interfacial tension and lowering oil viscosity and residual oil saturation in the reservoir [29,30]. The main target of this work is focusing on using integration steam with surfactant or polymer to improve heavy oil recovery. The hydrolyzed polyacrylamide polymer (HPAM), should be used for its efficiency in sweeping and modifying mobility of injection fluid [21]. The study should be extended to investigate the steam, surfactant, and polymer individually to compare with the integrated systems. The chemical structure of used materials is shown in Fig.1. The rheology parameters may be used to discuss the integration process.

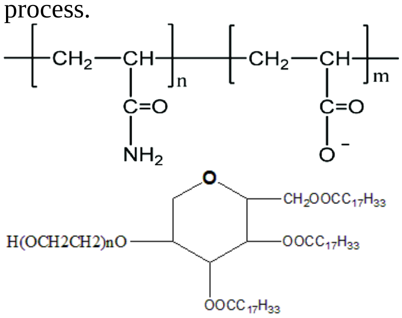


Fig.1 Chemical Structure of a) HPAM and b) E(20)STO

Materials and Experiments

Materials

HPAM was obtained from Sigma-Aldrich Co. (Egypt vendor) (Mw ~= 5000000)and commercial E(20)STO (Polyoxyethylene sorbitan Trioleate, acid value= 2) from Guangdong Huana Chemistry Co. (China).

Crude oil

Heavy crude oil and brine ([total dissolved solids (TDS), mg/L, salinity ≈ 75000 ppm]) were conducted from the Egyptian East desert. The crude oil has a 18 API. The crude oil properties are listed in Table 1

Core Samples

The core samples were delivered from Vinci company manufacturer of SFS system at Egyptian Petroleum Research Institute (EOR unit). The cores are placed in the hassler core holder to measure permeability. The backpressure regulator was set to 40 psi, the cores were saturated with formation water then crude oil was then injected at 1 cc/min flow rate until residual water saturation (Swi) was achieved. The properties of core samples are shown in Table 2.

Table 1: Physicochemical Properties of The Used Crude Oil

Property	Value
Density, gm/cc (ASTM D792)	0.941
API,^{O} (ASTM D287)	18
Asphaltene Content, wt.% (ASTM D6560, ASTM D792)	12.78
Resin Content wt%	13.2
Wax Content wt%	1.91
Pour Point ºC (ASTM D97	15

Table 2: Properties of Core Plugs

Property	Value
Length, cm	14 - 17
Diameter, cm	5.02
Pore Volume, cc	69 - 80
Porosity, %	19 -22
Permeability, md	80-110

Surface and Interfacial Tension Measurement

The surface tension measurements were investigated for formation water without and with adding surfactants at different concentrations at 50 °C using Attension Theta (Bioline Scientific; Finland). The surface-active and thermodynamic properties were calculated. The interfacial tension of the surfactant solutions at the oil−aqueous interface is an important parameter in evaluating the efficiency of surfactants toward EOR at reservoir conditions28. The IFT experiments were also measured on the same apparatus using Pendand drop method (ASTM ISO 19403-4).

Wettability Alteration Measurement

The wettability alteration measurements were carried out using the contact angle (CA) method (sessile drop). For the CAs of crude oil−brine/surfactant solution−rock, the acquired images were captured using Attension Theta (Sessile Method) (ASTM ISO 19403-5). All measurements for HPAM and E(20)STO were conducted at a constant temperature of 50 °C.

Flooding Test Conditions

Confining Pressure = 500 psi
Back Pressure = 50 psi
Injection Pressure 200 psi
Reservoir Temperature = 50 ºC
Permeability = 80-120 mD

The flooding experiments were carried out using steam flood system (SFS); the SFS is designed to perform tests on core plug samples. The pore pressure is measured at the inlet and outlet ports of the core sample by using relative pressure transducers. Pressure taps may be used to monitor the pressure along with the core. Likewise, the confining pressure is measured with a pressure transducer. The pressure control system, including the oven, pumps, valves, core holder, and transducers, are mounted on specific cabinets. An IBM-compatible computer is used to control the system's operation. The device comes with software that allows for automatic data collection and some simple calculations. The Hydrostatic type core holder belongs to the Vinci Technologies HY Series core holder. These core holders are routinely used for gas and liquid permeability testing and water flooding experiments. The core sample is held within a rubber sleeve by confining pressure (radial stress). The confining pressure simulates reservoir overburden pressure. Inlet and outlet end plugs allow fluids to be flooded through the core sample**.**

The setup was packed with cores with different lengths (5 – 10 cm), but the same diameter (5.08 cm). The properties of the cores are shown in Table 2. The saturation with formation water was carried out for two days, and then oil saturation was done. Waterflooding with formation (TDS: 75000 ppm) was performed to determine the oil recovery at the end of the secondary recovery stage. All sets of experiments steam, polymer, and surfactant individually or integrated.

the following flooding scenarios were applied: -

1. Water flooding before each run
2. Steam injection with different temperatures (150, 200,50,300 ºC)
3. Integration of Steam and E(20)STO flooding
4. Integration of steam and HPAM flooding
5. Integration of Steam, HPAM. And E(20)STO flooding

All of these experiments were performed at the thermal lab of the EOR unit, Egyptian Petroleum Research Institute.

Figures 8,9 show the SFS used for the flooding experiments.

Results and Discussion

In this work, different scenarios of improving heavy oil recovery were pronounced. The first was to test steam, surfactant, and HPAM flooding individually. The second scenario used integration between two methods, such as steam with surfactant or steam with polymer flooding. This study assesses the beneficial role of using integration methods in the enhanced oil recovery of heavy crude oil.

Surface active and Thermodynamic Properties of The Used Materials

The surface tension of both HPAM and the ethoxylated sorbitol trioleate (E(20)STO was measured at 50 , 75 ºC (reservoir and processing temperature). The results were plotted between σγ versus – ln C mol dm -3 in Fig.2 . the thermodynamic properties are illustrated in Table 4. Fig. 2 shows that, the HPAM has a little depression of surface tension (67-65 mNm^{-1}, at 50 ºC and 70 ºC respectively), this means that this polymer hasn't surface activity (surface inactive polymer). But from Fig.2, the surfactant exhibited great depression in the surface tension (good surface-active material). The γ, was 32 and 27 mNm^{-1} at 50 ºC and 70 ºC respectively). From Fig.2 the critical concentration for micelle formation (ccmf) was determined (2.52 and 1.26 10-5 mol/m^3, at 50 ºC and 70 ºC). at the ccmf the maximum reduction of surface tension was achieved. The surface-active parameters such; surface pressure effectiveness, πCMC, and adsorption efficiency PC20; the maximum excess of surface concentration, Γmax, and minimum occupied area/molecule in $Å^2$/molecule was calculated from the following equations on the base of surface tension data [31] .

$$\pi CMC = \gamma o - \gamma cmc \quad (1)$$

$$PC20 = -\log C20 \quad (2)$$

$$\Gamma max = \frac{1}{nRT}\left[\frac{d\gamma}{d(\ln c)}\right] \quad (3)$$

$$Amin = \frac{10^{18}}{N\,\Gamma max} \quad (4)$$

The surfactant effectiveness depends on γ (surface tension of pure solution) and γcmc (surface tension of surfactant solution). The quantity of surface tension depression (38 mNm^{-1}) is pointed to this surfactant has good surface activity properties. The term PC20 refers to the surfactant concentration at which it can decrease the surface tension of water by 20 mNm^{-1}. The adsorption efficiency PC20 and great effectiveness mean that the surfactant molecules can effectively saturate any interface, which shows surface attribute with required flexibility and tend to minimize the interfacial tension of the interface between oil and formation water [31]. regrading to the Γmax eq 3, the C is the molar concentration of surfactant solution, R is the gas universal constant (8.314 J/K mol^{-1}), T is the temperature in K, and γ is the surface tension mNm^{-1}. The Gibbs adsorption coefficient (n) is the number of molecules adsorbed at the interface. The value of Γmax points to the accumulating and adsorption enrichment of the surfactant molecules in the mol/cm^2 of the surface. Eq.4 detects the area occupied per molecule of surfactant on the surface (in $Å^2$ / molecule). N, is the Avogadro number. The low value of Amin points to the improved oil displacing capacity per molecule of surfactant. The used surfactant molecule gave Amin 174.27 $Å^2$ at 50 ºC and 161.48 $Å^2$ at 70 ºC. the Amin decreases by increasing temperature as the result of the thermal agitation on the surface. This property is very important for the integration methods and formulation to lower the IFT and improved oil solubility and attraction capacity, further increase of oil recovery [33,34]. The Gibbs free energy of micellization(Δ Gmic) and adsorption (Δ Gads) in KJ/mol are calculated from the following eqs. For the used nonionic surfactant [31].

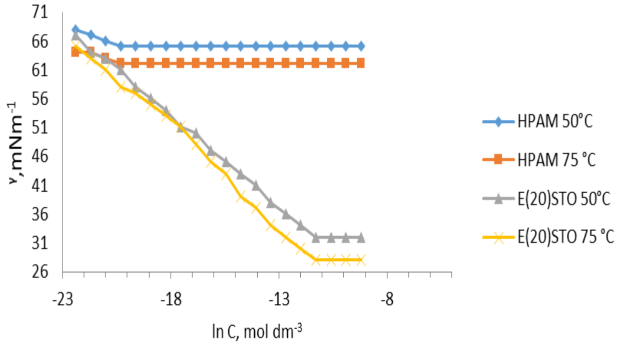


Fig.2 : Surface Tension vs ln C for E(20)STO and HPAM

Table 3 : Contact Angle and Interfacial Tension at 50 ºC

Sample	Static Contact Angle	Dynamic Contact Angle	IFT mNm^{-1}
Crude oil	160.55	157.3	26
HPAM	61.3	58.2	69
E(20)STO	15.6	10.4	$3x10^{-3}$

Table 4 : Surface Active and Thermodynamics Properties E(20)STO and HPAM* in Formation Water

Parameters / Temp.	CMC (mol/L) $*10^{-5}$	γ_{CMC} (mNm^{-1})	P_{C20} mol/cm^{-3} $*10^{-7}$	Γ_{max} (mol/cm^2) $*10^{-10}$	A_{min} ($Å^2$)	π_{CMC} mNm^{-1}	ΔG_{mic} (KJ/mol)	ΔG_{ads} (KJ/mol)
50 ⁰C	2.52	32	2.7	0.95	174.27	35	-28.43	-32.88
75 ⁰C	1.26	27	2.05	1.02	161.48	38	-32.63	-36.37

*Surface tension at 50 ⁰C and 70 ⁰C situated between 67-65 (surface inactive material)

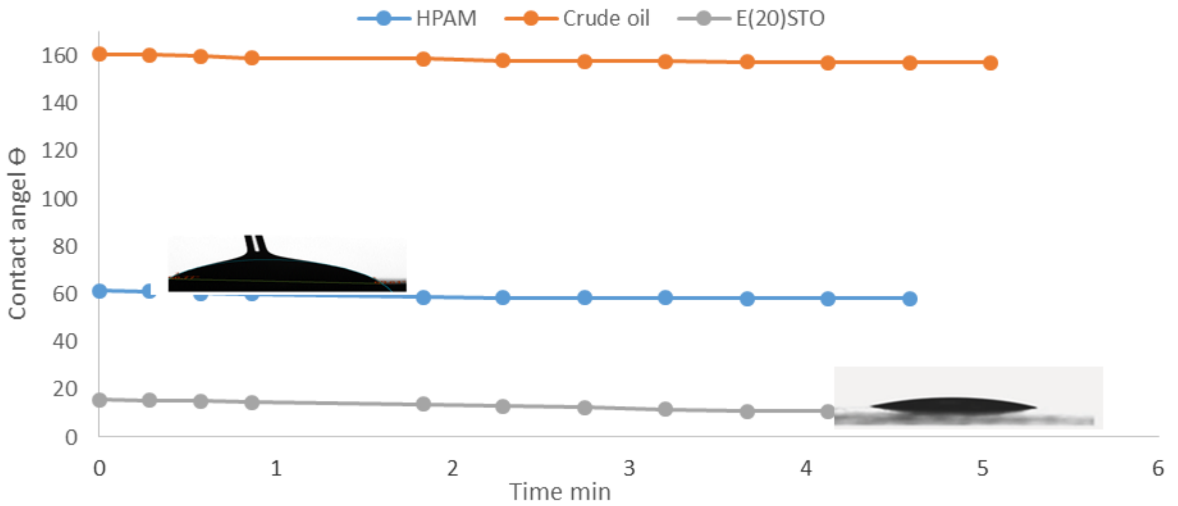


Fig.3 : Contact Angles of Crude Oil, HPAM and E(20)STO at 50 ºC

Δ Gmic = RTln CMC (5)

Δ Gads = Δ Gmic – [6.023 πcmc Amin]*10^{-3} (6)

The negative values of Δ Gmic as shown in Table.4 indicates to the micellization is a spontaneous process. Whenever the Δ Gads were found to more negative as compared to the Δ Gmic, this finding is resulting to the surfactant molecules favorable adsorption as compared to the micellization process. Increased temperature has a synergistic influence on the micellization and adsorption tendencies of surfactant molecules at the interface As the temperature increases, the Δ Gmic increases indicating that the tendency of surfactant molecules enhances to form micelles due to the decrease of surfactant ccmf. As the result of the decrease in the ccmf with temperature in Table 4, At lower concentrations in the aqueous solution, molecules' ability to agglomerate is observable. The adsorption of surfactants increases as the curvature of the air/aqueous or aqueous/oil interface increases. The mean of micelles formation indicates that this surfactant should form an emulsion of the heavy oil with the formation water. This feature exhibits effective interfacial interactions with the surrounding media. The adsorption of surfactant and minimizing the IFT leads to solubilizing the heavy oil to form oil in water emulsion [32-34]. This means that the surfactant system has significant support for any integration technique in the field of enhanced oil recovery (EOR). The IFT is a very crucial factor for the study of surfactant efficiency in oil recovery. The low value of IFT leads great ability to form oil in water emulsion to effectively displace the trapped oil in the pore throat of the reservoir [35]. The IFT values of the used surfactant are shown in Table 3. The IFT at 50 ºC was $3x10^{-3}$ mNm^{-1}, and the IFT between formation water and the used crude oil was 26 mNm^{-1} at 50 ºC. The obtained minimizing tension by using this surfactant as the above data in Table 3, means that this surfactant should form an emulsion with the heavy oil; further, the oil repelled from the pores, and the EOR should be increased. The term contact angle is very important in the field of EOR. As the data shown in Table 3 and Fig.3, the contact angle of the crude oil droplet is significantly high 160.55 static and 157.3 dynamic. This means that it is more hydrophobic, and the rock is completely oil-wet. By adding the HPAM, the contact angle decreased to 61.3 static and 582 dynamic. This means that the polymer makes the rock more water-wet and displaces the oil from the surface. Meanwhile, by using the E(20)STO, the great depression of contact angle was remarked as 15.6 static and 10.4 dynamic. This finding proved that the adsorption property of surfactant molecules on the interface minimized the IFT to $3x10^{-3}$ mNm^{-1}, which turned the rock into more and more water-wet, and the oil droplets were repelled to form an emulsion (o/w/o) at different forms; further, the removal of the heavy oil should be increased.

Rheological Behavior of HPAM/E(20) STO

The rheology investigation of four systems was carried out for the heavy crude oil, HPAM, E(20)STO, and HPAM / E(20)STO (50/50 %) at a concentration of 2%. The viscosity and shear stress versus shear rate are shown in Fig.4 for crude oil only, whereas, Fig.5 shows the viscosity against shear rate for HPAM (a) and its temperature profile in segment (b). segment (c and d) show Shear Rate vs. Viscosity of E(20)STO and viscosity-temperature profile of E(20)STO, (e and f) show the viscosity vs. shear rate and temperature profile of the mixture between HPAM and E(20) STO. The apparent; plastic and yield values of these systems are illustrated in Table 5. from the presented data in Fig.5, it was found that the crude oil exhibited shear thinning behavior. This non-Newtonian behavior of crude oil is very important to mobility control during the sweeping process, especially at adding the polymer and surfactant or a mixture of both of them during the flooding process. In spite of the increase of apparent plastic viscosity and yield value, decreases of these parameters with increasing temperature were remarked, as seen in Table 5. To evaluate the effect of adding polymer and surfactant on the flow properties of the heavy crude oil systems during the flooding process was studied at different temperatures (40, 50, 70 ºC) to find a relation between solution behavior and flooding behavior. The data of these parameters are listed in Table 5 and plotted in Fig.5. As shown in Fig.5.b and a for the temperature profile of HPAM and HPAM with E(20) STO, respectively, when temperature increases, the viscosity of the system decreases. This behavior might result due to different reasons, such as weakening hydrogen bond between water and polymer or surfactant molecules, increasing the chance of polymer of surfactant chains reducing the contact duration of the adjacent chains, and decreasing the average intermolecular hydrogen bonds and Vander Vals forces [36]. The viscosity reduction with temperature increase may be due to the crimpling and flexing of the additive molecules as the result of its dehydration and destruction of the polymer or surfactant configuration in the system [37]. The reduction of viscosity also depends on the activation energy of the Arrhenius equation, which is directly affected by temperature , the activation energy was coming from Eq.7 [38].

$$\eta t = AEa/RT \qquad (7)$$

Where η is the apparent viscosity(cp). A is the constant, Ea is the activation energy (KJ/mole), R is the universal gas constant (8.14 KJ/mole), T is the temperature K. The value of Ea, is listed in Table 5 and Fig.6. From these results, it can be seen that the Ea decrease with temperature increase. By inspection of the data of apparent plastic viscosity and ƮB in Table 5. It was found that the HPAM (as polymer surface inactive material) exhibited (20.24,17.5 cp and 1.72 pa respectively at 50 ºC (the most common temperature for Egyptian reservoir); meanwhile, they were 256.12, 209.87 cp, and 1.97 pa for crude oil at the same condition. Otherwise, the same parameters for the E(20)STO were; 9.24, 6.87 cp, and 1.4 pa. The high values of HPAM indicate the high mechanical stability of the polymer solution. These values were enhanced at the mixture system as shown in Table 5; 32.24, 26.44 cp, and 5.32 pa. This finding gives a good chance for this positive integration synergism between the HPAM and the surfactant, which should increase the sweeping efficiency of the polymer at the EOR of the heavy crude oil. In spite of the high viscosity and rheology parameters of the heavy crude oil, the positive integration synergism of the polymer with surfactant depended on the high mechanical stability of the polymer solution and surfactant depresses of the IFT. So, when this mixture integration system combines with steam at 300 ºC, the maximum enhancement of heavy crude oil should be achieved.

Table 5 : Rheological Properties at Different Temperatures

Sample Name	Temp. oC	Apparent Viscosity η ,cP	Plastic Viscosity µ cP	Yield Value (ƮB) Pa	Ea KJ/mole
Crude oil	40	442.48	389.45	3.75	4.79
	50	256.12	209.87	1.97	
	70	114.32	98.7	0.67	
HPAM	40	22.11	21.9	2.11	3.21
	50	20.24	17.5	1.72	
	70	16.74	12.49	1.53	
E(20)STO	40	15.0	14.5	1.99	1.02
	50	9.24	6.87	1.48	
	70	5.21	3.46	0.96	
HPAM+ E(20)STO	40	42.12	31.2	2.38	3.88
	50	32.24	26.94	1.97	
	70	21.47	19.31	1.88	

Steam flooding Process only

After installing the core samples in the SFS apparatus, the oil was injected till no water came out to be sure that the reservoir condition was achieved. Then, the water flooding was performed, and the displaced fluid was detected to calculate the recovery factor. Then, the steam at different temperatures was only injected after the water flooding process. Fig. 7 and Table 6 show the cumulative oil recovery during 1.4 PV FW flooding; about 39.9% of the OOIP was recovered. Upon switching to steam flooding, the incremental oil recovery was 11.8%,13.1%,16.7% and 19.7 % of the OOIP against temperatures; 150 ºC, 200 ºC , 250 ºC and 300 ºC, respectively. The total oil recovery during this experiment was 46%,49 %, 51%, and 53% of the OOIP to the different temperatures, respectively.

Table 6 : Summary of Flooding Experiments and Added Values for Each One of Them

	Experiments								
Temp. ºC	Water flooding only %	Water flooding + Steam %	Water flooding +E(20)STO %	Water flooding + HPAM %	Water flooding + steam +E(20)STO %	Water flooding +Steam +HPAM %	Water flooding +HPAM + steam +E(20)STO %	Steam %	E(20
150	39.9	46.49	48.7	51.85	53	52.7	64.3	11.8	16
200	41.88	49.5			56.2	53.7		13.1	
250	41.38	51.21			58.3	57.4		16.7	
300	41.86	53.32			59.2	58.1		19.7	

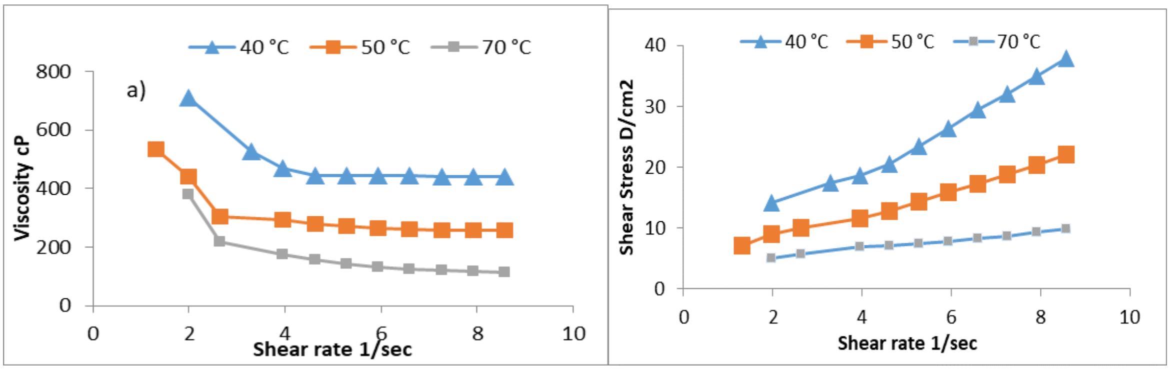
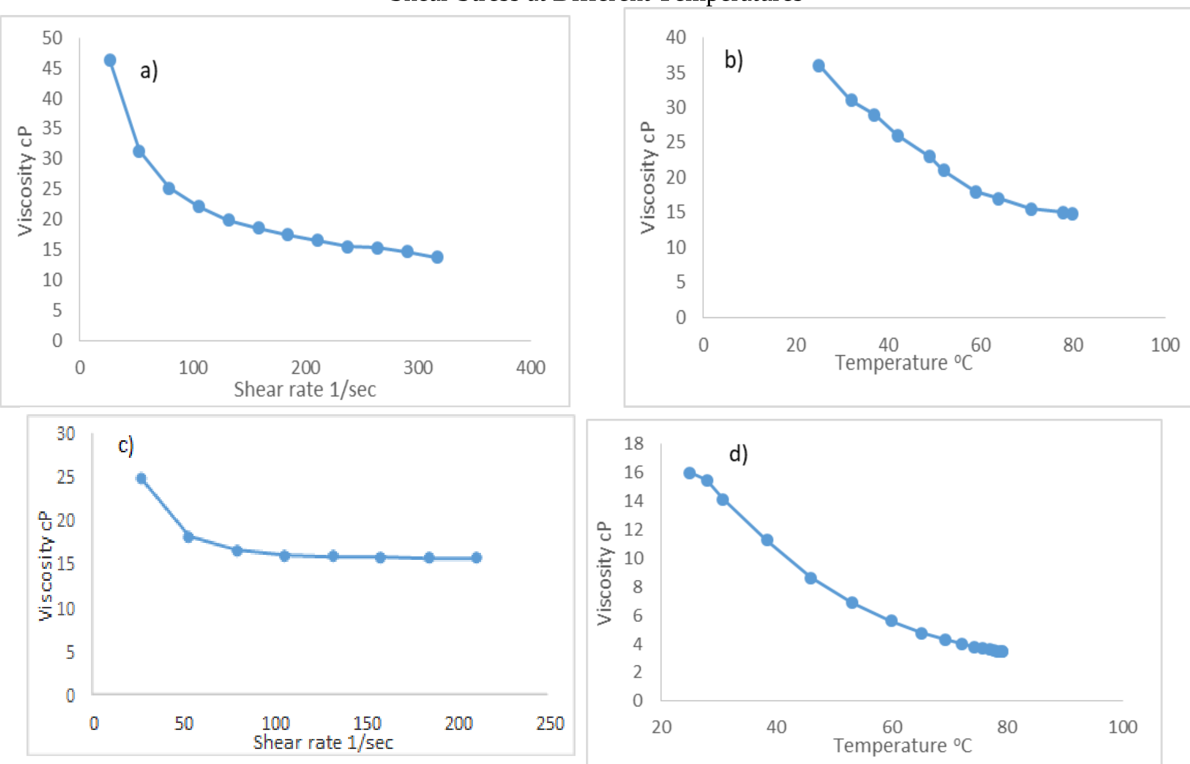


Fig 4 : Rheological Properties of Crude Oil a) Shear Rate vs Viscosity at Different Temperature b) Shear Rate vs Shear Stress at Different Temperatures



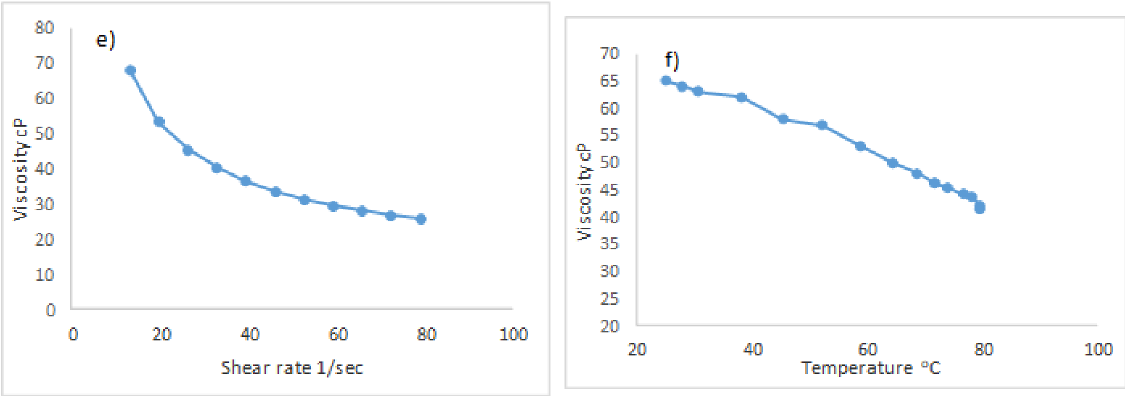


Fig.5 : Rheological Properties of HPAM a) Shear Rate vs Visocisty, b) Visocisty Temperature Profile of HPAM c) E(20)STO Shear Rate vs Viscosity, d) Viscosity Temperature Profile of E(20)STO, e) Shear Rate vs Viscosity of HPAM+E(20)STO, f) Visocisty Temperature Profile of HPAM+ E(20)STO

Integration of Steam and E(20)STO Flooding

The same core preparation and core flooding procedure and conditions were applied to the other cores. The oil recovery during the water flooding for all is about 39.3 % of the OOIP. Different steam temperatures were then injected and integrated with E(20)STO flooding. With respect to the surfactant steam flood (SSF), the co-injection of surfactant (as a surface-active chemical) with steam into the core provides a significant increase in oil production than that of the steam flood only.

Fig. 7 shows the combined oil recovery by water and surfactant steam floods versus pore volume injected. The enhancement of sweep efficiency is reflected in the improvement of displacement efficiency of surfactant steam floods. The reason may be that the surfactant steam mixture generates emulsion and foam in the reservoir and improves the oil recovery efficiency of steam flooding by diverting steam to high oil saturation zones [30]. The results showed that the integration mechanism between Steam and E(20)STO is better than using steam only; this integration was done at different steam temperatures as before and caused an incremental recovery of 21.7 %, 26.1%, 29.4%, and 31.9 %, respectively, with total oil recovery 53%, 56.2 %, 58.3%, and 59.2% respectively.

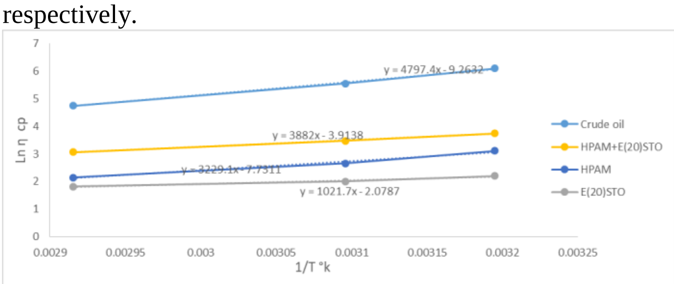
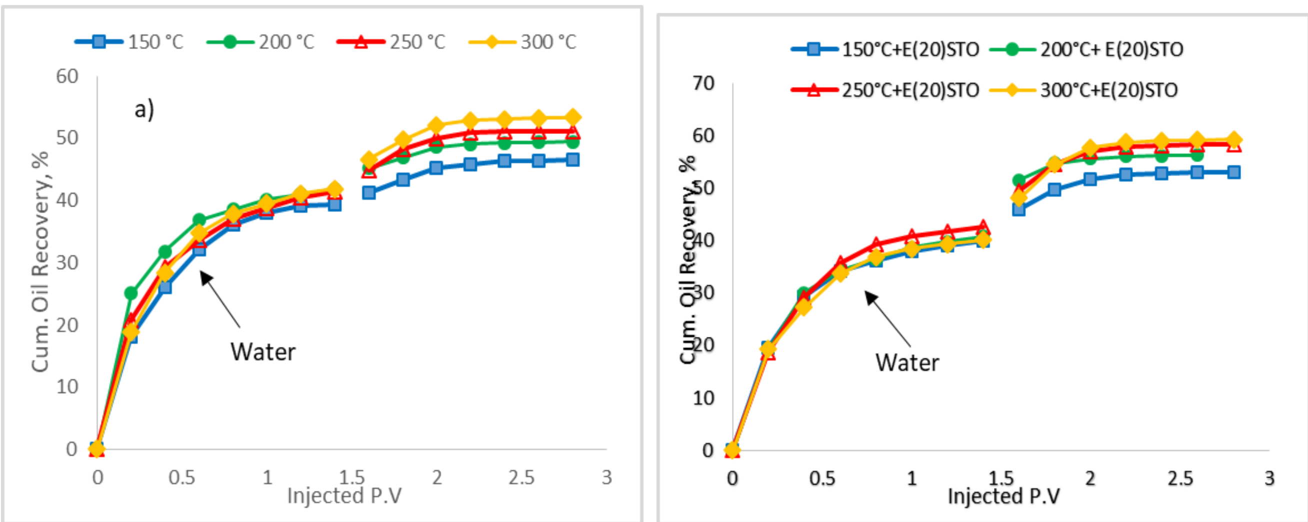


Fig.6 : Ln η vs 1/T Curve for Crude Oil, HPAM, E(20)STO and HPAM+E(20)STO



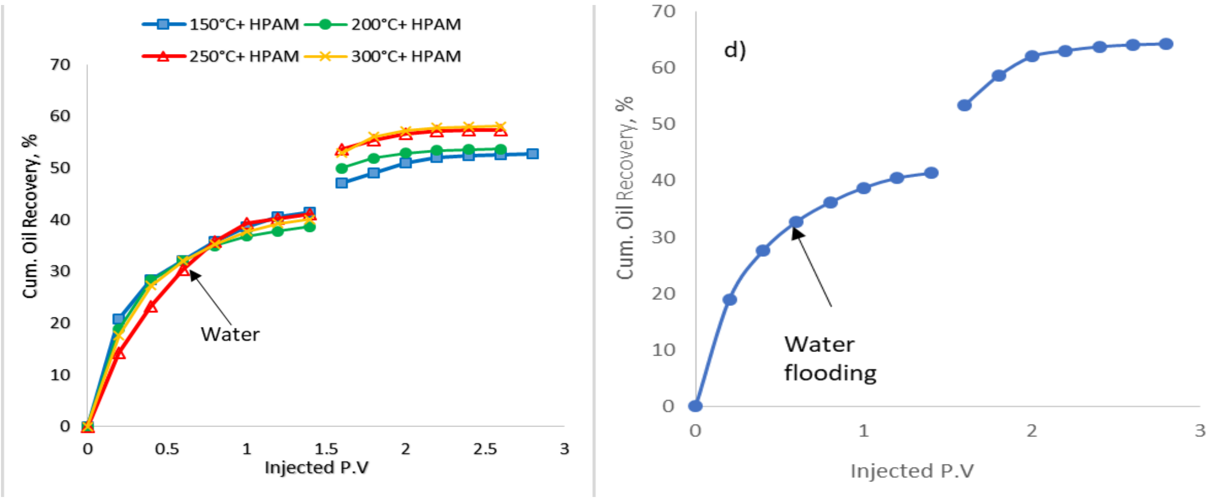


Fig.7 : Cumulative Oil Recovery % of Different Scenarios a) Steam Flooding Only at Different Temperatures, b) Integration Flooding of Different Steam Temperatures and E(20)STO, c) Integration Flooding of Different Steam Temperatures and HPAM, d) Integration Flooding of 300 ºC Steam and E(20)STO HPAM Mixture

Fig.8 : Steam Flood System 700 (SFS700)

Fig.9 : Steam Flood System- Main Oven

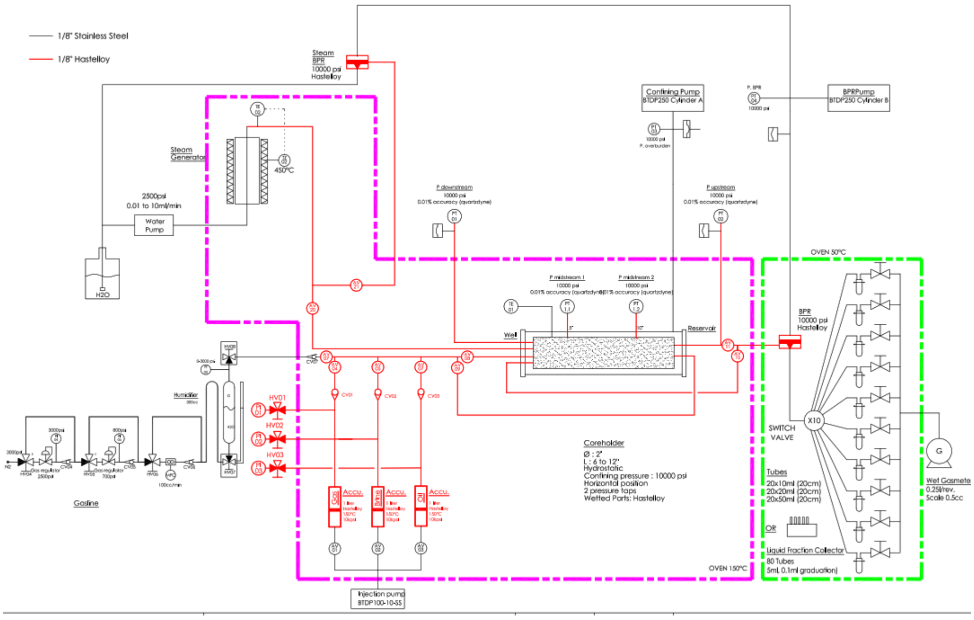


Fig. 10 : Schematic Diagram of SFS

Integration of steam and HPAM Flooding

The results of the HPAM /Steam flooding experiment are presented in Fig. 7. The oil recovery of the HPAM steam flood shows an improvement compared with the steam flooding. This improvement is attributed again to the viscosity reduction and surface and interfacial values. In addition, the addition of HPAM to the steam increases its gravity and reduces its mobility, which helps to reduce the tendency of steam to override, causing early breakthrough. HPAM steam process has better displacement efficiency than that of the steam drive. By comparison of surfactant steam and HPAM steam processes shows higher oil recovery by the surfactant steam process; this is because the surfactant solution shows lower surface tension values with crude oil than that shown by HPAM only. The incremental recovery after using HPAM steam integration at different steam temperature is 19.2%, 24.5%, 27.7% and 30.1 % receptively.

Integration of Steam, HPAM, and E(20)STO Flooding

The proposed surfactant HPAM steam flood technique is a scientific trial to combine the effectiveness and mechanism of surfactant, HPAM, and steam processes, as shown in Fig.7. This technique incorporates small and low concentrated surfactant (2 % wt. of E(20)STO) and HPAM (2g/l) solutions integrated with injected steam. Surfactant was used to decrease interfacial tension, thus the capillary forces at the condensed water displacement front. HPAM improves displacement efficiency, and steam reduces the oil viscosity and the surfactant reduces the interfacial tension to form oil in water emulsion to enhance sweeping and recovery. The result is a significant reduction in the capillary number and a potential increment in oil recovery of almost 19.4 % IOIP than the conventional steam flooding. This possible increase in oil recovery was mainly attributed to the following two reasons: (1) combined effective mechanisms of oil recovery (reduction of oil viscosity, reduction of interfacial tension, and emulsification) and (2) better displacement efficiency of this process [14].

Conclusion

Based on the experimental results of this study, it can be concluded that the HPAM steam or surfactant steam is an effective technique that can produce more additional oil recovery than the conventional steam flooding. Furthermore, the surfactant/HPAM steam flood proved that it has higher and recoverable oil production than other techniques. The advantage of the surfactant HPAM steam technique over other chemical steam floods (HPAM or steam or surfactant /steam) is mainly due to some drawbacks of these methods. The results showed that water flooding ranges from 39.9% to 41.86%. When the core is proceeded by polymer/surfactant, additional oil has been recovered. The flooding experiments showed that the maximum oil recovery was obtained by using steam integrated with polymer/surfactant solution (64.3 %). In comparison, steam exhibited that oil recovery equals 59.2 % with surfactant and 58.1% with polymer at the same temperature (300 ºC). The new integration techniques are expected to be applicable in the reservoirs after water flooding, steam-flooded reservoirs, and many other reservoirs that are not amenable to other EOR processes.

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Conflicts of interest

There are no conflicts of interest to declare.

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