

Research Article

# Analysis of Enhance Oil Recovery Methods, A Comparative Approach to Determine the Suitable Eor Method for an Experimental Reservoir

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## Abstract

This study presents a comparison of three Enhanced Oil Recovery (EOR) methods—Surfactant/Polymer (SP) EOR, Hot Water Injection EOR, and CO<sub>2</sub> Gas Injection EOR—to identify the most suitable technique for application in an experimental reservoir using simulated data of the reservoir. The methods were evaluated based on key performance indicators, including cumulative oil and water production, oil recovery factor, and water cut. The results demonstrate that Surfactant/Polymer EOR achieves the highest cumulative oil production (0.047815 MMSTB) and oil recovery factor (92.2909%), making it the most effective method for maximizing oil extraction. However, this method also produces a higher volume of water, necessitating robust water management strategies. Hot Water Injection EOR, while effective in heavy oil reservoirs, yielded the lowest oil production (0.0269035 MMSTB) but minimized water production. CO<sub>2</sub> Gas Injection EOR provided a balanced performance with moderate oil recovery and higher water production. Based on the comparative analysis of the simulation results, Surfactant/Polymer EOR is recommended as the most suitable recovery method for the experimental reservoir due to its outstanding oil recovery potential and overall production performance. Nevertheless, successful implementation of this method would require proper planning and management of the increased water production to optimize operational efficiency and economic viability

## Keywords

EOR, CO<sub>2</sub>, Surfactant/Polymer, Hot Water Injection

## 1. Introduction

To improve the production of hydrocarbon fluids from already-producing reservoirs, petroleum-producing companies frequently seek new methods to increase recovery rates to the maximum. Enhanced Oil Recovery stands undoubtedly as the best option for this endeavour, representing a collection of advanced

procedures designed to extract as much remaining oil from reservoirs as possible than conventional methods allow [1].

Enhanced Oil Recovery (EOR) offers ground-breaking techniques to exploit the production of hydrocarbons beyond the limitations of primary and secondary production methods.

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Recovery enhancement technology in mature oil fields plays an exceptional role in supporting the long-term stable production of crude oil and is a top priority for sustainable and high-quality oil field development [2, 3]. This research focuses on analyzing three EOR methods and choosing the most suitable one for an experimental reservoir. This experimental reservoir consists of a single oil-producing well, as well as a single injection well. Past and present research on Enhanced Oil Recovery is reviewed with emphasis on the surface phenomena involved. The nature of capillary pressure phenomena in porous media has been understood for some time, and much research has been devoted to the alteration of the surface forces that prevent the efficient displacement of oil by water. Early work often treated surface-active agents as wetting agents designed to remove the oil from the solid surface by classical detergent action [4].

The surfactant work, current work in blob mechanics, current research in CO<sub>2</sub> flooding, and past results in alcohol flooding all indicate that an expanding oil phase is very important for effective oil displacement. Therefore, much current research is directed toward methods that utilise materials (including gases such as CO<sub>2</sub> and mobility control agents) to dislodge oil blobs, or to prevent their entrapment by maintaining a continuous oil phase and improving sweep efficiency during displacement. The general direction of future research on enhanced oil recovery is predicted [5].

According to legend, the first successful attempts to force oil from underground rocks by the injection of another fluid occurred by accident. Wells were often abandoned improperly, and surface water was allowed to enter the productive sand zone. The first deliberate water flood for oil recovery may have occurred before 1740 when "running water was used to produce crude oil from galleries cut into the rocks bearing strata of 'tar and sand' [2]. Early operators feared that water entering the productive zone would "drown" the oil wells, and for years, many states had laws that prohibited the injection of water into oil-producing sands. However, the increased production from waterflooding was observed consistently, and by 1940, it was considered to be "unquestionably the most efficient method ever devised for increasing oil recovery" [6]. Despite the enormous effectiveness of waterflooding, the early engineers soon realised that waterflooding still bypassed some oil. A patent was granted in 1917 for the addition of alkali to the flooding water, and by 1925, engineers were describing how the surface forces that were responsible for holding the oil in the rock might be altered for better oil recovery. This project examines some of the EOR methods that can be adapted for the experimental reservoir and analyzes how effective they will be for the increment of production of the remaining oil [7].

## 2. Methodology

This paper provides an overview of how the various EOR

methodologies affected the experimental reservoir. The sample data acquired was modeled with CMG Reservoir Simulation Software and simulated with Petroleum Expert's MBAL Simulator to predict the future performance of the field. The EOR methods to be discussed encompass Thermal, Chemical, and CO<sub>2</sub> Gas Injection techniques, each tailored to a common reservoir conditions and fluid properties to optimize oil recovery rates of the experimental reservoir.

### 2.1. Data After Primary Production

#### *Reservoir Parameters*

- 1) Reservoir Length: 1000 feet
- 2) Reservoir Width: 100 feet
- 3) Reservoir Height: 20 feet
- 4) Oil-Water Contact: 50 feet
- 5) Dip Angle: 0 degrees
- 6) Permeability: 100 md
- 7) Porosity: 25%
- 8) Connate Water Saturation: 25%
- 9) Cut-Off Water Cut: 99%
- 10) Reservoir Pressure: 2000 psi

#### *Fluid Parameters*

- 1) Oil Density: 50.0 lb/ft<sup>3</sup>
- 2) Oil Viscosity: 5.0 cP (centipoise)
- 3) Oil Formation Volume Factor (FVF): 1.05 RB/STB
- 4) Water Density: 60.0 lb/ft<sup>3</sup>
- 5) Water Viscosity: 1.0 cP (centipoise)
- 6) Water Formation Volume Factor (FVF): 1.0 RB/STB

#### *Injected Fluid Parameters*

- 1) Injected Fluid Rate: 200 STB/day

#### *Relative Permeability (Corey Function)*

- 1) Residual Saturation of Relative Permeability of Water (Swc): 20%
- 2) Residual Saturation of Relative Permeability of Oil (Sor): 30%
- 3) Endpoint of Relative Permeability of Water (krw max): 0.5
- 4) Endpoint of Relative Permeability of Oil (kro max): 0.5
- 5) Exponent of Relative Permeability of Water (nw): 2.0
- 6) Exponent of Relative Permeability of Oil (no): 2.0

### 2.2. Modelling

Data in Figure 4 was used to develop a comprehensive model of the reservoir, ensuring that it accurately represents the reservoir's physical and geological properties. This model served as the foundation for simulating various reservoir behaviors and scenarios, allowing for a thorough analysis of its performance under different conditions. By integrating the data into the simulation, the researchers were able to predict the reservoir's response to various injection and production strategies, thereby providing valuable insights for optimizing reservoir management and enhancing oil recovery.

### 2.2.1. Procedure for Modelling with CMG

- 1) The Reservoir Model:
  - a) Opened CMG Builder and created a new project.
  - b) Defined the reservoir grid by setting the dimensions (number of cells in X, Y, Z directions), and specifying the grid size to capture the reservoir's heterogeneity.
- 2) Assigning Reservoir Properties:
  - a) Imported and assigned petrophysical properties (porosity, permeability, net-to-gross ratio) to the reservoir grid.
  - b) Entered fluid properties such as PVT (Pressure-Volume-Temperature) data for oil, gas, and water phases.
  - c) Defined relative permeability and capillary pressure curves to model multiphase flow behavior.
- 3) Setting Initial Conditions:
  - a) Specified the initial pressure distribution and temperature across the reservoir.
  - b) Defined initial saturations of oil, gas, and water based on reservoir data.
- 4) Defined Boundary Conditions and Wells:
  - a) Set up boundary conditions to represent external influences on the reservoir (e.g., constant pressure or no-flow boundaries).
  - b) Entered well locations, trajectories, and completion details, including perforation intervals and well types (producers/injectors).
  - c) Specified well controls such as production rates, injection rates, or bottom-hole pressures.
- 5) Running the Simulation and documentation:
  - a) Executed the simulation by running the CMG simulator.
  - b) Monitored the simulation progress and ensured there were no errors or issues during the run. Documented the modelling and simulation process, including key assumptions, model parameters, and results.

### 2.2.2. Simulation

Data listed in Figure 5 were used to simulate enhanced oil recovery (EOR) methods using MBAL software. This tool will allow the researcher to model the reservoir's response to various EOR techniques, including Water Flooding, Thermal Injection, Chemical Injection, and CO<sub>2</sub> Gas Injection, by inputting the collected data into the software. MBAL helped analyze the effects of these methods on reservoir performance, including production rates and overall recovery efficiency. By simulating different EOR scenarios, we identified the most effective strategies to maximise oil recovery and optimise the reservoir's production potential.

### 2.2.3. Procedure for Simulating with MBAL

- 1) Data Collection and Preparation:
- 2) Entered Data into MBAL:
  - a) Opened MBAL and created a new project.
  - b) Entered the reservoir data into the software, including

PVT data, reservoir properties, and historical production data.

- c) Defined the reservoir's initial conditions, such as initial pressure, oil saturation, and water saturation.
- 3) Model Setup:
  - a) Choose the appropriate EOR method(s) to simulate (e.g., waterflooding, gas injection, chemical EOR).
  - b) Set up the model by specifying the EOR parameters, such as injection rates, fluid properties of the injected substance, and the timing of the EOR process.
- 4) Run the Simulation:
  - a) Simulate to model the reservoir's response to the chosen EOR method(s).
  - b) Monitored key variables like pressure, oil production rate, and recovery factor throughout the simulation.

### 2.3. Model of the Reservoir

The experimental reservoir is modelled to in CMG to produce a graphical representation of the reservoir based on its properties as well as properties of the fluids it contains. The production structure of the reservoir includes one production well and one injection well.

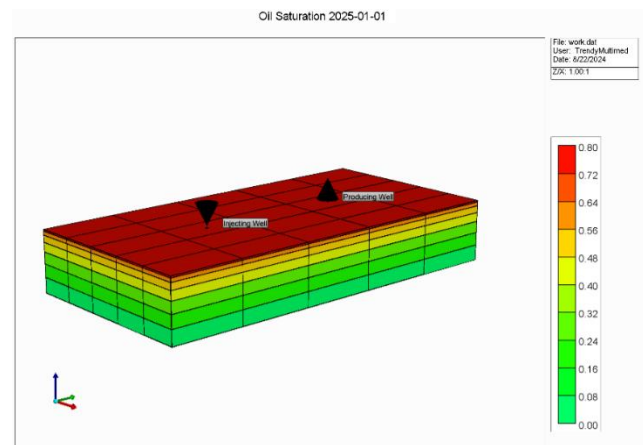
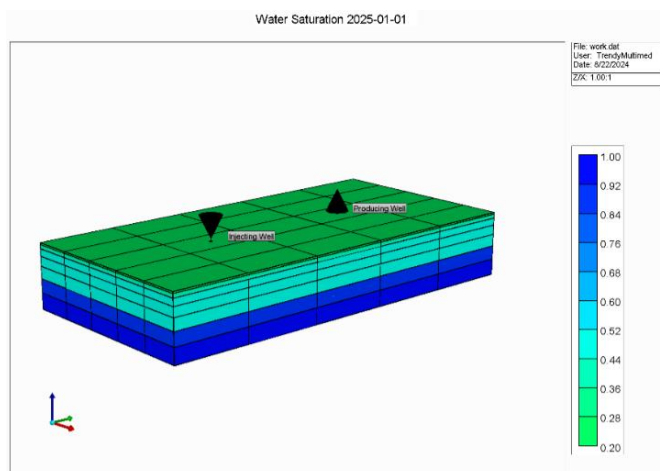


Figure 1. Experimental Reservoir model showing oil saturation.

Figure 1 shows a model of the experimental reservoir representing oil saturation to understand the distribution and behaviour of oil within a reservoir before secondary production. Oil saturation refers to the proportion of the pore space within the reservoir rock that is occupied by oil, expressed as a percentage. In the model, oil saturation is typically mapped throughout the reservoir, providing a spatial representation that shows how oil is distributed across different regions. This distribution is influenced by various factors, including the reservoir's geology, the properties of the fluids present, and the reservoir's production history. It can be determined that oil is more saturated at the top of the reservoir and decreases as it goes down the reservoir. This happens because water is denser than oil and will settle at the bottom. Engineers can identify

areas with high residual oil that may benefit from targeted EOR techniques, optimize recovery strategies, and predict fu-

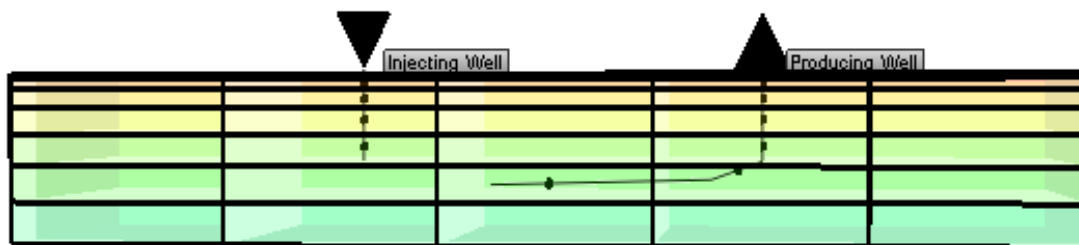
ture production trends. This detailed understanding of oil saturation distribution is essential for making informed decisions about reservoir management and maximizing oil recovery.



**Figure 2.** Experimental Reservoir model showing water saturation.

Figure 2 shows a model of the experimental reservoir showcasing the distribution and behaviour of water within a reservoir before secondary production. Water is highly concentrated at the bottom of the reservoir as a result of its higher

density as compared to oil, and the saturation of water decreases in the reservoir. Figure 3. Model of an experimental reservoir showing both vertical injection and deviated production wells.



**Figure 3.** Model of experimental reservoir showing both vertical injection and deviated production wells.

### 2.3.1. Simulation of Secondary Production

Water injection simulation of the data in Figure 3 with MBAL (from the Petroleum Expert IPM suite) predicted the future performance of the reservoir. The simulation predicted the amount of oil to be recovered, cumulative water produced, and other relevant information.

Figures 4 to 5 shows the calculated results of the water injection process, which highlights the performance indicators such as cumulative oil and water produced, recovery factor, and water cut, as well as other relevant factors. Cumulative oil produced is the total amount of oil produced during the simulation period, providing evidence of the effectiveness of the water injected in displacing oil towards the production well. Cumulative water produced, on the other hand, is the amount of water produced alongside oil. The recovery factor, defined

as the ratio of the amount of oil recovered to the total amount of oil initially in place, serves as a key indicator of the success of the injection process. As water is injected into the reservoir, it displaces the oil towards the production wells, increasing the overall recovery. The simulation typically reveals a gradual increase in the recovery factor over time, indicating improved oil extraction. However, the effectiveness of this process is influenced by various factors such as reservoir heterogeneity, water injection rate, and fluid properties, shown in Figure 6 graph of water injection simulation showing cumulative oil produced and cumulative water produced over. In scenarios where these factors are optimised, the simulation shows a higher recovery factor, reflecting efficient oil displacement and better reservoir management. It can be determined from Figures 9 to 13 that on 2/27/25, water production of water began. This point is called the breakthrough.

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# CALCULATION DETAILS #
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Time (date m/d/y)	Avg. Oil Rate (STB/day)	Water Cut (percent)	Cum Oil Produced (MMSTB)	Cum Wat. Produced (MMSTB)	Cum Wat. Injected (MMSTB)	Recovery Factor (percent)	Water Saturation (fraction)
01/01/2025	476.2	0.000	0.000	0.000	0.000	0.07	0.251
01/01/2025	476.2	0.000	0.000	0.000	0.000	0.53	0.254
01/02/2025	476.2	0.000	0.001	0.000	0.001	1.07	0.258
01/03/2025	476.2	0.000	0.001	0.000	0.001	1.60	0.262
01/03/2025	476.2	0.000	0.001	0.000	0.001	2.13	0.266
01/04/2025	476.2	0.000	0.002	0.000	0.002	2.67	0.27
01/05/2025	476.2	0.000	0.002	0.000	0.002	3.20	0.274
01/05/2025	476.2	0.000	0.002	0.000	0.002	3.73	0.278
01/06/2025	476.2	0.000	0.003	0.000	0.003	4.27	0.282
01/07/2025	476.2	0.000	0.003	0.000	0.003	4.80	0.286
01/08/2025	476.2	0.000	0.003	0.000	0.004	5.33	0.29
01/08/2025	476.2	0.000	0.004	0.000	0.004	5.87	0.294
01/09/2025	476.2	0.000	0.004	0.000	0.004	6.47	0.299
01/10/2025	476.2	0.000	0.004	0.000	0.005	7.00	0.303
01/10/2025	476.2	0.000	0.005	0.000	0.005	7.53	0.306
01/11/2025	476.2	0.000	0.005	0.000	0.005	8.07	0.311
01/12/2025	476.2	0.000	0.005	0.000	0.006	8.60	0.314
01/13/2025	476.2	0.000	0.006	0.000	0.006	9.13	0.318
01/13/2025	476.2	0.000	0.006	0.000	0.006	9.67	0.322
01/14/2025	476.2	0.000	0.006	0.000	0.007	10.20	0.326
01/15/2025	476.2	0.000	0.007	0.000	0.007	10.73	0.33
01/15/2025	476.2	0.000	0.007	0.000	0.008	11.27	0.334
01/16/2025	476.2	0.000	0.008	0.000	0.008	11.80	0.338
01/17/2025	476.2	0.000	0.008	0.000	0.008	12.33	0.342
01/18/2025	476.2	0.000	0.008	0.000	0.009	12.87	0.346
01/18/2025	476.2	0.000	0.009	0.000	0.009	13.40	0.35
01/19/2025	476.2	0.000	0.009	0.000	0.009	13.93	0.354
01/20/2025	476.2	0.000	0.009	0.000	0.010	14.47	0.358
01/20/2025	476.2	0.000	0.010	0.000	0.010	15.00	0.362
01/21/2025	476.2	0.000	0.010	0.000	0.010	15.53	0.366
01/22/2025	476.2	0.000	0.010	0.000	0.011	16.07	0.37
01/23/2025	476.2	0.000	0.011	0.000	0.011	16.60	0.374
01/23/2025	476.2	0.000	0.011	0.000	0.011	17.13	0.378
01/24/2025	476.2	0.000	0.011	0.000	0.012	17.67	0.382
01/25/2025	476.2	0.000	0.012	0.000	0.012	18.20	0.386
01/25/2025	476.2	0.000	0.012	0.000	0.013	18.73	0.39
01/26/2025	476.2	0.000	0.012	0.000	0.013	19.27	0.394
01/27/2025	476.2	0.000	0.013	0.000	0.013	19.80	0.398
01/28/2025	476.2	0.000	0.013	0.000	0.014	20.33	0.402
01/28/2025	476.2	0.000	0.013	0.000	0.014	20.87	0.406
01/29/2025	476.2	0.000	0.014	0.000	0.014	21.40	0.41
01/30/2025	476.2	0.000	0.014	0.000	0.015	21.93	0.414
01/30/2025	476.2	0.000	0.014	0.000	0.015	22.47	0.418
01/31/2025	476.2	0.000	0.015	0.000	0.015	23.00	0.422
02/01/2025	476.2	0.000	0.015	0.000	0.016	23.53	0.426
02/02/2025	476.2	0.000	0.015	0.000	0.016	24.07	0.43
02/02/2025	476.2	0.000	0.016	0.000	0.016	24.60	0.434
02/03/2025	476.2	0.000	0.016	0.000	0.017	25.13	0.438
02/04/2025	476.2	0.000	0.016	0.000	0.017	25.67	0.442
02/04/2025	476.2	0.000	0.017	0.000	0.017	26.20	0.446
02/05/2025	476.2	0.000	0.017	0.000	0.018	26.73	0.45
02/06/2025	476.2	0.000	0.017	0.000	0.018	27.27	0.454

Figure 4. A table of the results of the simulated water injection process (Continue on next page).

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02/07/2025	476.2	0.000	0.018	0.000	0.019	27.80	0.458
02/07/2025	476.2	0.000	0.018	0.000	0.019	28.33	0.462
02/08/2025	476.2	0.000	0.018	0.000	0.019	28.87	0.466
02/09/2025	476.2	0.000	0.019	0.000	0.020	29.40	0.47
02/09/2025	476.2	0.000	0.019	0.000	0.020	29.93	0.474
02/10/2025	476.2	0.000	0.019	0.000	0.020	30.47	0.478
02/11/2025	476.2	0.000	0.020	0.000	0.021	31.00	0.482
02/12/2025	476.2	0.000	0.020	0.000	0.021	31.53	0.486
02/12/2025	476.2	0.000	0.020	0.000	0.021	32.07	0.49
02/13/2025	476.2	0.000	0.021	0.000	0.022	32.60	0.494
02/14/2025	476.2	0.000	0.021	0.000	0.022	33.13	0.498
02/14/2025	476.2	0.000	0.021	0.000	0.022	33.67	0.502
02/15/2025	476.2	0.000	0.022	0.000	0.023	34.20	0.506
02/16/2025	476.2	0.000	0.022	0.000	0.023	34.73	0.51
02/17/2025	476.2	0.000	0.022	0.000	0.024	35.27	0.514
02/17/2025	476.2	0.000	0.023	0.000	0.024	35.80	0.518
02/18/2025	476.2	0.000	0.023	0.000	0.024	36.33	0.522
02/19/2025	476.2	0.000	0.023	0.000	0.025	36.87	0.526
02/19/2025	476.2	0.000	0.024	0.000	0.025	37.40	0.53
02/20/2025	476.2	0.000	0.024	0.000	0.025	37.93	0.534
02/21/2025	476.2	0.000	0.024	0.000	0.026	38.47	0.538
02/22/2025	476.2	0.000	0.025	0.000	0.026	39.00	0.542
02/22/2025	476.2	0.000	0.025	0.000	0.026	39.53	0.546
02/23/2025	476.2	0.005	0.025	0.000	0.027	40.07	0.55
02/24/2025	420.3	12.256	0.026	0.000	0.027	40.58	0.554
02/25/2025	180.0	63.332	0.026	0.000	0.028	41.09	0.558
02/27/2025	125.5	74.571	0.026	0.001	0.029	41.61	0.562
03/02/2025	107.4	78.296	0.027	0.002	0.030	42.14	0.566
03/06/2025	95.9	80.639	0.027	0.004	0.032	42.68	0.57
03/09/2025	87.0	82.442	0.027	0.005	0.034	43.20	0.574
03/13/2025	79.2	84.031	0.028	0.007	0.036	43.74	0.578
03/18/2025	72.1	85.465	0.028	0.009	0.038	44.28	0.582
03/23/2025	65.8	86.750	0.028	0.011	0.041	44.81	0.586
03/28/2025	59.9	87.944	0.029	0.013	0.043	45.34	0.59
04/03/2025	54.6	89.030	0.029	0.016	0.046	45.87	0.594
04/10/2025	49.5	90.055	0.030	0.019	0.050	46.41	0.598
04/17/2025	44.9	90.987	0.030	0.022	0.053	46.93	0.602
04/25/2025	40.5	91.867	0.030	0.025	0.057	47.47	0.606
05/04/2025	36.5	92.677	0.031	0.030	0.062	48.00	0.61
05/13/2025	32.8	93.427	0.031	0.034	0.066	48.54	0.614
05/24/2025	29.3	94.124	0.031	0.039	0.072	49.07	0.618
06/06/2025	26.1	94.770	0.032	0.045	0.078	49.60	0.622
06/19/2025	23.1	95.365	0.032	0.052	0.085	50.13	0.626
07/05/2025	20.4	95.917	0.032	0.059	0.093	50.67	0.63
07/23/2025	17.9	96.421	0.033	0.067	0.102	51.20	0.634
08/12/2025	15.5	96.886	0.033	0.077	0.112	51.73	0.638
09/05/2025	13.4	97.312	0.033	0.089	0.124	52.27	0.642
10/02/2025	11.5	97.700	0.034	0.102	0.137	52.80	0.646
11/03/2025	9.7	98.052	0.034	0.118	0.153	53.33	0.65
12/11/2025	8.1	98.371	0.034	0.136	0.172	53.87	0.654
01/26/2026	6.7	98.657	0.035	0.159	0.195	54.40	0.658
03/23/2026	5.4	98.912	0.035	0.187	0.223	54.93	0.662
04/17/2026	5.0	99.000	0.035	0.199	0.236	55.13	0.663

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*Figure 5. A table of the results of the simulated water injection process.*

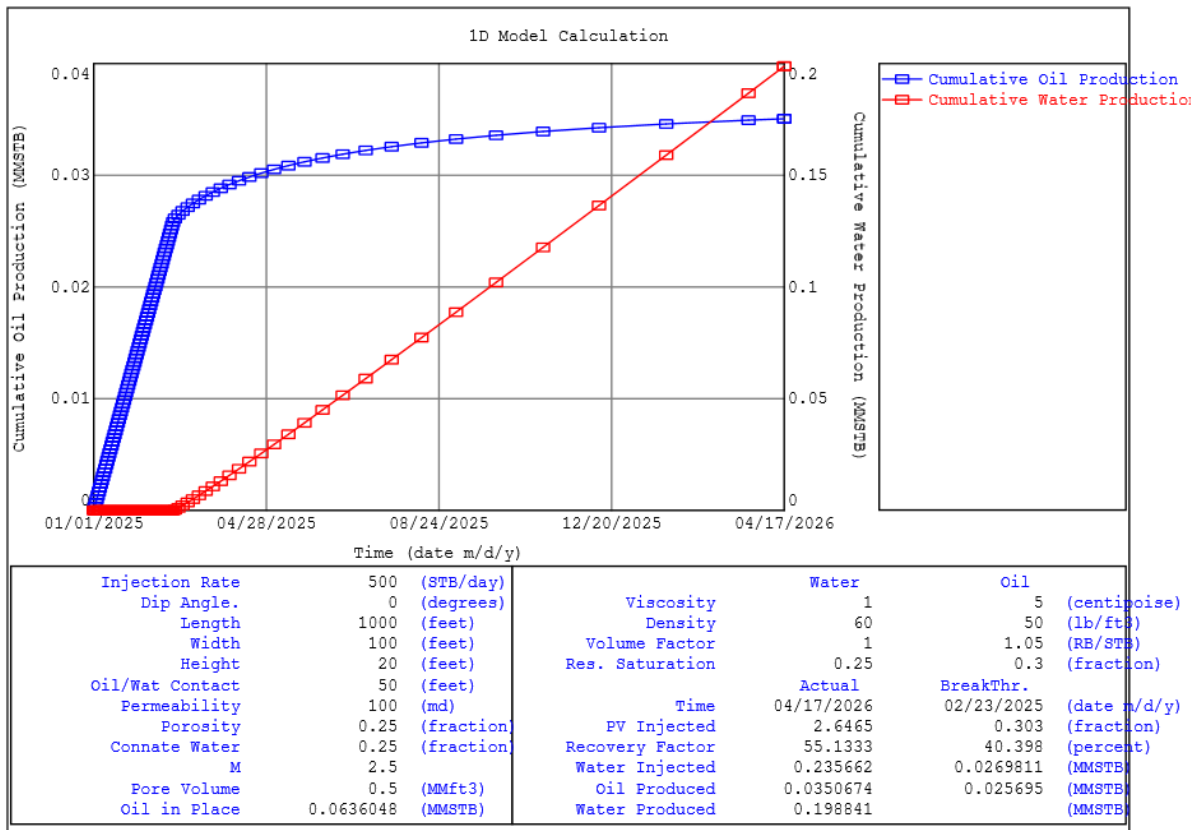


Figure 6. Graph of water injection simulation showing cumulative oil produced and cumulative water produced over time.

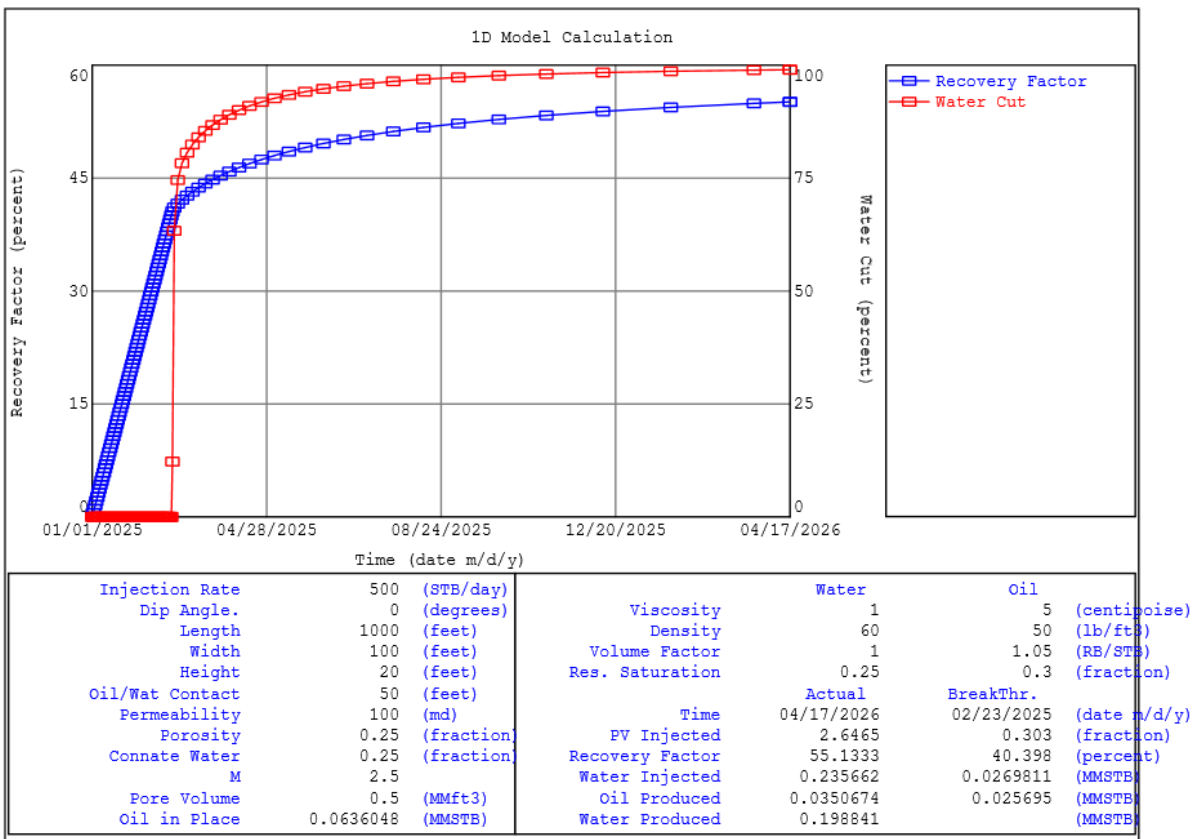


Figure 7. Graph of water injection simulation showing recovery factor and water cut over time.

Figure 6 shows a graph depicting cumulative oil and water production over time following a water injection simulation. This illustrates the dynamic response of the reservoir to the injection process. Initially, the cumulative oil production increases at a steady rate as water injection helps to displace the oil towards the production wells. However, as the simulation progresses, the cumulative water production begins to rise, reflecting the breakthrough of injected water into the production stream. This increase in water production is often accompanied by a tapering off in the rate of oil production, as water increasingly occupies the pore spaces within the reservoir. The separation between the oil and water production curves indicates the effectiveness of the waterflood, with a smaller gap suggesting higher water cut and reduced oil recovery efficiency. Over time, the cumulative oil production curve tends to plateau, while the cumulative water production continues to climb, highlighting the challenge of maintaining oil recovery as water encroachment becomes more dominant.

Figure 7 shows a graph depicting water cut and recovery factor over time following a water injection simulation, which illustrates the dynamic interplay between water production and oil recovery during the flooding process. Initially, the water cut is low, reflecting a predominance of oil in the produced fluids as the injected water has yet to reach the production wells. Over time, as water continues to be injected and displaces the oil, the water cut gradually increases, indicating that a larger proportion of water is being produced alongside the oil. Concurrently, the recovery factor shows a steady rise, demonstrating that more oil is being recovered from the reservoir. At early stages, the recovery factor climbs rapidly as easily displaceable oil is produced. However, as the water cut continues to rise, the rate of increase in the recovery factor begins to taper off, signalling that oil recovery is becoming less efficient as more water and less oil are being produced. This graph is crucial for understanding the efficiency and limits of the water flooding process, helping to optimise injection strategies and improve oil recovery.

### 2.3.2. Enhanced Oil Recovery Simulation

*Updated Reservoir Parameters after Secondary Production (Matured field):*

- 1) Reservoir Length: 1000 feet
- 2) Reservoir Width: 100 feet
- 3) Reservoir Height: 20 feet
- 4) Oil-Water Contact: 50 feet
- 5) Dip Angle: 0 degrees
- 6) Permeability: 50 md (reduced, indicating reservoir damage or depletion)
- 7) Porosity: 20% (reduced, which reflects compaction)
- 8) Connate Water Saturation: 40% (increased, reflecting more water in the reservoir)
- 9) Cut-Off Water Cut: 99%
- 10) Reservoir Pressure: 1000 psi (reduced, typical of a depleted reservoir)

11) Grain Density: 1.2 g/cm<sup>3</sup>

*Fluid Parameters:*

- 1) Oil Density: 55.0 lb/ft<sup>3</sup> (slightly increased, indicating heavier crude after lighter components have been produced)
- 2) Oil Viscosity: 10.0 cP (increased, lighter components are produced first, leaving heavier oil behind)
- 3) Oil Formation Volume Factor (FVF): 1.10 RB/STB (slightly increased, reflecting changes in reservoir conditions)
- 4) Water Density: 60.0 lb/ft<sup>3</sup>
- 5) Water Viscosity: 1.0 cP
- 6) Water Formation Volume Factor (FVF): 1.0 RB/STB

*Injected Fluid Parameters:*

- 1) Injected Fluid Rate: 100 STB/day (unchanged)
- 1) *Relative Permeability (Corey Function):*
- 2) Residual Saturation of Relative Permeability of Water (Swc): 20% (increased, reflecting a more water-saturated reservoir)
- 3) Residual Saturation of Relative Permeability of Oil (Sor): 30% (increased, indicating more trapped oil)
- 4) Endpoint of Relative Permeability of Water (krw max): 0.8 (reduced, reflecting reduced mobility of water in the reservoir)
- 5) Endpoint of Relative Permeability of Oil (kro max): 0.9 (reduced, reflecting reduced oil mobility)
- 6) Exponent of Relative Permeability of Water (nw): 1.0 (slightly increased)
- 7) Exponent of Relative Permeability of Oil (no): 1.0 (slightly increased)

### 2.3.3. Surfactant/ Polymer Injection

*EOR Input*

Table 1 indicate EOR Input Data for Polymer Concentration, Apparent Viscosity, Surfactant Concentration and Surface Tension.

*Table 1. EOR Input Data.*

Polymer Concentration (ppm)	Apparent Viscosity (Centipoise)	Surfactant Concentration (ppm)	Surface Tension (dyne/cm)
10,000	5	1,000	0.1
30,000	50	3,000	0.01
50,000	100	50,000	0.001

Rock Absorption = 0.001 mg/g

Oil Partition Coefficient = 0.001 mg/g

*EOR Schedule*

Table 2 shows EOR Schedule indicate PV Injected, Polymer Concentration and Surfactant Concentration.

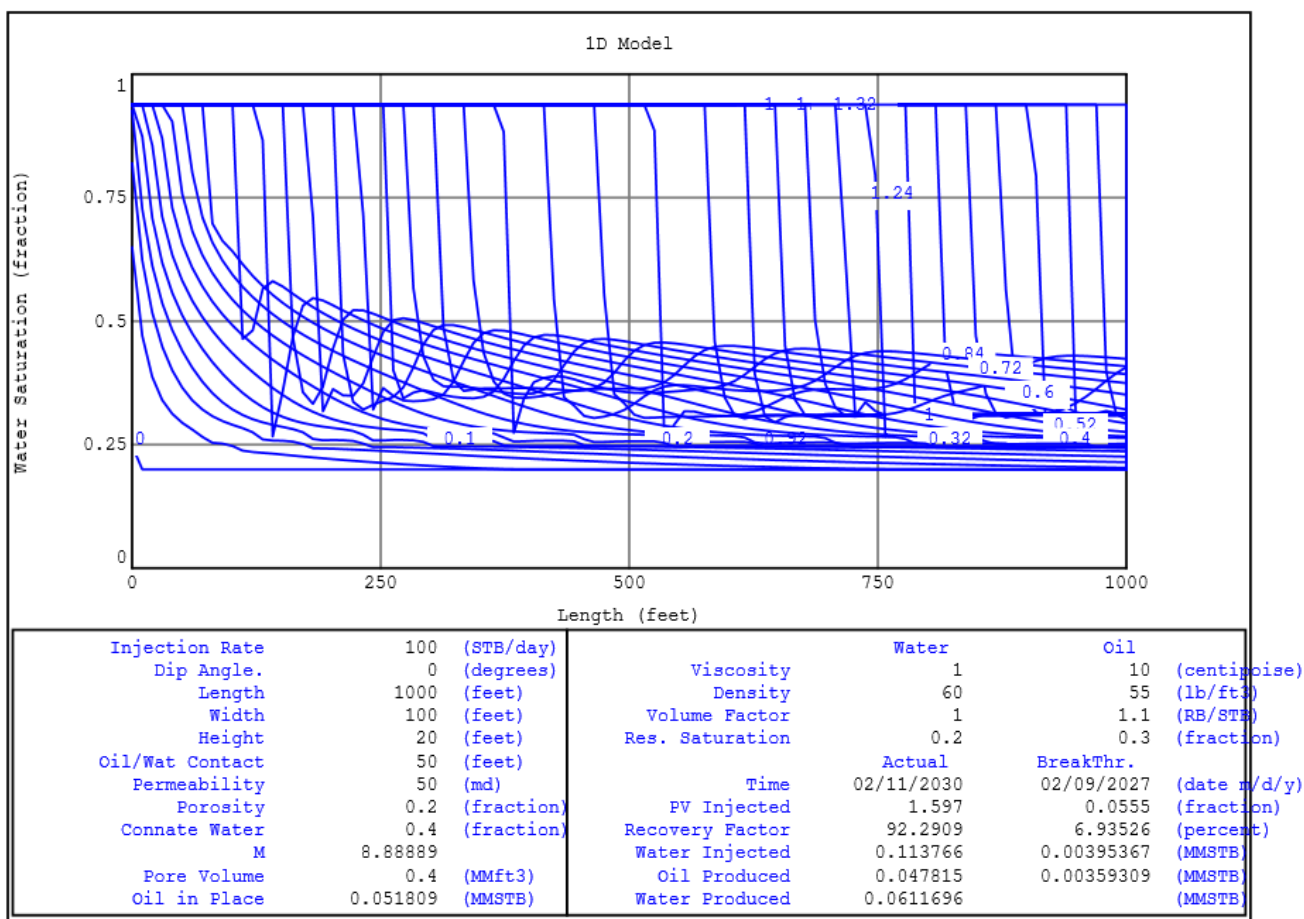
**Table 2.** EOR Schedule.

PV Injected	Polymer Concentration (ppm)	PV Injected	Surfactant Concentration (ppm)
0.2	0	0.2	50,000
100	10,000	100	0

### 3. Results and Discussion After Simulation

Surfactant/Polymer Enhanced Oil Recovery (EOR) is an advanced technique aimed at improving oil recovery by injecting surfactants and polymers into the reservoir. The sur-

factants reduce the oil-water interfacial tension, making it easier for the trapped oil to be displaced, while polymers increase the viscosity of the injected water, improving sweep efficiency and reducing water channelling. The effectiveness of this method is often evaluated using key metrics like cumulative oil produced, recovery factor, cumulative water produced, and water cut. Cumulative oil produced and recovery factor are crucial indicators of the success of the EOR process, with the recovery factor reflecting the overall efficiency of oil extraction relative to the original oil in place. A successful surfactant/polymer EOR project typically shows a significant increase in cumulative oil produced and a corresponding rise in the recovery factor, as the injected chemicals enhance oil displacement. The cumulative water produced, on the other hand, demonstrates the effectiveness of the surfactant/polymer injection in minimizing water cut and optimizing reservoir performance.



**Figure 8.** A graph of water saturation to length after surfactant/ polymer EOR.

**Figure 8.** Above is a graph that shows the saturation of water across the length of the reservoir after surfactant/ polymer EOR. It also displays the results from the simulation after three years. It displays a recovery factor of 92%, 0.047815 MMSTB of oil produced, and 0.061 MMSTB of water produced.

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#####  
# CALCULATION DETAILS #  
#####

Time (date m/d/y)	Avg. Oil Rate (STB/day)	Water Cut (percent)	Cum Oil Produced (MMSTB)	Cum Wat. Produced (MMSTB)	Cum Wat. Injected (MMSTB)	Recovery Factor (percent)	Water Saturation (fraction)
01/01/2027	90.9	0.000	0.000	0.000	0.000	0.06	0.201
01/03/2027	90.9	0.000	0.000	0.000	0.000	0.50	0.204
01/06/2027	90.9	0.000	0.001	0.000	0.001	1.06	0.208
01/09/2027	90.9	0.000	0.001	0.000	0.001	1.56	0.212
01/12/2027	90.9	0.000	0.001	0.000	0.001	2.06	0.216
01/14/2027	90.9	0.000	0.001	0.000	0.001	2.50	0.22
01/17/2027	90.9	0.000	0.002	0.000	0.002	3.00	0.224
01/20/2027	90.9	0.000	0.002	0.000	0.002	3.50	0.228
01/23/2027	90.9	0.000	0.002	0.000	0.002	4.06	0.233
01/26/2027	90.9	0.000	0.002	0.000	0.003	4.56	0.236
01/29/2027	90.9	0.000	0.003	0.000	0.003	5.06	0.24
02/01/2027	90.9	0.000	0.003	0.000	0.003	5.56	0.244
02/04/2027	90.9	0.000	0.003	0.000	0.003	6.06	0.248
02/07/2027	90.9	0.058	0.003	0.000	0.004	6.56	0.252
02/09/2027	89.2	2.123	0.004	0.000	0.004	7.06	0.256
02/12/2027	86.1	5.734	0.004	0.000	0.004	7.54	0.26
02/15/2027	83.2	9.268	0.004	0.000	0.005	8.00	0.264
02/18/2027	80.1	12.902	0.004	0.000	0.005	8.51	0.268
02/22/2027	77.0	16.527	0.005	0.000	0.005	9.05	0.272
02/25/2027	74.5	19.467	0.005	0.000	0.006	9.51	0.276
03/01/2027	72.0	22.428	0.005	0.000	0.006	10.02	0.28
03/04/2027	69.7	25.111	0.005	0.000	0.006	10.50	0.284
03/08/2027	67.3	27.789	0.006	0.000	0.007	11.02	0.288
03/12/2027	65.2	30.218	0.006	0.001	0.007	11.52	0.292
03/16/2027	63.3	32.429	0.006	0.001	0.007	12.01	0.296
03/20/2027	61.4	34.624	0.006	0.001	0.008	12.52	0.3
03/25/2027	59.6	36.618	0.007	0.001	0.008	13.02	0.304
03/29/2027	58.0	38.432	0.007	0.001	0.009	13.50	0.308
04/02/2027	56.4	40.215	0.007	0.001	0.009	14.01	0.312
04/07/2027	55.0	41.822	0.008	0.001	0.010	14.51	0.316

Figure 9. Results of surfactant/ polymer flooding EOR (Continue on next page).

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04/12/2027	53.6	43.373	0.008	0.002	0.010	15.03	0.32
04/17/2027	52.4	44.656	0.008	0.002	0.011	15.51	0.324
04/22/2027	51.3	45.877	0.008	0.002	0.011	16.00	0.328
04/27/2027	50.3	47.008	0.009	0.002	0.012	16.53	0.332
05/02/2027	49.5	47.904	0.009	0.002	0.012	17.01	0.336
05/07/2027	48.8	48.700	0.009	0.003	0.013	17.51	0.34
05/13/2027	48.2	49.332	0.009	0.003	0.013	18.01	0.344
05/18/2027	47.8	49.806	0.010	0.003	0.014	18.51	0.348
05/23/2027	47.5	50.135	0.010	0.003	0.014	19.00	0.352
05/29/2027	47.3	50.351	0.010	0.004	0.015	19.52	0.356
06/03/2027	47.2	50.450	0.010	0.004	0.015	20.01	0.36
06/09/2027	47.2	50.480	0.011	0.004	0.016	20.53	0.364
06/14/2027	47.2	50.459	0.011	0.005	0.017	21.01	0.368
06/20/2027	47.3	50.391	0.011	0.005	0.017	21.50	0.372
06/25/2027	47.4	50.266	0.011	0.005	0.018	22.02	0.376
07/01/2027	47.5	50.116	0.012	0.005	0.018	22.51	0.38
07/06/2027	47.7	49.954	0.012	0.006	0.019	23.00	0.384
07/12/2027	47.8	49.783	0.012	0.006	0.019	23.53	0.388
07/17/2027	48.0	49.632	0.012	0.006	0.020	24.02	0.392
07/23/2027	48.1	49.476	0.013	0.006	0.020	24.52	0.396
07/28/2027	48.2	49.323	0.013	0.007	0.021	25.01	0.4
08/02/2027	48.4	49.162	0.013	0.007	0.021	25.51	0.404
08/08/2027	48.5	49.023	0.013	0.007	0.022	26.01	0.408
08/13/2027	48.6	48.918	0.014	0.007	0.022	26.51	0.412
08/18/2027	48.7	48.805	0.014	0.008	0.023	27.01	0.416
08/24/2027	48.8	48.687	0.014	0.008	0.024	27.52	0.42
08/29/2027	48.9	48.593	0.015	0.008	0.024	28.02	0.424
09/03/2027	48.9	48.553	0.015	0.008	0.025	28.53	0.428
09/09/2027	49.1	48.401	0.015	0.009	0.025	29.03	0.432
09/14/2027	49.1	48.367	0.015	0.009	0.026	29.50	0.436
09/19/2027	49.2	48.219	0.016	0.009	0.026	30.01	0.44
09/24/2027	49.5	47.963	0.016	0.009	0.027	30.52	0.444
09/30/2027	50.2	47.167	0.016	0.010	0.027	31.03	0.448
10/05/2027	47.6	49.992	0.016	0.010	0.028	31.52	0.452
10/10/2027	47.7	49.947	0.017	0.010	0.028	32.01	0.456
10/16/2027	47.7	49.868	0.017	0.010	0.029	32.50	0.46
10/21/2027	47.8	49.779	0.017	0.011	0.029	33.03	0.464
10/27/2027	48.0	49.532	0.017	0.011	0.030	33.52	0.468

Figure 10. Results of surfactant/ polymer flooding EOR (Continue on next page).

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11/01/2027	48.1	49.432	0.018	0.011	0.030	34.02	0.472
11/06/2027	47.8	49.827	0.018	0.011	0.031	34.52	0.476
11/12/2027	45.9	51.923	0.018	0.012	0.032	35.03	0.48
11/17/2027	45.7	52.080	0.018	0.012	0.032	35.50	0.484
11/23/2027	45.7	52.128	0.019	0.012	0.033	36.00	0.488
11/29/2027	45.6	52.204	0.019	0.012	0.033	36.51	0.492
12/05/2027	45.5	52.302	0.019	0.013	0.034	37.01	0.496
12/10/2027	45.4	52.445	0.019	0.013	0.034	37.51	0.5
12/16/2027	45.2	52.629	0.020	0.013	0.035	38.01	0.504
12/22/2027	45.0	52.857	0.020	0.014	0.036	38.50	0.508
12/28/2027	44.8	53.148	0.020	0.014	0.036	39.03	0.512
01/02/2028	44.5	53.473	0.020	0.014	0.037	39.52	0.516
01/08/2028	44.1	53.848	0.021	0.014	0.037	40.01	0.52
01/14/2028	43.7	54.306	0.021	0.015	0.038	40.52	0.524
01/20/2028	43.2	54.826	0.021	0.015	0.039	41.03	0.528
01/26/2028	42.7	55.409	0.022	0.015	0.039	41.53	0.532
02/01/2028	42.1	56.055	0.022	0.016	0.040	42.02	0.536
02/07/2028	41.4	56.762	0.022	0.016	0.040	42.51	0.54
02/14/2028	40.7	57.571	0.022	0.016	0.041	43.02	0.544
02/20/2028	39.9	58.434	0.023	0.017	0.042	43.52	0.548
02/27/2028	39.1	59.338	0.023	0.017	0.042	44.01	0.552
03/04/2028	38.2	60.319	0.023	0.018	0.043	44.51	0.556
03/11/2028	37.2	61.309	0.023	0.018	0.044	45.00	0.56
03/18/2028	36.3	62.331	0.024	0.018	0.044	45.51	0.564
03/25/2028	35.4	63.335	0.024	0.019	0.045	46.00	0.568
04/02/2028	34.4	64.331	0.024	0.019	0.046	46.50	0.572
04/10/2028	33.5	65.295	0.024	0.020	0.047	47.02	0.576
04/18/2028	32.7	66.179	0.025	0.020	0.047	47.52	0.58
04/25/2028	32.0	66.981	0.025	0.021	0.048	48.01	0.584
05/04/2028	31.3	67.741	0.025	0.021	0.049	48.51	0.588
05/12/2028	30.6	68.455	0.025	0.022	0.050	49.02	0.592
05/21/2028	30.0	69.100	0.026	0.022	0.051	49.52	0.596
05/29/2028	29.4	69.684	0.026	0.023	0.052	50.01	0.6
06/07/2028	28.9	70.238	0.026	0.024	0.052	50.51	0.604
06/16/2028	28.4	70.766	0.026	0.024	0.053	51.02	0.608
06/25/2028	28.0	71.234	0.027	0.025	0.054	51.50	0.612
07/05/2028	27.5	71.704	0.027	0.026	0.055	52.02	0.616
07/14/2028	27.1	72.127	0.027	0.026	0.056	52.51	0.62

*Figure 11. Results of surfactant/ polymer flooding EOR (Continue on next page).*

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07/24/2028	26.7	72.541	0.027	0.027	0.057	53.01	0.624
08/03/2028	26.3	72.946	0.028	0.028	0.058	53.52	0.628
08/12/2028	26.0	73.317	0.028	0.028	0.059	54.00	0.632
08/23/2028	25.6	73.697	0.028	0.029	0.060	54.52	0.636
09/02/2028	25.3	74.048	0.028	0.030	0.061	55.01	0.64
09/12/2028	25.0	74.396	0.029	0.030	0.062	55.51	0.644
09/22/2028	24.6	74.729	0.029	0.031	0.063	56.00	0.648
10/03/2028	24.3	75.060	0.029	0.032	0.064	56.51	0.652
10/14/2028	24.0	75.375	0.030	0.033	0.065	57.00	0.656
10/25/2028	23.7	75.679	0.030	0.034	0.066	57.51	0.66
11/04/2028	23.5	75.935	0.030	0.034	0.067	58.00	0.664
11/16/2028	23.3	76.122	0.030	0.035	0.069	58.52	0.668
11/27/2028	23.3	76.092	0.031	0.036	0.070	59.01	0.672
12/08/2028	23.9	75.552	0.031	0.037	0.071	59.51	0.676
12/18/2028	25.4	73.972	0.031	0.038	0.072	60.00	0.68
12/28/2028	28.8	70.337	0.031	0.038	0.073	60.50	0.684
01/05/2029	34.3	64.529	0.032	0.039	0.074	61.02	0.688
01/13/2029	38.3	60.145	0.032	0.039	0.074	61.53	0.692
01/19/2029	40.1	58.184	0.032	0.040	0.075	62.01	0.696
01/25/2029	40.8	57.478	0.032	0.040	0.076	62.52	0.7
02/01/2029	41.0	57.291	0.033	0.040	0.076	63.02	0.704
02/07/2029	41.0	57.291	0.033	0.041	0.077	63.50	0.708
02/13/2029	40.9	57.353	0.033	0.041	0.078	64.01	0.712
02/20/2029	40.8	57.427	0.033	0.041	0.078	64.51	0.716
02/26/2029	40.8	57.488	0.034	0.042	0.079	65.02	0.72
03/04/2029	40.7	57.524	0.034	0.042	0.079	65.52	0.724
03/11/2029	40.7	57.537	0.034	0.042	0.080	66.03	0.728
03/17/2029	40.7	57.533	0.034	0.043	0.081	66.50	0.732
03/23/2029	40.7	57.521	0.035	0.043	0.081	67.01	0.736
03/30/2029	40.8	57.506	0.035	0.043	0.082	67.51	0.74
04/05/2029	40.8	57.493	0.035	0.044	0.083	68.01	0.744
04/12/2029	40.8	57.485	0.035	0.044	0.083	68.52	0.748
04/18/2029	40.8	57.484	0.036	0.045	0.084	69.02	0.752
04/24/2029	40.8	57.498	0.036	0.045	0.084	69.50	0.756
04/30/2029	40.7	57.541	0.036	0.045	0.085	70.01	0.76
05/07/2029	40.7	57.621	0.037	0.046	0.086	70.51	0.764
05/13/2029	40.6	57.724	0.037	0.046	0.086	71.01	0.768
05/20/2029	40.5	57.820	0.037	0.046	0.087	71.51	0.772

*Figure 12. Results of surfactant/ polymer flooding EOR (Continue on next page).*

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05/26/2029	40.4	57.887	0.037	0.047	0.088	72.01	0.776
06/01/2029	40.4	57.931	0.038	0.047	0.088	72.51	0.78
06/08/2029	40.3	57.970	0.038	0.047	0.089	73.01	0.784
06/14/2029	40.3	58.006	0.038	0.048	0.090	73.51	0.788
06/21/2029	40.3	58.022	0.038	0.048	0.090	74.01	0.792
06/27/2029	40.3	58.011	0.039	0.048	0.091	74.51	0.796
07/04/2029	40.3	58.003	0.039	0.049	0.092	75.01	0.8
07/10/2029	40.3	58.033	0.039	0.049	0.092	75.51	0.804
07/16/2029	40.2	58.111	0.039	0.050	0.093	76.00	0.808
07/23/2029	40.1	58.213	0.040	0.050	0.093	76.50	0.812
07/30/2029	40.0	58.291	0.040	0.050	0.094	77.02	0.816
08/05/2029	40.0	58.279	0.040	0.051	0.095	77.52	0.82
08/11/2029	40.1	58.186	0.040	0.051	0.095	78.02	0.824
08/18/2029	40.2	58.095	0.041	0.051	0.096	78.51	0.828
08/24/2029	40.2	58.078	0.041	0.052	0.097	79.01	0.832
08/31/2029	40.2	58.101	0.041	0.052	0.097	79.51	0.836
09/06/2029	40.2	58.112	0.041	0.052	0.098	80.01	0.84
09/12/2029	40.2	58.142	0.042	0.053	0.099	80.50	0.844
09/19/2029	40.1	58.197	0.042	0.053	0.099	81.00	0.848
09/26/2029	40.1	58.198	0.042	0.053	0.100	81.52	0.852
10/02/2029	40.2	58.163	0.042	0.054	0.101	82.02	0.856
10/08/2029	40.1	58.204	0.043	0.054	0.101	82.52	0.86
10/15/2029	40.1	58.248	0.043	0.055	0.102	83.01	0.864
10/21/2029	40.1	58.173	0.043	0.055	0.103	83.51	0.868
10/28/2029	40.2	58.146	0.044	0.055	0.103	84.01	0.872
11/03/2029	40.1	58.261	0.044	0.056	0.104	84.50	0.876
11/10/2029	40.1	58.266	0.044	0.056	0.104	85.03	0.88
11/16/2029	40.2	58.072	0.044	0.056	0.105	85.52	0.884
11/23/2029	40.2	58.161	0.045	0.057	0.106	86.02	0.888
11/29/2029	40.0	58.370	0.045	0.057	0.106	86.52	0.892
12/05/2029	40.0	58.314	0.045	0.057	0.107	87.01	0.896
12/12/2029	40.4	57.861	0.045	0.058	0.108	87.51	0.9
12/18/2029	40.2	58.064	0.046	0.058	0.108	88.01	0.904
12/25/2029	39.8	58.587	0.046	0.059	0.109	88.50	0.908
12/31/2029	39.2	59.248	0.046	0.059	0.110	89.03	0.912
01/07/2030	40.9	57.317	0.046	0.059	0.110	89.50	0.916
01/13/2030	43.0	55.047	0.047	0.060	0.111	90.02	0.92
01/20/2030	41.2	56.995	0.047	0.060	0.112	90.53	0.924
01/26/2030	31.4	67.634	0.047	0.060	0.112	91.01	0.928
02/01/2030	44.3	53.618	0.047	0.061	0.113	91.50	0.932
02/08/2030	68.8	26.099	0.048	0.061	0.113	92.01	0.936
02/11/2030	0.0		0.048	0.061	0.114	92.29	0.938

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Figure 13. Results of surfactant/ polymer flooding EOR.

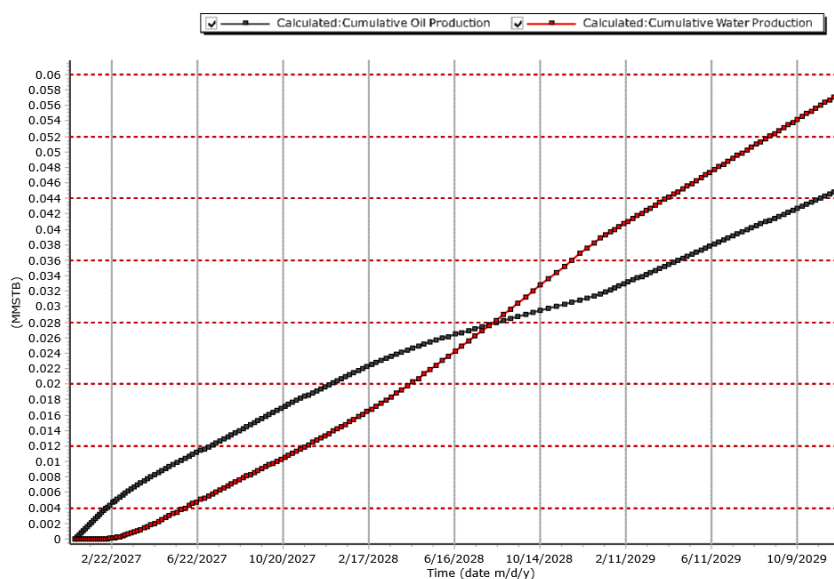


Figure 14. Graph of cumulative oil and water production after surfactant/ polymer flooding EOR.

Figure 14 shows a graph showing cumulative oil and water produced against time following surfactant/polymer injection; the trends typically reveal the enhanced oil recovery (EOR) effects of the treatment. Initially, there is an observable increase in the rate of cumulative oil production as the surfactant and polymer work to reduce interfacial tension and improve the sweep efficiency, respectively. This results in more efficient displacement of oil towards the production wells. The cumulative oil curve will typically show a steeper slope compared to pre-injection periods, reflecting the success of the EOR method. Meanwhile, the cumulative water production

may also rise, especially if water production was already significant before injection. However, the polymer's role in reducing water mobility might slow the rate of water cut increase, resulting in a more favourable oil-to-water ratio. Over time, as the effects of the surfactant/polymer injection diminish, the slope of the cumulative oil curve may gradually flatten, signalling a decrease in incremental oil recovery. This graph provides a clear visual representation of the effectiveness and duration of the enhanced recovery process achieved through surfactant/polymer injection. At the point of intersection, both curves produced 0.028 MMSTB of oil and water, respectively.

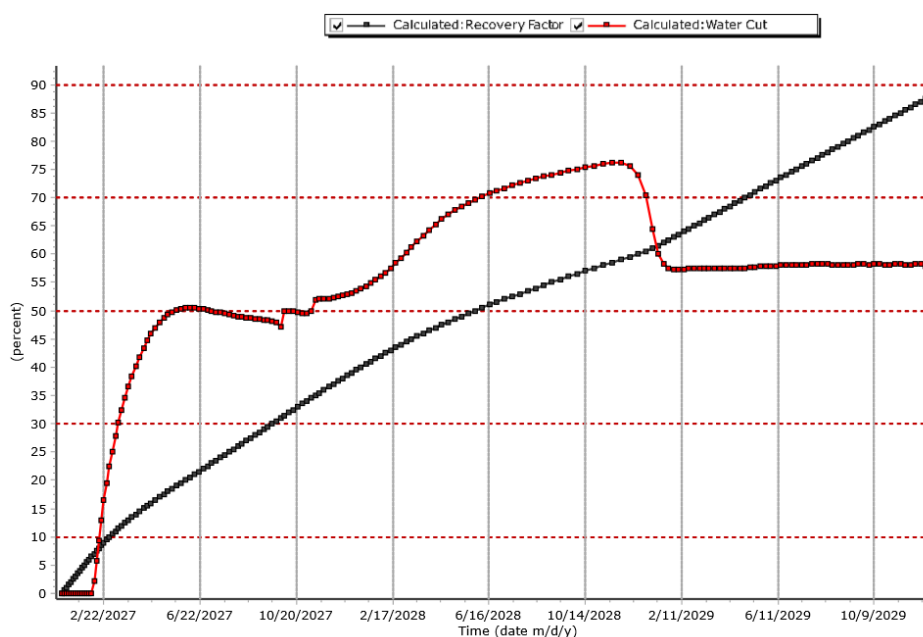


Figure 15. A graph of recovery factor and water cut against time after surfactant/ polymer injection.

Figure 15 shows a graph depicting the recovery factor and water cut against time following surfactant/polymer injection, which provides valuable insights into the enhanced oil recovery (EOR) process. Initially, after the injection of surfactants and polymers, the recovery factor begins to rise more rapidly compared to conventional water flooding, indicating improved oil displacement and mobilization. This is due to the reduction in interfacial tension and the increase in sweep efficiency provided by the surfactant/polymer mixture. Over time, the recovery factor continues to increase, but at a slower rate as the process progresses. Concurrently, the water cut—a measure of the proportion of water in the produced fluids—initially remains low as the injected chemicals help to mobilise trapped oil. However, as the injection progresses, the water cut typically starts to rise, indicating that more water is being produced relative to oil. This increase in water cut is expected as the easily recoverable oil is produced, and the reservoir starts producing more water. The overall trend in the graph illustrates the effectiveness of surfactant/polymer injection

in improving oil recovery while also highlighting the inevitable increase in water cut over time as the reservoir matures.

### 3.1. Hot Water EOR Simulation

Table 3 shows injection data for hot water EOR

Table 3. Injection data for hot water EOR.

PV Injected	Injection Temperature (deg F)
100	1000

- 1) Rock Specific Heat: 0.22 BTU/lb/F
- 2) Formation GOR: 800 scf/STB
- 3) Oil Gravity: 44 API
- 4) Gas Gravity: 0.8 sp. gravity

- 5) Water Salinity: 14000 ppm
- 6) Mole Percentage H<sub>2</sub>S: 0%
- 7) Mole Percentage CO<sub>2</sub>: 0%
- 8) Mole Percentage N<sub>2</sub>: 0%
- 9) Reservoir Pressure: 2000 psig
- 10) Reservoir Temperature: 250 deg F

### 3.2. Results of Simulation

The results from the hot water enhanced oil recovery (EOR) method indicate significant improvements in both cumulative

oil and water production, as well as an increased recovery factor. The cumulative oil production demonstrates a noticeable increase due to the reduction in oil viscosity and improved mobility, allowing for more efficient displacement of oil. Simultaneously, cumulative water production also rises as the injected hot water efficiently sweeps through the reservoir, displacing both oil and water. The recovery factor shows a marked enhancement, reflecting the effectiveness of the hot water injection in mobilizing and recovering additional oil from the reservoir. These results underscore the potential of hot water EOR as a viable method for improving oil recovery in suitable reservoirs.

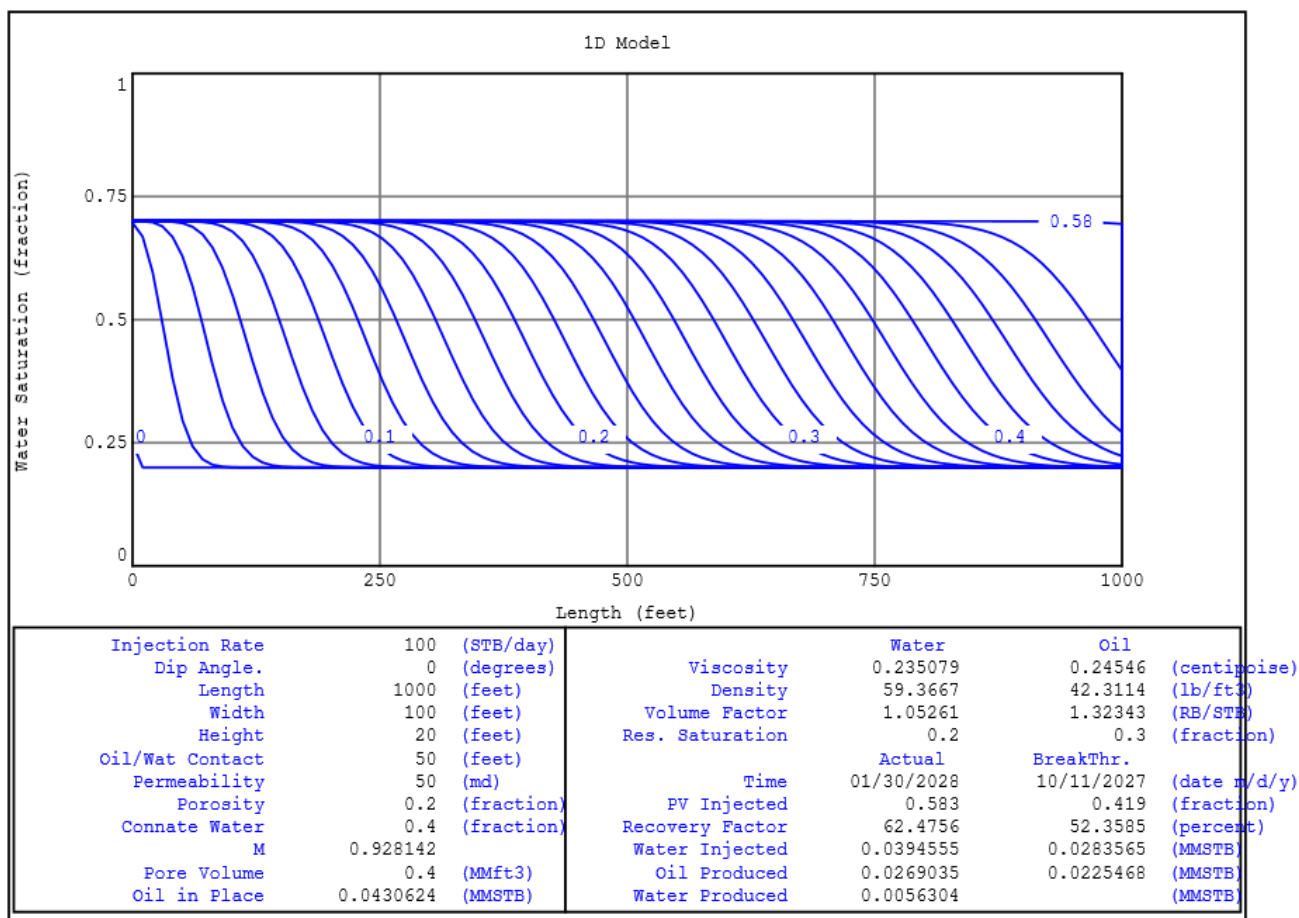


Figure 16. A graph of water saturation to length after hot water injection EOR.

Figure 16 shows a graph that shows the saturation of water across the length of the reservoir after surfactant/ polymer EOR. It also displays the results from the simulation after three years. It displays a recovery factor of 62%, 0.0269 MMSTB of oil produced, 0.00563 MMSTB of water produced, and Figures 17 to 20 results of the hot water injection simulation.

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# CALCULATION DETAILS #  
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Time (date m/d/y)	Avg Oil Rate (STB/day)	Water Cut (percent)	Cum Oil Produced (MMSTB)	Cum Wat. Produced (MMSTB)	Cum Wat. Injected (MMSTB)	Recovery Factor (percent)	Water Saturation (fraction)
01/01/2027	79.5	0.000	0.000	0.000	0.000	0.06	0.201
01/03/2027	76.7	0.000	0.000	0.000	0.000	0.50	0.204
01/06/2027	73.7	0.000	0.000	0.000	0.000	1.06	0.208
01/09/2027	71.8	0.000	0.001	0.000	0.001	1.56	0.212
01/11/2027	70.3	0.000	0.001	0.000	0.001	2.06	0.216
01/14/2027	69.2	0.000	0.001	0.000	0.001	2.50	0.22
01/16/2027	68.2	0.000	0.001	0.000	0.001	3.00	0.224
01/19/2027	67.4	0.000	0.001	0.000	0.001	3.50	0.228
01/22/2027	66.6	0.000	0.001	0.000	0.001	4.06	0.233
01/25/2027	66.1	0.000	0.002	0.000	0.002	4.56	0.236
01/28/2027	65.7	0.000	0.002	0.000	0.002	5.06	0.24
01/30/2027	65.3	0.000	0.002	0.000	0.002	5.56	0.244
02/02/2027	65.0	0.000	0.002	0.000	0.002	6.06	0.248
02/05/2027	64.7	0.000	0.002	0.000	0.002	6.56	0.252
02/07/2027	64.5	0.000	0.002	0.000	0.002	7.06	0.256
02/10/2027	64.3	0.000	0.003	0.000	0.002	7.56	0.26
02/13/2027	64.2	0.000	0.003	0.000	0.003	8.06	0.264
02/16/2027	64.0	0.000	0.003	0.000	0.003	8.56	0.268
02/18/2027	63.9	0.000	0.003	0.000	0.003	9.06	0.272
02/21/2027	63.8	0.000	0.003	0.000	0.003	9.56	0.276
02/24/2027	63.7	0.000	0.003	0.000	0.003	10.06	0.28
02/26/2027	63.6	0.000	0.004	0.000	0.003	10.56	0.284
03/01/2027	63.6	0.000	0.004	0.000	0.004	11.06	0.288
03/04/2027	63.5	0.000	0.004	0.000	0.004	11.56	0.292
03/06/2027	63.5	0.000	0.004	0.000	0.004	12.06	0.296
03/09/2027	63.4	0.000	0.004	0.000	0.004	12.56	0.3
03/12/2027	63.4	0.000	0.004	0.000	0.004	13.06	0.304
03/15/2027	63.4	0.000	0.005	0.000	0.004	13.56	0.308
03/17/2027	63.3	0.000	0.005	0.000	0.004	14.06	0.312
03/20/2027	63.3	0.000	0.005	0.000	0.005	14.56	0.316

Figure 17. Results of hot water injection simulation (Continue on next page).

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03/23/2027	63.3	0.000	0.005	0.000	0.005	15.06	0.32
03/25/2027	63.3	0.000	0.005	0.000	0.005	15.56	0.325
03/28/2027	63.3	0.000	0.006	0.000	0.005	16.06	0.329
03/31/2027	63.3	0.000	0.006	0.000	0.005	16.50	0.332
04/02/2027	63.2	0.000	0.006	0.000	0.005	17.00	0.336
04/05/2027	63.2	0.000	0.006	0.000	0.005	17.50	0.34
04/08/2027	63.2	0.000	0.006	0.000	0.006	18.00	0.344
04/10/2027	63.2	0.000	0.006	0.000	0.006	18.50	0.348
04/13/2027	63.2	0.000	0.007	0.000	0.006	19.00	0.352
04/16/2027	63.2	0.000	0.007	0.000	0.006	19.50	0.356
04/18/2027	63.2	0.000	0.007	0.000	0.006	20.00	0.36
04/21/2027	63.2	0.000	0.007	0.000	0.006	20.50	0.364
04/24/2027	63.2	0.000	0.007	0.000	0.007	21.00	0.368
04/27/2027	63.2	0.000	0.007	0.000	0.007	21.50	0.372
04/29/2027	63.2	0.000	0.008	0.000	0.007	22.00	0.376
05/02/2027	63.2	0.000	0.008	0.000	0.007	22.50	0.38
05/05/2027	63.2	0.000	0.008	0.000	0.007	23.00	0.384
05/07/2027	63.2	0.000	0.008	0.000	0.007	23.50	0.388
05/10/2027	63.2	0.000	0.008	0.000	0.007	24.00	0.392
05/13/2027	63.2	0.000	0.008	0.000	0.008	24.50	0.396
05/16/2027	63.2	0.000	0.009	0.000	0.008	25.00	0.4
05/18/2027	63.2	0.000	0.009	0.000	0.008	25.50	0.404
05/21/2027	63.2	0.000	0.009	0.000	0.008	26.00	0.408
05/24/2027	63.2	0.000	0.009	0.000	0.008	26.50	0.412
05/26/2027	63.2	0.000	0.009	0.000	0.008	27.00	0.416
05/29/2027	63.2	0.000	0.009	0.000	0.009	27.50	0.42
06/01/2027	63.2	0.000	0.010	0.000	0.009	28.00	0.424
06/03/2027	63.2	0.000	0.010	0.000	0.009	28.50	0.428
06/06/2027	63.2	0.000	0.010	0.000	0.009	29.00	0.432
06/09/2027	63.2	0.000	0.010	0.000	0.009	29.50	0.436
06/12/2027	63.2	0.000	0.010	0.000	0.009	30.00	0.44
06/14/2027	63.2	0.000	0.010	0.000	0.010	30.50	0.444
06/17/2027	63.2	0.000	0.011	0.000	0.010	31.00	0.448
06/20/2027	63.2	0.000	0.011	0.000	0.010	31.56	0.452
06/23/2027	63.2	0.000	0.011	0.000	0.010	32.06	0.456
06/25/2027	63.2	0.000	0.011	0.000	0.010	32.56	0.46
06/28/2027	63.2	0.000	0.011	0.000	0.010	33.06	0.464
07/01/2027	63.2	0.000	0.011	0.000	0.010	33.56	0.468

Figure 18. Results of hot water injection simulation (Continue on next page).

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07/04/2027	63.2	0.000	0.012	0.000	0.011	34.06	0.472	
07/06/2027	63.2	0.000	0.012	0.000	0.011	34.56	0.476	
07/09/2027	63.2	0.000	0.012	0.000	0.011	35.06	0.48	
07/12/2027	63.2	0.000	0.012	0.000	0.011	35.56	0.484	
07/14/2027	63.2	0.000	0.012	0.000	0.011	36.06	0.488	
07/17/2027	63.2	0.000	0.013	0.000	0.011	36.56	0.492	
07/20/2027	63.2	0.000	0.013	0.000	0.012	37.06	0.496	
07/23/2027	63.2	0.000	0.013	0.000	0.012	37.56	0.5	
07/25/2027	63.2	0.000	0.013	0.000	0.012	38.06	0.504	
07/28/2027	63.2	0.000	0.013	0.000	0.012	38.56	0.508	
07/31/2027	63.2	0.000	0.013	0.000	0.012	39.06	0.512	
08/02/2027	63.2	0.000	0.014	0.000	0.012	39.56	0.516	
08/05/2027	63.2	0.000	0.014	0.000	0.012	40.06	0.52	
08/08/2027	63.2	0.000	0.014	0.000	0.013	40.56	0.524	
08/10/2027	63.2	0.000	0.014	0.000	0.013	41.06	0.528	
08/13/2027	63.2	0.000	0.014	0.000	0.013	41.56	0.532	
08/16/2027	63.2	0.000	0.014	0.000	0.013	42.06	0.536	
08/19/2027	63.2	0.000	0.015	0.000	0.013	42.56	0.54	
08/21/2027	63.2	0.001	0.015	0.000	0.013	43.06	0.544	
08/24/2027	63.2	0.001	0.015	0.000	0.014	43.56	0.548	
08/27/2027	63.2	0.002	0.015	0.000	0.014	44.06	0.552	
08/29/2027	63.2	0.003	0.015	0.000	0.014	44.56	0.556	
09/01/2027	63.2	0.005	0.015	0.000	0.014	45.06	0.56	
09/04/2027	63.2	0.007	0.016	0.000	0.014	45.56	0.564	
09/07/2027	63.2	0.011	0.016	0.000	0.014	46.06	0.568	
09/09/2027	63.2	0.017	0.016	0.000	0.015	46.56	0.572	
09/12/2027	63.2	0.026	0.016	0.000	0.015	47.06	0.576	
09/15/2027	63.2	0.038	0.016	0.000	0.015	47.56	0.58	
09/17/2027	63.1	0.056	0.016	0.000	0.015	48.06	0.584	
09/20/2027	63.1	0.080	0.017	0.000	0.015	48.56	0.588	
09/23/2027	63.1	0.114	0.017	0.000	0.015	49.06	0.592	
09/26/2027	63.1	0.161	0.017	0.000	0.015	49.56	0.596	
09/28/2027	63.0	0.225	0.017	0.000	0.016	50.06	0.6	
10/01/2027	63.0	0.311	0.017	0.000	0.016	50.56	0.604	
10/04/2027	62.9	0.425	0.017	0.000	0.016	51.06	0.608	
10/06/2027	62.8	0.576	0.018	0.000	0.016	51.56	0.612	
10/09/2027	62.6	0.772	0.018	0.000	0.016	52.06	0.616	
10/12/2027	62.5	1.027	0.018	0.000	0.016	52.56	0.62	

Figure 19. Results of hot water injection simulation (Continue on next page).

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10/14/2027	62.2	1.353	0.018	0.000	0.017	53.04	0.624	
10/17/2027	62.0	1.766	0.018	0.000	0.017	53.53	0.628	
10/20/2027	61.6	2.286	0.018	0.000	0.017	54.02	0.632	
10/23/2027	61.2	2.934	0.019	0.000	0.017	54.50	0.636	
10/26/2027	60.5	3.845	0.019	0.000	0.017	55.04	0.64	
10/28/2027	59.8	4.846	0.019	0.000	0.017	55.52	0.644	
10/31/2027	58.9	6.225	0.019	0.000	0.018	56.05	0.648	
11/03/2027	57.9	7.708	0.019	0.000	0.018	56.51	0.652	
11/06/2027	56.5	9.704	0.020	0.000	0.018	57.02	0.656	
11/09/2027	54.9	12.085	0.020	0.000	0.018	57.51	0.66	
11/13/2027	52.8	15.225	0.020	0.000	0.018	58.05	0.664	
11/16/2027	50.6	18.521	0.020	0.000	0.018	58.51	0.668	
11/19/2027	47.5	23.167	0.020	0.000	0.019	59.04	0.672	
11/23/2027	44.0	28.469	0.020	0.000	0.019	59.53	0.676	
11/27/2027	39.8	34.910	0.021	0.000	0.019	60.03	0.68	
12/02/2027	34.9	42.472	0.021	0.000	0.019	60.51	0.684	
12/07/2027	28.8	52.172	0.021	0.001	0.020	61.01	0.688	
12/14/2027	21.1	64.543	0.021	0.001	0.020	61.52	0.692	
12/24/2027	12.2	79.257	0.021	0.001	0.021	62.00	0.696	
01/30/2028	0.8	98.634	0.021	0.003	0.023	62.48	0.7	

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Figure 20. Results of hot water injection simulation (Continue on next page).

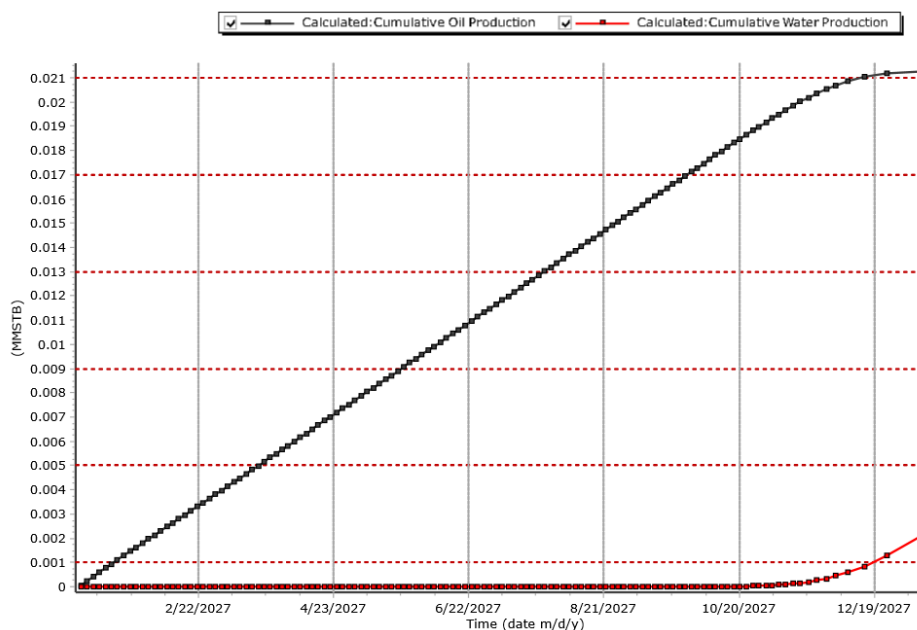


Figure 21. Graph of cumulative oil and water production against time after hot water injection EOR.

Figure 21 A graph plotting cumulative oil and water production against time following hot water Enhanced Oil Recovery (EOR) injection typically shows distinct trends that highlight the impact of the thermal method on reservoir performance. Initially, there may be a period where cumulative oil production rises gradually, as the injected hot water propagates through the reservoir, reducing oil viscosity and improving mobility. This leads to an accelerated increase in oil production as more oil is displaced towards the production wells. The cumulative water production curve might initially

increase at a slower pace but may start to rise more sharply as a breakthrough occurs, and the injected water reaches the production wells. Over time, as the reservoir undergoes continued thermal stimulation, the rate of oil production may stabilise or decline, while water production continues to increase, reflecting the eventual dominance of water in the produced fluids. The separation between the oil and water production curves over time can indicate the efficiency of the EOR process, with a wider gap suggesting better oil recovery before significant water breakthrough.

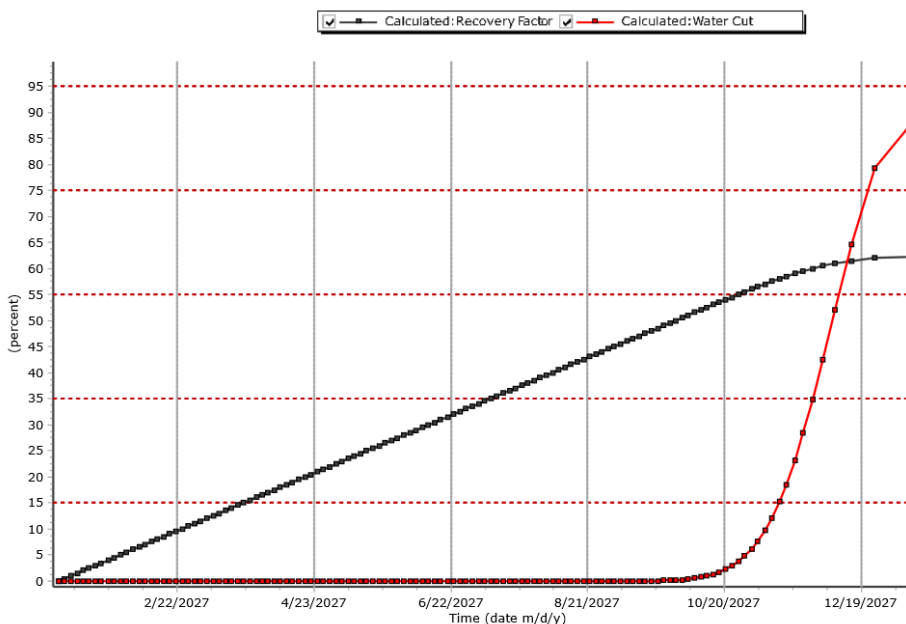


Figure 22. Graph of recovery factor and water cut against time after hot water injection EOR.

Figure 22 shows a graph plotting water cut and recovery factor against time following hot water Enhanced Oil Recovery (EOR) injection. The water cut typically starts low as the injected hot water primarily displaces oil towards the production wells. Over time, as the reservoir becomes increasingly swept by the injected water, the water cut begins to rise, reflecting the increased production of water relative to oil. This rise in water cut is usually gradual at first, but can accelerate as more of the reservoir is swept. The recovery factor, which represents the cumulative percentage of oil extracted from the reservoir, initially increases steadily as the hot water injection improves oil mobility and displacement efficiency. However, as the water cut continues to rise, the rate of increase in the recovery factor tends to slow down, indicating diminishing returns on additional oil recovery. The overall shape of these curves helps in understanding the effectiveness and longevity of the hot water injection process, providing critical insights into the timing and need for potential adjustments in the EOR strategy.

### 3.3. Gas Injection (CO<sub>2</sub>) EOR Simulation

#### EOR Input

Table 4 shows EOR input data and Table 5 show the EOR schedule data.

Table 4. EOR Input data.

CO <sub>2</sub> Concentration in Oil	Oil Viscosity Reduction
0.01	0.4
0.05	0.3
0.1	0.2

#### EOR Schedule

Table 5. EOR schedule data.

PV Injected	CO <sub>2</sub> Concentration in Injected Water
100	0.9

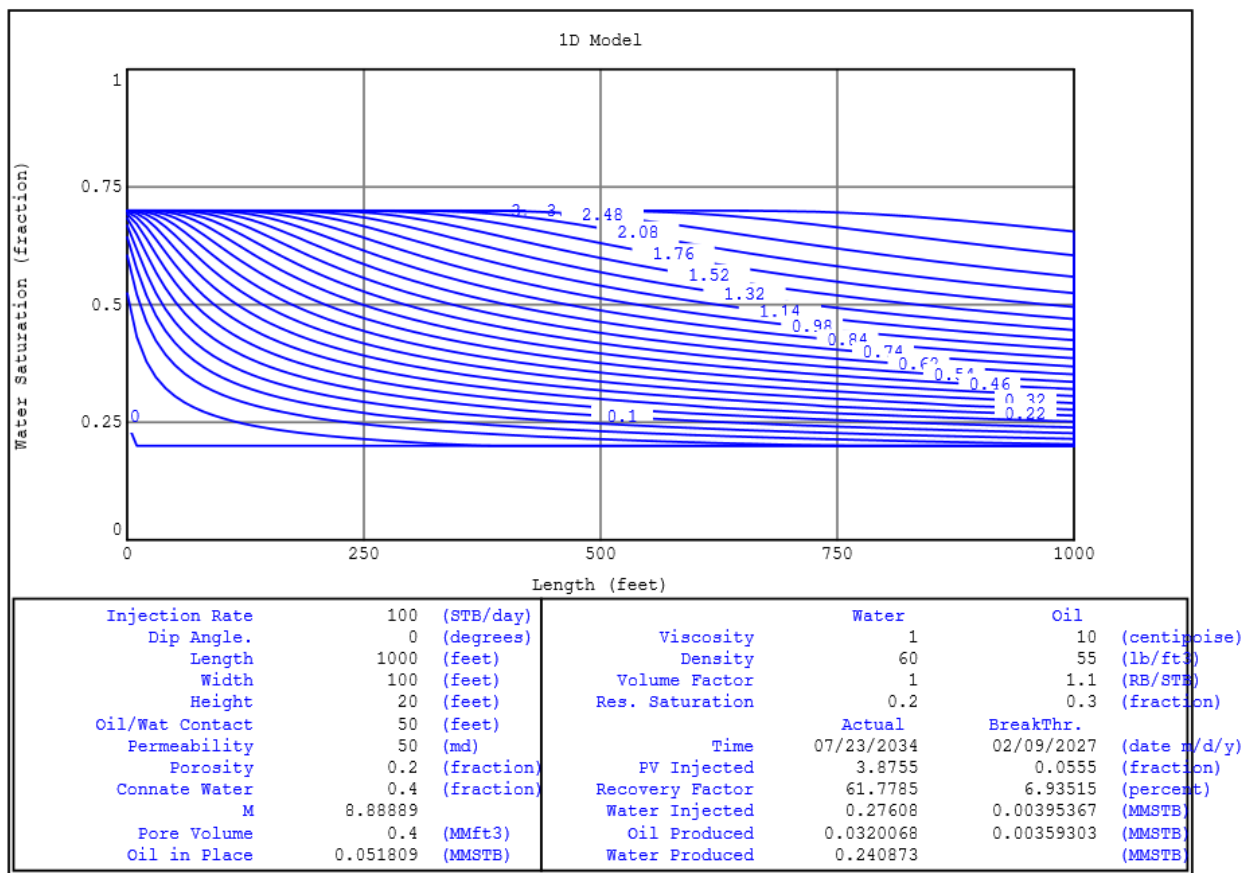


Figure 23. Graph of water saturation in the reservoir against length.

Figure 23 shows a graph that displays the results from the simulation after three years. It displays a recovery factor of

61%, 0.032 MMSTB of oil produced, 0.240 MMSTB of water produced, and Mbal data shown in Figures 24-27.

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# CALCULATION DETAILS #  
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Time (date m/d/y)	Avg.Oil Rate (STB/day)	Water Cut (percent)	Cum Oil Produced (MMSTB)	Cum Wat. Produced (MMSTB)	Cum Wat. Injected (MMSTB)	Recovery Factor (percent)	Water Saturation (fraction)
01/01/2027	90.9	0.000	0.000	0.000	0.000	0.06	0.201
01/03/2027	90.9	0.000	0.000	0.000	0.000	0.50	0.204
01/06/2027	90.9	0.000	0.001	0.000	0.001	1.06	0.208
01/09/2027	90.9	0.000	0.001	0.000	0.001	1.56	0.212
01/12/2027	90.9	0.000	0.001	0.000	0.001	2.06	0.216
01/14/2027	90.9	0.000	0.001	0.000	0.001	2.50	0.22
01/17/2027	90.9	0.000	0.002	0.000	0.002	3.00	0.224
01/20/2027	90.9	0.000	0.002	0.000	0.002	3.50	0.228
01/23/2027	90.9	0.000	0.002	0.000	0.002	4.06	0.233
01/26/2027	90.9	0.000	0.002	0.000	0.003	4.56	0.236
01/29/2027	90.9	0.000	0.003	0.000	0.003	5.06	0.24
02/01/2027	90.9	0.000	0.003	0.000	0.003	5.56	0.244
02/04/2027	90.9	0.000	0.003	0.000	0.003	6.06	0.248
02/07/2027	90.9	0.063	0.003	0.000	0.004	6.56	0.252
02/09/2027	89.1	2.192	0.004	0.000	0.004	7.06	0.256
02/12/2027	86.0	5.856	0.004	0.000	0.004	7.54	0.26
02/15/2027	83.0	9.436	0.004	0.000	0.005	8.00	0.264
02/18/2027	79.9	13.120	0.004	0.000	0.005	8.51	0.268
02/22/2027	76.8	16.804	0.005	0.000	0.005	9.04	0.272
02/25/2027	74.2	19.800	0.005	0.000	0.006	9.51	0.276
03/01/2027	71.6	22.824	0.005	0.000	0.006	10.01	0.28
03/05/2027	69.0	25.834	0.005	0.000	0.006	10.54	0.284
03/08/2027	66.9	28.325	0.006	0.000	0.007	11.01	0.288
03/12/2027	64.7	30.834	0.006	0.001	0.007	11.50	0.292
03/16/2027	62.5	33.331	0.006	0.001	0.008	12.03	0.296
03/21/2027	60.5	35.613	0.006	0.001	0.008	12.53	0.3
03/25/2027	58.6	37.710	0.007	0.001	0.008	13.02	0.304
03/29/2027	56.9	39.644	0.007	0.001	0.009	13.50	0.308
04/03/2027	55.2	41.578	0.007	0.001	0.009	14.00	0.312
04/08/2027	53.5	43.499	0.008	0.001	0.010	14.52	0.316

Figure 24. Results of CO<sub>2</sub> gas injection EOR (Continue on next page).

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04/13/2027	51.9	45.270	0.008	0.002	0.010	15.03	0.32
04/18/2027	50.4	46.912	0.008	0.002	0.011	15.52	0.324
04/23/2027	48.9	48.542	0.008	0.002	0.011	16.03	0.328
04/28/2027	47.6	50.056	0.009	0.002	0.012	16.53	0.332
05/04/2027	46.3	51.466	0.009	0.003	0.012	17.01	0.336
05/09/2027	45.0	52.867	0.009	0.003	0.013	17.52	0.34
05/15/2027	43.8	54.174	0.009	0.003	0.013	18.00	0.344
05/21/2027	42.6	55.471	0.010	0.004	0.014	18.51	0.348
05/28/2027	41.5	56.750	0.010	0.004	0.015	19.03	0.352
06/03/2027	40.4	57.879	0.010	0.004	0.015	19.51	0.356
06/09/2027	39.3	59.059	0.010	0.005	0.016	20.03	0.36
06/16/2027	38.4	60.104	0.011	0.005	0.017	20.51	0.364
06/23/2027	37.4	61.137	0.011	0.005	0.017	21.00	0.368
06/30/2027	36.5	62.153	0.011	0.006	0.018	21.51	0.372
07/07/2027	35.6	63.102	0.011	0.006	0.019	22.00	0.376
07/14/2027	34.7	64.030	0.012	0.007	0.020	22.51	0.38
07/22/2027	33.9	64.892	0.012	0.007	0.020	23.01	0.384
07/30/2027	33.1	65.728	0.012	0.008	0.021	23.51	0.388
08/06/2027	32.4	66.496	0.012	0.008	0.022	24.01	0.392
08/15/2027	31.7	67.227	0.013	0.009	0.023	24.52	0.396
08/23/2027	30.8	68.249	0.013	0.009	0.023	25.01	0.4
08/31/2027	29.9	69.228	0.013	0.010	0.024	25.51	0.404
09/09/2027	29.1	70.063	0.013	0.010	0.025	26.02	0.408
09/18/2027	28.4	70.819	0.014	0.011	0.026	26.51	0.412
09/27/2027	27.7	71.553	0.014	0.012	0.027	27.01	0.416
10/07/2027	27.0	72.272	0.014	0.012	0.028	27.52	0.42
10/17/2027	26.3	72.953	0.015	0.013	0.029	28.01	0.424
10/27/2027	25.7	73.622	0.015	0.014	0.030	28.51	0.428
11/06/2027	25.1	74.280	0.015	0.014	0.031	29.02	0.432
11/16/2027	24.5	74.905	0.015	0.015	0.032	29.51	0.436
11/27/2027	23.9	75.519	0.016	0.016	0.033	30.01	0.44
12/08/2027	23.3	76.123	0.016	0.017	0.034	30.51	0.444
12/19/2027	22.8	76.698	0.016	0.018	0.035	31.00	0.448
12/31/2027	22.2	77.280	0.016	0.019	0.036	31.51	0.452
01/12/2028	21.7	77.834	0.017	0.019	0.038	32.01	0.456
01/24/2028	21.2	78.378	0.017	0.020	0.039	32.51	0.46
02/05/2028	20.7	78.896	0.017	0.021	0.040	33.00	0.464
02/18/2028	20.2	79.419	0.017	0.022	0.041	33.51	0.468

Figure 25. Results of CO<sub>2</sub> gas injection EOR (Continue on next page).

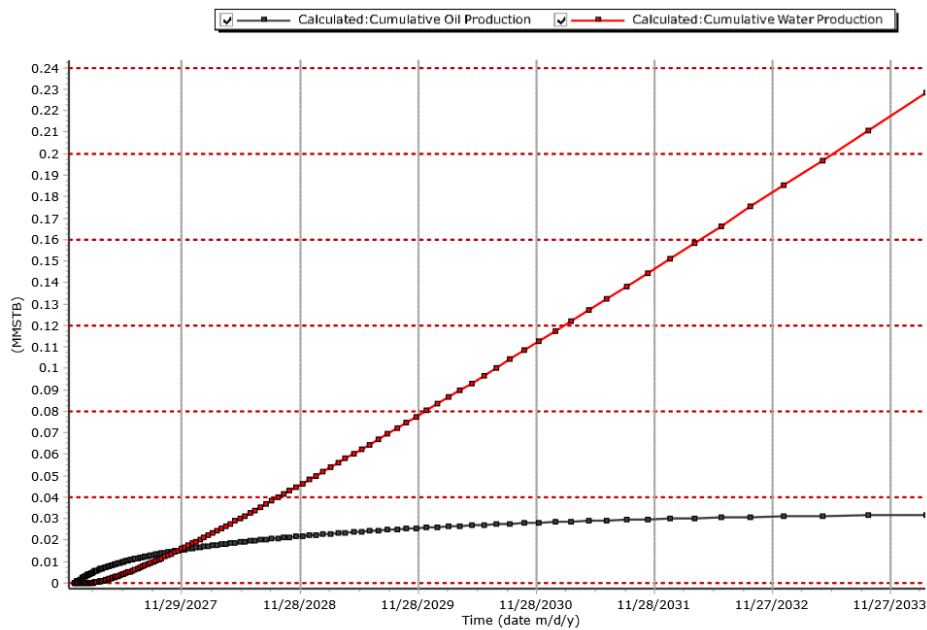
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03/02/2028	19.7	79.932	0.018	0.023	0.043	34.01	0.472	
03/15/2028	19.2	80.421	0.018	0.024	0.044	34.51	0.476	
03/29/2028	18.7	80.900	0.018	0.025	0.045	35.00	0.48	
04/12/2028	18.3	81.381	0.018	0.027	0.047	35.51	0.484	
04/26/2028	17.8	81.841	0.019	0.028	0.048	36.01	0.488	
05/11/2028	17.4	82.291	0.019	0.029	0.050	36.50	0.492	
05/26/2028	17.0	82.741	0.019	0.030	0.051	37.01	0.496	
06/10/2028	16.5	83.172	0.019	0.031	0.053	37.51	0.5	
06/26/2028	16.1	83.593	0.020	0.033	0.054	38.00	0.504	
07/12/2028	15.7	84.013	0.020	0.034	0.056	38.50	0.508	
07/29/2028	15.3	84.424	0.020	0.035	0.058	39.01	0.512	
08/15/2028	14.9	84.825	0.020	0.037	0.059	39.51	0.516	
09/02/2028	14.6	85.217	0.021	0.038	0.061	40.00	0.52	
09/20/2028	14.2	85.607	0.021	0.040	0.063	40.51	0.524	
10/08/2028	13.8	85.987	0.021	0.041	0.065	41.01	0.528	
10/27/2028	13.5	86.358	0.022	0.043	0.067	41.50	0.532	
11/16/2028	13.1	86.726	0.022	0.045	0.069	42.01	0.536	
12/06/2028	12.8	87.085	0.022	0.046	0.071	42.50	0.54	
12/26/2028	12.4	87.440	0.022	0.048	0.073	43.00	0.544	
01/16/2029	12.1	87.786	0.023	0.050	0.075	43.50	0.548	
02/08/2029	11.7	88.135	0.023	0.052	0.077	44.01	0.552	
03/02/2029	11.4	88.468	0.023	0.054	0.079	44.50	0.556	
03/25/2029	11.1	88.802	0.023	0.056	0.081	45.00	0.56	
04/18/2029	10.8	89.132	0.024	0.058	0.084	45.50	0.564	
05/12/2029	10.4	89.457	0.024	0.060	0.086	46.01	0.568	
06/06/2029	10.1	89.772	0.024	0.062	0.089	46.50	0.572	
07/02/2029	9.8	90.087	0.024	0.065	0.091	47.00	0.576	
07/29/2029	9.5	90.401	0.025	0.067	0.094	47.51	0.58	
08/26/2029	9.2	90.705	0.025	0.069	0.097	48.00	0.584	
09/23/2029	8.9	91.011	0.025	0.072	0.100	48.51	0.588	
10/23/2029	8.6	91.311	0.025	0.075	0.103	49.01	0.592	
11/22/2029	8.3	91.604	0.026	0.078	0.106	49.50	0.596	
12/24/2029	8.0	91.898	0.026	0.080	0.109	50.00	0.6	
01/26/2030	7.7	92.192	0.026	0.083	0.112	50.51	0.604	
03/01/2030	7.5	92.478	0.026	0.087	0.116	51.00	0.608	
04/05/2030	7.2	92.763	0.027	0.090	0.119	51.50	0.612	
05/12/2030	6.9	93.049	0.027	0.093	0.123	52.00	0.616	
06/19/2030	6.6	93.330	0.027	0.097	0.127	52.50	0.62	

Figure 26. Results of CO<sub>2</sub> gas injection EOR (Continue on next page).

MBAL Program - V14.0.0.0							Thu Aug 22 09:	
07/29/2030	6.3	93.610	0.027	0.100	0.131	53.00	0.624	
09/09/2030	6.1	93.889	0.028	0.104	0.135	53.50	0.628	
10/23/2030	5.8	94.168	0.028	0.108	0.139	54.00	0.632	
12/07/2030	5.5	94.444	0.028	0.113	0.144	54.50	0.636	
01/25/2031	5.2	94.724	0.028	0.117	0.149	55.00	0.64	
03/16/2031	5.0	95.000	0.029	0.122	0.154	55.50	0.644	
05/09/2031	4.7	95.278	0.029	0.127	0.159	56.00	0.648	
07/05/2031	4.4	95.558	0.029	0.132	0.165	56.50	0.652	
09/03/2031	4.1	95.840	0.030	0.138	0.171	57.00	0.656	
11/07/2031	3.9	96.123	0.030	0.144	0.177	57.50	0.66	
01/16/2032	3.6	96.412	0.030	0.151	0.184	58.00	0.664	
03/31/2032	3.3	96.705	0.030	0.158	0.192	58.50	0.668	
06/22/2032	3.0	97.005	0.031	0.166	0.200	59.00	0.672	
09/21/2032	2.7	97.314	0.031	0.175	0.209	59.50	0.676	
01/02/2033	2.4	97.636	0.031	0.185	0.219	60.00	0.68	
05/01/2033	2.0	97.976	0.031	0.197	0.231	60.50	0.684	
09/19/2033	1.7	98.340	0.032	0.211	0.245	61.00	0.688	
03/17/2034	1.3	98.746	0.032	0.228	0.263	61.50	0.692	
07/23/2034	1.0	99.001	0.032	0.241	0.276	61.78	0.694	

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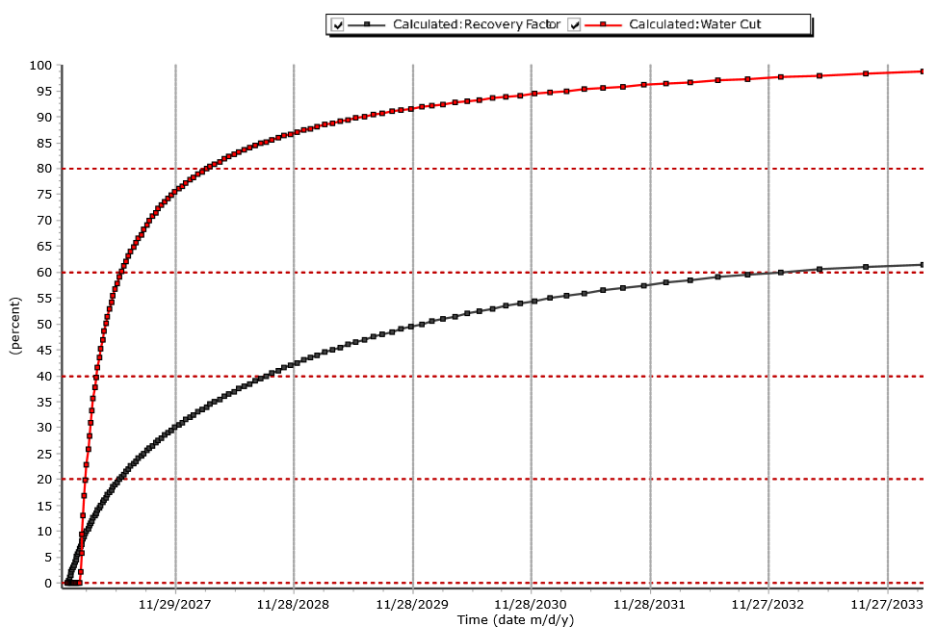
Figure 27. Results of CO<sub>2</sub> gas injection EOR.



**Figure 28.** Graph of cumulative oil and water produced against time after CO<sub>2</sub> injection EOR.

Figure 28 shows a graph plotting cumulative oil and water production against time following CO<sub>2</sub> gas Enhanced Oil Recovery (EOR) injection, which typically shows distinct trends that reflect the impact of CO<sub>2</sub> on reservoir performance. Initially, cumulative oil production may rise sharply as the CO<sub>2</sub> injection enhances oil recovery by reducing oil viscosity and improving its mobility, thereby increasing the displacement efficiency. Over time, the rate of oil production might stabilize or slow down as the CO<sub>2</sub> front progresses through the reservoir and production approaches the economic limit. Simultaneously, cumulative water production often increases at a

slower rate initially but may accelerate as the injected CO<sub>2</sub> displaces water towards the production wells. This rise in water production could indicate a breakthrough of CO<sub>2</sub> and the onset of increased water cut, a common occurrence in mature reservoirs undergoing gas injection EOR. The graph provides valuable insights into the timing and effectiveness of the CO<sub>2</sub> injection, highlighting the balance between enhanced oil recovery and the accompanying increase in water production, which are critical for evaluating the economic viability of the EOR process.



**Figure 29.** Graph of recovery factor and water cut against time after CO<sub>2</sub> injection EOR.

**Figure 29** A graph plotting water cut and recovery factor against time following CO<sub>2</sub> gas Enhanced Oil Recovery (EOR) injection typically reveals crucial insights into the efficiency and dynamics of the recovery process. Initially, after CO<sub>2</sub> injection begins, the recovery factor generally increases as the injected CO<sub>2</sub> reduces oil viscosity and improves oil displacement, leading to enhanced oil production. During this early phase, the water cut, which represents the ratio of water to the total produced fluids, may remain low as more oil is mobilized and produced. Over time, as the CO<sub>2</sub> continues to displace oil, the recovery factor continues to rise, albeit at a gradually decreasing rate as the process reaches diminishing returns. Concurrently, the water cut may start to increase as the injected CO<sub>2</sub> fronts pass through the reservoir, eventually leading to

breakthrough and the production of more water relative to oil. The intersection of rising water cut and the plateauing recovery factor is a critical point, indicating the need for potential adjustments in the injection strategy or the consideration of moving towards well abandonment. This trend provides operators with valuable information on the optimal duration and effectiveness of the CO<sub>2</sub> EOR process.

## 4. Conclusion and Recommendation

**Table 6** show the Simulation Results of surfactant/Polymer, Hot water injection and CO<sub>2</sub> gas injection EOR

**Table 6.** Simulation Results.

	Surfactant/ Polymer EOR	Hot Water Injection EOR	CO <sub>2</sub> Gas Injection EOR
Cumulative Oil Produced (MMSTB)	0.047815	0.0269035	0.0320068
Cumulative Water Produced (MMSTB)	0.0611696	0.0056304	0.240873
Oil Recovery Factor (%)	92.2909	62.4756	61.7785

### 4.1. Conclusions

#### 4.1.1. Surfactant/Polymer EOR

Surfactant/Polymer (SP) flooding results in the highest cumulative oil production among the three methods, with 0.047815 MMSTB (million stock tank barrels). This superior performance is due to the effectiveness of surfactants in reducing interfacial tension, which mobilizes trapped oil, and the role of polymers in improving the sweep efficiency of the injected water. The significant oil production indicates that Surfactant/Polymer flooding is highly effective in enhancing oil recovery, particularly in this experiment.

The cumulative water production in SP flooding is 0.0611696 MMSTB, which is relatively high compared to the other methods. This increased water production is a trade-off for the high oil recovery, as the enhanced sweep efficiency can also lead to increased water cuts over time. This large quantity of water can be treated and reinjected back into the reservoir to continue the enhancement of the reservoir. SP flooding achieves an impressive oil recovery factor of 92.2909%, the highest among the three EOR methods. This high recovery factor reflects the method's ability to mobilise a significant

portion of the remaining oil in the reservoir, making it a highly effective EOR technique, as shown in **Table 6**.

#### 4.1.2. Hot Water Injection EOR

Hot Water Injection EOR produces 0.0269035 MMSTB of oil, which is the lowest among the three methods. The primary mechanism for oil recovery in this method is viscosity reduction, which is particularly effective in heavy oil reservoirs. However, its impact is less pronounced in light oil reservoirs, leading to lower cumulative oil production. While effective in specific reservoir conditions, hot water injection is less versatile compared to SP flooding and CO<sub>2</sub> injection, resulting in lower overall oil recovery. This method has the lowest cumulative water production at 0.0056304 MMSTB. The low water production is advantageous in terms of operational costs and handling, but it also reflects the limited oil recovery efficiency compared to SP flooding. The oil recovery factor for hot water injection is 62.4756%, which is moderate. While effective in reducing oil viscosity and improving mobility, the method does not achieve the same level of oil recovery as SP flooding. However, it still offers a viable option in heavy oil reservoirs where other methods may not be as effective.

### 4.1.3. CO<sub>2</sub> Gas Injection EOR

CO<sub>2</sub> gas injection results in 0.0320068 MMSTB of cumulative oil production, which is higher than hot water injection but lower than SP flooding. CO<sub>2</sub> injection works by reducing oil viscosity and swelling the oil, which enhances its mobility and recovery. The method is particularly effective in light to medium oil reservoirs where miscibility can be achieved. The cumulative oil production reflects the CO<sub>2</sub> injection's capability to mobilize oil that might otherwise remain trapped in the reservoir. With a cumulative water production of 0.240873 MMSTB, CO<sub>2</sub> gas injection produces the highest amount of water among the three methods. This high water production can be a challenge in terms of water handling and disposal, potentially increasing operational costs. The oil recovery factor for CO<sub>2</sub> gas injection is 61.7785%, which is comparable to hot water injection but significantly lower than SP flooding. The effectiveness of CO<sub>2</sub> injection is highly dependent on reservoir conditions, particularly the ability to achieve miscibility. In suitable reservoirs, the recovery factor can be enhanced, but it remains less effective than SP flooding in this comparison.

### 4.1.4. Summary

Surfactant/Polymer EOR stands out with the highest cumulative oil production and oil recovery factor, making it the most effective method in this comparison. However, it also results in a relatively high cumulative water production.

Hot Water Injection EOR produces the least oil but also has the lowest cumulative water production, making it a cost-effective option in certain reservoirs, particularly those with heavy oil.

CO<sub>2</sub> Gas Injection EOR offers a balance between oil production and recovery factor, with a higher cumulative oil production than hot water injection, but with a trade-off of higher water production. This method is effective in suitable reservoirs, especially where miscibility can be achieved.

## 4.2. Recommendation for the Most Effective EOR Method

Based on the comparison of Surfactant/Polymer EOR, Hot Water Injection EOR, and CO<sub>2</sub> Gas Injection EOR, the Surfactant/Polymer EOR method emerges as the most effective Enhanced Oil Recovery (EOR) technique.

### 4.2.1. Factors to Consider in Recommendation

**Highest Cumulative Oil Production:** Surfactant/Polymer EOR produced 0.047815 MMSTB of oil, significantly outperforming the other methods. This indicates its superior ability to mobilize and recover oil, particularly in reservoirs where conventional methods may fall short.

**Highest Oil Recovery Factor:** With a recovery factor of 92.2909%, Surfactant/Polymer EOR demonstrates exceptional efficiency in extracting oil from the reservoir. This high

recovery rate translates into a more complete utilization of the reservoir's potential, making it a highly effective option for maximizing production.

**Trade-Off in Water Production:** While Surfactant/Polymer EOR does result in higher cumulative water production, the increased oil recovery justifies this trade-off. Effective water management strategies can mitigate the challenges associated with higher water cuts.

### 4.2.2. Recommendation

For this experimental reservoir, where maximizing oil recovery is the primary objective, Surfactant/Polymer EOR is the recommended method. Its ability to significantly enhance oil production and achieve a high recovery factor makes it the most effective EOR technique in this context. However, it is essential to implement robust water handling and disposal strategies to manage the increased water production associated with this method.

Overall, Surfactant/Polymer EOR is the best choice for maximizing oil recovery and ensuring the most efficient use of reservoir resources.

## Abbreviations

EOR	Enhanced Oil Recovery
SP	Surfactant/Polymer
MMSTB	Million Stock Tank Barrels
MBAL	Material Balance
PVT	Pressure-Volume-Temperature

## Conflicts of Interest

The authors declare no conflicts of interest.

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