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Simulation of Vertical Waterflooding In a Hawaz Reservoir Using Eclipse for Reservoir Pressure Maintenance

*Madi Abdullah Naser[a], Abdulhafiz Younis Mokhetar[b], Ibrahim Abubakar Aldukali[c], Omar Ibrahim Azouza[d], Abdulhadi Elsounousi Khalifa [e], Mays Al-Reem Saleh[f], Esraa Abdel Hamid[g]

[a]Department of Chemical and Petroleum Engineering, School of Applied Sciences and Engineering, Academy for Postgraduate Studies , Janzour, Tripoli, Libya.
[b,] Department of Marine Engineering and Floating Platforms, Faculty of Engineering, University of Tripoli.Tripoli, Libya.
[c] Petroleum Engineering Department, Faculty of Engineering, Sebha Univeristy, Sebha, Libya.
[d]Department of Industrial Engineering and Manufacturing, Faculty of Engineering, Misurata University, Misurata, Libya.
[e,f,g] Petroleum Engineering Department, College of Engineering Technology, Janzour, Tripol, Libya.

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Eclipse
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ABSTRACT

Water injection has proven to be one of the most successful, efficient and cost-effective reservoir management strategies. By reinjecting treated and filtered water into tanks, this approach can help maintain tank pressure, increase hydrocarbon production, and reduce environmental impact. The goal of this project is to create a water injection model using Eclipse tank simulation software to better understand water injection methods to maintain tank pressure. A basic reservoir model is utilized in this investigation. The simulation was performed about 52 years using ECLIPSE Reservoir simulator. In all cases, result shows that oil production with water injection is higher compared with the base case. With this, it would be preferred to apply waterflooding for oil recovery in depleted reservoirs to the use of primary methods. It is also observed that water breakthrough is earlier and water production increases gently with water injection rates. Sensitivity on the injection rate using the 3D model showed that the injection rate has impact on the process. The pressure increases with high injection water rate in all cases. Despite higher reservoir pressure and early in water breakthrough, water flooding accounts for less oil recovery due to rapid water production. Generally, based on the results and discussions, it can be concluded that the water injection option can be used to increase the reservoir pressure to a good extent.

محاكاة الغمر المائي العمودي في خزان الهوازباستخدام برنامج ECLIPSE للحفاظ على ضغط الخزان.

*مادي عبدالله نصر [1] و عبدالحفيظ يونس مختار [2] و ابراهيم أبوبكر الدوكالي [3] و عمر إبراهيم اعزوزة [4] و عبدالهادى السنوسى خليفة [5] و ميس الريم صلاح [5] و اسراء عبدالحميد [5]

[1]قسم الهندسة الكيميائية والنفط, مدرسة العلوم التطبيقية والهندسية,الاكاديمية الليبية للدراسات العليا, جنزور طرابلس، ليبيا.
[2]قسم الهندسة البحرية والمنصات العائمة ، كلية الهندسية, جامعة طرابلس، طرابلس ، ليبيا.
[3]قسم هندسة النفط والغاز. كلية الهندسة، جامعة سبها. ليبيا.
[4]قسم الهندسة الصناعية والتصنيع، كلية الهندسة، جامعة مصراته، ليبيا.
[5] قسم هندسة النفط والغاز ، كلية التقنية الهندسية , جنزور ، طرابلس ، ليبيا

الكلمات المفتاحية:
بئر عمودي
فيضان المياه
خزان الحواز
ECLIPSE
دعم الضغط.

الملخص

لقد أثبت حقن المياه أنه أحد أكثر استراتيجيات إدارة الخزانات نجاحًا وكفاءة وفعالية من حيث التكلفة. ومن خلال إعادة حقن المياه المعالجة والمفلترة في الخزانات، يمكن أن يساعد هذا النهج في الحفاظ على ضغط الخزان، وزيادة إنتاج الهيدروكربونات، وتقليل التأثير البيئي. الهدف من هذا المشروع هو إنشاء نموذج لحقن الماء

*Corresponding author:
E-mail addresses: madi.naser@academy.edu.ly ,(A. Mokhetar) hafeed66@gmail.com ,(I. Aldukali) Ibr.aldukali@sebhau.edu.ly ,(O. Azouza) Omar.i.azouza@gmail.com ,(A. Khalifa) abdalhadi8027@gmail.com ,(M. Saleh) Mayssalehalreem@gmial.com ,(E. Abdel Hamid) Haminesraa@gmail.com

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باستخدام برنامج محاكاة خزان Eclipse لفهم طرق حقن الماء بشكل أفضل للحفاظ على ضغط الخزان. تم استخدام نموذج الخزان الأساسي في هذا البحث. تم إجراء المحاكاة منذ حوالي 52 عامًا باستخدام محاكي المكامن Eclipse. وفي جميع الحالات أظهرت النتائج أن إنتاج الزيت بحقن الماء أعلى مقارنة بالحالة الأساسية. وبهذا، سيكون من المفضل تطبيق الغمر المائي لاستعادة النفط في الخزانات المستنفدة بدلاً من استخدام الطرق الأولية. ويلاحظ أيضًا أن اختراق الماء يكون مبكرًا ويزداد إنتاج الماء برفق مع معدلات حقن الماء. أظهرت الحساسية لمعدل الحقن باستخدام النموذج ثلاثي الأبعاد أن معدل الحقن له تأثير على العملية. ويزداد الضغط مع ارتفاع نسبة ماء الحقن في جميع الحالات. على الرغم من ارتفاع ضغط الخزان والاختراق المبكر للمياه، فإن فيضانات المياه تمثل انخفاضًا في استخراج النفط بسبب الإنتاج السريع للمياه. بشكل عام، بناءً على النتائج والمناقشات، يمكن الاستنتاج أنه يمكن استخدام خيار حقن الماء لزيادة ضغط الخزان إلى حد جيد.

1. Introduction

An oil and gas reservoir is a rock formation in which oil and natural gas accumulate. They are collected in small, connected rock pores and are trapped within the reservoir by adjacent, capped, impermeable rock layers. Primary oil recovery describes the production of hydrocarbons under the natural driving mechanisms present in the reservoir without supplemental assistance from injected fluids such as gas or water. In most cases, the natural drive mechanism is a relatively inefficient process and results in lower overall oil recovery. The lack of sufficient natural drive in most tanks has led to the practice of supplementing natural tank power by introducing some form of artificial drive, the primary method being gas or water injection. Water flooding is perhaps the most common method of secondary recovery. However, before embarking on a secondary restoration project, it must be clearly demonstrated that natural restorations are insufficient; Otherwise there is a risk of wasting the significant capital investment required for the secondary recovery project.

The following factors determine the suitability of the filter tank for water flooding:

1. Reservoir geometry,
2. Fluid properties,
3. Reservoir depth,
4. Lithology and rock properties,
5. Fluid saturations,
6. Reservoir uniformity and pay continuity,
7. Primary reservoir-driving mechanisms.

Problem Statement: Oil reservoirs are usually consisting of hydrocarbons (oil and gas) and bottom water. The natural depletion of the reservoir occurs by the natural energy of the reservoir. Reservoirs pressures are usually high in the beginning and this will transmit the fluid from the reservoir to the surface. However, after some time of production, when the reservoir pressure falls down, water comes into the formation and starts to produce through the wellbore. This happens because of the disturbance in gravitational force in the reservoir, which results in water production along with oil.

Objectives: The goal of this paper is to create a water injection model utilizing Eclipse reservoir simulation software to better understand water injection methods for reservoir pressure maintenance.

Methodology: The simulations were performed for 35 years by injecting water at a constant rate through a vertical well. Water was injected to the equivalent depth as the production well. The same lateral distance was maintained between the injection and production well. Different simulations were performed by varying the injection rate from 100 b/d to 1000 b/d for each case. The base case without water injection was taken as reference.

8. Field Data:

The area of study is located in Murzuq Basin and covers a huge area extending southward into Niger. This area is one of the Murzuq oil fields and it is called H field. It is located in concession NC186 that was encountered by several exploratory and development wells, distributed on the northwestern flank of Murzuq Basin, southwestern part of Libya (Fig. 1).

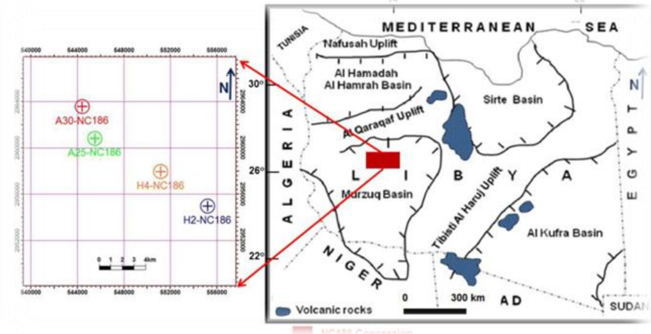

Figure 1: Location of the NC186 (After Adel Mohamed, 2016)

Location Map: On the other hand, structure contour maps have been carried out for H field and illustrates the same structural feature of paleo-high (Fig. 2).

2-D Seismic: It has been affected by the structural and tectonic movements of Murzuq Basin and created paleo-high during the post-Hawaz erosional events. This feature of paleohigh is clearly represented in the 2-D seismic line shown in next figure by Repsol Oil Operation represented in the area of study as shown in the Fig . 3.

Structure Contour Map: 9 exploratory wells distributed in H oil fields in concession NC186 will be the focus of this study. These wells were drilled in Hawaz reservoir of Middle Ordovician. This formation is informally subdivided into 8 horizons, named H1 to H8. Some units have been subdivided into sub-units. Each horizon is characterized by its own petrophysical parameters.

Geologic Background: Murzuq Basin is one of the most significant basins in Southwestern Libya. This basin has a triangular shape and extended toward the border of south from Libya with Niger. The sedimentary fill is predominately Paleozoic in age, while the Mesozoic and Cenozoic sediments are also represented and located above the Precambrian crystalline basement (Fig. 4).

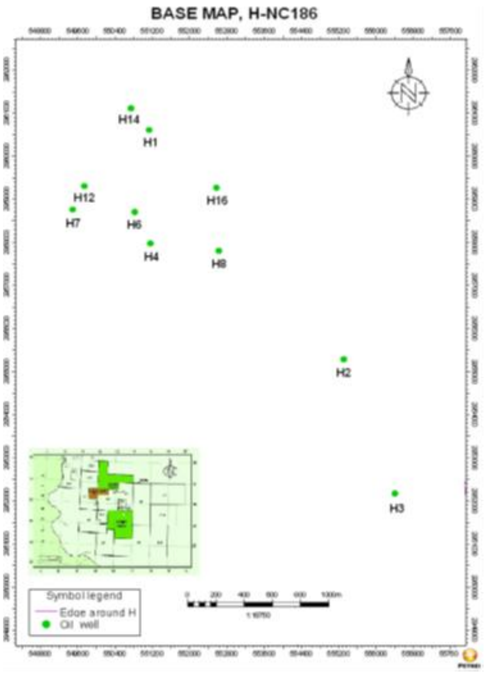

Figure 2: Location map of the concession 186, Murzuq Basin, Libya (After Adel Mohamed, 2016)

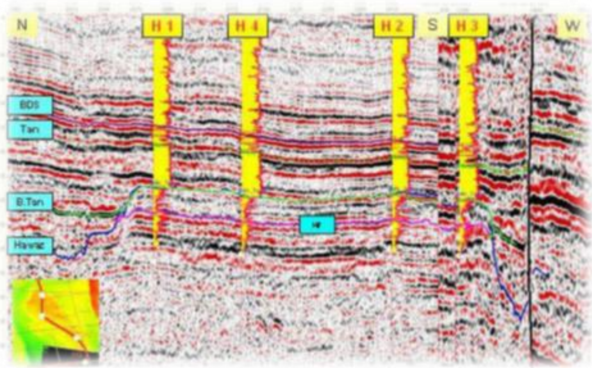

Figure 3: D seismic line for H1, H4, H2 and H3, H-field NC186 wells, Murzuq Basin (After Adel Mohamed, 2016)

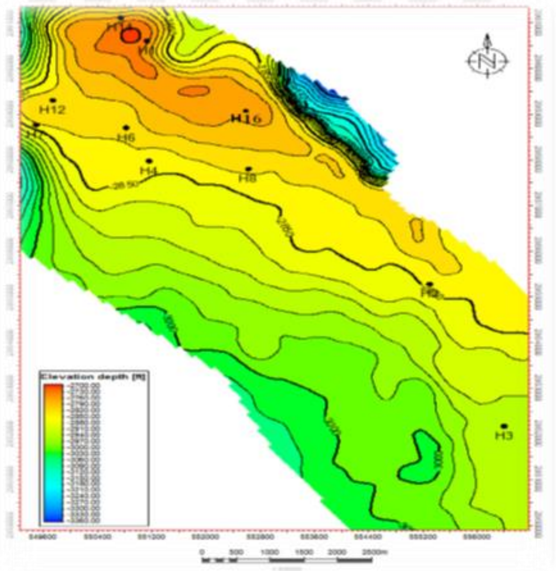

Figure 4: Structure contour map for Hawaz reservoir in H field

(After Adel Mohamed, 2016)

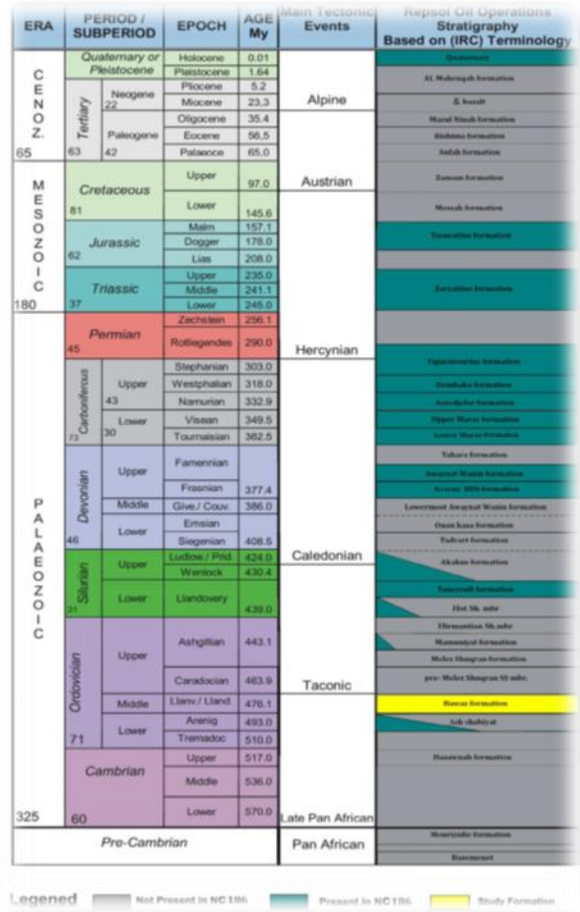

Figure 5: Stratigraphic column of H oil field, NC186, NW Murzuq Basin, Southwestern Libya (After Adel Mohamed, 2016)

9. Model Set-Up:

Grid Description: The 3D grid is a simple corner point geometrical grid with a dimension of 50 x 65 x 30 grid blocks which is a total of 97500 cells as shown in next figure 6.

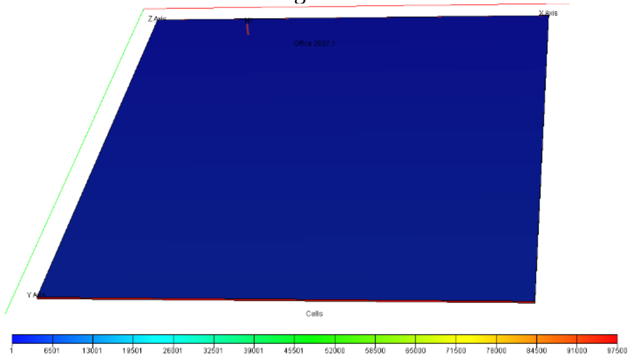

Figure 6: 3D Grid Showing Total Active Cells

Well Information: Next figure No 7 and Table No 1 give an overview of the well information. There are 10 production wells.

Table 1: 3D Model Well Information

Well Name	Date	Location in X	Location in Y
H1	01/05/2023	13	5
H2	01/06/2023	41	35
H3	01/07/2023	48	52
H4	01/08/2023	13	20
H6	01/09/2023	11	16
H7	01/10/2023	23	21
H8	01/11/2023	4	12
H12	01/12/2023	11	3
H14	01/01/2024	23	14
H16	01/02/2024		

The next figure shows 3D model well information for a field that consists of 10 production wells. The first well was drilled and produced at 1/5/2023. The second well was drilled and produced at 1/6/2023. The third well was drilled and produced at 1/7/2023. The fourth well was drilled and produced at 1/8/2023. In addition, the fifth well was drilled and produced at 1/9/2023. The sixth well was drilled and produced at 1/9/2023. The seventh well was drilled and produced at 1/10/2023. The eighth well was drilled and produced at 1/11/2023. Then, the ninth well was drilled and produced at 1/12/2023.

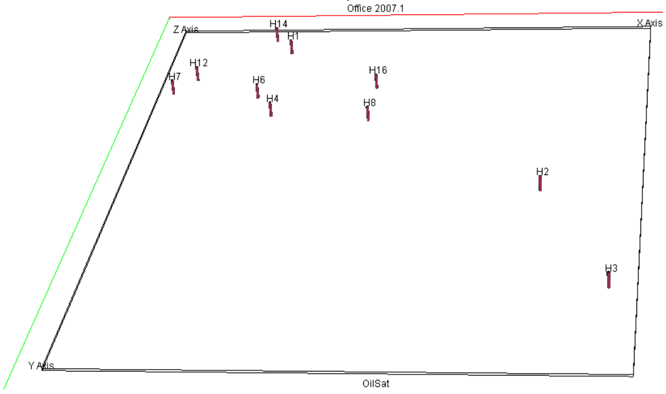

Figure 7: 3D Model Well Information

Rock Properties: As in the 3D models, the fluid phases present are water, oil, gas and dissolved gas. Next figure shows the permeability distribution for X. This reservoir is homogeneous with average permeability is 1412 mD.

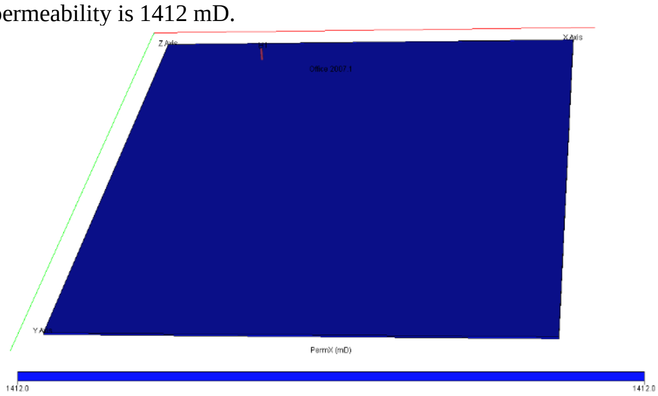

Figure 8: 3 D model for X Permeability Disruption at Layer No 1

Next figure (Fig. 9) is showing the porosity distribution in layer number 1 with the average porosity is 0.18.

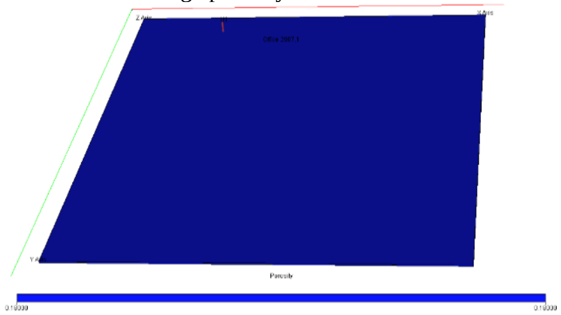

Figure 9: 3 D model for Porosity Disruption at Layer No 1

Next figure (Fig. 10) is showing the gas saturation in layer number 1 with the lowest value is 12%, the highest value is 61%, and the average is 36%.

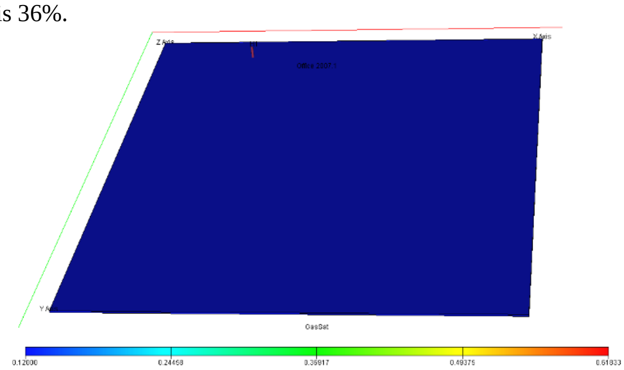

Figure 10: 3 D model for Gas Saturation at Layer No 1

Next figure (Fig. 11) is showing the oil saturation in layer number 1 with the lowest value is 26%, the highest value is 76%, and the average is 51%.

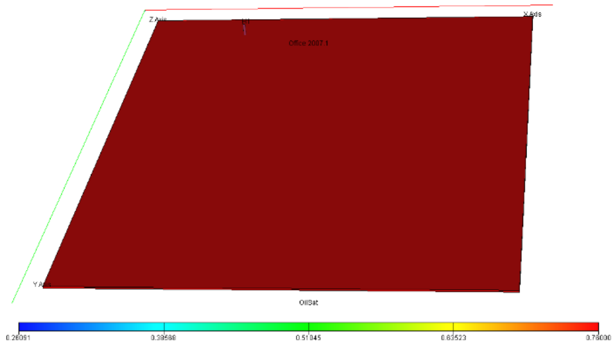

Figure 11: 3 D model for Oil Saturation at Layer No 1

Next figure (Fig. 12) is showing the water saturation in layer number 1 with the lowest value is 0.12, the highest value is 0.12093 and the average is 0.12046.

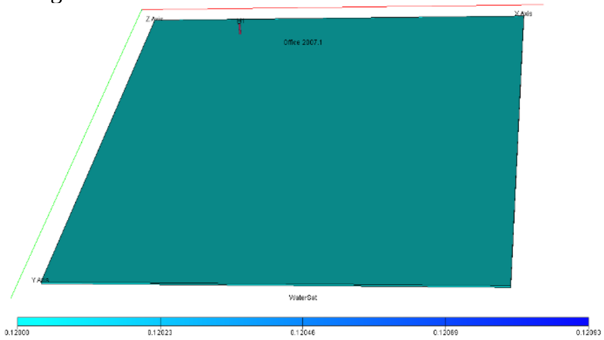

Figure 12: 3 D model for Water Saturation at Layer No 1

Next figure (Fig. 13) is showing the pressure distribution in layer number 1 with the lowest value is 89 psia, the highest value is 1874 psia and the average is 981 psia.

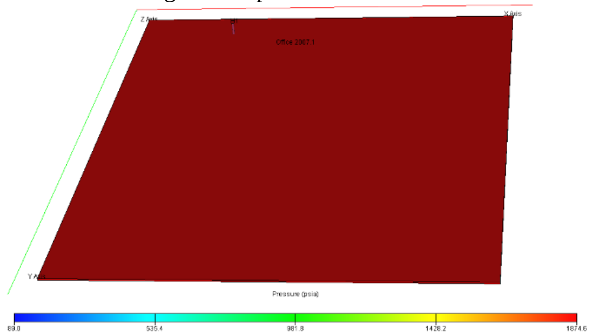

Figure 13: 3 D model for Pressure Disruption at Layer No 1

10. Primary Recovery:

Oil Production Rate Trend at Primary Recovery: In this section, it’s a natural production, and it was from 2023 to 2075. Figure 24 shows the following oil production rate trend at primary recovery. From 2023 to 2075 means normal production without water injection. We note that in the first well, production began to reach about 200 million barrels per day, and after adding the third well, production increased by 2 million, and production began to reach about 400 million barrels per day, and after adding the fourth well, production increased by approximately 500 million.

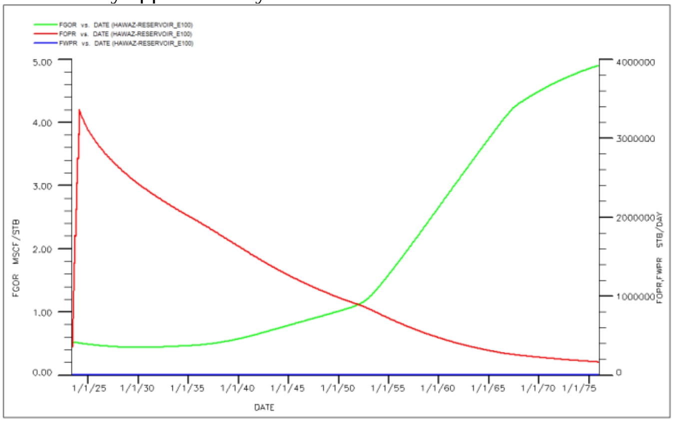

Figure 14: Oil Production Rate, Gas Oil Ratio, and Water

Production Rate Trend at Primary Recovery

Gas Oil Ratio Trend at Primary Recovery: This figure (Fig. 15) shows water production rate trend at primary recovery. We notice an increase at the end of the line, as shown for the year 2075, and the water production increased at 2075 by approximately 800 stb/day.

Water Cut Trend at Primary Recovery: This figure shows the water cut trend at primary recovery. We notice an increase at the end of the line, as shown for the year 2075, but it increased by a very small percentage and the minimum was approximately 0.006.

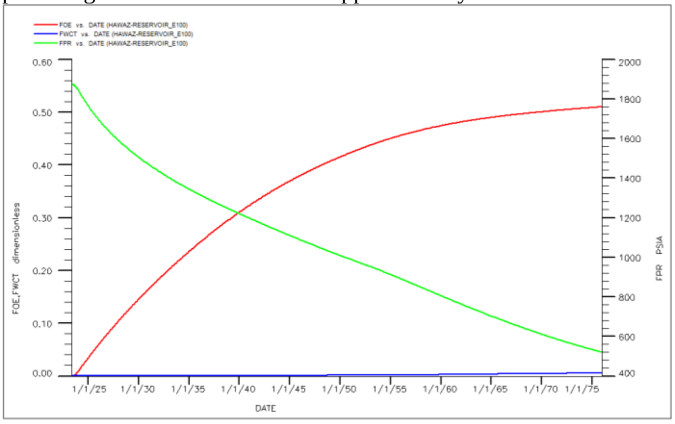

Figure 15: Water Cut, Recovery Factor, and Pressure Trend at Primary Recovery

Recovery Factor Trend at Primary Recovery: This figure (Fig. 15) shows recovery factor trend at primary recovery or field oil efficiency. We notice an increase in the recovery factor due to an increase in production (meaning it is a direct relationship).

Pressure Trend at Primary Recovery: This figure (Fig. 15) shows the pressure trend at primary recovery. It is true that the pressure in this field is weak and equal to 1800, but it has a decline as shown at the end of the line. This is the main reason for the water injection to increase the pressure.

Field Oil Production Total Trend at Primary Recovery: This figure (Fig. 16) shows the cumulative production of oil. We note when predicting the end of the year 2075, the cumulative production will be about 2 * 1010 bbl, i.e. (2 billion or about 2 billion). That is, the more production increases, the cumulative production increases

Field Gas Production Total Trend at Primary Recovery: This figure (Fig. 16) shows the cumulative production of gas. We notice an increase in the cumulative production of gas until the year 2075, and the increase was about 2 * 1010 scf, or about 2 billion.

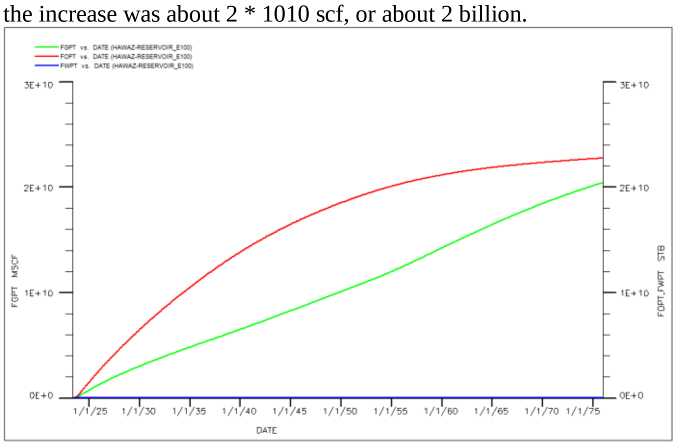

Figure 16: Field, Gas, Water, and Oil Production Total Trend at Primary Recovery

Field Water Production Total Trend at Primary Recovery: This figure (Fig. 16) shows the cumulative water production. We notice an increase in the accumulation of water until the year 2075. The increase was about 2 * 107, or about 20 million.

11. Water Injection:

Injection well location: The following figure (Fig. 17) and table No 2 show the location of the injection wells. This method is called direct injection. Between every two wells produce an injection well. For example: H7 and H4 production wells, and I4 injection wells were placed between them. In addition, wells H14 and H1, including the injection well I1.

After determining the location of the water injection wells, water was injected into the edges of the reservoir, i.e. in the water area, to increase the pressure of the reservoir.

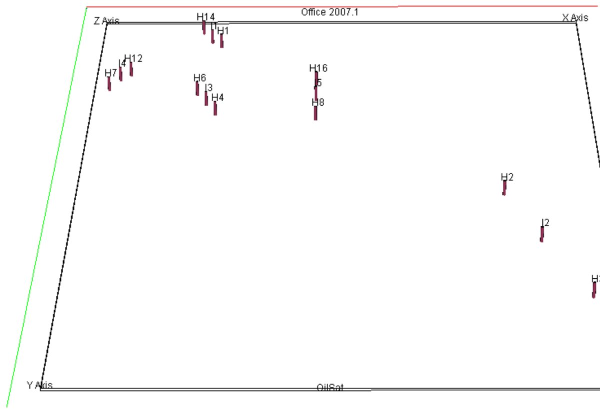

Figure 17: Injection well location

Table 2: Injection well location

Well Name	Date	Location in X	Location in Y
I1	01/03/2024	12	5
I2	01/04/2024	44	43
I3	01/05/2024	12	18
I4	01/06/2024	3	13
I5	01/07/2024	23	17

The first water injection well was at 03/31/2024. Besides, the location of the this well on x = 12 and y = 5. The second water injection well was at 01/04/2024. Besides, the location of the this well on x = 44 and y = 43. The third water injection well was at 01/05/2024. Besides, the location of the this well on x = 12 and y = 18. The fourth water injection well was at 01/06/2024. Besides, the location of the this well on x = 3 and y = 13. The fifth water injection well was at 01/07/2024. Besides, the location of the this well on x = 23 and y = 17.

Injection well Rate: After determining the location of the injection wells, the best daily water injection rate is now determined for each well. Besides, we have 10 scenarios, its meaning 10 cases, to determine the best rate for the water to be injected. In addition, each time (500BBL/DAY) is injected into one well. The total injection of wells, for example, in the first case, is 2500BBL/DAY. In the second case, for one well per day, 1000BBL/DAY, and the total rate of 5wells injection was 5000, and so on as shown in the next table No 3.

Table 3: Injection well Rate for each Scenarios

Scenarios	Water Injection per Well BBL/DAY	Total Water Injection BBL/DAY
Scanario#1	500	2500
Scanario#2	1000	5000
Scanario#3	1500	7500
Scanario#4	2000	10000
Scanario#5	2500	12500
Scanario#6	3000	15000
Scanario#7	3500	17500
Scanario#8	4000	20000
Scanario#9	4500	22500
Scanario#10	5000	25000

In the fifth case, the rate of water injection for one well per day was 2500BBL/DAY, and the total rate of water injection for the field per day is 12500BBL/DAY. In the sixth case, the rate of water injection for one well per day was 3000BBL/DAY, and the total rate of water injection for the field per day is15000BBL/DAY. In the seventh case, the rate of water injection for one well per day was 3500BBL/DAY, and the total rate of water injection for the field per day is 17500BBL/DAY. In the eighth case, the rate of water injection for one well per day was 4000BBL/DAY, and the total rate of water injection for the field per day is 20000BBL/DAY. In the ninth case, the rate of water injection for one well per day was 4500BBL/DAY, and the total rate of water injection for the field per day is 22500BBL/DAY. In the tenth case, the rate of water injection per well per day was 5000BBL/DAY, and the total rate of water injection into the field per day is 25000BBL/DAY.

Scenario#1: We have 5 wells injections. The injection started on

(1/3/2024) and ended on (1/7/2024), and the total number of injections in these wells per day is 2500 as shown in the next table No 4.

Table 4: Injection well Rate Results for Scanario#1

Well Name	Date	Rate BBL/DAY	Injection Total
I1	01/03/2024	500	
I2	01/04/2024	500	
I3	01/05/2024	500	2500
I4	01/06/2024	500	
I5	01/07/2024	500	

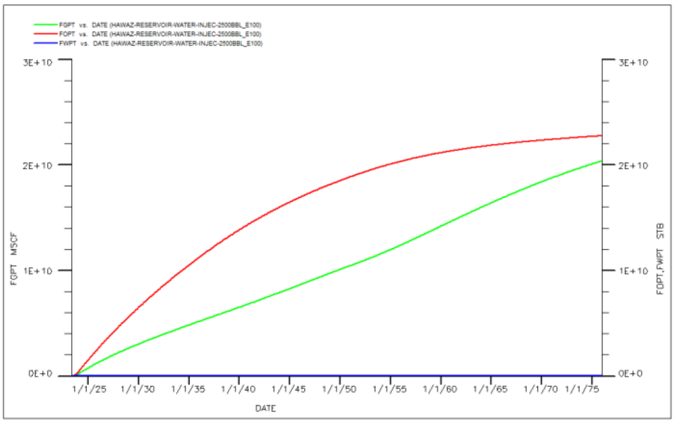

Figure 18: Field Oil, Gas, and Water Production Total Results for Scanario#1

This figure (Fig. 19) shows field oil production total results. We notice that, an increase in oil production total results due to injection water. Next figure shows the field gas production total results. We notice that, there is increase in gas production total results, because there is gas production every day. This figure shows field pressure results. We notice a slight decrease in pressure. Water injection is here to maintain pressure, not to increase pressure. The increase in the reservoir pressure occurs in only one case, that the amount of oil produced is the same as the amount of water that is injected, in this case the pressure increases. We notice an increase in recovery factor due to the increase in oil production.

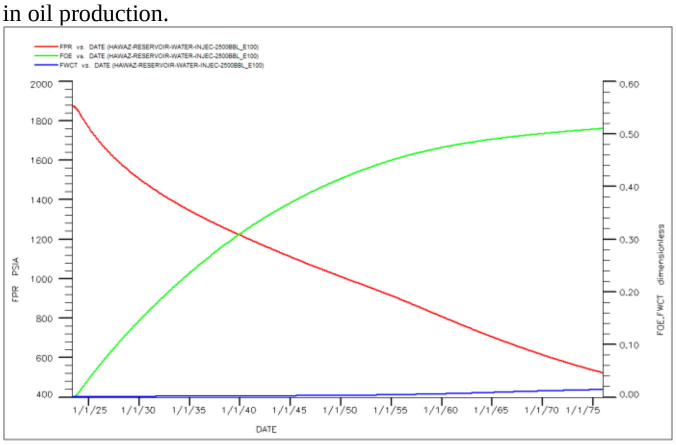

Figure 19: Field Pressure, Oil Recovery Factor, and Field Water Cut Results for Scanario#1

This figure (Fig. 19) shows water cut results. We notice an increase in the water cut due to water injection causing an increase in the water cut. This figure shows field water production total results. We notice an increase in water production due to water injection causing an increase in water production.

Comparison Water Injection Rates: This table No 5 shows a comparison of the 10 cases, and the last value of each last figures of the 10 scenarios is placed to find out the best rate injection water. And after drawing a relationship between (FORT vs Rate), (FGRT vs Rate)....etc, to get a comparison between the best rate injection water.

Table 5: Comparison Water Injection Rates Results

	FOPT	FGPT	FWPT	FWCT	FPR	FGOR	FOE
Base Case	2.275E+10	2.04E+10	2.2E+07	0.006	520.07	4.90	0.5097
2500	2.275E+10	2.04E+10	1.7E+05	0.014	522.79	4.89	0.5096
5000	2.274E+10	2.03E+10	8.1E+07	0.023	525.38	4.87	0.5095
7500	2.27E+10	2.03E+10	1.1E+08	0.030	527.85	4.86	0.5095
10000	2.274E+10	2.02E+10	1.3E+08	0.036	530.14	4.85	0.5094
12500	2.274E+10	2.02E+10	1.6E+08	0.042	532.36	4.83	0.5094
15000	2.274E+10	2.01E+10	1.8E+08	0.049	534.62	4.82	0.5094
17500	2.274E+10	2.01E+10	2.1E+08	0.056	536.91	4.80	0.5094
20000	2.274E+10	2.00E+10	2.3E+08	0.063	539.23	4.79	0.5094
22500	2.274E+10	2.00E+10	2.6E+08	0.069	541.55	4.77	0.5093
25000	2.273E+10	1.99E+10	2.8E+08	0.076	543.86	4.76	0.5093

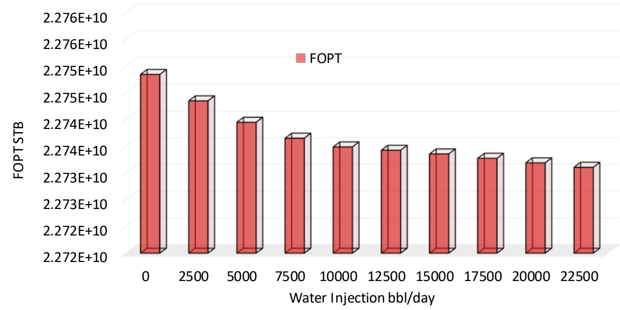

Figure 20: Comparison of Field Oil Production Total Results

The curve shows the line at zero oil production without water injection. We notice a decrease in the total production of oil, the decrease was very slight and it is in the third number after the decimal point. The difference could be in 100 barrels, or 200 barrels.

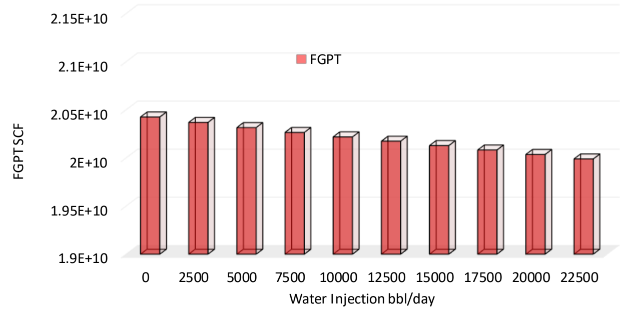

Figure 21: Comparison of Field Gas Production Total Results

This figure (Fig. 21) shows the relationship between (FGPT VS Rate). We notice a decrease due to oil decreasing.

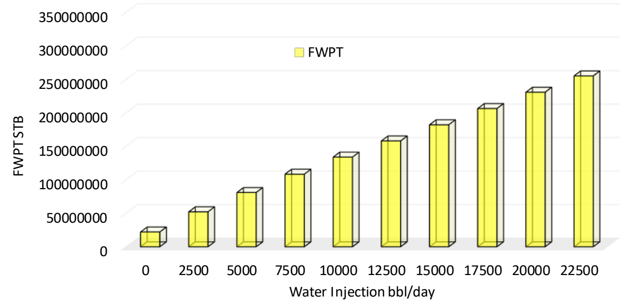

Figure 22: Comparison of Field Water Production Total Results

This figure (Fig. 22) shows the relationship between (FWPT VS Rate). We note that an increase occurred, and the main reason is due to an increase in the amount of water injection, which led to an increase in the amount of water production, and the other reason is a slight decrease that occurred in the total production of water and oil.

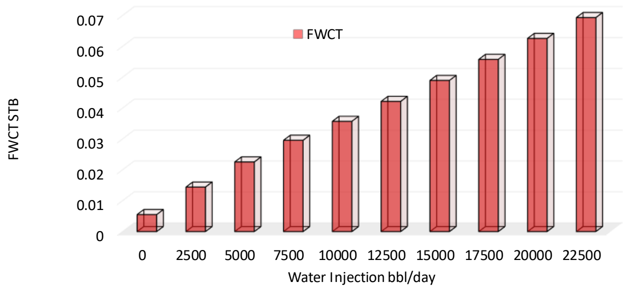

Figure 23: Comparison of Field Water Cut Results

This figure (Fig. 23) shows the relationship between (WC VS Rate). We note that an increase occurred, and the main reason is due to an increase in the amount of water injection, which led to an increase in the amount of water production, and the other reason is a slight decrease that occurred in the total production of water and oil.

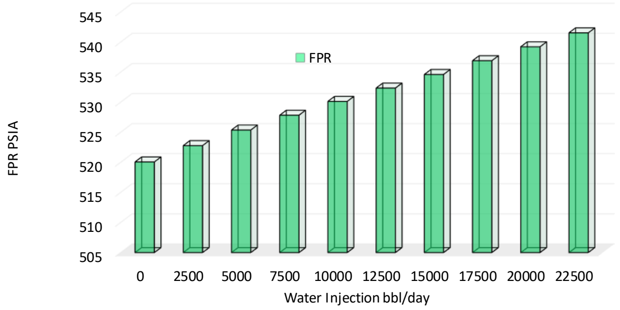

Figure 24: Comparison of Field Pressure Results

This figure (Fig. 23) shows the relationship between (FPR VS Rate). We notice an increase in pressure and a good increase. When production is normal, we notice the pressure was equivalent to 520 psi, but when injecting 22500 BBL/DAY, the pressure began to increase and reached approximately 540 psi.

This figure (Fig. 25) shows the relationship between (FGOR VS Rate). We notice a decrease due to the lack of expansion in the gas oil, which was explained above, and due to an increase in pressure, which led to a decrease in GOR.

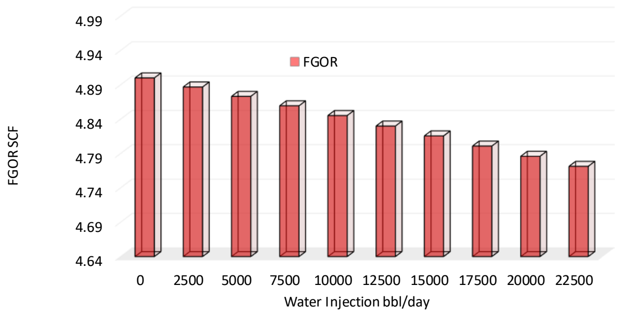

Figure 25: Comparison of Field Gas Oil Ratio Results

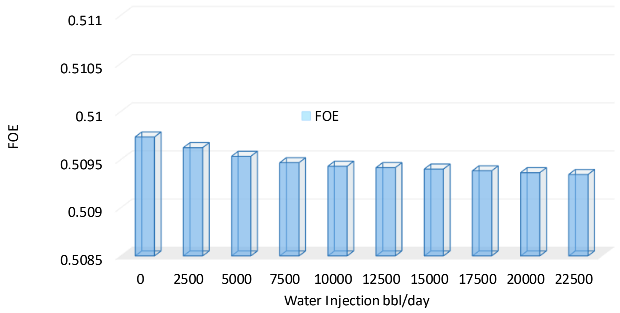

Figure 26: Comparison of Field Oil Efficiency Results

This figure (Fig. 26) shows the relationship between (FOE VS Rate). We notice a decrease due to a decrease in oil production, but the decrease was constant = 50%, and the decrease was at point. We note that in normal production, the RF was approximately 51%, and at 22500 BBL/DAY it decreased and became the equivalent of 50%, and the rest of the rate was 50%, but the difference in the decrease is small. Therefore, the most important thing is that the pressure was maintained and we noticed the increase in it, because our search title says reserve pressure maintenance

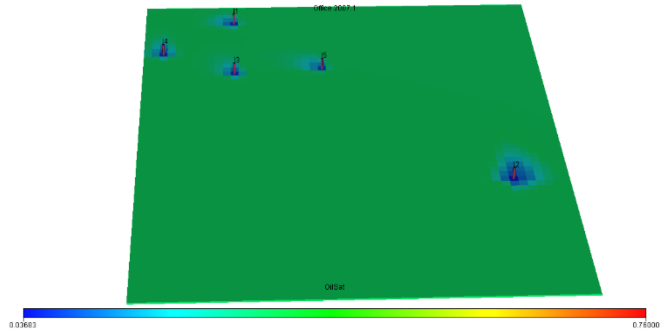

Figure 27: Oil Saturation Map at layer 21 at the end of Water Injection (2075)

This figure (Fig. 27) shows oil saturation layer (21). Now in this model we have (layers 30). Oil saturation at 2075 has changed and the reason for that is production or injection.

This figure (Fig. 28) shows gas saturation layer (21), because in this model we have (layers30). Gas saturation at 2075- has changed and the reason for that is production or injection.

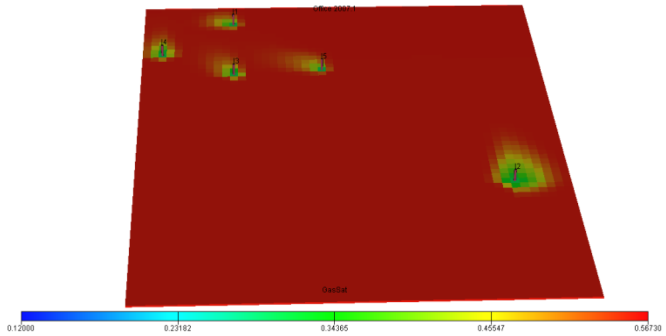

Figure 28: Gas Saturation Map at layer 21 at the end of Water Injection (2075)

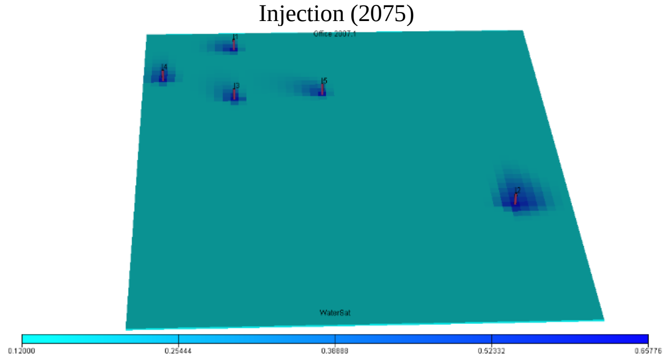

Figure 29: Water Saturation Map at layer 21 at the end of Water Injection (2075)

This figure (Fig. 29) shows (water saturation at layer 21), because in this model we have (layers30). Water saturation at 2075- has changed and the reason for that is production or injection.

12. Conclusion and Recommendation:

Conclusion: This project a simulation of vertical waterflooding in a Hawaz reservoir using Eclipse for reservoir pressure maintenance. Also, compares oil production rate, water cut, reservoir pressure increases, accumulated oil production and recovery factor in vertical waterflooding in a homogeneous reservoir. The simulation was performed about 52 years using ECLIPSE Reservoir simulator. Eclipse is a sophisticated software for the simulation of water-flooding. In all cases, result shows that oil production with water injection is higher compared with the base case. With this, it would be preferred to apply waterflooding for oil recovery in depleted reservoirs to the use of primary methods. It is also observed that water breakthrough is earlier and water production increases gently with water injection rates. Sensitivity on the injection rate using the 3D model showed that the injection rate has impact on the process. The pressure increases with high injection water rate in all cases. Despite higher reservoir pressure and early in water breakthrough, water flooding accounts for less oil recovery due to rapid water production.

Recommendation: Generally, based on the results and discussions, it can be concluded that the water injection option can be used to increase the reservoir pressure to a good extent

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