Original Article

Numerical Simulation by STARS (CMG) using Surfactants for Enhanced Oil Recovery in a Reservoir

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Abstract

In Ecuador, heavy crude oil represents 20% of the proven reserves at the national level. However, producing them has been challenging because of their low recovery factor due to their characteristics, high oil viscosities, and low mobility, among others. This makes developing and implementing improved or tertiary recovery methods and technologies necessary; therefore, the aim is to produce the maximum available resources in an environmentally friendly way. New advances in hydrocarbon extraction technologies in recent years have been tested and one of them, on which this research focuses, is using chemical methods in which solvents are injected to modify viscosity in aqueous solutions. Thus, displacing the oil generates very low interfacial tensions between the crude oil and water by adsorption in the liquid-liquid phase. Therefore, the selection of a reservoir that meets the required characteristics for the respective application of this method was carried out. Furthermore, increasing the sweep efficiency will optimize the mobility of the oil bank toward the producing wells, thus improving the recovery factor. Consequently, upon running the simulation, the results show that continuous surfactant flooding resulted in 84.5% recovery, SP flooding 89.4%, and ASP flooding with the highest recovery factor of 90.13%. This is due to the synergistic contribution of the IFT reduction using surfactant and the mobility ratio per polymer reduction, thus improving the overall sweep efficiency by a better margin. At the same time, alkali is responsible for decreasing the amount of the active surfactant used as it is a lower-cost agent [1].

Keywords: Enhanced oil recovery, STARS (CMG) software, Reservoir simulation and modeling, Surfactant injection.

INTRODUCTION

In Ecuador, new techniques are being sought for oil extraction, which cannot be extracted conventionally. Oil is the main source of energy in the world. Over time, its exploitation and production have decreased, promoting the implementation of new extraction techniques that increase recovery efficiency. Nowadays, to extract or increase production, it is necessary to assist the reservoir with enhanced oil recovery (EOR) methods or tertiary recovery. Surfactant substances can be used, which decrease the surface tension that often keeps the oil retained inside the pores of the rock, preventing the crude oil from moving quickly toward the producing well [1].

Considering the mechanisms of action of surfactant molecules, the interfacial tension in the water-oil system, the change in wettability of the rock, the decrease in surfactant adsorption in the pore throats of the reservoir and, consequently, a significant increase in capillary number.

These methods are used in mature oil reservoirs to maintain or increase the recovery factor. In addition, they optimize the flow of hydrocarbons from the reservoir to the well or recover more oil after primary and secondary recovery (water and gas injections) are not profitable through the application of heat and chemicals or solvents. Also, [1] and [20] point out that EOR is a process by which external energy and materials are introduced into the reservoir to influence the interfacial tension (IFT) between oil and water, fluid properties, wettability conditions, pressure gradient formation to prevail over oil retention and mobilization.

Flooding or displacement using surfactants is one of the most efficient techniques in chemical EOR since the 1970s, which mainly aims to recover residual oil between 20 and 40%; because they can significantly reduce the IFT (interfacial tension) and alter the wetting properties. It should be noted that in order to improve the crude oil recovery rate, the dimensionless capillary number, which is the ratio of viscous forces to inertia forces, should be increased ([21], [20]).

An ultra-low interfacial tension (IFT) between crude oil and formation water of about 0.001 mN/m is needed to increase the number of capillaries for efficient oil displacement. Similarly, the surfactant is generically referred to as soap. However, it is a contraction of the term surface active agent. It can adsorb at the interfaces of two immiscible phases (oil and water) and change the free energy of those interfaces. This is because surfactants have a hydrophilic and hydrophobic group in their structure. The hydrophilic group will attract water, while the hydrophobic group will attract oil by reducing the IFT between crude oil and formation water to improve oil recovery ([23],[20]).

However, it is important to know their classification:

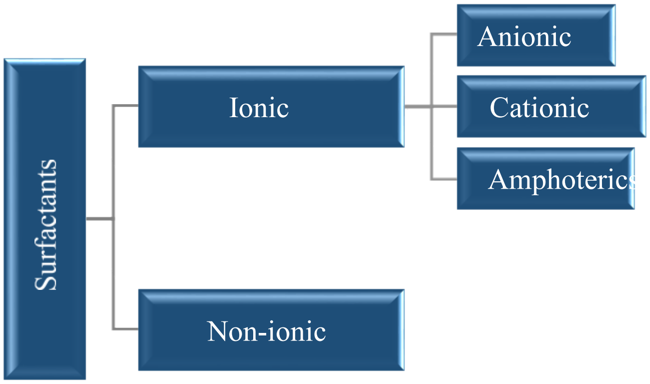


Figure 1 Classification of Surfactants [12].

However, the injection stages of a surfactant must be taken into account, which are:

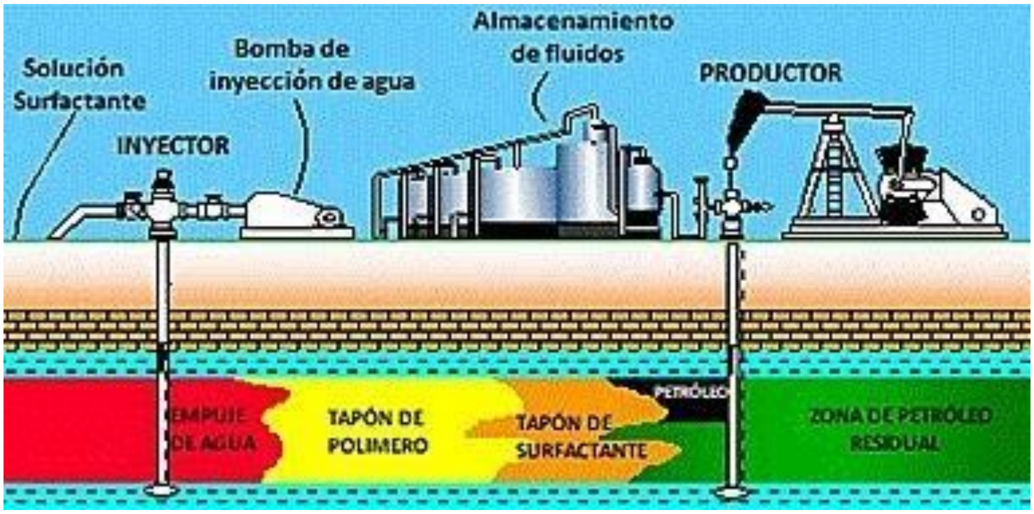


Figure 2 Surfactant Injection Stages

Adapted from [19]

1. Water Preflow
2. Surfactant
3. Polymeric Solution
4. Water

5. Displacement of the oil bank

Similarly, the final simulation tool that was considered and sequentially selected to model the experimental data was CMG's STARS simulator.

In the present study, a series of flooding experiments were conducted to find additional recovery using water, alkali, polymer and surfactant, thus determining a successful simulation using STARS software (CMG) and the results were compared with each other. Using a methodical approach to identify the best input values, simulation models were created for both water flooding or displacement and surfactant flooding, SP and ASP, which produced results that matched well with the experimental data. In addition, these models successfully matched both water cut and cumulative oil production (Figure 3).

Ultimately, understanding how to simulate surfactant behavior at the core scale will improve the ability to model surfactant flooding at the field scale.

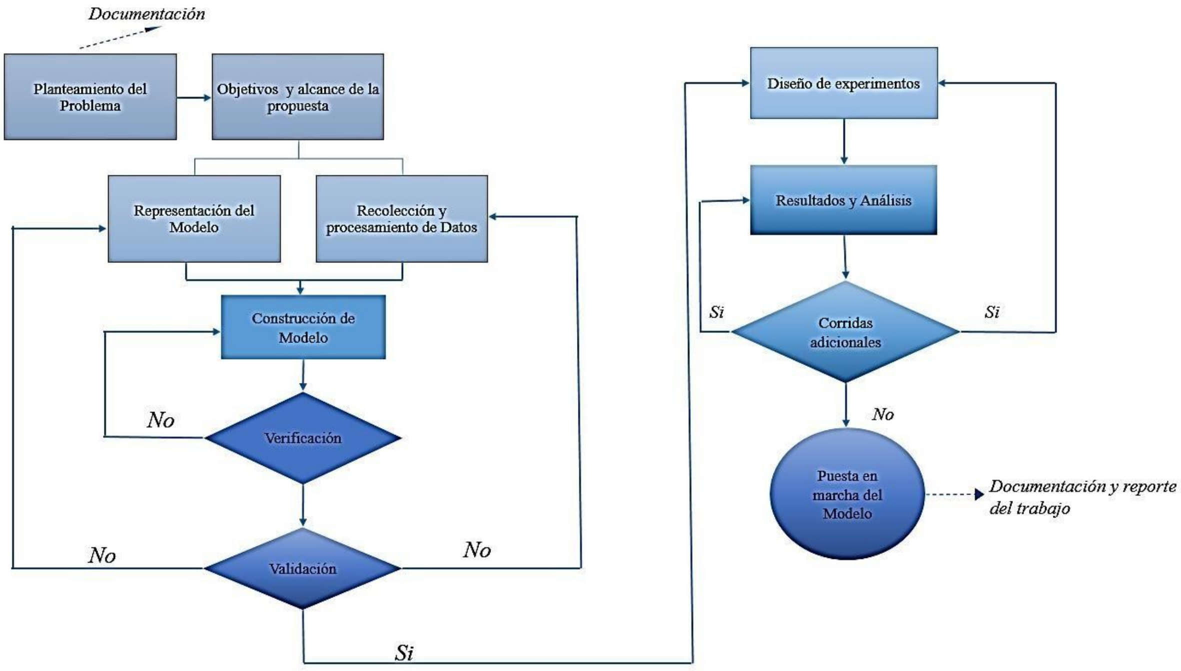


Figure 3 Flowchart of the Simulation Steps

Adapted from [22]

THEORETICAL FRAMEWORK

Heavy Crude

Heavy oil is a liquid oil of less than 20°API or more than 200 cp viscosity at reservoir conditions and is a somewhat mobile fluid under naturally occurring pressure gradients [18].

Equivalently, the crude oil used in this study is 10.5°API, which has a density between 1 and 0.92 g/cm3.

For this reason, heavy crudes are classified as follows:

Table 1. Chemical Classification Source: Adapted from [24].

	Density of oil fractions (gr/cm^3)		
Fractions	Paraffin base	Intermediate base	Naphthenic base
250 - 275 °C (@ P. Atm.)	> 0,8251	0,8251 - 0,8597	<0,8597
275 - 300 °C (@ 5,3 KPa.)	> 0, 8762	0,8762 - 0,9334	<0,9334

This research focuses mainly on chemical injection methods, considered a special branch of EOR processes to produce residual oil after water injection. Each of these chemicals is injected into the reservoir through injector wells to reduce capillary and interfacial forces in the reservoir and allow oil displacement in the porous medium.

A. Polymer Injection

It is one of the most cost-effective techniques used for more than 40 years, which allows an additional recovery of 5 to 15% of oil. The most common use is in water injection processes, increasing its viscosity and forming a plug of high molecular weight polymers to improve the water-oil mobility ratio, obtaining a better displacement and areal and vertical sweep.

In addition, the most commonly used polymers in the petroleum industry are:

- Polyacrylamides
- Biopolymer, and
- Semi-synthetics

B. Surfactant Injection

Surfactants are organic substances or salts formed from organic compounds in oil that alter wettability, decrease the surface tension between the dispersed and continuous phase, increase the solubility of oil in water or dissipate additives in water or oil. In addition, it reduces residual oil saturation, which is related to capillary number.

For a substance to be considered surfactant, it requires two groups:

- A polar (hydrophilic) dissolves perfectly in water (head), for example sugar, formic acid and urea. In addition, this group can have charged or uncharged groups.
- And another non-polar (hydrophobic), also called lipophilic (glue), dissolves in hydrocarbons, oils or fats; that is, it is insoluble in water. (See Figure 4).

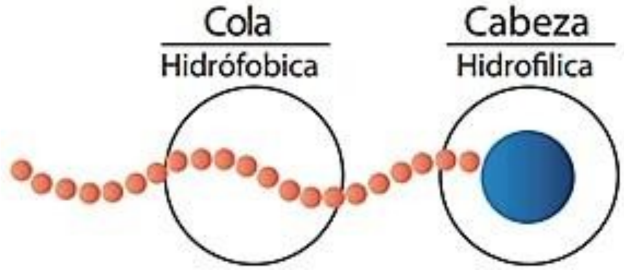


Figure 4. Surfactant Groups [10].

C. Alkaline Injection

Alkaline injection is a very complex method that uses an in situ emulsion process, where it is required to add to the injection water chemical substances such as caustic soda or sodium carbonate, sodium orthosilicate, ammonium hydroxide, sodium hydroxide, sodium hydroxide, sodium silicate between 0.1 - 2.5% or another product to increase the pH to values between 8 and 10, sodium silicate between 0.1 - 2.5% or another product to increase the pH to values between 8 and 10, which react with the organic acids contained in the oil in the reservoir, this contact generates surfactants, allowing the crude oil to be produced by mechanisms such as wettability change, reduction of the interfacial tension between the oil (displaced fluid) and the alkaline solution (the displacer), emulsification of the oil in water and oil trapping. Sometimes low tensions between 0.01 - 0.001 dyne/cm are obtained.

For the application of this method in heavy crudes, the concentration of the alkaline agent must be lower, between 0.1 and 1%, forming an emulsion with lower viscosity than the oil and optimizing the flow through the reservoir.

However, we must take into account that the injection of two or more chemical additives played an important role in this research, which are:

D. Injection of Mixtures of Chemical Additives a. Injection of Surfactants - Polymers (SP)

It consists of successively injecting different fluids and forming a plug with each one of them, which must move in a piston-like flow so that each new fluid must push the fluid that precedes it.

The use of a surfactant-polymer gives more oil recovery than an injection of surfactant alone due to the synergistic contribution of IFT reduction by the surfactant and mobility ratio reduction by the polymer ([8]).

b. Alkaline - Surfactant - Polymer Injection (ASP)

Defined as the combination of an alkaline system, surfactant and polymer designed to be used after water injection. This injection aims to reduce capillary and viscous forces to prevent hydrocarbon retention in the reservoir by controlling the reduction of interfacial tension and mobility of the displacement front.

Using alkali and surfactants helps to modify the interfacial tension between water and oil, increasing the capillary number (Nc) and thus improving the displacement efficiency; however, in the case of water viscosity, polymers are used. Therefore, using these three chemicals helps in better recovery than using them separately.

METHODOLOGY

In this study, a series of sensitivities were carried out, including generating waterfloods; using water, alkali, polymer and surfactants through reservoir simulation software, and from the results obtained, comparing each model and determining the best recovery factor.

Experimental waterflood sensitivities were developed using a base chemical simulation model for the reservoir named “Hope,” where the values used are obtained from different sources of information.

The simulator used is CMG with two applications; IMEX, a conventional black oil simulator and STARS, a new-generation thermal and advanced process reservoir simulator. In addition, Gmsh software was used to generate surface contour and thickness maps.

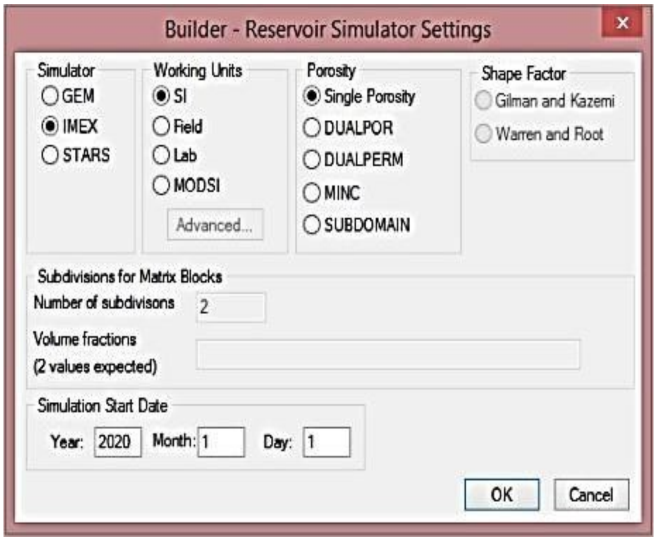
The following is a description of the creation of the simulation mesh, the type of simulator used and each component section.

A. Input/Output Control

This section includes information about the type of simulator, working units, porosity, and simulation start date, among others. For example, the simulation will start on January 01, 2020.

Types of simulation models.

There are different models or simulation modeling types, such as black oil, compositional and thermal models. In this case, the black-oil model is used because it applies to reservoirs with the presence of three phases: oil, gas and water [3] (Figure 5).



Builder - Reservoir Simulator Settings

Simulator
○ GEM
● IMEX
○ STARS

Working Units
● SI
○ Field
○ Lab
○ MODSI

Porosity
● Single Porosity
○ DUALPOR
○ DUALPERM
○ MINC
○ SUBDOMAIN

Shape Factor
○ Gilman and Kazemi
○ Warren and Root

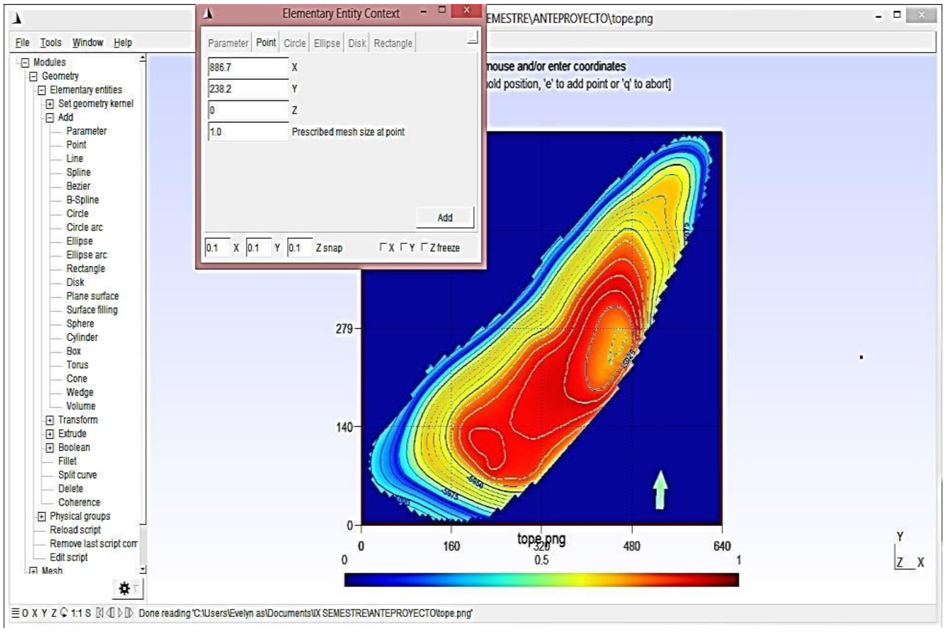
Subdivisions for Matrix Blocks
Number of subdivisons: 2
Volume fractions (2 values expected):

Simulation Start Date
Year: 2020 Month: 1 Day: 1

Figure 5. I/O Control Section.

Source: Iturralde et al. (2020).

Because one data is used, the tops and thicknesses of the contour maps were obtained using Gmsh software [1] (Figure 6).


Elementary Entity Context

886.7 X
238.2 Y
0 Z
1.0 Prescribed mesh size at point

0.1 X 0.1 Y 0.1 Z snap ☐ X ☐ Y ☐ Z freeze

EMESTRE\ANTEPROYECTO\tope.png

mouse and/or enter coordinates
old position, 'e' to add point or 'q' to abort]

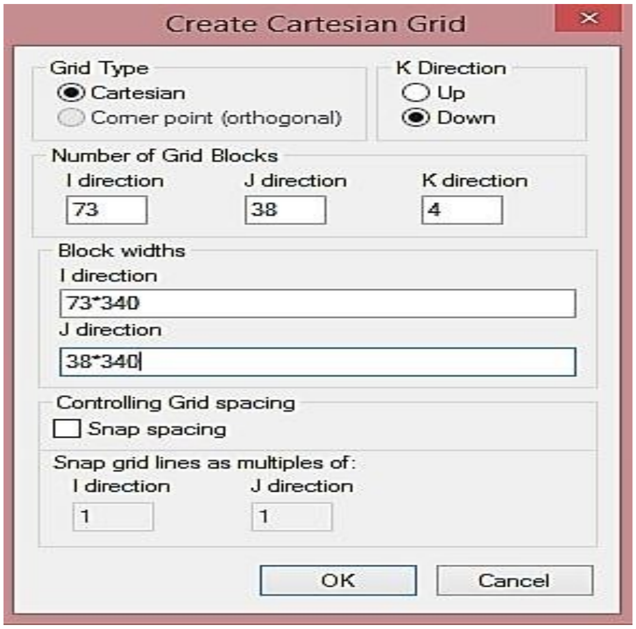
Done reading 'C:\Users\Evelyn as\Documents\IX SEMESTRE\ANTEPROYECTO\tope.png'

Figure 6. Construction of tops and thicknesses of the structure map in GMSH.

Source: Iturralde et al. (2020).

B. Reservoirs (Reservoir Description)

This section details the geometric characteristics of the mesh, formation properties, structure maps (tops and thicknesses), porosity, and permeability, among others. The type of mesh chosen is “Cartesian mesh,” although there are other types, such as regular, irregular, and structured meshes. In addition, the corner point geometry was specified as 75 (I-direction) x 38 (J-direction) x 4 (K-direction) (Figures 7 and 8).


Create Cartesian Grid

Grid Type
● Cartesian
○ Corner point (orthogonal)

K Direction
○ Up
● Down

Number of Grid Blocks
I direction 73
J direction 38
K direction 4

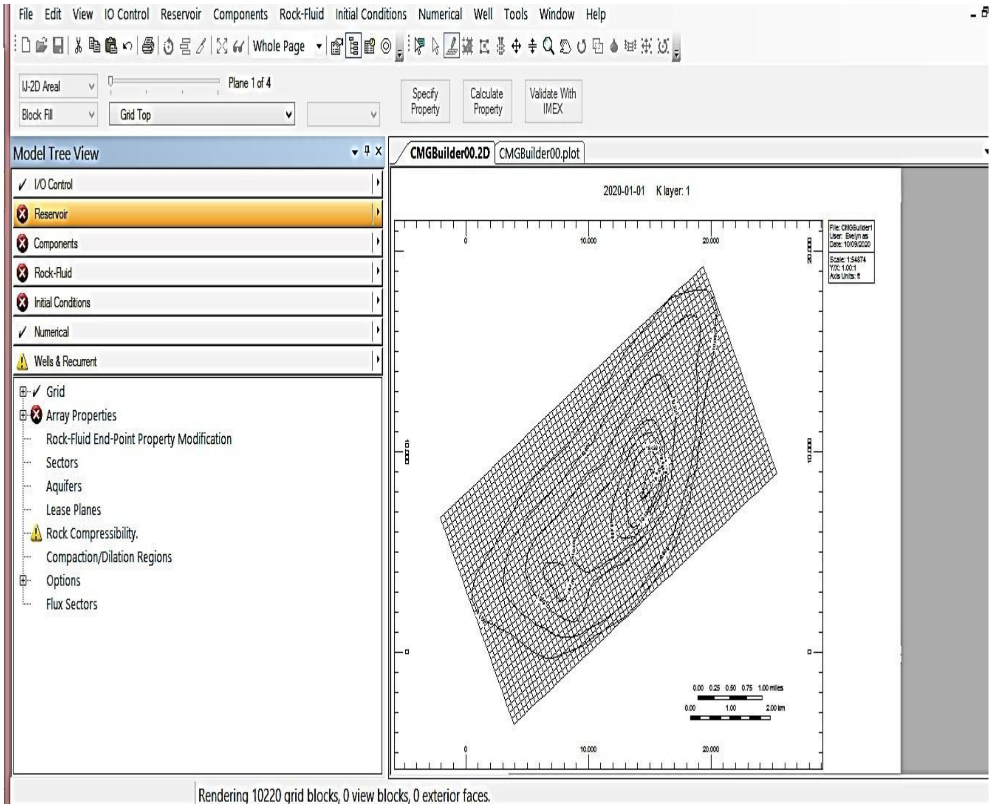
Block widths
I direction 73*340
J direction 38*340

Controlling Grid spacing
☐ Snap spacing

Snap grid lines as multiples of:
I direction 1
J direction 1

Figure 7. Meshing sizing

Source: Iturralde et al. (2020).



Rendering 10220 grid blocks, 0 view blocks, 0 exterior faces.

Figure 8. Contour map with Cartesian corner point grid

Source: Gutiérrez et al. (2020)

Rock properties

The general properties of the rock are specified, after which the following data sheet is displayed (Figure 9).

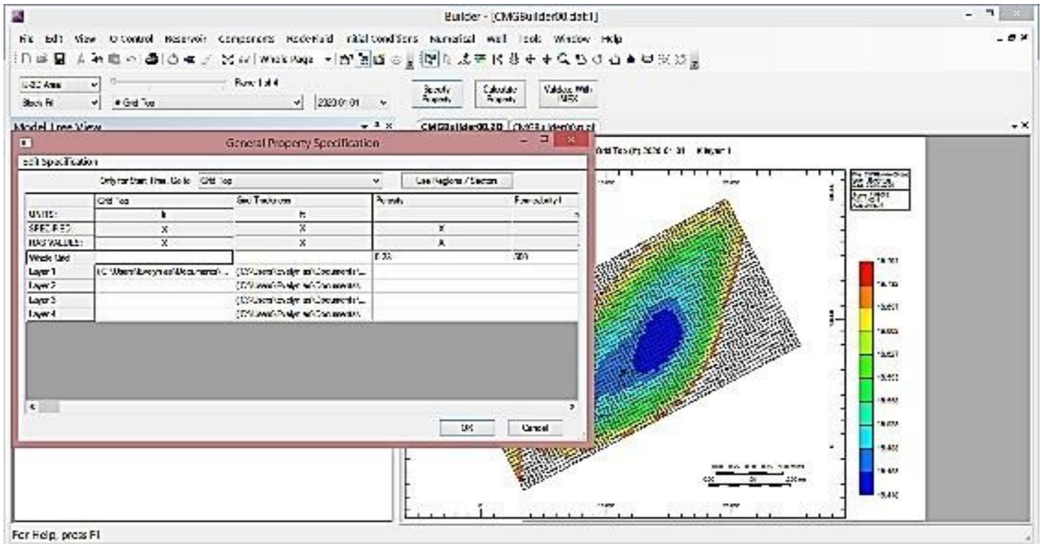


Figure 9. General properties specification spreadsheet

Source: Gutierrez, Benavides, Morales & Iturralde (2020)

In box 1 of layer 1, select Geological Map as the data source option and choose the file“To10flt_fld.bn”.

We repeat this action for the thickness of the mesh in cell 1 of layer 1, with the difference that we now select “Thickflt1.bn” in the values in the file box1. 25% of the total thickness of the map was also assigned for each of the four layers in the grid.

Finally, the calculations of each of these properties are carried out throughout the entire mesh (interpolation method).

C. Components

In this section, the PVT information of the fluid is entered (Table 2).

Table 2. Fluid properties

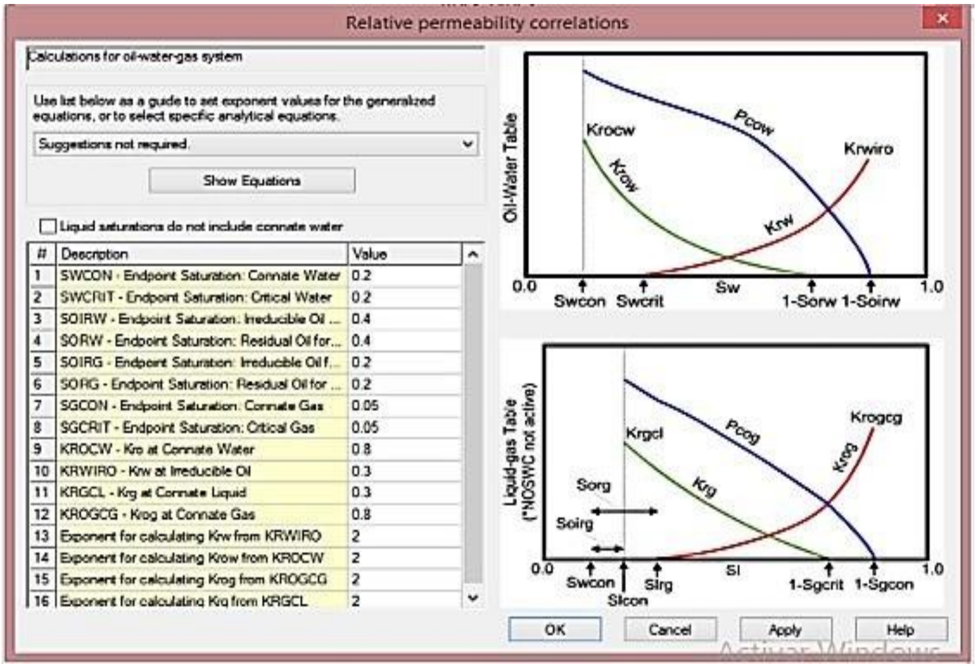
PROPERTIES	VALUE	RANGE
Reservoir temperature [°F] [°F	158	155 -195
Reservoir pressure [psi].	3450	3450
Bubble pressure [psi] [psi	1140	1140
API Gravity [°API] [°API	10,5	9,5 -11,5
Gravity specific to the gas	0,7	0,7
Dissolved gas ratio [PCN/BN].	105	100 -110
Water salinity [ppm] [ppm	1500-1300	1500 1300
Oil viscosity	112,5	100 -300

Source: Gutiérrez et al. (2020)

In this case, such data were generated using the information entered in the “Black Oil quick mode” window. However, it is also possible to enter or edit the values directly.

D. Rock-fluid interaction

Here, the types of processes that depend on the displacement and type of modeling (two-phase or three-phase), and wettability are detailed. In addition, the relative permeability curves are added (Figure 10).



Calculations for oil-water-gas system

Use list below as a guide to set exponent values for the generalized equations, or to select specific analytical equations.

Suggestions not required.

☐ Liquid saturations do not include connate water

#	Description	Value
1	SWCON - Endpoint Saturation: Connate Water	0.2
2	SWCRIT - Endpoint Saturation: Critical Water	0.2
3	SOIRW - Endpoint Saturation: Irreducible Oil ...	0.4
4	SORW - Endpoint Saturation: Residual Oil for...	0.4
5	SOIRG - Endpoint Saturation: Irreducible Oil f...	0.2
6	SORG - Endpoint Saturation: Residual Oil for ...	0.2
7	SGCON - Endpoint Saturation: Connate Gas	0.05
8	SGCRIT - Endpoint Saturation: Critical Gas	0.05
9	KROCW - Kro at Connate Water	0.8
10	KRWIRO - Krw at Irreducible Oil	0.3
11	KRGCL - Krg at Connate Liquid	0.3
12	KROGCG - Krog at Connate Gas	0.8
13	Exponent for calculating Krw from KRWIRO	2
14	Exponent for calculating Krow from KROCW	2
15	Exponent for calculating Krog from KROGCG	2
16	Exponent for calculating Krg from KRGCL	2

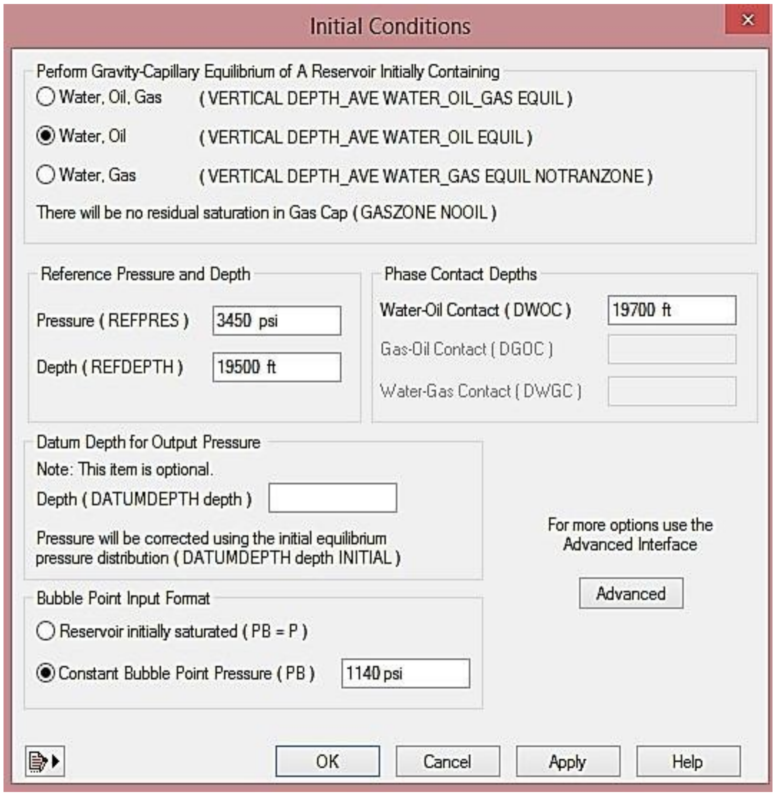
Figure 10. Relative Permeability Correlations

Source: Gutiérrez et al. (2020)

E. Initial conditions

This section specifies the reservoir pressure and reference depth data.

(average depth of the sand of interest); as well as the water-oil contact (Figure 11).


Initial Conditions

Perform Gravity-Capillary Equilibrium of A Reservoir Initially Containing

○ Water, Oil, Gas (VERTICAL DEPTH_AVE WATER_OIL_GAS EQUIL)

● Water, Oil (VERTICAL DEPTH_AVE WATER_OIL EQUIL)

○ Water, Gas (VERTICAL DEPTH_AVE WATER_GAS EQUIL NOTRANZONE)

There will be no residual saturation in Gas Cap (GASZONE NOOIL)

Reference Pressure and Depth

Pressure (REFPRES): 3450 psi

Depth (REFDEPTH): 19500 ft

Phase Contact Depths

Water-Oil Contact (DWOC): 19700 ft

Gas-Oil Contact (DGOC):

Water-Gas Contact (DWGC):

Datum Depth for Output Pressure

Note: This item is optional.

Depth (DATUMDEPTH depth):

Pressure will be corrected using the initial equilibrium pressure distribution (DATUMDEPTH depth INITIAL)

Bubble Point Input Format

○ Reservoir initially saturated (PB = P)

● Constant Bubble Point Pressure (PB): 1140 psi

For more options use the Advanced Interface

Figure 11. Initial Conditions

Source: Gutiérrez et al. (2020)

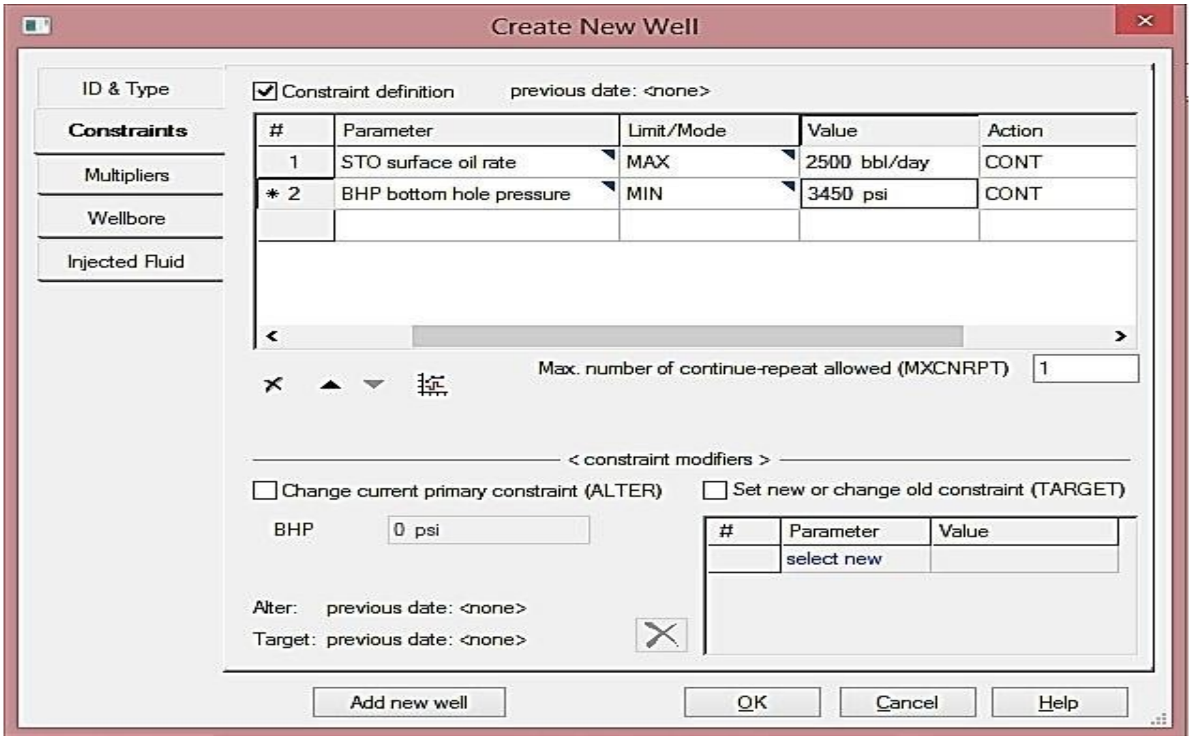
F. Numerical methods

Values, such as maximum time step size, pressure and saturation, and type of numerical method, are generated by default so that no different values are assigned.

G. Wells and recurring data

In this section, the good array is defined. In this case, a five-point pattern was used to perform the simulation. The industry's most widely used well model is the five-point pattern due to the significant advantage concerning the closest flow path. In addition, it consists of a straight line between the production well and the injection well, which means that it is a strongly conductive model; it also provides good areal sweep efficiency and is the most economical well pattern [1],[20]. The inverted five-point pattern has the injector well in the center, where the injected water sweeps the oil front remaining in the reservoir, and the injected water travels to the four producing wells [13] (Figures 12 and 13).

The first parameter of the producing wells at the start-up date is the maximum surface oil rate, 2500 Bbl/day, and the second is the bottom-hole pressure, 3450 psi [1].



☑ Constraint definition previous date: <none>

#	Parameter	Limit/Mode	Value	Action
1	STO surface oil rate	MAX	2500 bbl/day	CONT
* 2	BHP bottom hole pressure	MIN	3450 psi	CONT

Max. number of continue-repeat allowed (MXCNRPT) 1

< constraint modifiers >

☐ Change current primary constraint (ALTER)

BHP 0 psi

☐ Set new or change old constraint (TARGET)

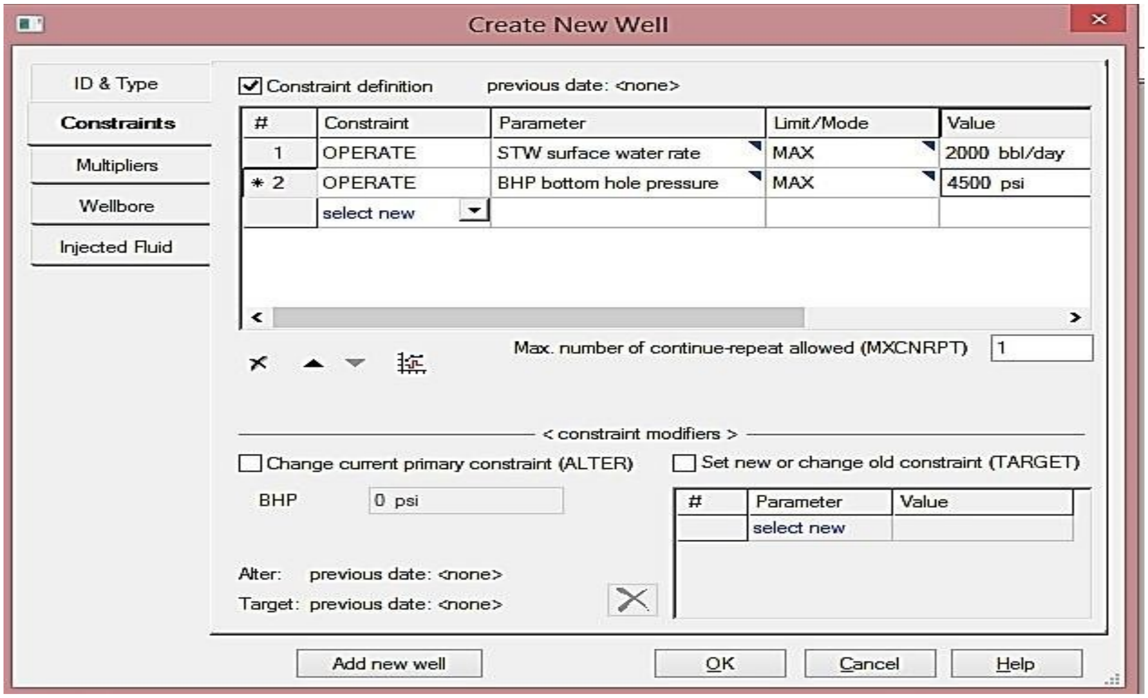
#	Parameter	Value
	select new	

Alter: previous date: <none>

Target: previous date: <none>

Figure 12. Producing well

Source: Iturralde et al. (2020).



☑ Constraint definition previous date: <none>

#	Constraint	Parameter	Limit/Mode	Value
1	OPERATE	STW surface water rate	MAX	2000 bbl/day
* 2	OPERATE	BHP bottom hole pressure	MAX	4500 psi
	select new			

Max. number of continue-repeat allowed (MXCNRPT) 1

< constraint modifiers >

☐ Change current primary constraint (ALTER)

BHP 0 psi

☐ Set new or change old constraint (TARGET)

#	Parameter	Value
	select new	

Alter: previous date: <none>

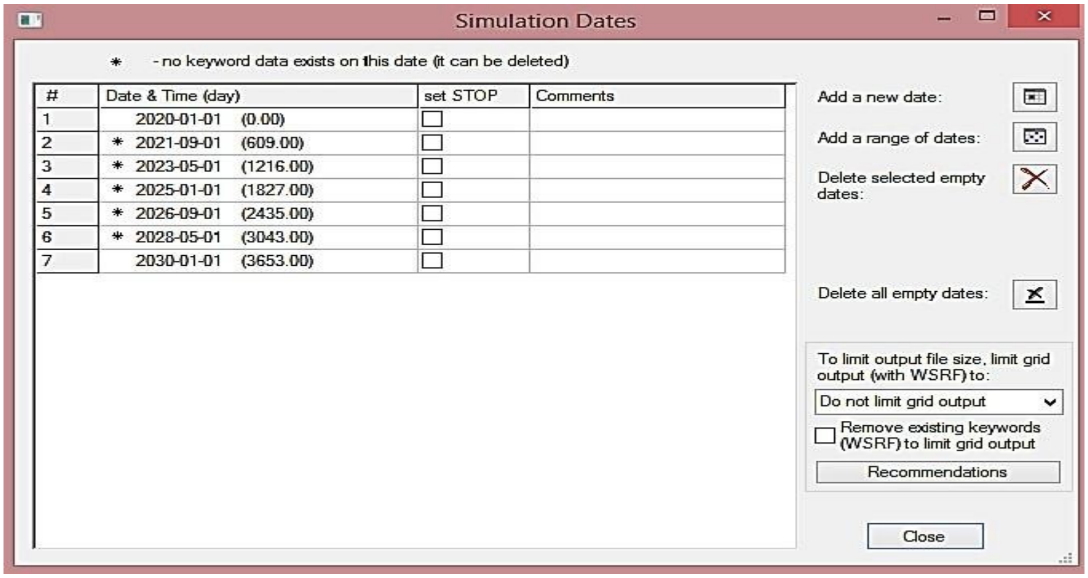
Target: previous date: <none>

Figure 13. Injector Well

Fuente Gutiérrez et al. (2020)

Dates

Here configuring the dates and times that the simulation will be carried out (Figure 14).



#	Date & Time (day)	set STOP	Comments
1	2020-01-01 (0.00)	☐	
2	* 2021-09-01 (609.00)	☐	
3	* 2023-05-01 (1216.00)	☐	
4	* 2025-01-01 (1827.00)	☐	
5	* 2026-09-01 (2435.00)	☐	
6	* 2028-05-01 (3043.00)	☐	
7	2030-01-01 (3653.00)	☐	

Do not limit grid output

☐ Remove existing keywords (WSRF) to limit grid output

Figure 14. Simulation Dates

Fuente Gutiérrez et al. (2020)

After this last section, the IMEX model is converted to the STARS compositional model to perform the surfactant injection study [1].

H. Creation of the Surfactant Component

In the components section, choose the ‘Process Wizard’ option and select the fluid package implicit in CMG STARS, in this case, ‘Alkaline, surfactant, and polymer model’ (Figure 15).

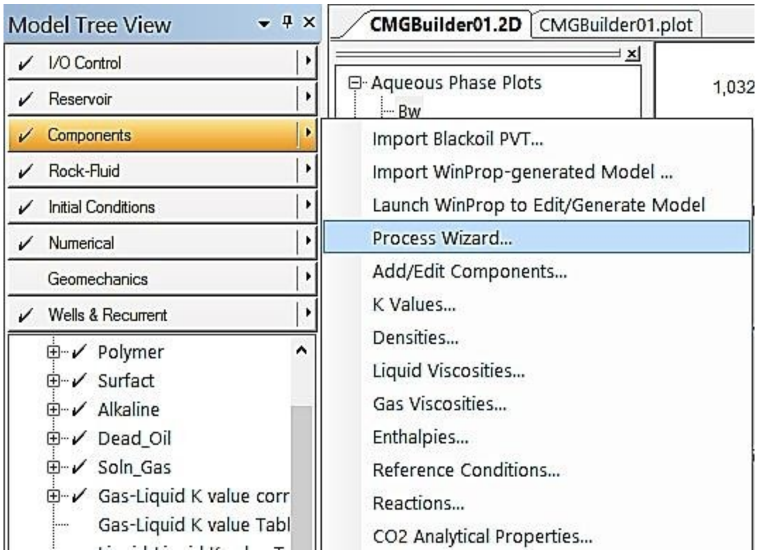
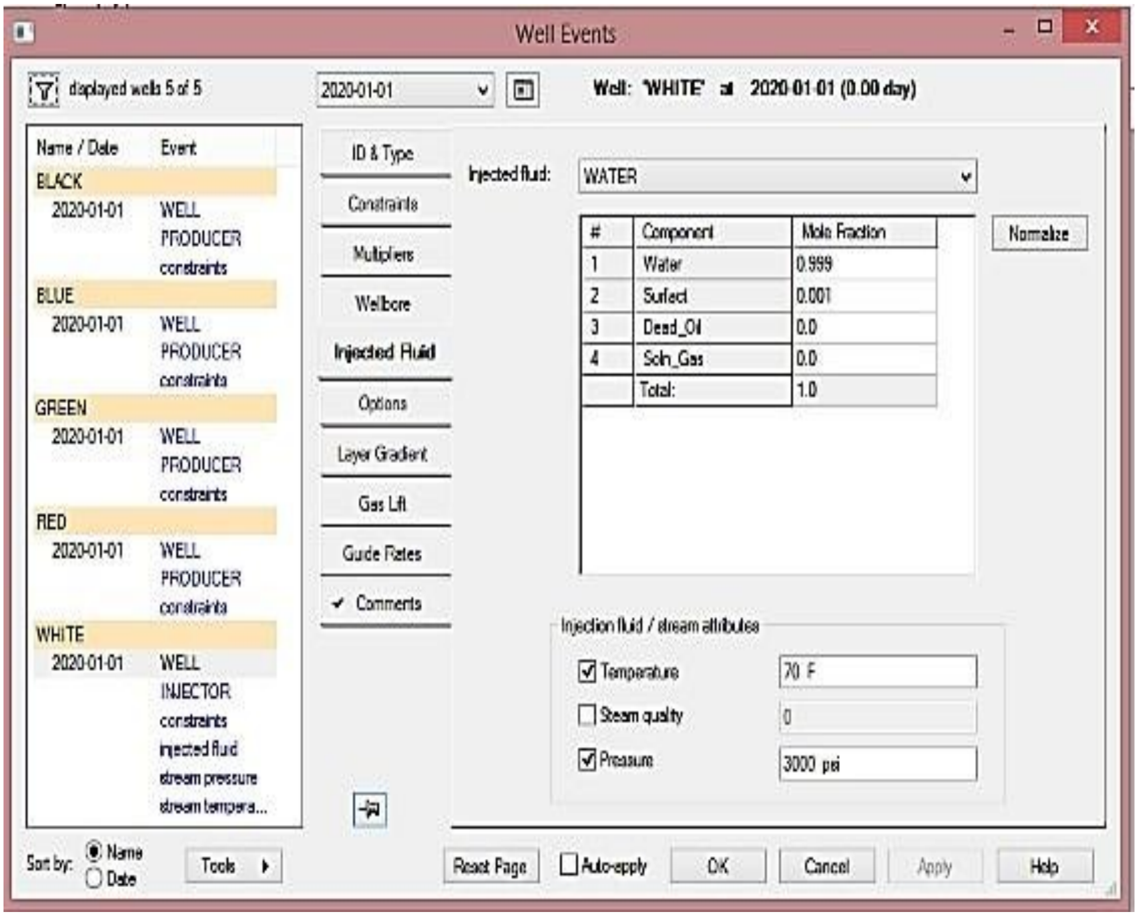


Figure 15. Menu for surfactant creation

Source: Iturralde et al. (2020).

Then, the model to be simulated is chosen, either surfactant injection (add 1 component), SP or ASP process. Finally, add the component and the rock region. Also, you will observe the different interfacial tension values for the concentration of surfactant, polymer or alkali. The selected component(s) will appear in the 'Injected Fluid section of Well & Recurrent' (Figure 16).



displayed wells 5 of 5

2020-01-01

Well: 'WHITE' at 2020-01-01 (0.00 day)

Name / Date	Event
BLACK	
2020-01-01	WELL PRODUCER constraints
BLUE	
2020-01-01	WELL PRODUCER constraints
GREEN	
2020-01-01	WELL PRODUCER constraints
RED	
2020-01-01	WELL PRODUCER constraints
WHITE	
2020-01-01	WELL INJECTOR constraints injected fluid stream pressure stream tempera...

Injected fluid: WATER

#	Component	Mole Fraction
1	Water	0.999
2	Surfact	0.001
3	Dead_Oil	0.0
4	Soln_Gas	0.0
	Total:	1.0

Injection fluid / stream attributes

☑ Temperature 70 F

☐ Steam quality 0

☑ Pressure 3000 psi

Sort by: ● Name ○ Date

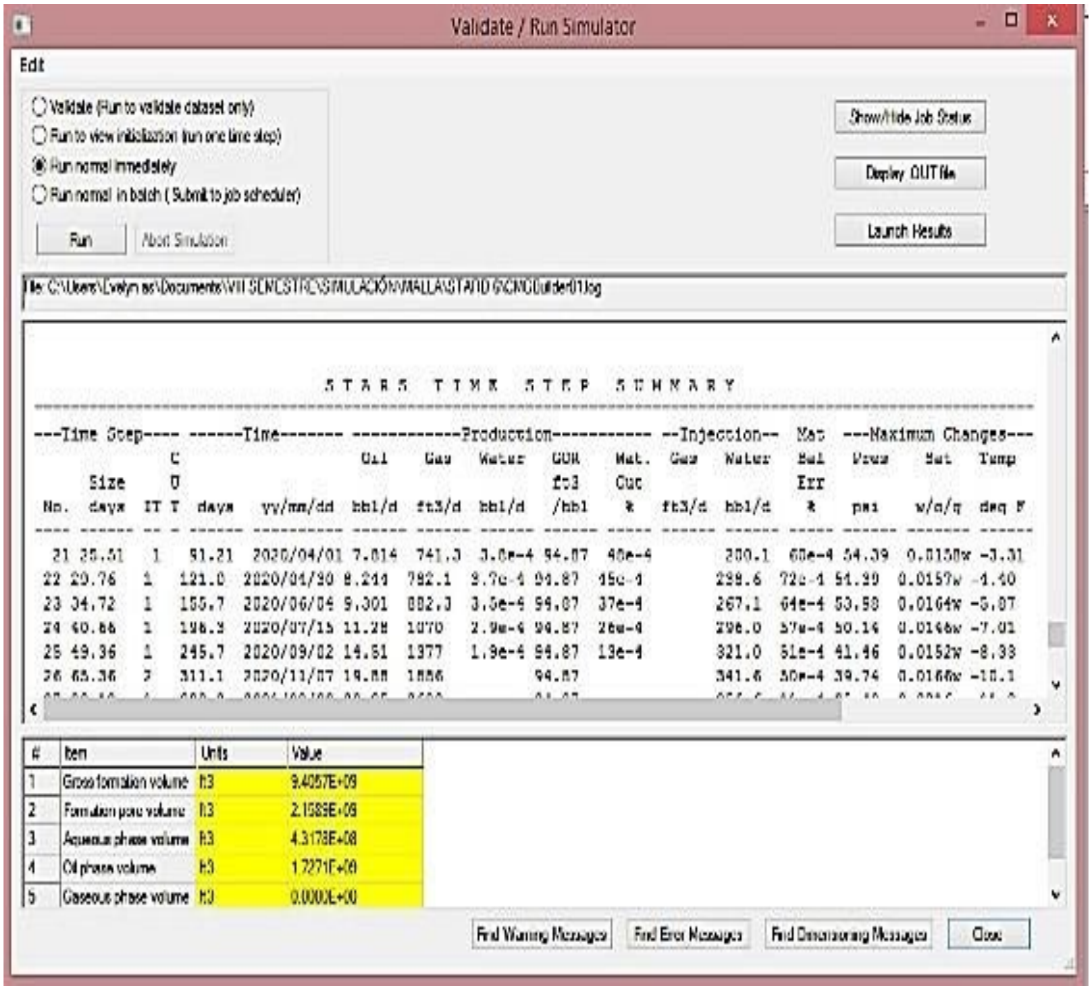
☐ Auto-apply

Figure 16. Characteristics of the fluid to be injected

Source: Gutiérrez et al. (2020)

Data Validation

In order to confirm that the information provided is correct, it is essential to validate the data, which is possible through the option 'Validate With STARS' and finally performs the run through 'Run normal immediately.' The file generates the simulation results, such as injection rates and production, among other parameters for each time interval. It will also report the total fluid production and injection, the number of warnings and errors, the iteration cycles required to solve the problem, and the simulation time [7] (Figure 17).



○ Validate (Run to validate dataset only)
○ Run to view initialization (run one time step)
● Run normal immediately
○ Run normal in batch (Submit to job scheduler)

File: C:\Users\Evelyn as\Documents\VII SEMESTRE\SIMULACIÓN\MALLA\STARD 6\CMGBuilder01.log

```
                                   S T A R S   T I M E   S T E P   S U M M A R Y
=======================================================================================================================
---Time Step---- ------Time------- ------------Production----------- --Injection--  Mat  ---Maximum Changes---
              C                     Oil    Gas    Water   GOR   Wat.  Gas   Water   Bal   Pres    Sat     Temp
      Size    U                                           ft3   Cut                 Err
 No.  days IT T  days   yy/mm/dd   bbl/d  ft3/d  bbl/d   /bbl    %   ft3/d  bbl/d    %    psi    w/o/g   deg F
---- ------ -- - ------ ---------- ------ ------ ------ ------ ----- ------ ------ ----- ------ ------- ------
  21 25.51   1   91.24 2020/04/01 7.814  741.3  3.8e-4 94.87  40e-4        280.1  68e-4 54.39  0.0158w -3.31
  22 29.76   1   121.0 2020/04/30 8.244  782.1  3.7e-4 94.87  45e-4        258.6  72e-4 51.29  0.0157w -4.40
  23 34.72   1   155.7 2020/06/04 9.301  882.3  3.5e-4 94.87  37e-4        267.1  64e-4 53.58  0.0164w -5.87
  24 40.66   1   196.3 2020/07/15 11.28  1070   2.9e-4 94.87  26e-4        296.0  57e-4 50.14  0.0146w -7.01
  25 49.36   1   245.7 2020/09/02 14.61  1377   1.9e-4 94.87  13e-4        321.0  51e-4 41.46  0.0152w -8.33
  26 65.36   2   311.1 2020/11/07 19.88  1886          94.87               341.6  50e-4 39.74  0.0166w -10.1
```

#	Item	Units	Value
1	Gross formation volume	ft3	9.4057E+09
2	Formation pore volume	ft3	2.1589E+09
3	Aqueous phase volume	ft3	4.3178E+08
4	Oil phase volume	ft3	1.7271E+09
5	Gaseous phase volume	ft3	0.0000E+00

Figure 17. Results of the simulation run

Fuente Gutiérrez, Benavides, Morales & Iturralde (2020)

RESULTS AND DISCUSSION

This section presents the results of sensitivities performed for CMG prediction, modeling or simulation (STARS).

Therefore, it must be considered that the injection time is 25 years, from January 2020 to January 2045. In addition, the simulation is carried out with a constant flow rate and concentration, with which it can be deduced that, with a higher volume of surfactant, it is possible to produce more residual oil after primary and secondary recovery [13].

The results obtained from the chemical process are accompanied by the results obtained from the water injection to establish the recovery factor's increase and determine the technical feasibility of implementing EOR methods [17].

To compare the recovery factors of the chemical processes, the case was first made based on primary recovery, showing the behavior of oil production, where the oil is produced by the natural energy of the reservoir.

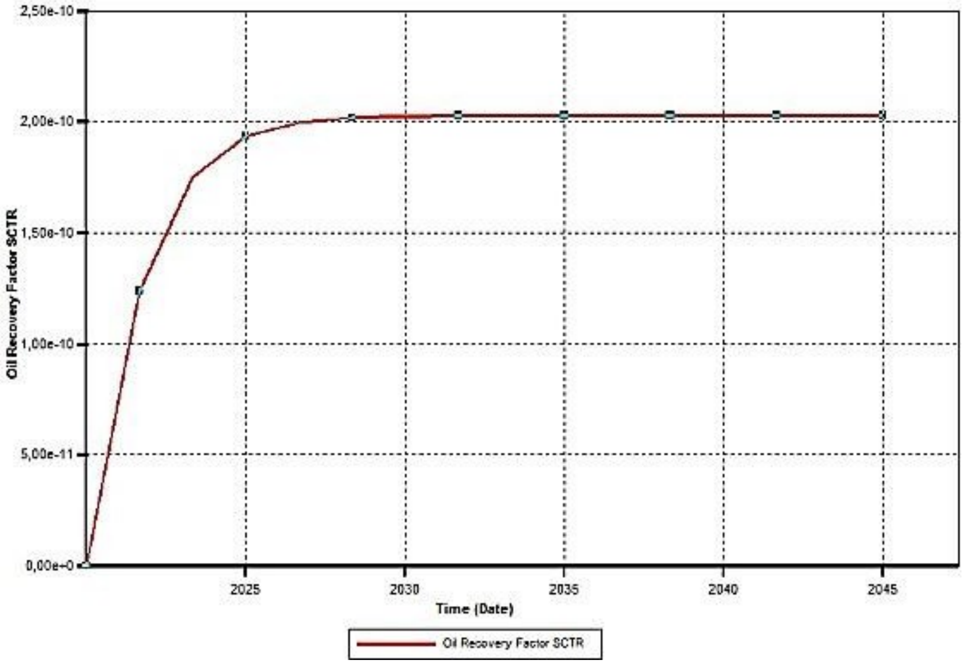


Figure 18. Recapture Factor - Primary Recoveries

Source: Gutiérrez et al. (2020)

After the primary oil recovery analysis, a secondary recovery is carried out, which is better known as the water flooding method used after the decline of the primary recovery, whose objective is to increase the natural energy to displace the oil (Figure 2).

However, suppose none of these methods is sufficient or is no longer useful. In that case, enhanced recovery is finally applied, being an application and optimization of advanced techniques in which the aim is to recover as much oil in situ (POES) without affecting the properties of the rock, introducing conditions or fluids that are not found in the reservoir and managing to control the phenomena causing the trapping of crude oil, wettability, fluid viscosity and interfacial tension (IFT) that exists between oil and water; because the reservoir may still contain 60 - 80% of POES after the application of previous recovery methods, thus avoiding well abandonment and economic losses.

However, some reservoirs contain crudes that cannot produce naturally or by a secondary mechanism, so they directly use an enhanced recovery method; that is, depending on the type of crude oil, the application of each mechanism depends on the type of crude.

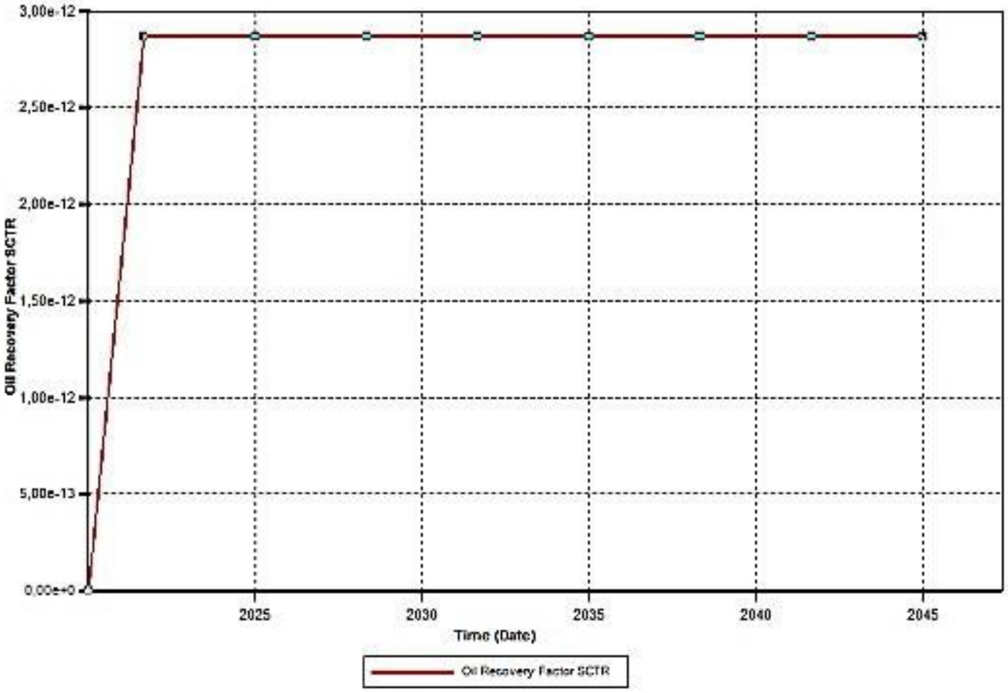


Figure 19. Recovery Factor - Secondary Recovery

Source: Gutiérrez et al. (2020)

After the reservoir tolerated water flooding under optimal conditions, only 2.8684 ∗ 10−10 % of the oil was recovered. However, when the surfactant is injected, oil recovery can increase up to 84.5% depending on the surfactant concentration; in this case, it remained at 0.1% by weight. (Figure 3).

Since this chemical injected decreases the interfacial tension and mobilizes the residual oil, which creates an oil bank where oil and water flow continuously, the main objective is to recover the residual oil between 20 and 40% of the porous volume.

It should also be noted that some projects fail because the interfacial tension is not reduced enough for the oil to move, and not be displaced by the injected fluid.

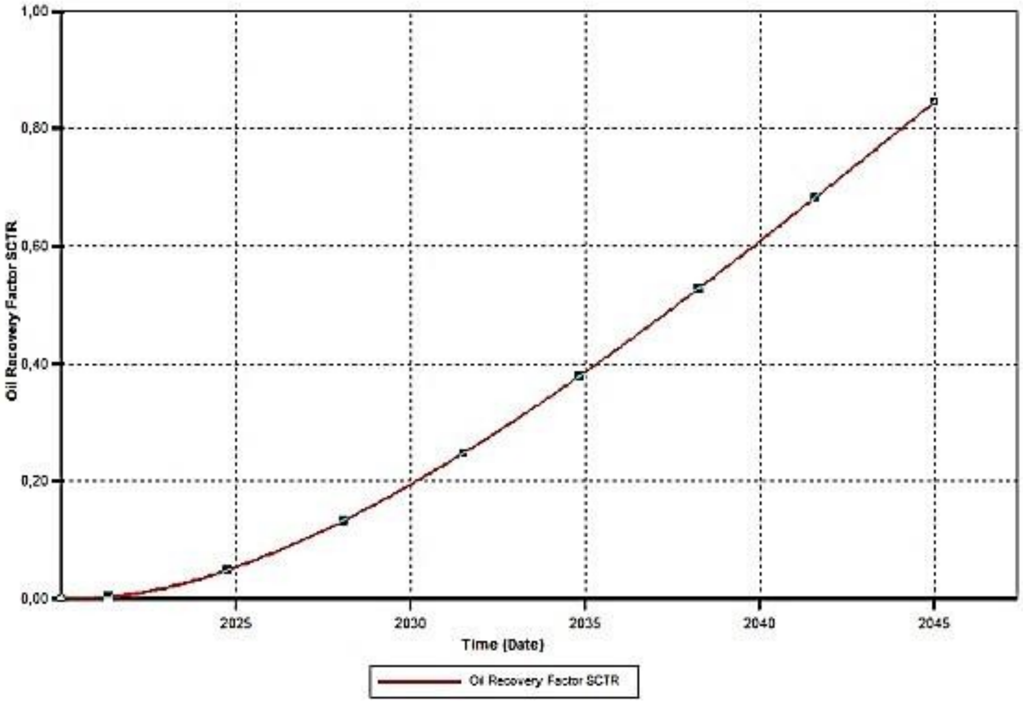


Figure 20. Recovery Factor - Surfactant Injection

Source: Gutiérrez et al. (2020)

The SP method is one of the most attractive for heavy crude oil reservoirs; its application implies high costs as it is a combined procedure, which is why the recovery factor must be considerably higher than other methods (Figure 4).

The use of a surfactant-polymer gives more oil recovery than an injection of surfactant alone due to the synergistic contribution of IFT reduction by the surfactant and mobility ratio reduction by the polymer (Farizal Hakiki, 2015)

Combining these two agents allows the remaining reserves to be displaced more effectively. Furthermore, the partial solubility of the surfactant in both oil and water allows it to be placed at the interface and accelerates oil mobility by reducing interfacial tension and capillary forces. On the other hand, the polymer increases the viscosity of the water, forming a continuous front that will prevent rapid interdigitation. Therefore, the union of these two processes increases viscous forces while capillary forces decrease, which causes an increase in capillary number, hence, an increase in recoverable reserves (Marcillo, 2015), mainly because each chemical agent fulfills a specific function.

The surfactant increases the mobility of the oil and decreases the interfacial tension between the fluids.

Finally, the polymer increases the water's viscosity and facilitates the oil's displacement toward the producing wells.

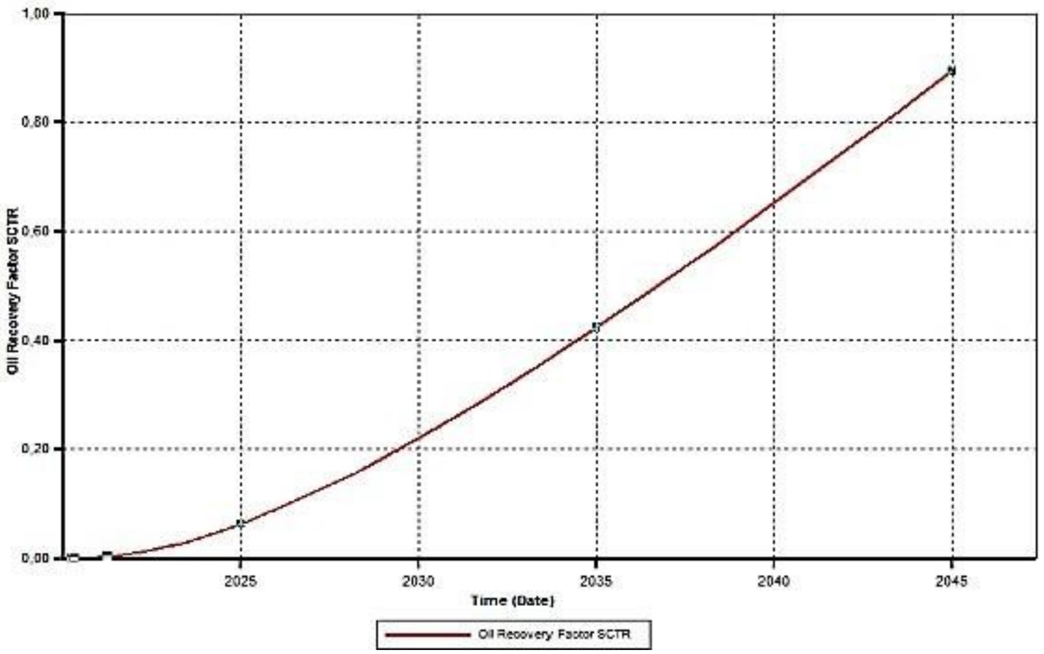


Figure 4. Recovery Factor - SP Injection

Source: Iturralde et al. (2020).

Finally, the ASP method is one of the most effective. However, the only limit to its implementation is the high costs because it is 40% more expensive than an individual procedure (see Figure 5).

This injection aims to reduce capillary and viscous forces to avoid hydrocarbon retention in the reservoir by controlling the reduction of interfacial tension and mobility of the displacement front.

One of the parameters that define the effectiveness of this process is the alkali since it is absorbed in the rock and prevents the adsorption of the surfactant and polymer, increasing its efficiency [14].

Similarly, using alkali and surfactants helps to modify the interfacial tension between water and oil, increasing the capillary number (Nc) and thus improving the displacement efficiency; however, in the case of water viscosity, polymers are used. Therefore, using these three chemicals helps in better recovery than using them separately.

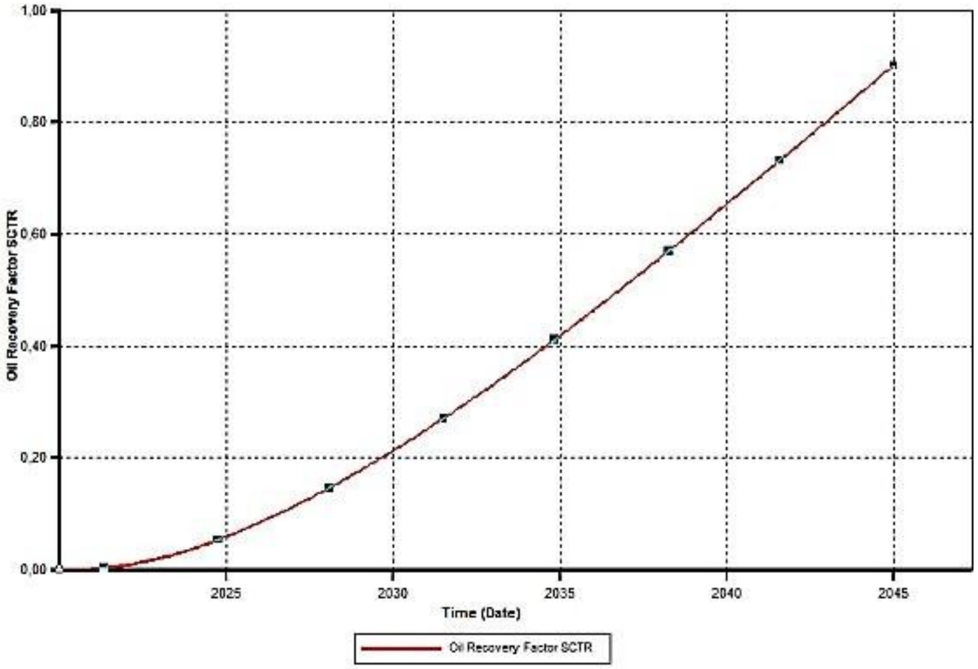


Figure 5. Recovery Factor - ASP Injection

Source: Iturralde et al. (2020).

The following table shows the total oil production in percentage and barrels for all stages of oil recovery under optimal conditions, where the best method is the ASP Injection scenario with a recovery factor of 90.13%, while the other scenarios showed a value below this.

Table 4. Total oil production in % and bbl for all stages of oil recovery under optimal conditions.

Recovery **method**		**Recovery factor (%)**	**Cumulative production of oil (bbl)**
Primary		$2.0283 * 10^{-8}$	0.000304923
Secondary		2.8684 * 10-10	0.00000431
Tertiary	**S**	84.5	2412800
	SP	89.4	2550000
	ASP	90.13	$2{,}574 * 10^{6}$

Source: Iturralde et al. (2020).

CONCLUSIONS

Surfactant flooding is an enhanced recovery method (EOR) applied when primary and secondary recovery is insufficient for oil recovery. This is because it has been shown to increase cumulative oil production after waterflooding. In addition, the longer the surfactant flooding period, the higher the oil recovery.

Depending on the nature of the reservoir, surfactant flooding has some degree of benefits. The main problem for this oil field is the high viscosity of the oil. Although surfactants act by reducing the viscosity of the oil. Optimized surfactant flooding only provides about a 5% increase in oil recovery after conventional methods, depending on the type of crude oil.

The additional oil recovery in the case of ASP injection was higher than when only surfactant was used. This is due to the synergistic contribution of IFT reduction using surfactant and reduction of mobility ratio per polymer, thus improving the overall sweep efficiency by a better margin, compared to surfactant injection, where only IFT reduction is available. At the same time, alkali is responsible for decreasing the amount of surfactant. Therefore, the results show that continuous surfactant flooding led to 84.5% recovery, SP flooding 89.4%, and ASP flooding with the highest recovery factor of 90.13%.

The percentage of water cut-off reaches 100% and decreases after using continuous surfactant flooding to 11.30%, in SP flooding to 12.32% and finally in ASP flooding to 12.76%.

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AUTHORS' CONTRIBUTIONS

Johanna Benavides Chalacán: research conception, methodology design, data validation, data analysis and interpretation, manuscript writing.

Evelyn Morales Villarroel: research conception, methodology design, data validation in the simulator, data analysis and interpretation, manuscript writing.

Marllelis del Valle Gutiérrez Hinestroza, Sadi Iturralde Kure, methodology design, data analysis and interpretation, drafting of the manuscript, critical revision of the intellectual content of the manuscript.

CONFLICT OF INTEREST

The authors declare no conflicts of interest related to this study. The sponsors had no role in the design of the study, in the collection, analysis, or interpretation of data; in the writing of the manuscript, or decisions to publish the results.

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