Optimization Water flooding and Gas flooding and Water Alternating Gas (WAG) and calculation of Minimum Miscibility Pressure (MMP) using CMG software, Ideal case

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الملخص يؤكد هذا البحث على الحاجة الملحة لتطوير تقنيات الاستخلاص المعزز للنفط، وخاصة الغمر بثاني أكسيد الكربون القابل للامتزاج لضمان الاستخدام المستدام للموارد الطبيعية واستغلالها على النحو الأمثل.

استخدمت الدراسة برنامج CMG لمحاكاة سيناريوهات مختلفة للاستخلاص المعزز للنفط، بما في ذلك الغمر بالمياه، والغمر بثاني أكسيد الكربون، والغمر بالغاز المتناوب بالماء وقاني أكسيد الكربون .تم فحص طريقة الغمر بالمياه والغاز المتناوب على وجه التحديد لتقييم عامل الاسترداد والإنتاجية في المكمن" الخزان واختبار نسب مختلفة للغمر بالمياه والغاز ومعدلات التدفق .حيث لوحظت النتيجة الأكثر فعالية مع نسبة غمر بالمياه والغاز 2:1 ومعدل تدفق 2222 برميل يوميا، مما أدى إلى تحقيق عامل استرداد 72.26 ٪ .تضمن البحث أيضا تحديد الحد الأدنى لضغط الامت ا زج لتحديد الظروف التي يصبح فيها الغاز" قاني أكسيد الكربون " قابلا للامتزاج". تم إجراء توقعات لإنتاج النفط الت ا ركمي وعوامل الاسترداد من عام 1756 إلى عام 2232 ,ومقارنة سيناريوهات التدفق الطبيعي والغمر بالمياه والغاز المتناوب على النفط . وتستند الدراسة إلى العمل السابق الذي قامت به مجموعة النمذجة الحاسوبية) CMG (في عام , 2222 باستخدام افت ا رضاتهم وتكوين نمط افتراضي مقلوب مكون من 6 آبار، حاقن واحد و 6منتجين.

Abstract:

This research emphasizes the critical need for advancing Enhanced Oil Recovery (EOR) techniques, particularly miscible CO2 flooding, to ensure the sustainable use of natural resources and their optimal exploitation. The study utilized CMG software to simulate various EOR scenarios, including Water Flooding, CO2 Flooding, and CO2 Water Alternating Gas (WAG) Flooding. The WAG method was specifically examined to assess the reservoir's recovery factor and productivity, testing different WAG ratios and flow rates. The most effective outcome was observed with a WAG ratio of 2:1 and a flow rate of 2000, achieving a recovery factor of 90.25%. The

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research also involved determining the Minimum Miscibility Pressure (MMP) to identify the conditions under which CO2 becomes miscible. Projections of cumulative oil production and recovery factors were made from 1965 to 2030, comparing natural flow and EOR scenarios. The study builds on previous work by the Computer Modelling Group (CMG) in 2020, using their assumptions and a default inverted 5-SPOT pattern configuration with 1 injector and 4 producers.

1.1 Introduction:

Oil recovery operations have traditionally been divided into three stages, namely primary, secondary, and tertiary. These stages historically represented the chronological production from a reservoir. The first stage, primary production, occurred naturally due to the displacement energy present in the reservoir. Over time, the reservoir pressure decreases, and the natural displacement energy diminishes, resulting in a reduction in the amount of extracted oil. In such cases, secondary processes can be employed to increase the reservoir pressure and push the oil towards the well, leading to the extraction of additional quantities of oil. The methods used in traditional secondary recovery include water flooding, pressure maintenance, and gas injection, although water flooding is now nearly synonymous with secondary recovery. The tertiary recovery was typically initiated after the secondary process becomes useless This may occur when the oil becomes more difficult to flow or when it exhibits poor wettability characteristics. The third stage involved obtaining additional oil after water flooding (or other secondary processes) through the use of miscible gases, chemicals, and/or thermal energy to displace the remaining oil .[1]

The chronological sequence is generally not applicable in the order of primary, secondary, and tertiary processes. This is because the secondary process may be considered primary, for example, at the beginning of the well's life when the pressure is low, and we resort to using secondary techniques to increase the pressure. Similarly, the tertiary process may be considered primary, for example, at the beginning of the well's life when the pressure is high but the oil viscosity is high or when the interfacial tension between the oil and rocks is high. In such cases, we resort to using thermal methods, which are part of tertiary recovery techniques, to reduce the oil density and mobilize it towards the production wells. It should be noted that the decision to employ the third process depends on the specific conditions of each oil field, including its geographic features, rock properties, and the characteristics of the oil present.

There may be cases where the third process is used as a primary operation in certain oil fields that possess specific attributes making them suitable for this type of recovery. Due to such circumstances, the term "tertiary recovery" has fallen out of

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favor in petroleum engineering literature, and the use of "enhanced oil recovery" (EOR) as a designation has become more widely accepted .[1]
Another commonly used descriptive term is "improved oil recovery" (IOR), which encompasses a broader range of activities, including reservoir characterization, improved reservoir management, and infill drilling, in addition to EOR.

1.2 Miscible Methods:

Homogeneous fluid replacement technology is used in the oil and gas industry to increase oil recovery from mature oil fields. This process involves injecting a fluid such as carbon dioxide (CO_2), nitrogen, alcohols, liquefied petroleum gas (LPG), or rich gas as a homogeneous fluid to move the remaining oil towards the production well .[1] When CO_2 is used as a homogeneous fluid, it is injected into the reservoir at high pressure and dissolves in the oil, reducing its viscosity and making it easier to move towards the production well. This process is known as "homogeneous CO_2 flooding". Nitrogen can also be used as a homogeneous fluid, but it is not as effective as CO_2 due to its low solubility in oil .[1]

1.3 Water Flooding:

Also known as water injection, is a process used in enhanced oil recovery to increase the production of oil or natural gas from oil fields. Large volumes of water are injected into oil reservoirs at high pressure to enhance the extraction of extractable compounds from the deposits.[1]
The primary objective of using water flooding is to increase production from oil fields and recover residual compounds in the deposits that cannot be extracted through conventional techniques. Water flooding is considered one of the most well-known enhanced oil recovery methods and is effective in increasing production.[1]

1.4 Gas Flooding:

- **By Hydrocarbon Gases:**

Gas flooding by using hydrocarbon gases is a process of enhanced oil recovery (EOR) that involves injecting gas into the reservoir to displace the oil and increase the pressure. Hydrocarbon gases are gases that contain mostly hydrocarbons, such as methane, ethane, propane, butane, etc. Hydrocarbon gas flooding can be either miscible or immiscible, depending on the pressure, temperature, and composition of the gas and oil. Miscible gas flooding means that the gas and oil can mix together and form a single phase, while immiscible gas flooding means that the gas and oil remain separate phases.[3]
Hydrocarbon gases can also improve the oil quality by reducing the viscosity and density of the oil. However, hydrocarbon gas flooding also has some challenges, such as high cost, low sweep efficiency, and environmental issues.[1]

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 Non-Hydrocarbon Gases:

Gas flooding by non-hydrocarbon gases is a process of enhanced oil recovery (EOR), that involves injecting gases other than hydrocarbons into the reservoir to displace the oil and increase the pressure. Non-hydrocarbon gases differ from hydrocarbon gases in their chemical composition, as they contain gases other than hydrocarbons, such as carbon dioxide (CO_2) and nitrogen (N_2) .[2]

The injection of non-hydrocarbon gases is used to improve oil recovery by increasing reservoir pressure and altering the oil properties. Injecting non-hydrocarbon gases may have different effects on the oil and reservoir compared to hydrocarbon gas injection.[2]

1.5 Water Alternating Gas (WAG) Process:

The Water Alternating Gas (WAG) process is a widely used Enhanced Oil Recovery (EOR) technique that involves injecting water and gas alternately into an oil reservoir to improve oil recovery. This process is achieved by injecting water and gas into the reservoir in a predetermined sequence, with each cycle lasting several weeks to several months.[1]

During the water injection phase, water is injected into the reservoir, displacing the oil and pushing it towards the production well. The water injection also helps maintain the pressure in the reservoir, which can increase the recovery of oil.[1]

During the gas injection phase, gas is injected into the reservoir, which helps to displace the remaining oil and push it towards the production well. The gas injection phase also helps to reduce the viscosity of the oil, making it more mobile and easier to extract.[1]

The WAG process is particularly effective in oil reservoirs with high permeability and heterogeneity, as it helps to prevent the gas from bypassing the oil and flowing directly to the production well. The alternating injection of water and gas also helps to reduce the risk of gas breakthrough, which can lead to reduced oil recovery.[1]

1.6 Ideal Case Overview:

This study was conducted based on a previous study conducted by CMG company in 2020 using the company's assumptions and default on inverted 5 spot pattern " Injector and TT1,TT4,TT6,TT7 as producers".

In oil field development, a variety of production configurations and fluid injection methods are employed. Among these, the "five-spot" pattern stands out as the most commonly used. The study spans from 1965 to 1990, marking the defined production stage. Following 1990, the prediction stage begins and extends until 2000, as natural flow prediction. During this phase, there is a noticeable decline in

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production and a slight reduction in pressure, indicating a natural decrease in well productivity and reservoir pressure.

The year 2000 marks the initiation of the EOR stage, introduced to increase production while the reservoir pressure remains relatively high. The study explores several EOR techniques, including Water Flooding, CO2 flooding, and Water-Alternating-Gas (WAG). Water Flooding is utilized to raise reservoir pressure and enhance oil recovery by injecting water into wells adjacent to the production wells, thereby pushing the oil towards these wells and improving pressure distribution within the reservoir. The CO2 flooding technique involves injecting carbon dioxide to increase oil recovery, while WAG is a method that alternates the injection of water and gas to improve extraction efficiency and pressure distribution, thus enhancing oil recovery.

The study employs the CMG program to model and simulate the impacts of WAG, CO2, and Water Flooding on oil extraction. Its objective is to assess the efficiency of these techniques and identify the optimal conditions for their application to maximize productivity and enhance oil recovery. A critical step in creating the model and simulating the EOR scenarios is determining the minimum miscibility pressure (MMP). The MMP is essential for the effectiveness of EOR techniques, as it is the lowest pressure at which injected CO2 can mix with the oil in the reservoir, leading to more efficient oil recovery.

1.7 Results And Discussion:

1.7.1 Minimum Miscibility Pressure (MMP):

In this study, we meticulously followed a multi-step approach to determine the Minimum Miscibility Pressure (MMP) for enhanced oil recovery. we systematically progressed through various stages, culminating in the precise calculation of MMP. The forthcoming discussion will delve into the critical steps involved, including:

1- Matching Saturation Pressure for non – Lumped Fluid:

The first calculated saturation pressure is 732.711 psia, this value needs to be re-matched to better align with the experimental saturation pressure result after regression is 740.05 psia, this value is close to the experimental saturation pressure740 psia.

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*                                                *
*             WINPROP   2021.10                  *
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* Computer Modelling Group Ltd., Calgary, Canada *
*                      3                         *
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luid characetion
Summary of Regression Results

   Calculation  Data   Pressure    Experimental   Before      After       ERROR       ERROR      Weight
     option     type  (MF-SWELL)       data      regression  regression  reduction    after      factor
   -----------  ----  ----------  ------------  ----------  ----------  ----------  ----------  ----------
    5 PRESSAT
                PSAT                7.4000E+02  7.3271E+02  7.4005E+02  9.7781E-03  7.1733E-05  1.0000E+00

   ERROR Reduction = ERROR before regression - ERROR after regression
   ERROR = (experimental - calculated) / experimental
```

Figure 1. Saturation pressure before lumping.

2- Matching saturation pressure for lumped fluid:

The first calculated saturation pressure is 690.85 psia, this value needs to be re-matched to better align with the experimental saturation pressure result after regression is 740.04 psia, which is closer to the experimental pressure even than before lumping.

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**************************************************
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* Computer Modelling Group Ltd., Calgary, Canada *
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Summary of Regression Results

   Calculation  Data   Pressure    Experimental   Before      After       ERROR       ERROR      Weight
     option     type  (MF-SWELL)       data      regression  regression  reduction    after      factor
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    5 PRESSAT
                PSAT                7.4000E+02  6.9085E+02  7.4004E+02  6.6376E-02  4.8390E-05  1.0000E+00

   ERROR Reduction = ERROR before regression - ERROR after regression
   ERROR = (experimental - calculated) / experimental
```

Figure 2. Saturation pressure after lumping.

3- Predicting Laboratory Experiments:

The Separator Test will be relied upon to ensure the success of the predicting laboratory experiments.

This will be achieved by matching GOR, API, and FVF.

Table 1. Comparison between experimental and calculated GOR, FVF and API.

Data Type	Experimental Data	Calculated Data
GOR	247	246.98
FVF	1.18	1.1811
API	40	40

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4- Determining Minimum Miscibility Pressure (MMP):
The calculated MMP is 2510 psia, this value is equal to the experimental minimum miscibility pressure which is 2510 psia.

```
**=-=-=CMG GEM EOS Model
**REM
**NC 7 7
*PRNGEM
*TRES  186.0
*AQUEOUS-DENSITY  *LINEAR
*SOLUBILITY
*TEMP  186.0
*PRES  2510.0

**=-=-=     END
```

Figure 3. Calculated Minimum Miscibility Pressure.

- In this case the reservoir pressure is 5000 psia, the reservoir pressure plays a crucial role in determining the CO2 MMP.
- As the reservoir pressure decreases, the CO2 MMP typically increases.
- This means that at higher reservoir pressures, the CO2 MMP is lower, and the injected CO2 Is more likely to mix effectively with the oil and enhance oil recovery. Conversely, as the reservoir pressure decreases, the CO2 MMP increases, making it more challenging for the CO2 to mix with the oil and achieve efficient displacement.

1.7.2 RF Results Comparison:

Table 2. RF for Various Time Periods and EOR Scenarios

-

Process	Time (Years)	Calculated Cumulative oil production bbl	Oil Recovery Factor %
Defined primary production stage	1965-1990	15643086	27.23
Natural flow prediction	1965-2000	23270982	40.50

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Natural flow prediction	**1965-2030**	**42149964**	**73.357**
Water Flooding	**1965-2030**	**43747584**	76.138
CO2 Flooding	**1965-2030**	**52024784**	90.544
WAG Flooding	**1965-2030**	**50798868**	88.41

The table presents recovery factor values for the four scenarios.

- We observe that the difference in recovery factor (RF) between water flooding and natural flow prediction is minimal, water flooding exceeds prediction without EOR by only (2.78%), (0.549%) from the total volume of reservoir.
- However, there is a noticeable disparity between the natural flow prediction, CO_2 injection, and water-alternating-gas (WAG) methods. Specifically, CO_2 injection increases the recovery factor by (17.186%), while WAG increases it by (15.052%).

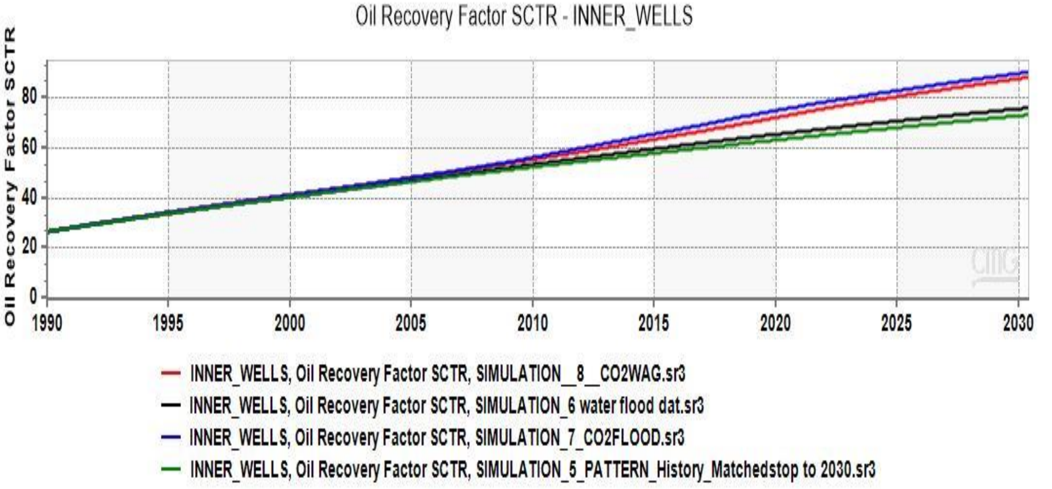

Figure 4. Oil recovery factor for the 4 scenarios of prediction.

- As we observe from the values presented in the table and the highest cumulative oil production and recovery factor corresponds to the CO_2 process, the RF percentage of CO_2 exceeds WAG process by (2.134%).
- This is because a larger amount of CO_2 is injected during the same time frame, resulting in increased sweep and displacement efficiency.

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1.7.3 Quality Check:

This comparison will be made between the results obtained in this study and CMG company's results in terms of cumulative oil production and recovery factor. The company's available results pertain to two cases: WAG and CO2.

1.7.4 Cumulative oil production Quality Check:

Table 3. Comparison between the values of the calculated results and CMG company's results for the cumulative oil production.

Process	Time (Years)	Calculated Cumulative oil production bbl	CMG Cumulative oil production bbl
Natural flow prediction	1965-2030	42149964	-
Water Flooding	1965-2030	43747584	-
CO2 Flooding	1965-2030	52024784	52033369
WAG Flooding	1965-2030	50798868	50816163.5

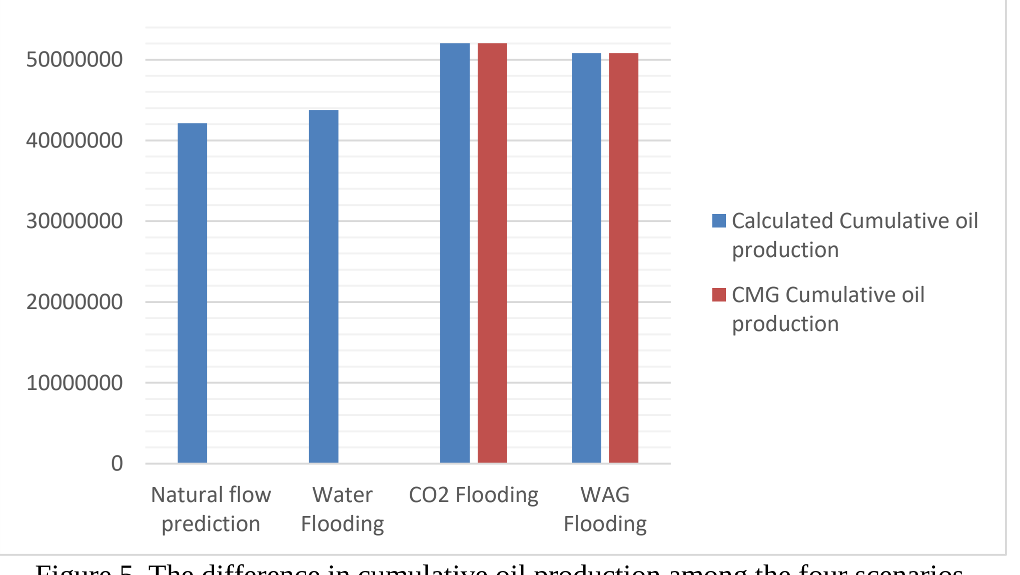

Figure 5. The difference in cumulative oil production among the four scenarios.

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1.7.5 Recovery Factor Quality Check:

Table 4. Comparison between the values of the calculated results and CMG company's results for the recovery factor.

Process	Time (Years)	Calculated Oil recovery factor %	CMG Oil recovery factor %
Natural flow prediction	**1965-2030**	**73.357%**	**-**
Water Flooding	**1965-2030**	**76.138%**	**-**
CO2 Flooding	**1965-2030**	**90.5444%**	90.558**%**
WAG Flooding	**1965-2030**	**88.41%**	88.44**%**

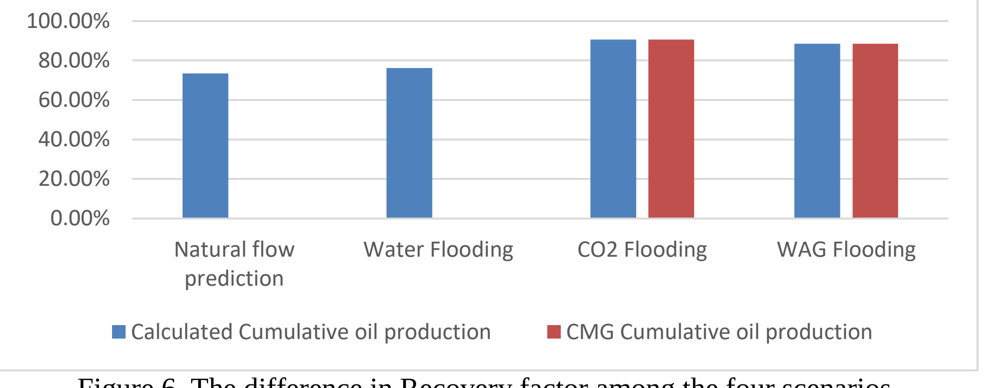

Figure 6. The difference in Recovery factor among the four scenarios.

1.7.6 Error percentages:

The percent error between the calculated values and the values obtained from CMG simulations in both cases is minimal. Consequently, we can confidently assert that the preceding processes were successful.

The flow rate, Injection rate and pressure are constant in the 4 scenarios.

- The WAG process was chosen for additional tests because the (2.134%), percentage may not cover the additional costs, such as operational expenses, associated with CO_2 injection.

1.7.7 Effect Of Change In WAG Ratio:

The following WAG ratios was tested at constant flow rate depending on the time ratio "Month" Co2 to Water: (1:1), (1:2), (1:3), (2:1), (3:2), (6:6).

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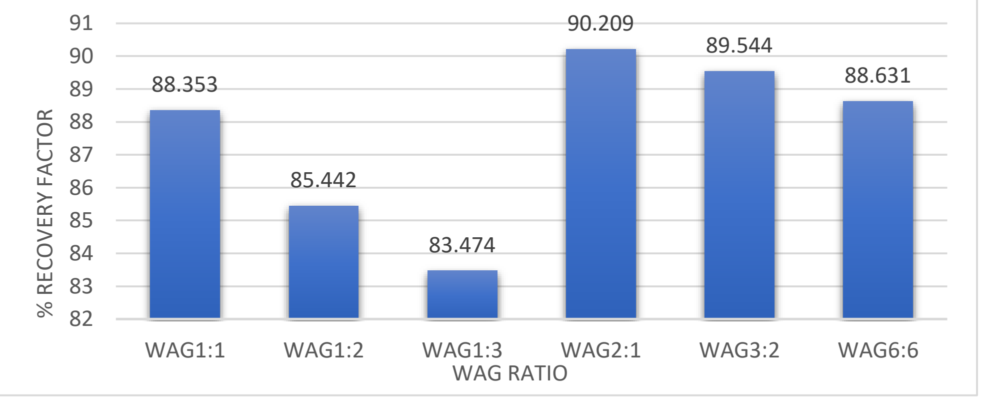

Figure 7. Recovery factor for tested WAG ratios.

- Based on the results shown above and from the figure, we can observe that the highest recovery factor is for the (WAG 2:1) process at (90.209%). We also see that the closest result to this is for the (WAG 3:2) process at (89.544%). This is because injecting CO2 gas generally results in higher RF rates compared to other processes.
- While the lowest recovery factor was for the (WAG 1:3) process at (83.474%). This is because a lower gas injection ratio will result in a lower RF.

1.7.8 Effect Of Change In Flow Rate:

The change in flow rate for the inner-production wells was tested on the following WAG ratios: (3:3), (3:2), (1:1), (2:1), (6:6).

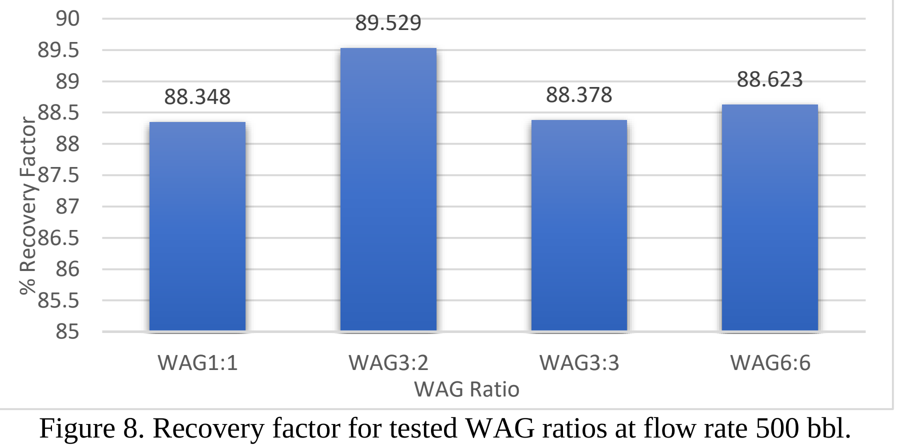

Figure 8. Recovery factor for tested WAG ratios at flow rate 500 bbl.

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1- Recovery Factor at Flow rate 500 bbl:

- As shown in the figure above, it is observed that the highest RF percentage is for the (WAG 3:2) process at (89.529%).
- While the percentages for the other processes are similar, the lowest RF percentage is for the (WAG 1:1) process at (88.348%).

2- Recovery Factor at Flow rate 1000 bbl:

3-

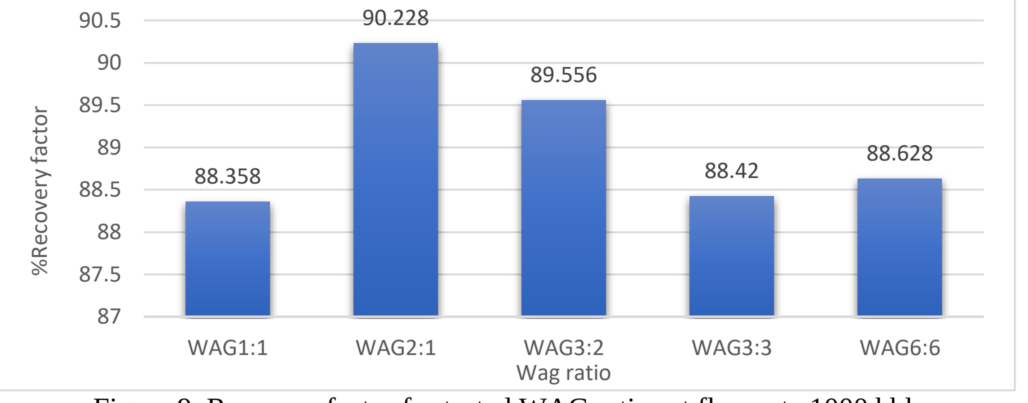

Figure 9. Recovery factor for tested WAG ratios at flow rate 1000 bbl.

- As the results and the figure above indicate that the highest RF percentage is for the (WAG 3:2) process at (90.25%).

As we can observe, there is a significant similarity between the RF percentages for the (WAG 3:2) and (WAG 2:1) processes, with (WAG 3:2) having a marginally higher RF percentage by (0.022%).

4- Recovery Factor at Flow rate 1500 bbl:

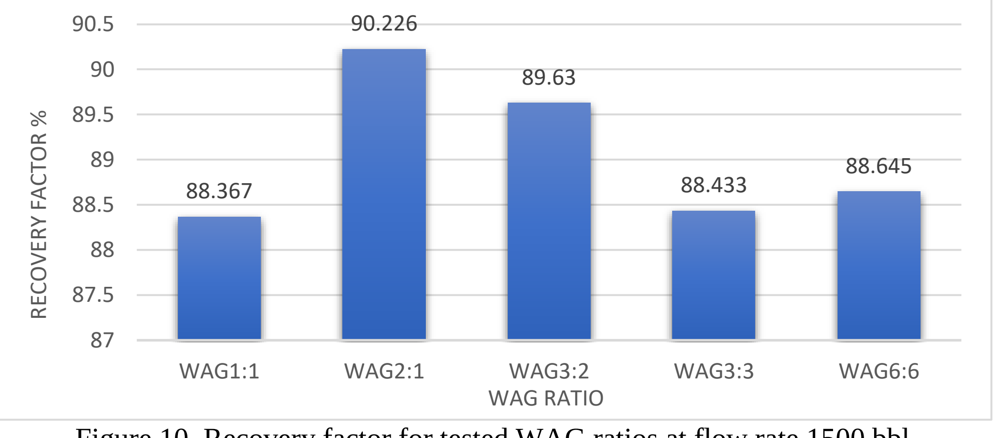

Figure 10. Recovery factor for tested WAG ratios at flow rate 1500 bbl.

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- As illustrated in the table and figure, the highest RF rate is for the (WAG 2:1) process at (90.226%), while the lowest rate is for the WAG 1:1 process at (88.367%).

5- Recovery Factor at Flow rate 2000 bbl:

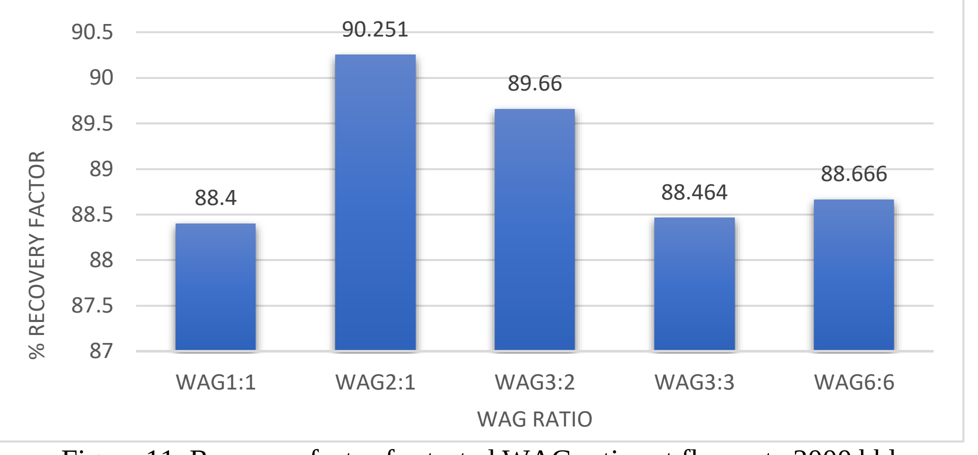

Figure 11. Recovery factor for tested WAG ratios at flow rate 2000 bbl.

- As illustrated in the table and figure, the highest RF rate is for the (WAG 2:1) process at (90.251 %), while the lowest rate is for the WAG 1:1 process at (88.40%).
- There is no significant difference in the results when changing the flow rate at (2000 bbl) and (1500 bbl), as they show almost the same recovery factor percentage.

Conclusion:

1. A significant improvement in the Recovery Factor has been achieved using the WAG process compared to conventional extraction techniques.
2. It has been determined that the appropriate WAG ratio depends on injecting a suitable amount of carbon dioxide compared to water, and further studies should be conducted to determine the optimal values for the ratio.
3. The impact of changing the Flow Rate on WAG performance has been analyzed, and the results have shown that certain flow rate values can enhance recovery efficiency.
4. The MMP (Minimum Miscibility Pressure) was determined using WINPROP and is equal to 2510.

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5. The water cut decreased in water flooding, and CO_2 had the highest rate of reduction.
6. The highest Recovery Factor was achieved with CO_2.
7. This study demonstrates the high effectiveness of using miscible flooding.

Recommendations:

1. Field experiments are recommended to evaluate the efficiency of the WAG process in real oil fields and identify the factors that affect its performance in different scenarios.
2. It is recommended to improve control over the distribution of carbon dioxide and water in the field by applying liquid distribution enhancement techniques, such as using sweep media or improving well design.
3. Expanding the scope of the study is recommended to evaluate the impact of varying carbon dioxide concentration and fluid properties on WAG performance under different conditions.
4. Economic studies are recommended to assess the project's cost and analyze its economic benefits, including the cost analysis of carbon dioxide usage and storage.
5. Improving the monitoring and surveillance of carbon dioxide and water distribution in the field is recommended using advanced geophysical imaging techniques and remote sensing technologies.
6. Conducting a study on 7-spot and 9-spot patterns is recommended.

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