Study of Alternative Technology for Increasing Oil Recovery Factor on Mature Oil Fields

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Abstract– A determining factor in the development of mature oil fields is the natural depletion suffered by the reservoirs as a function of time. The use of technologies that allow the increase or sustainable maintenance of oil production is essential to achieve the development of these mature oil fields. Technologies such as polymer flooding, which allows to increase the energy of the reservoir, and increase the oil sweep. The objective of this work is to determine the best polymer injection scenario, if any, through the application of numerical reservoir simulation, in the mature oil field of the Ecuadorian coast, to increase the oil recovery factor. The scenarios will be simulated with data from level B of the Socorro formation of the mature oil field, partially hydrolyzed polyacrylamide polymers (HPAM) and sulfonated polyacrylamide AN125VHM will be used, at different concentrations and injection rates. Finally, the economic analysis will be carried out with the net present value (NPV) and the internal rate of return (IRR).

Keywords—Enhanced Oil Recovery EOR, Mature Oilfield, Oil Recovery Factor RF, Polymer Flooding, Numerical Reservoir Simulation.

I. INTRODUCTION

Once the primary and secondary recovery cycle has finished, the reservoir still contains 60% to 80% of the oil originally in place. Currently, the use of enhanced oil recovery (EOR) methods allows the extraction of significant additional volumes to those obtained by production through conventional methods. One of the EOR methods is polymer flooding, which is based on improving the mobility ratio of the displacing fluid, whether it is less than or equal to that of the displaced fluid.

Reference [1] indicates that polymer flooding reduces costs related to water management, the process requires less water to recover the same amount of oil than a simple water flooding recovery; therefore, costs related to water treatment and management are reduced. It is a cost effective EOR technique proven for over 40 years in commercial applications allowing an additional 5% to 15% oil recovery. The best commercial projects have increased about 1 barrel of oil for every \$1 to \$3 of polymer (onshore). According to this perspective, this work will help to determine if the project in the mature oil field of the Ecuadorian coast, Block 1, based on a practical and theoretical design of enhanced recovery, is feasible for its implementation.

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The productive life of the mature oil field of the Ecuadorian coast begins in 1991, being the Socorro producing formation, which is divided into four levels such as level B, level E, level C and level D.

The Socorro formation of the mature oil field has an original oil in place (POES) of 45.412x10^6 barrels of oil (or 45.412 MMbbl), whose levels have the following initial oil recovery factors: level D 8.25%, level C 11.45%, level B 13.51 % and level E 10%. The accumulated production as of April 30, 2011 is 1.7 MMbbl, and the remaining reserves are 2.8 MMbbl [2]. Since 1998, the main problem in the oil field arose, which was low oil production due to fluid and pressure losses.

The mature oil field has extraction systems such as mechanical beam pumping and swabbing, which are inefficient due to their low performance due to the lack of optimization in operation, which increases operation and maintenance costs. Currently, of the total number of wells drilled, 2% produce natural flow, 33% by swabbing and 65% by mechanical beam pumping [3]

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II MATURE OILFIELD DESCRIPTION

A. *Location*

The mature oil field of the Ecuadorian coast is located in the southern part of Block 1 in southwestern Ecuador, in the Province of Santa Elena, Canton Santa Elena, between the communes of San Pablo, Santa Rosa, Cerro Alto and Morrillo. Block 1 has an area of 4,000 km², of which 3,000 km² is offshore and 1,000 km² on land [2]; as shown in Fig. #1.

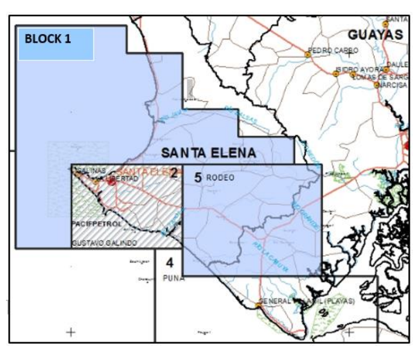

Fig. 1. Location of Mature Oil Field in Ecuador's Coast [4]

B. *Geology*

Block 1 is geographically located south of the Colonche fault that separates the Chongon Colonche mountain range from the Santa Elena Uplift/Progreso Basin. The mature oil field is an anticline structure, which has four main reservoirs within the Socorro Formation, from bottom to top they are denominated as: "E", "B", "C" and "D" respectively. It contains in its lithology fine-grained sandstone intercalated with shale, dolomite and siltstone, it has an approximate thickness of 1,480 ft. [5]. Table I shows the producing levels of the oil field, with their respective top and bottom.

TABLE I
TOP AND BOTTOM OF PRODUCING LEVELS OF THE MATURE OIL FIELD [6]

Formationn	Level	Top (ft.)	Base (ft.)
Socorro	D	1291	1330
	C	1577	1610
	B	2120	1610
	E	2.300	-----

C. *Petrophysics and Fluids*

Table II shows the main petrophysical and fluid characteristics of the Socorro Formation, for each of the producing levels of the field. According to Table II, Level B, among the four levels, presents the best petrophysical values to carry out the polymer flooding project; with high permeability and porosity, as well as lower water saturation and higher API gravity of the crude oil.

D. *Production Conditions*

The mature oil field is divided into 3 sections: North, Central and South. It has 46 wells, of which 39 are producers, 5 are closed, 1 is abandoned and 1 is a reinjector. The extraction mechanisms of producing wells are: mechanical beam pumping, natural flow and swabbing [7]. Table III shows the wells in the field with their respective production mechanisms.

The official POES (Original Oil in Place) of the oil field is 45.412 MMbbl, with an initial oil recovery factor by levels as shown in Table II. The original proven reserves have been estimated at 4.8 MMbbl, and the remaining reserves at 2.8 MMbbl [8].

The average production of the field is 40.51 barrels per day (bbl/d) of oil and 59.49 bbl/d of water, with an average reservoir pressure of 500 – 800 psi, an average BSW of 70%, average salinity of 22,000 – 42,200 ppm and a average API gravity of 36.4 [9].

III. POLYMER FLOODING

A. *Polymer flooding process*

According to Reference [1], polymer flooding is a profitable technique proven for more than 40 years in commercial applications allowing an additional oil recovery of 5% to 15%. The best projects have raised about 1 barrel of oil for every $1 to $3 of polymer (onshore).

Reference [10] indicates that the process usually starts with pumping water containing surfactants to reduce the interfacial tension between the oil and water phases and to alter the wettability of the reservoir rock to improve the oil recovery. Polymer is then mixed with water and injected continuously for an extended period of time (can take several years). When about 30% to 50% of the reservoir pore volume in the project area has been injected, the addition of polymer stops and the drive water is pumped into the injection well to drive the polymer slug and the oil bank in front of it toward the production wells. Fig. # 2 shown the illustration of the polymer flooding process.

Most of the polymers used for EOR fall into two sets: synthetic polymers and biopolymers. The most commonly used among them are synthetic (PAM) and partially hydrolyzed polyacrylamide (HPAM), the biological polysaccharide, Xanthan, and some modified natural polymers, including HEC (hydroxyl ethyl cellulose), guar gum and sodium carboxymethyl cellulose [11]. Every polymer has its own advantages and disadvantages for a specific reservoir.

TABLE II
PETROPHYSICAL AND FLUID PARAMETERS OF SOCORRO FORMATION [6]

Level	Thickness Ho (ft.)	Porosity ϕ (%)	Permeability k (md.)	Gravity API	Water resistivity Rw (ohm-m)	Water Saturation Sw (%)	Oil Recovery Factor RF (%)	Initial Pressure Pi (psi)	Actual Pressure Pr (psi)
D	39.38	16.5	114	34.3	0.19	41	8.25	649	320
C	34	16.8	286	34	0.24	11.45	11.45	966	520
B	25.4	25.4	444	40.8	0.2	13.51	13.51	968	490
E	35	21	-----	-----	0.21	10	10		------

TABLE III
WELLS OF THE MATURE OILFIELD AND THEIR RESPECTIVE PRODUCTION MECHANISM [7]

Wells		Production Mechanism	
Drilled	46	Producing	39
Producing	39	Natural flow	3
Reinjector	1	Hydraulic pump	4
Injector	0	Electro-submersible pump	0
Abandoned	1	Sucker rod pump	20
Closed	5	Swabbing	12

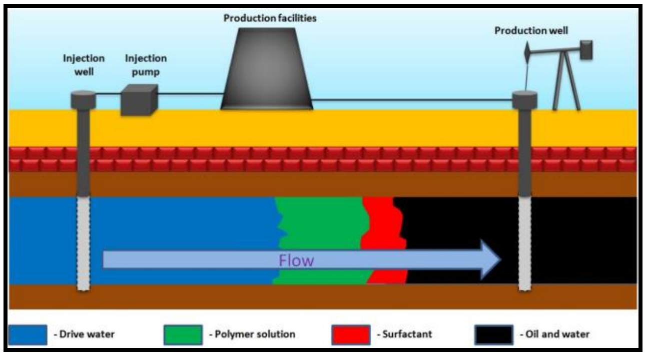

Fig. 2. Polymer Flooding Process [10]

B. Types of Polymers

PAM (Polyacrylamide) with its high molecular weight (> $1.0x10^6$ g/mol) was the first thickening agent used for aqueous solutions. PAM is stable up to 90°C at normal salinity and up to 62°C at seawater salinity. Therefore, it is somewhat restricted to on-shore operations only [11]. High salinity can reduce the viscosity properties of the PAM.

Partially hydrolyzed polyacrylamide (HPAM) is one of the most popular polymer used today. HPAM is obtained by partial hydrolysis of PAM or by copolymerization of sodium acrylate with acrylamide [11]. HPAM's advantages include its tolerance to high mechanical forces present during the flooding of a reservoir, low cost, and its resistance to bacterial attack. This polymer can be used for temperatures up to 99°C depending on brine hardness. A few of its modifications, such as HPAMAMPS co-polymers and sulphonated polyacrylamide can withstand 104°C and 120°C respectively [12]. The disadvantage of HPAM lies in its high sensitivity to the brine salinity, hardness and presence of surfactants or other chemicals. This makes it very ineffective in reservoirs containing salts [11]. In this work we use HPAM and the modification AN125VHM also known as Floopam.

Xanthan gum, a polysaccharide, is produced by different bacteria (one of which is Xanthomonas campestris) through fermentation of glucose or fructose. The molecule generally has very high molecular weight (2 – 50e6 g/mol) and very rigid polymer chains. This makes Xanthan gum relatively insensitive to high salinity and hardness. The polymer is compatible with most surfactants and other injection fluid additives used in tertiary oil recovery formulations. Xanthan gum is usually produced as broth in concentrated form that can be easily diluted to working concentrations without any complex mixing equipment. Xanthan is thermally stable in the range from 70°C to 90°C [11]. Nonetheless, this compound is very sensitive to bacterial degradation when injected into the field containing low-temperature regions in the reservoir. Furthermore, it has been reported that xanthan can have some cellular debris that cause plugging [12].

C. Mechanisms present in the reduction of the mobility ratio.

The advantage of adding polymer to the injection water can be explained by considering the mobility radius equation (M). The objective is to reach a value less than or equal to 1, so that the mobility of oil (λ_o) is greater than or equal to the mobility of water (λ_w) within the reservoir.

$$M = (k_w*\mu_o)/(k_o*\mu_w) \quad (1)$$

M: Mobility ratio

k_w, k_o: Effective permeability to water and to oil respectively.

μ_w, μ_o: Dynamic viscosity of water and oil respectively.

However, the decrease in mobility is not only due to the increased viscosity of the water, but also to retention mechanisms of the polymer molecules in the porous medium.

Retention. In terms of polymer flooding, it is the amount of the chemical agent that is retained in the porous medium, for which the adsorption of the solid surface and the entrapment in the porous space act.

Adsorption. It is an irreversible process in which the injected polymer adheres-retains in the rock due, among other reasons, to its chemical and electrical affinity with it. This process causes a decrease in the permeability of the rock to the flow of the aqueous phase and is correlated with the concentration of adsorbed polymer [13].

Resistance factor. It is the correlation between the mobility of water and the mobility of the polymer solution [13].

$$R_f = \lambda_w/\lambda_p \quad (2)$$

R_f: Resistance factor.

λ_w, λ_p: Water mobility and polymer mobility repectively.

Residual resistance factor. It is the water mobility ratio, which can also be expressed in terms of water permeability initially and after the injection of the chemical agent such as polymers [13].

$$R_{rf} = k_{wi}/k_{wa}$$

R_{rf}: Residual resistance factor

k_{wi}, k_{wa}: Effective permeability o water before and after water flooding, respectively.

Inaccessible pore volume. It is the total porous volume that is inaccessible to the polymeric solution, due to the difference in size between the polymer molecules with respect to the size of the pore throat of the rock. The inaccessible pore volume is assumed to be constant for each rock type in the model.

D. Screening for the design of polymer flooding.

Table IV shows the main criteria for the design of polymer flooding, according to Paris [14].

TABLE IV
SCREENING FOR THE DESIGN OF POLYMER FLOODING [14]

	Parameter	Criteria
Oil	API Gravity	> 25
	Viscosity	< 150 centipoise (cp)
	Composition	Uncritical
Reservoir	Residual oil saturation	< 10% of mobile oil pore volume
	Net thickness	Uncritical
	Depth	< 9,000 ft
	Mobility ratio	2 - 40
	Permeability	< 20 millidarcy (md)
	Heterogeneity factor	0.5 – 0.8
	Temperature	< 175 F – 240 F
Water	Salinity	Low
Lithology		Sandstones preferably, but can be used in carbonates Limestone with high porosity should be avoided.

IV. SIMULATION DESIGN

A. Software used in the simulation stage

The software used for the development of the reservoir simulation of this work is the STARS software belonging to the company Computer Modeling Group, CMG, and GMSH for the generation of contour and thickness surface maps. CMG STARS is ideal for the simulation of reservoirs with thermal-type processes and advanced processes, that is, it develops advanced modeling in processes that involve steam flooding, in-situ combustion, solvents and chemical products.

GMSH is a three-dimensional finite element mesh generator with an integrated CAD engine and post-processor. Its design goal is to provide a fast, lightweight, easy-to-use meshing tool with parametric input and advanced visualization capabilities. It is based on four modules: Geometric (CAD), Mesh, Solver and Postprocessing. They are prescribed interactively through the graphical user interface (GUI) or in text files using Gmsh's own programming language.

B. Level B contour design using GMSH.

From the isopach map of level B of the mature oil field (see Fig. #3), 639 points were defined with their respective coordinates, as well as depths and thicknesses. This information will be used in the CMG software for the creation of the static model. Fig. #4 shows the contour map created using GMSH.

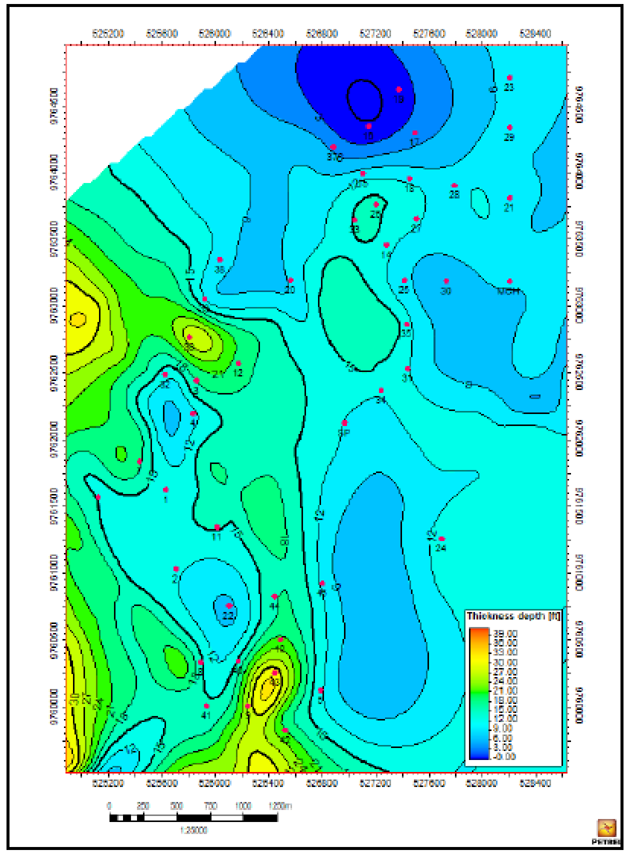

Fig. 3.Isopac Map of Level B [15]

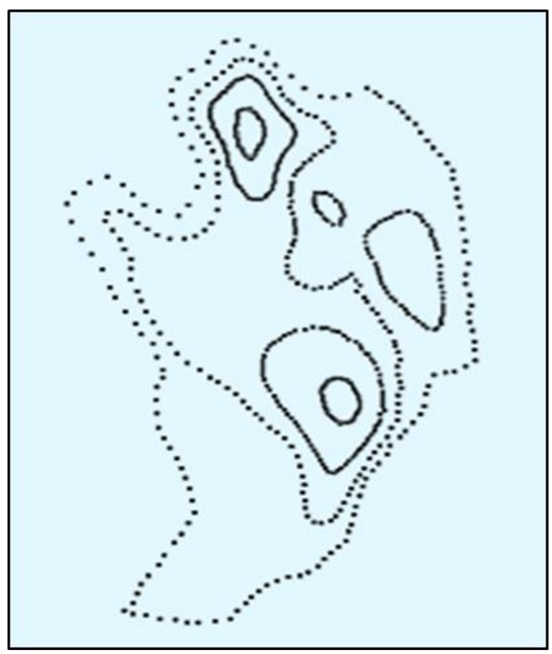

Fig. 4.Contour Map of Level B. GMSH Version 2020

C. Level B grid design using CMG

In the I/O Control module, the type of simulator is established, the units with which it is going to work, type of porosity and finally the date on which the simulation of the reservoir will begin. In this case, the STARS simulator is used, with field units, a single porosity since it is considered a homogeneous and isotropic reservoir, and the start date is January 1, 1992.

Using the information generated at each of the contour map points, the grid is created by choosing the orthogonal corner point grid type, and entering the dimensions 49 (I-direction) x 83 (J-direction) x 10 (K -direction), the K-direction specifies that the reservoir is divided into 10 layers in a downward direction. Also, that each block in direction I and J has a distance of 100 ft.

Once this information has been entered, the three-dimensional grid system for Level B of the oil field is generated in CMG, as shown in Fig. #5.

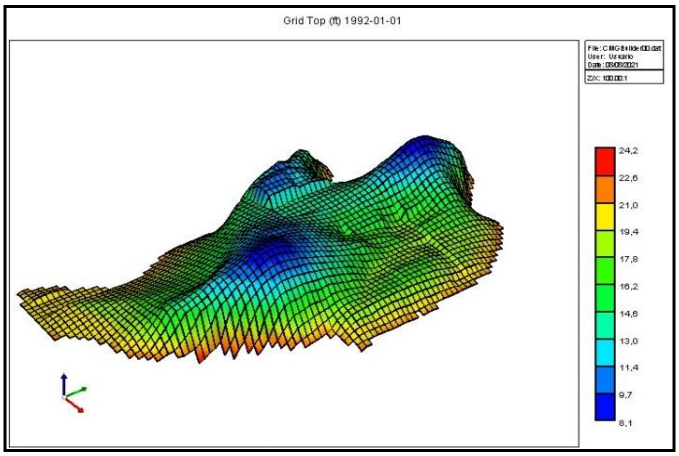

Fig. 5. Three-dimensional grid of Level B. CMG Version 2015.10

D. PVT properties and rock-fluid interaction

The average input values for the generation of the PVT properties of the oil field are shown in Table V.

TABLE V
AVERAGE PVT PROPERTIES FOR LEVEL B [6]

Reservoir Temperature (F)	Reservoir pressure (psi)	Bubble point pressure (psi)	Oil density (lb/ft^3)	Gas density (lb/ft^3)
97	600	400	40.8	0.772

The software, through the use of correlations, will generate the specific PVT properties for the Level B of the mature field. In the same way, CMG estimates the rock-fluid interaction characteristics for Level B.

E. Well operating conditions.

In this stage, the producing and injection wells are placed within the area of interest. The chosen arrangement is 5 inverted wells, where the injection well is in the center and 4 producing wells in the corners. The selected vertical wells in the field are: Pacoa 09, Pacoa 10, Pacoa 40, Pacoa 42, Pacoa 43, where the Pacoa 43 well becomes an injection well due to its low production.

The location of the wells, taking each one of the grid blocks as a reference, is shown in Table VI; likewise, the location of the wells in the grid is shown in Fig. #6.

TABLE VI
WELL LOCATION ACCORDING WITH GRID BLOCKS

Type of Well	Location	
	Start (I J K)	End (I J K)
Producing	23 52 1	23 52 10
Producing	27 33 1	27 33 10
Producing	17 46 1	17 46 10
Producing	33 54 1	33 54 10
Inyector	30 42 1	30 42 10

Once the wells have been located in the reservoir model, the well data is entered. The information of the producing wells is compiled with their production history, where the maximum surface oil rate is variable and for the injection well the maximum surface liquid rate and the bottomhole pressure are entered; this depending on the injection scenarios.

For this case study, the simulation time span will be 6 years. The start date will be January 1, 2021 and will end on January 1, 2027.

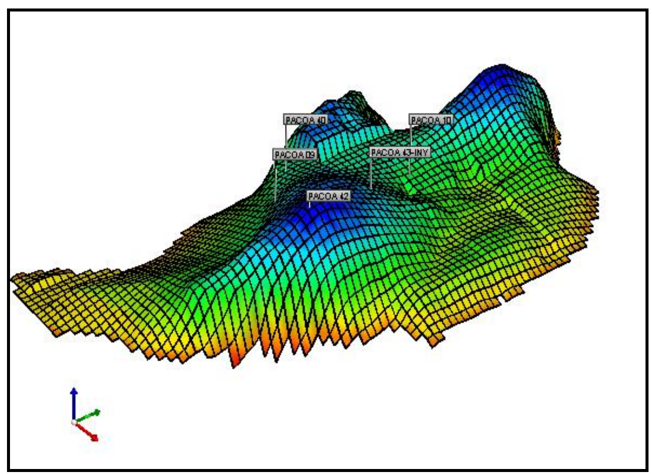

Fig. 6. Grid block with wells of Level B. CMG Version 2015.10

E. Polymer Characteristics.

As already mentioned, the two types of polymers to use are HPAM and AN125VHM, the parameters needed to create them in the simulator are the resistance factor and the Accessible pore volume. According to Reference [15], the Resistance factors for HPAM and AN125VHM is 3 in both cases; while the accessible pore volume is 0.7 for the HPAM, and 0.75 for the AN125VHM.

For the model, it is estimated that the quantity of the polymer does not decrease over time and that there is no variation in wettability; Polymer adsorption data (mg/100g rock) and polymer weight percentage are specific properties of each polymer and were established according to Reference [16].

Table VI shows the molar fraction values of the polymers for each of the concentrations to be studied in this work.

TABLE VI
MOLAR FRACTION VALUES OF POLYMER CONCENTRATION [17]

Concentration (ppm)	Molar fraction of HPAM	Molar fraction of AN125VHM
1,000	2.253889754e-06	1.502148794e-06
1,500	3.380832072e-06	2.253295319e-06
2,000	4.507765911e-06	3.004287656e-06

V. ECONOMIC EVALUATION

To meet the objectives of this project, a financial feasibility study was carried out on the application of this improved collection system. Said evaluation was carried out from January 1, 2021, until January 1, 2027. The financial tools Net Present Value (NPV) and Internal Rate of Return (IRR) were used for the technical scenario that generates the highest oil recovery factor; that is, because polymer flooding is a last recovery technique, so that after it is done, other techniques to recover residual oil would be very expensive. Each case study was evaluated using three different oil prices, pessimistic stage of USD 52, moderate stage of USD 61.72 and optimistic stage of USD 72.49. These prices are averaged over the last 8 months of 2021.

A range of acceptable and unacceptable was established, if the NPV is positive and the IRR is greater than 10%, then it is considered acceptable; if these two conditions are not met, it will be considered unacceptable.

Reference [18] indicates that the initial investment for chemical injection in Block I is USD 490,000.00; It also indicates that the cost of a barrel of water injected is USD 0.12. Other parameters that will be taken into account are production costs (on average USD 23.54/barrel) [19], polymer cost per barrel (depends on concentration), and treatment of produced water (USD 0.25/barrel) [20].

VI. RESULTS

A. *HPAM Case.*

Table VII presents the results of the oil recovery factor, using the HPAM polymer at different production rates and different concentrations, for the six years of simulation.

TABLE VII
OIL RECOVERY FACTOR AT THE END OF THE HPAM POLYMER FLOODING SIMULATION

	Oil Recovery Factor (%)		
Injection rate (bbl/d)	1,000 ppm	1,500 ppm	2,000 ppm
1,000	7.49	7.43	7.35
1,500	8.35	8.24	8.11
2,000	8.64	8.45	8.30

Fig. #7 shows the behavior of the oil recovery factor for a concentration of 1,000 ppm of polymer, and the different injection rates. Fig. #8 and Fig. #9 show the behavior of the oil recovery factor for concentrations of 1,500 and 2,000 ppm of HPAM polymer, respectively.

The results of the behavior of the injection rates show that with the increase in the injection rate, there is an increase in the oil recovery factor. In contrast, analyzing the results with respect to the polymer concentration, it is shown that the higher the polymer concentration, the oil recovery factor decreases; although, for this specific case of the mature field, the difference between the oil recovery factor results for the different stages is small.

Therefore, the optimal scenario for the HPAM polymer injection process is 1,000 ppm concentration at an injection rate of 2,000 bbl/d and an injection pressure of 1,500 psi, which shows an oil recovery factor of 8.64%.

B. *AN125VHM Case.*

Table VIII presents the results of the oil recovery factor, using the AN125VHM polymer at different production rates and different concentrations, for the six years of simulation.

TABLE VIII
OIL RECOVERY FACTOR AT THE END OF THE AN125VHM POLYMER FLOODING SIMULATION

	Oil Recovery Factor (%)		
Injection rate (bbl/d)	1,000 ppm	1,500 ppm	2,000 ppm
1,000	7.28	7.32	7.35
1,500	8.17	8.22	8.23
2,000	8.79	8.84	8.84

Fig. #10 shows the behavior of the oil recovery factor for a concentration of 1,000 ppm of polymer, and the different injection rates. Fig. #11 and Fig. #12 show the behavior of the oil recovery factor for concentrations of 1,500 and 2,000 ppm of AN125VHM polymer, respectively.

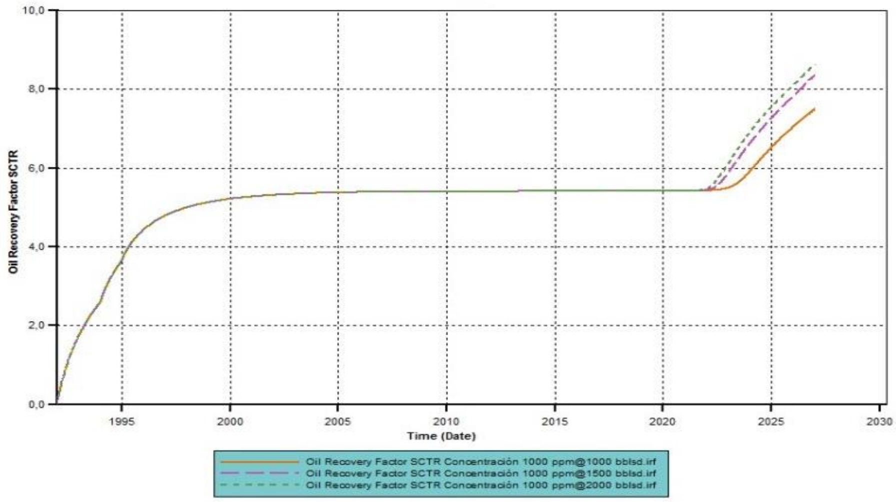

Fig. 7. Oil Recovery Factor for different injection rates of HPAM at 1,000ppm. CMG Version 2015.10

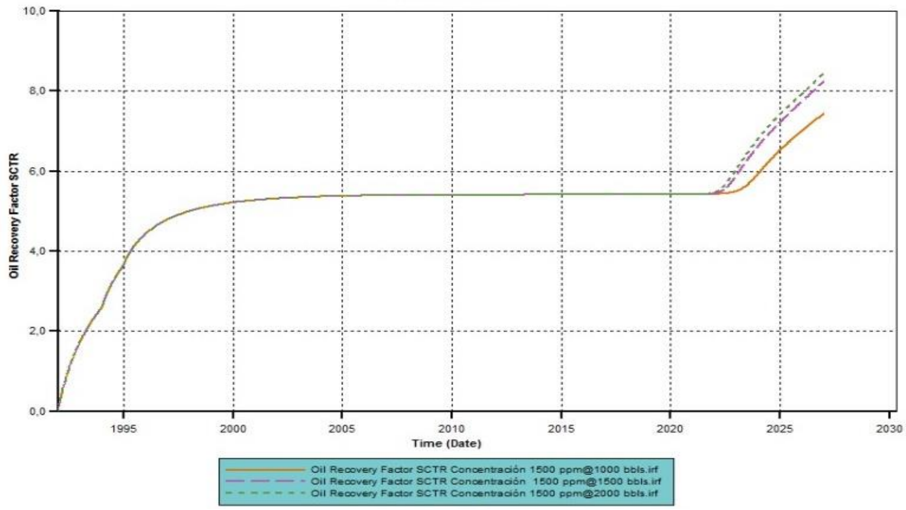

Fig. 8. Oil Recovery Factor for different injection rates of HPAM at 1,500ppm. CMG Version 2015.10

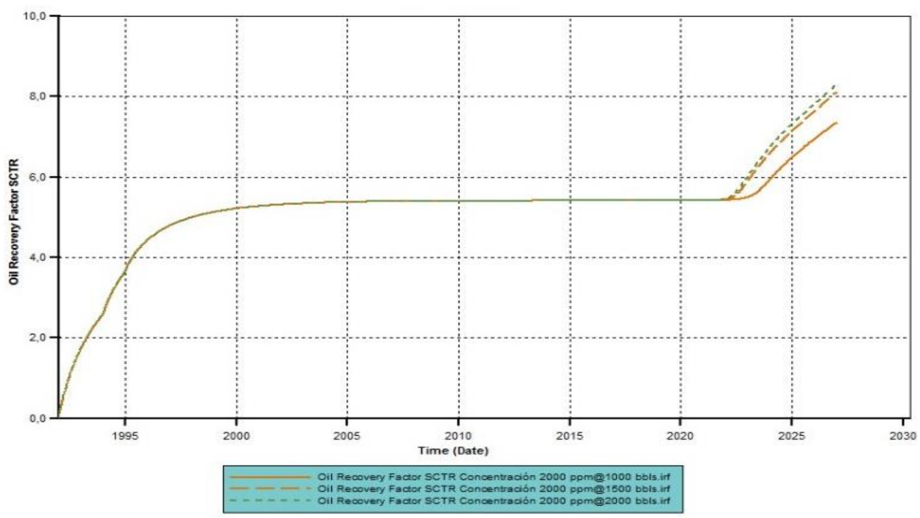

Fig. 9. Oil Recovery Factor for different injection rates of HPAM at 2,000ppm. CMG Version 2015.10

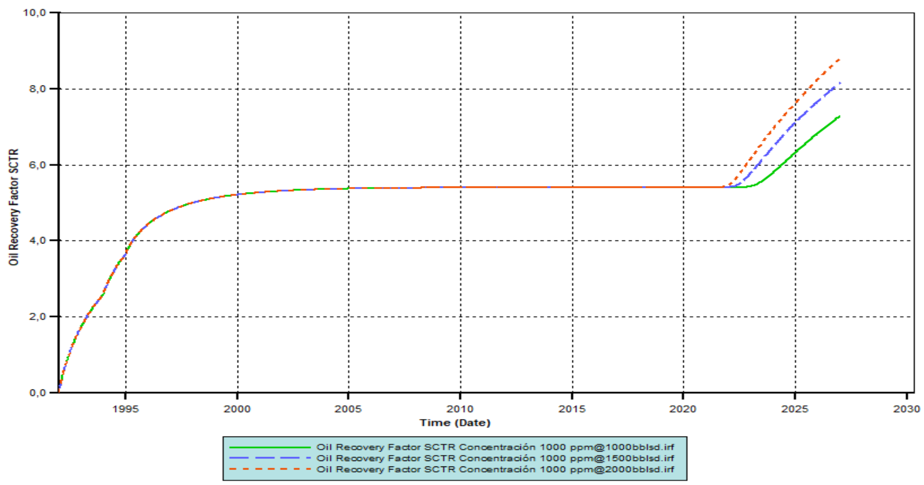

Fig. 10. Oil Recovery Factor for different injection rates of AN125VHM at 1,000ppm. CMG Version 2015.10

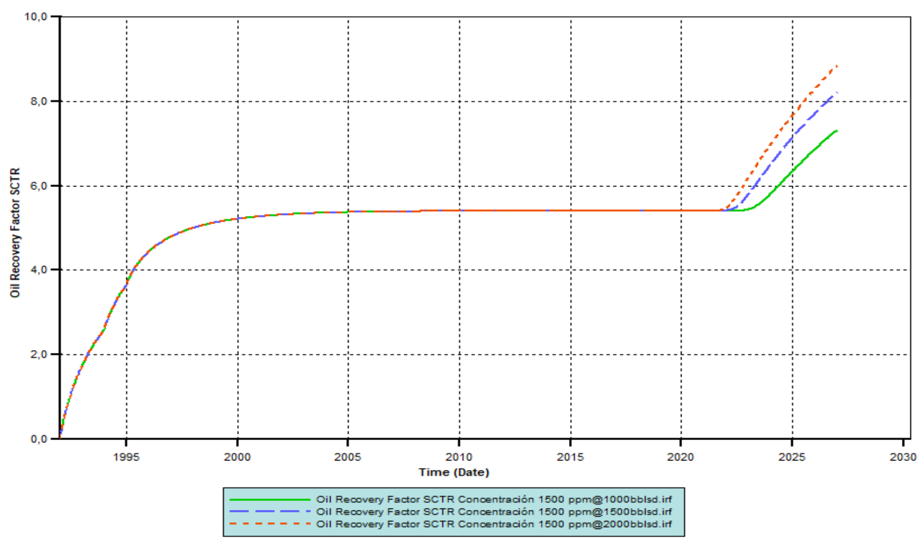

Fig. 11. Oil Recovery Factor for different injection rates of AN125VHM at 1,500ppm. CMG Version 2015.10

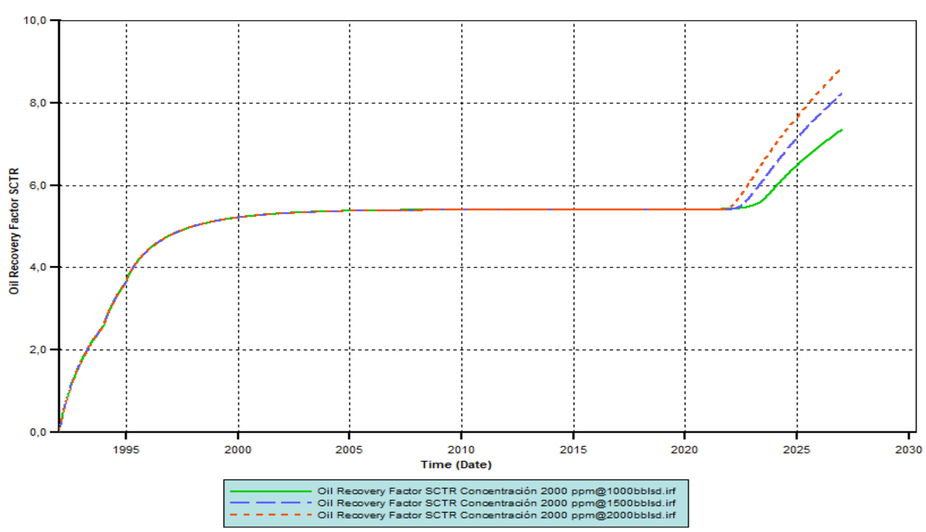

Fig. 12. Oil Recovery Factor for different injection rates of AN125VHM at 2,000ppm. CMG Version 2015.10

Therefore, the optimal scenario for the AN125VHM polymer flooding process is 1,500 ppm concentration at an injection rate of 2,000 bbl/d with a recovery factor of 8.85%.

C. Economic Evaluation.

Table IX shows the net present value and the internal return rate of the scenario chosen in the technical analysis of HPAM polymer injection, for the three oil price scenarios.

TABLE IX
ECONOMIC EVALUATION OF HPAM POLYMER FLOODING

	\$52.00/bbl	\$61.72/bbl	\$72.49/bbl
NPV(USD)	-647,737.02	-377,782.57	-78,666.38
IRR (%)	-----	-17	5
RANGE	Unacceptable	Unacceptable	Unacceptable

The economic analysis shows that although the favorable price scenario obtains a positive IRR, the net present value is negative, which is why it remains in the unacceptable range. In the price scenario of 61.72 dollars per barrel of oil, the NPV and the IRR are negative, so it is considered a non-stable scenario. In the case of the pessimistic price scenario, the IRR formula did not converge to a certain value, so it is also considered unacceptable.

Table X shows the net present value and the internal return rate of the scenario chosen in the technical analysis of AN125VHM polymer flooding, for the three oil price scenarios.

TABLE X
ECONOMIC EVALUATION OF AN125VHM POLYMER FLOODING

	\$52.00/bbl	\$61.72/bbl	\$72.49/bbl
NPV(USD)	-836,465.82	-579,297.83	-294,343.35
IRR (%)	-----	-36	-8
RANGE	Unacceptable	Unacceptable	Unacceptable

The economic analysis shows that under none of the scenarios considered positive values of NPV or IRR are obtained; therefore, for all three price scenarios, the AN125VHM polymer injection project is considered unacceptable.

VII. CONCLUSIONS

Analyzing of the graphs of the recovery factor of the HPAM polymer, a particular behavior was obtained with respect to the concentrations of 1,000, 1,500 and 2,000 ppm, denoting that while the concentration increases as a function of the injection flow rates of 1,000, 15, 00 and 2,000 bbl/d oil production tends to decline. Because if the polymer concentration increases, the water becomes more viscous, causing the mobility of the solution with respect to the oil to be low and a good sweeping efficiency is not achieved. Proving that this mature field, having light crude oil, does not need higher concentration values as in the cases of fields with heavy crude oil.

In the case of the HPAM polymer flooding simulation, an increase of 8.64% was obtained in the recovery factor of Level B of the mature oil field, the three oil barrel price scenarios were Unacceptable; this despite the low price of the polymer, but the production costs of a barrel of oil influenced the net present value to be negative in all cases.

For the case studies proposed, an arrangement of 5 inverted wells was defined and through the technical analysis of the tests carried out with the CMG program, it was determined that the technical application of the AN125VHM polymer injection is viable, since it is the one that obtained higher result of the recovery factor with a value of 8.85%; but based on the economic analysis carried out, it is not profitable for its implementation due to the high production costs in the field, in addition to the cost of the polymer.

Mature oil fields, having the particularity of presenting low production and high production costs, require new technologies that allow the recovery factor to be increased technically and economically; For this particular case, the chemical injection turned out to be very expensive compared to the estimated production, but it is encouraged to continue with simulation work on the different enhanced oil recovery techniques in order to optimize the production of these mature oil fields.

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