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A Comparative Study of Water and Gas Injection Simulation in Libyan X Field Using Eclipse Software

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A B S T R A C T

The main goal of this study (which the comprehensive reservoir study for Libyan X Field plan of development) is to predict future performance of a reservoir and find ways and means of optimizing the recovery of some of the hydrocarbon under various operating conditions. The simulator results show the reservoir pressure history curve is matching to the stimulation curve, this gives a good indication of the input data that has been entered to the model. The driving mechanism for all those reservoirs it comes from three natural forces, which are fluid expansion, PV compressibility, and water influx. The best method to choose as secondary recovery for this oil field is water and gas Injection. Water and gas Injection have the largest Total Field Recovery. Water and gas Injection have the highest Reservoir Pressure at the end of the project. The highest percentage of oil recovery was when the water and gas were injected and it reached 58%, then when the water was injected and it reached 55%, and then when the gas was actually injected and it reached 54%. The field pressure rise was greater when water and gas were injected, and the pressure reached 792 psi, while it was less when only water was injected, reaching 435.5 psi, and when only gas was injected, it reached 412.9 psi. Finally, central objective of this master thesis with the help of reservoir simulation fulfilled to produce future prediction that will lead to optimize reservoir performance which meant reservoir developed in the manner that brings utmost benefit to the commercial business.

دراسة مقارنة لمحاكاة حقن الماء والغازلحقل X الليبي باستخدام برنامج Eclipse.

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الكلمات المفتاحية:
دراسة محاكاة
حقن المياه والغاز
المجال X الليبي
دراسة مقارنة
برنامج Eclipse

الملخص

الهدف الرئيسي من هذه الدراسة (وهي دراسة المكمن الشاملة لخطة تطوير الحقل الليبي X) هو التنبؤ بالأداء المستقبلي للمكمن وإيجاد السبل والوسائل لتحسين استخلاص بعض الهيدروكربونات في ظل ظروف التشغيل المختلفة. تظهر نتائج المحاكاة أن منحنى تاريخ ضغط الخزان يتطابق مع منحنى التحفيز، وهذا يعطي مؤشرا جيدا للبيانات المدخلة التي تم إدخالها إلى النموذج. آلية القيادة لجميع تلك الخزانات تأتي من ثلاث قوى طبيعية، وهي تمدد السوائل، والانضغاط الكهروضوئي، وتدفق المياه. أفضل طريقة لاختيار الاستخلاص الثانوي لحقل النفط هذا هي حقن الماء والغاز. يتمتع حقن الماء والغاز بأكبر قدر من الاسترداد الحقلي الإجمالي. يتمتع حقن المياه والغاز بأعلى ضغط خزان في نهاية المشروع. أعلى نسبة استخلاص للنفط كانت عند حقن الماء والغاز وبلغت 58%، ثم عند حقن الماء وصلت إلى 55%، ثم عند حقن الغاز فعلياً وصلت إلى 54%. وكان ارتفاع الضغط الميداني أكبر عند حقن الماء والغاز، ووصل الضغط إلى 792 رطل لكل بوصة مربعة، بينما كان أقل عند حقن الماء فقط، ليصل إلى 435.5 رطل لكل بوصة مربعة، وعند حقن الغاز فقط وصل إلى 412.9 رطل لكل بوصة مربعة. أخيرًا، تم تحقيق الهدف الرئيسي لرسالة الماجستير هذه بمساعدة محاكاة المكامن لإنتاج تنبؤات مستقبلية تؤدي إلى تحسين أداء المكمن مما يعني تطوير المكمن بطريقة تحقق أقصى فائدة للأعمال التجارية.

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1. Introduction

Today fossil fuels supply more than 85% of the world's energy. Currently, we are producing roughly 87 million barrels per day 32 billion barrels per year in the world. That means every year the industry has to find twice the remaining volume of oil in the North Sea just to meet the target to replace the depleted reserves. Of the 32 billion barrels produced each year, almost 22 billion come out of sandstone reservoirs. The reserves and production ratios in sandstone fields have around 20 years of production time left. The proven and probable reserves in carbonate fields have around 80 years of production time left (Montaron, 2008). The purpose of secondary recovery is to maintain reservoir pressure and to displace hydrocarbons toward the wellbore. The most common secondary recovery techniques are gas injection and waterflooding. Normally, gas is injected into the gas cap and water is injected into the production zone to sweep oil from the reservoir. A pressure-maintenance program can begin during the primary recovery stage, but it is a form or enhanced recovery.

Objective: The main goal of this study (which the comprehensive reservoir study for Libyan X Field plan of development) is to predict future performance of a reservoir and find ways and means of optimizing the recovery of some of the hydrocarbon under various operating conditions.

The key objectives of this study are:

1. To collect and analysis data for Libyan X Field oil and gas field.
2. To analyze production and pressure histories to understand the performance of Libyan X Field reservoir, drive mechanism of the Libyan X Field reservoir and remaining oil reserve.
3. To determine the optimal production strategy.
4. To predict future production performance for applying water and gas injection.
5. To study the effect of water and gas injection ratio and the injection rate on the production performance.

2. **Methodology:** The reservoir simulations project in this thesis will be dedicated to "X Cretaceous Reservoir" which is one of the major accumulations of X Field. The methodologies of this study are:

2.1 Reservoir Potential Analysis: Material balance evaluations that identify the main reservoir driving force using available data by material balance Software. Reservoir depletion analysis to know what happen in natural depletion in this Filed. Production decline analysis to identify well production problems and to predicate well performance and life based on real production data. The production rate versus time plot is commonly used to diagnose well and reservoir performance, so we do the production decline rate by the production rate vs. time.

2.2 Reservoir characterizations: The reservoir description and analysis consist of PVT analysis, routine and special core data and analysis SCAL.

2.3 Reservoir Simulation: Model Constriction to generate a numerical model counting to determine the rock and the fluid properties distribution and grid size. Forecasting, the model can be used to forecast future performance of the reservoir based on selected development strategy.

2.4 Secondary Recovery: in simple terms, the secondary recovery is the addition of basic water-flood and gas injection.

Waterflooding is perhaps the most common method of secondary recovery. However, before undertaking a secondary recovery project, it should be clearly proven that the natural recovery processes are insufficient; otherwise, there is a risk that the substantial capital investment required for a secondary recovery project may be wasted.

Lithology and Rock Properties: Reservoir lithology and rock properties that affect flood ability and success are Porosity, Permeability, Clay content, and Net thickness.

2.5 Fluid Saturations: In determining the suitability of a reservoir for waterflooding, a high oil saturation that provides a sufficient supply of recoverable oil is the primary criterion for successful flooding operations.

2.6 PVT Data Analysis for X Field:

The figure below shows how the solution gas oil ratio changes as a function of pressure at constant reservoir temperature.

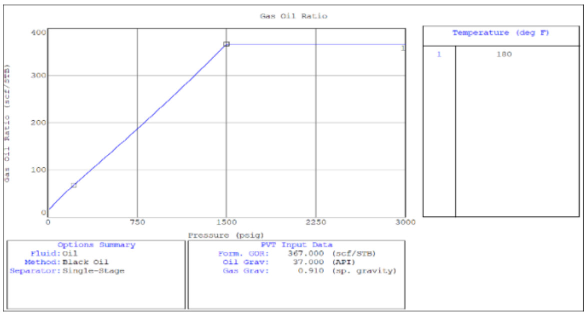

Figure 1: Gas/oil ratio (GOR) vs. Pressure for X Field

The oil viscosity is strongly dependent on the values estimated for both the bubble point pressure and the solution gas-oil ratio.

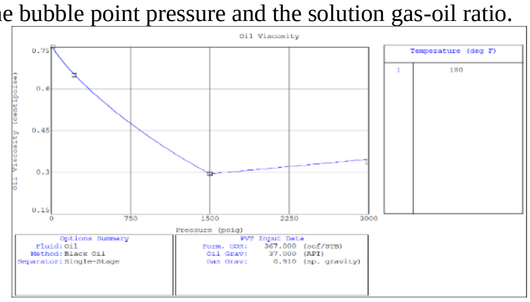

Figure 2:Crude Oil Viscosity vs. Pressure for X Field

The typical shape of oil formation volume factor is illustrating in the figure below:

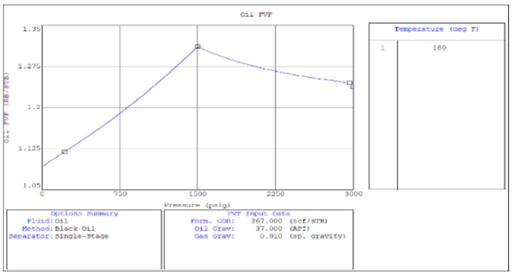

Figure 3:Oil Formation Volume Factor vs. Pressure for X Field

The figure above shows how the formation volume factor changes as a function of pressure at constant reservoir temperature. When the pressure decreases below the bubble point pressure, more gas is liberating from the liquid phase, making the oil much denser.

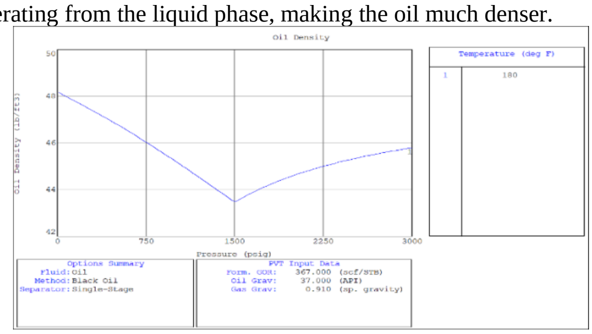

Figure 4:Oil Density vs. Pressure for X Field

The figure below shows that the formation volume factor is inversely proportional to pressure.

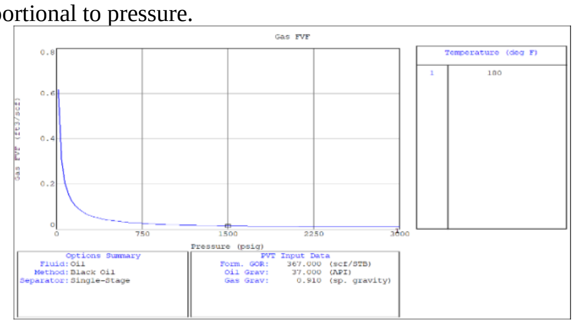

Figure 5:Gas Formation Volume Factor vs. Pressure for X Field

2.7 Reservoir Potential Analysis and Depletion Analysis

Figure 1 shows the methodology of driving mechanism as showing in the following flow chart:

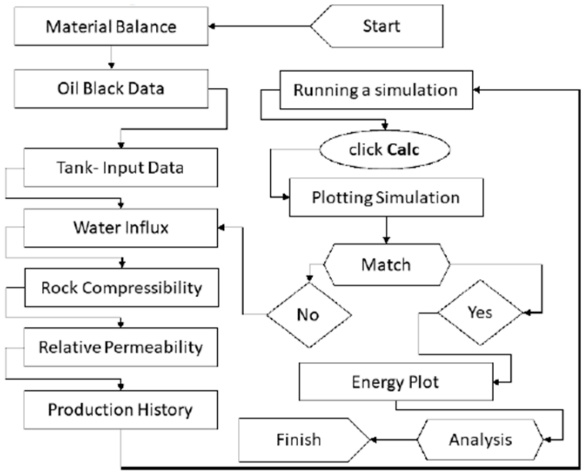

Figure 6: Flow Chart Explains the Steps of methodology of MBAL used in this Study After Madi et al 2021

Figure 2 shows the reservoir pressure history and simulation vs time. The history reservoir pressure curve is matching to the stimulation curve, this gives a good allusion of the input data that has been entered to the model.

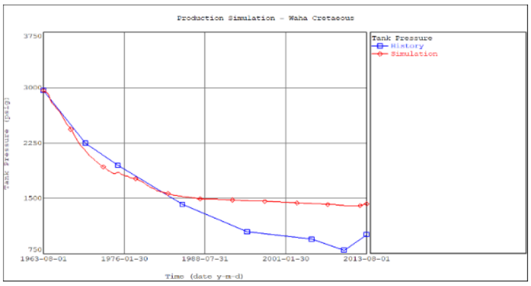

Figure 7: Production History with Time VS Pressure for X Field

The plot describes the prevalent energy system present in the reservoir; water influx, pore volume compressibility, fluid expansion, ingestions etc.

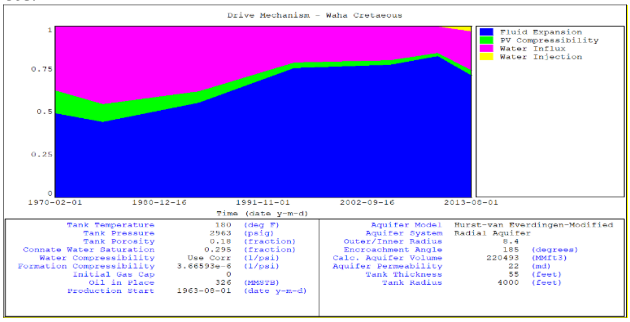

Figure 8: Driving Forces for X Field

The following figure shows the cumulative water production of the field. We note that in the axis. The Y-axis represents the cumulative total production of water in the MMSTB unit. The cumulative water production approximately 44 million STP.

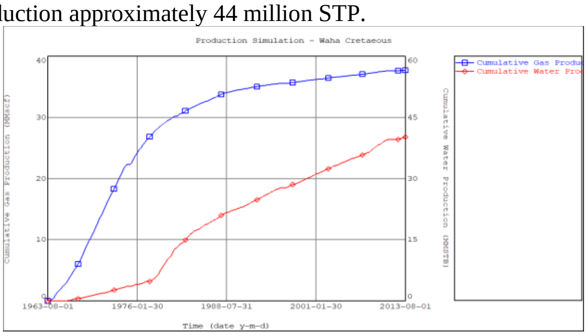

Figure 9: Field Water and Gas Cumulative X Field

The following figure shows the cumulative production, as shown also, the Y-axis represents the cumulative gas production in the unit of MMSCF, while in the X-axis it represents the time. We note that there is an increase in gas production amounting to approximately 40 million scf. The following figure shows the field pressure, the pressure in units of psig. It began with 300 psig and decline due to production to approximately 750 psi in 2012, but it began to rise due to the water injection to approximately 850 psig in 2023. The following figure shows the cumulative production of the field from 1963 to 2013 in the Y-axis. The cumulative production of total oil is represented in the unit of MMSTP, while in the approximately cumulative production of total oil 100 MMSTB.

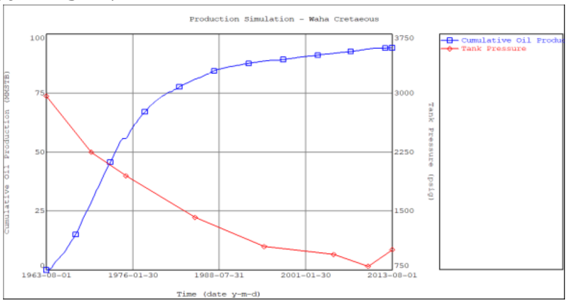

Figure 10: Oil Cumulative and Field Pressure X Field

2.8 Reservoir Simulation

Numerical Model Cells: The next figure shows the numerical model cells. The number of cells in X direction is 57 cells, and the number of cells in Y direction is 46 cells, the number of cells in z direction is 56 cells.

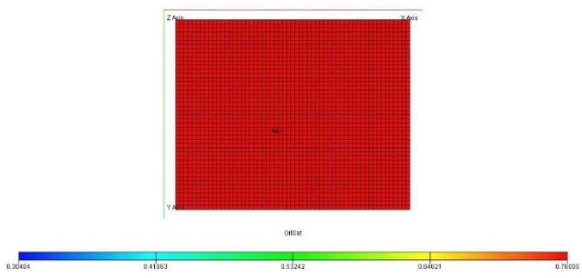

Figure 11: Numerical Model Cells

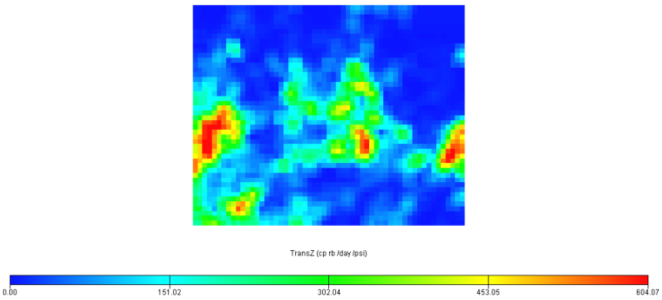

Figure 12: Permeability Distribution Layer 5

The following figure shows the porosity. The porosity ranges from 6% to 35%. Of course, this porosity is layer number five.

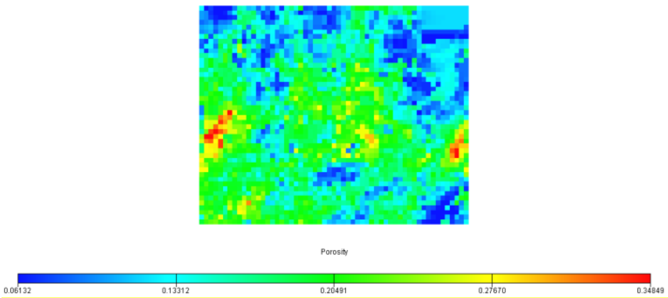

Figure 13: Porosity Distribution Layer 5

The following table shows the production history of the wells. We note that there is the name of the well, whether it is a producer or an injection. For example, we have the well A60IS produced 4/1964 to 1/3/ 2011, well A65 has a production allowance from June 1, 1964 to August 1, 1982, and well A132 has a production from August 1, 2006 to August 1, 2013.The well A97 does not produce.

Table 1: Schedule of History Production Wells

Well Name	From	To
A 60	1964-04-01	2011-03-01
A 65	1964-06-01	1982-02-01
A 132	2006-08-01	2013-08-01
A 41	1963-08-01	1981-04-01
A 86	1967-11-01	2001-08-01

A 97	No	No
A 42	1963-10-01	2013-08-01

The next table shows the injection schedule for the injection wells. There are three types, A71, A63, and A119. Water injection into these wells for well A71 began from 7/2012 to 8/2013 with an injection rate of 9818 barrels per day, while well A63 actually started from 8/2012 to 8/2013 at a daily water right rate of 456 and the well A119. Water injection began from **8**/2013 to 8/2013 with a daily right rate of 102 barrels per day.

Table 2: Schedule of History Injection Wells

Well Name	Start Injection	to	Injection Rate
A71	01/07/2012	2013-08-01	9818
A63	01/08/2012	2013-08-01	4556
A119	01/04/2013	2013-08-01	102

The following figure shows the total amount of water injected to 2013. We notice that the total amount of water injected reached 5 million and 400,000 barrels. The following figure shows the history field water injection total. As the rate increased, the productivity actually increased. The following figure shows the history field water production rate with water injection. We notice that there is an increase in water productivity from water, but the increase is considered slight. The following figure shows the history field gas production rate with water injection. We notice that there is an increase in gas productivity, but it is considered, to a reasonable extent, a small increase, just like normal production without water injection.

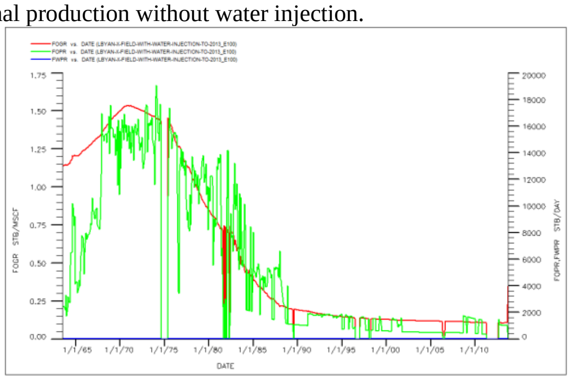

Figure 14: History Field Oil, Water, and Gas Production Rate with Water Injection

The following figure shows the history field pressure with water injection. We notice that at the end of the injection up to the year 2013, the pressure reached 728 PSI. The following figure shows the history oil recovery vs. time with water injection. We notice that there is an increase in the oil recovery with the increase in water injection, as the oil recovery reached 47% of the original oil.

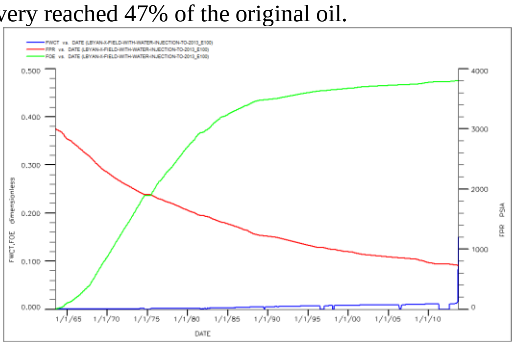

Figure 15: History Field Pressure and Oil Recovery with Water Injection

The following figure shows the history field gas production total with water injection. We notice that the gas productivity is increasing until it reached one point 1.5 x 106 SCF. The following figure shows the history field oil production total with water injection. We notice that the total oil productivity reached 97501336 barrels. The following figure shows the total water productivity for the field without water injection. We notice that the total water productivity at the end of 2013 reached 176,000 barrels. The following figure shows the water saturation in layer No. 30 at the end of the water injection in 2013. We notice that the water saturation in the layer starts from 12% to 73%.

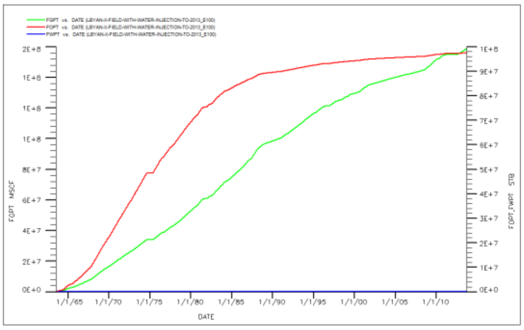

Figure 16: History Field Gas, Oil, and Water Production Total with Water Injection

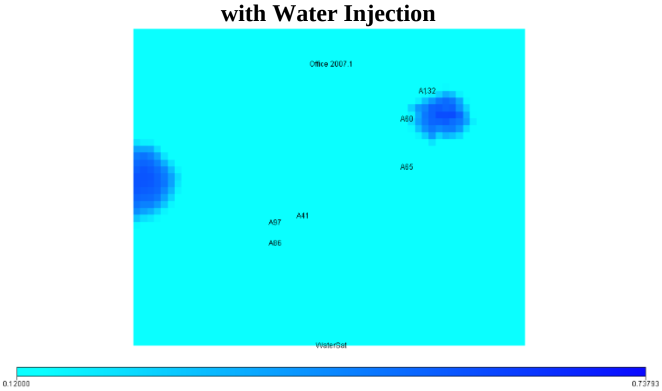

Figure 17: Water Saturation Layer 30 for History Water Injection

The following figure shows the oil saturation in layer No. 30 at the end of injection in 2013. We notice that the oil saturation in this layer starts from 0.003 from to 76%.

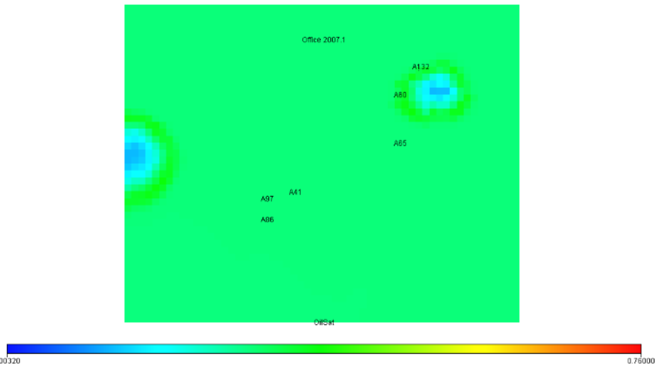

Figure 18: Oil Saturation Layer 30 for History Water Injection

The following figure shows gas saturation in layer No. 30 until the end of water injection in 2013. We notice that gas saturation starts from 12% to 59%.

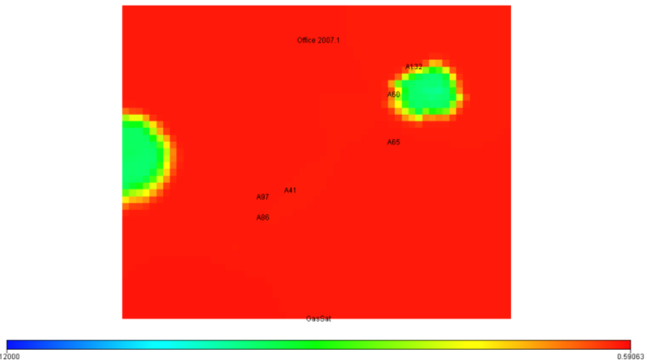

Figure 19: Gas Saturation Layer 30 for History Water Injection

CASE#2: Prediction Water Injection- From 01-04-2022 to 01-05-2052: In this section, we will display the results of water injection from April 2022 to May 2052. The following table shows the forecast table for producing for seven wells. For example, we have the well A60, at first, its production was operating from April 1964 to March 2011. Here, production will start from April 2022 to May 5, 2052, and well A65 will start producing from April 2022 to May 2052. All wells here will begin production from April 2022 to May 2052 such as well A65, A132, A41, A86, A97, and A42.

Table 3: Schedule of Prediction Production Wells

Well Name	Start Prod	Stop Prod	Start Prod	Stop Prod
A 60	1964-04-01	2011-03-01	01-04-2022	01-05-2052
A 65	1964-06-01	1982-02-01	01-04-2022	01-05-2052
A 132	2006-08-01	2013-08-01	01-04-2022	01-05-2052
A 41	1963-08-01	1981-04-01	01-04-2022	01-05-2052
A 86	1967-11-01	2001-08-01	01-04-2022	01-05-2052
A 97	No	No	01-04-2022	01-05-2052
A 42	1963-10-01	2013-08-01	01-04-2022	01-05-2052

The following table shows the wells' prediction of the injected productivity. For example, at well A71 injection from April 2022 to May 2052, with water injection rate is 9818 bbl per day. while the well A163 with injection rate is 456 bbl per day, and the A119 with an injection rate is 102 barrels per day.

Table 4: Schedule of Prediction Water Injection Wells

Well Name	Start Injection	Stop Injection	Injection Rate
A71	01-04-2022	01-05-2052	9818
A63	01-04-2022	01-05-2052	4556
A119	01-04-2022	01-05-2052	102

The next figure shows the prediction field pressure with water injection. It is noted that at the end of the injection there is a slight increase water injection, and the pressure reached an end in the year 2052 to 435.5 psia. Next figure shows the prediction oil recovery vs. time with water injection, so we notice at the end of the water injection, and in the year 2052 oil recovery increased to about 60%. This means that 60% of the original oil was produced by water injection.

Next figure shows the prediction field oil gas ratio with water injection. In the following figure we notice that the production flow rate of gas production of the field increased due to the injection of water and reached at the end of the year 2052 a rate of 5.9 STB-MSCF. Next figure shows the prediction field water cut with water injection. In the following figure we notice that the amount has increased due to water injection to 90% of the total production in the year 2025.

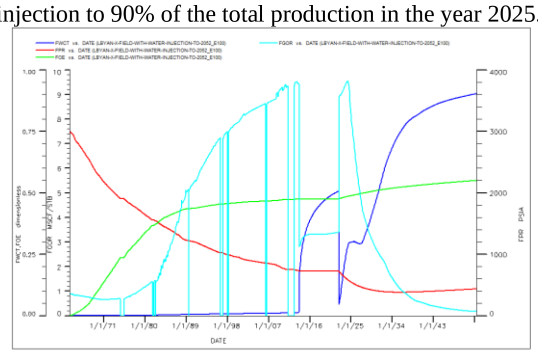

Figure 20: Prediction Field Pressure with Water Injection

The next figure shows the prediction field water production rate with water injection. An increase in water production due to the volume of water injection was in 2052 to more than 7,000 barrels per day. The next figure shows the prediction field oil production rate with water injection. From the appearance of this situation, we notice that the productivity of the field, and I said it was approximately 52 at the end, to approximately 2,000 bbl to 500 barrels per day. This figure shows the prediction field gas production rate with water injection. We notice that in the beginning there was an increase in the rate of gas production reaching above 30 million standards, and with the increase in injections, the rate decreased due to the water injection. At the end of 2022, it reached zero, and this is a good indicator that the process of injecting water with this supplement preserved the gas.

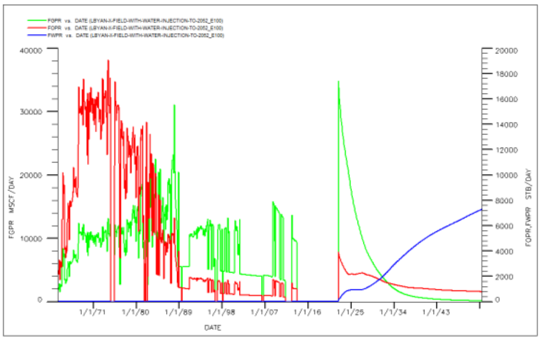

Figure 21: Prediction Field Water, Gas, Oil Production Rate with Water Injection

Next figure shows the prediction field gas production total with water injection. We notice in the following figure that the total gas production in the field is increasing, increasing at the beginning of the field and ending by an amount of 2.10 108 MSCF. Next figure shows the prediction field oil production total with water injection. The following figure shows the cumulative production of total extraction of the field. We note that the beginning of the water injection instead of oil production increases until it reaches its final limit in the year 2025, approximately is 1.2 x 108 STB. Next figure shows the prediction field water production total with water injection. The following figure shows the cumulative water production for all the field. We note that the cumulative water production increased to approximately 42.4 million barrels of water in the year 2052. The next figure shows the prediction field water injection total. The figure shows the total amount of water injected, as the water injection into three wells reached is 1.6 106 barrels.

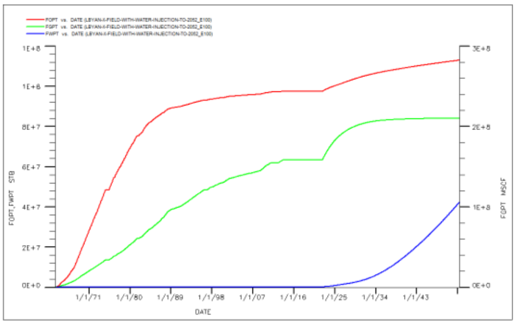

Figure 22: Prediction Field Gas, Oil, and Water Production Total with Water Injection

Next figure shows the water saturation layer 1 for prediction water injection. The following figure shows the water saturation in layer number one at the end of the injection in the years 2052. We notice that the saturation in this layer starts from 12% to 81%. Of course, here it increased to 81% due to the water injection, and we notice this average water saturation of 46%.

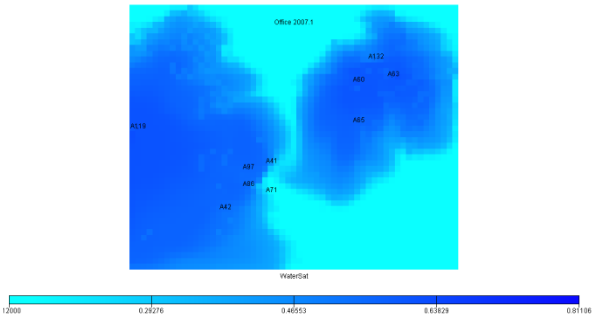

Figure 23:Water Saturation Layer 1 for Prediction Water Injection

The following figure shows the oil saturation in layer number one, and this is at the end of the injection for the year 2052. We notice that the saturation in this layer starts from traveling to 76% with the average being 38%.

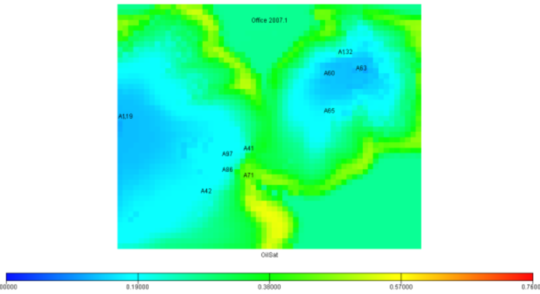

Figure 24: Oil Saturation Layer 1 for Prediction Water Injection

The following figure shows the gas saturation in layer one at the end of water injection in the year 2052. From the figure we notice that the gas saturation in the layer starts from 12% to 62%, with the average saturation being 37%.

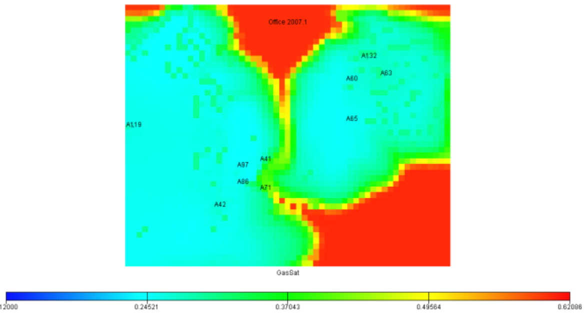

Figure 25: Gas Saturation Layer 1 for Prediction Water Injection

The following figure shows the oil productivity rate for all wells vs time. We notice that the most productive well was for well No. A85, then well No. A41, then well No. A42, and then well No. A60.

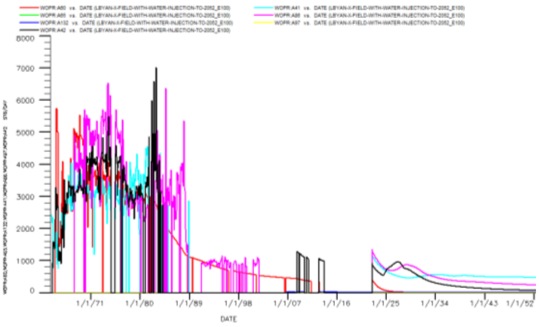

Figure 26: Well Water Cut for Prediction Water Injection

The following figure shows the water productivity rate in all the wells. We notice that the highest water productivity in the well was in well A60, then in well A132, then in well A42, then in well A85, and then in well A41.

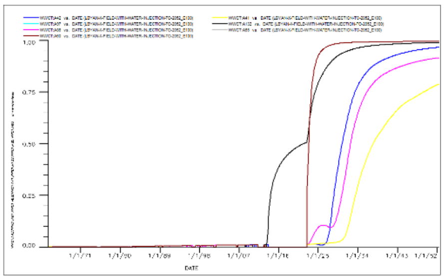

Figure 27: Well Water Production for Prediction Water Injection

2.9 Gas Injection

A reservoir maintenance or secondary recovery method that uses injected gas to supplement the pressure in an oil reservoir or field. In most cases, a field will incorporate a planned distribution of gas-injection wells to maintain reservoir pressure and effect an efficient sweep of recoverable liquids. The following table shows the names of wells after which the production phase began in our project from 4/1/2022 to 5/1/2022. We note that all wells started production from 4/1/2024 to 5/1/2022.

Table 5: Schedule of Prediction Production Wells for Gas Injection

Well Name	Start Production	To	Start Production	To
A 60	1964-04-01	2011-03-01	01-04-2022	01-05-2052
A 65	1964-06-01	1982-02-01	01-04-2022	01-05-2052
A 132	2006-08-01	2013-08-01	01-04-2022	01-05-2052
A 41	1963-08-01	1981-04-01	01-04-2022	01-05-2052
A 86	1967-11-01	2001-08-01	01-04-2022	01-05-2052
A 97	No	No	01-04-2022	01-05-2052
A 42	1963-10-01	2013-08-01	01-04-2022	01-05-2052

The following table shows the gas injection wells, well I01, I02, I03, and I04. The injection process began from 1/4/2022 to 1/5/2022. It also shows the location of the wells.

Table 6: Schedule of Prediction Gas Injection Wells

Well Name	Start Injection	Stop Injection
I01	01-04-2022	01-05-2052
I02	01-04-2022	01-05-2052
I03	01-04-2022	01-05-2052
I04	01-04-2022	01-05-2052

The following figure shows a map of the production wells with the right gas wells. We note that the ones in yellow are the gas injection, while the second wells are the production wells. Here we have 4 injection wells and four and 9 injection.

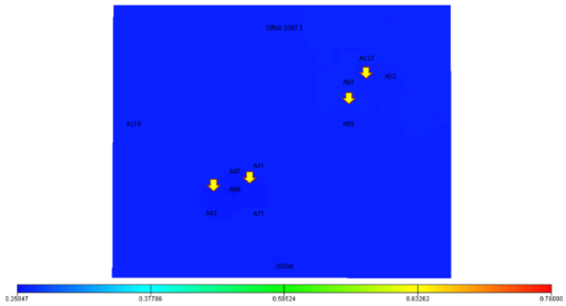

Figure 28: Gas Injection Rate

The following table shows the conditions of the field. The amount of gas was injected into the wells, starting with MMSCF-DAY per well, and the total injections per day for case number one was four 4 MMSCF-DAY. For the second case, the injection rate was increased or the injection rate was raised from one million to two million, and the total for the entire field was 8 million. And so, on until we reached case number 10, which is really gas at a daily rate for each well of 10 million, and the total amount of the field was 40 million.

Table 7: Gas Injection Rates.

NO	Well	Total
	MSCF-DAY	MSCF-DAY
Case#1	1000	4000
Case#2	2000	8000
Case#3	3000	12000
Case#4	4000	16000
Case#5	5000	20000
Case#6	6000	24000
Case#7	7000	28000
Case#8	8000	32000
Case#9	9000	36000
Case#10	10000	400000

The following figure shows the field gas-oil ratio results at different gas injection rates. Likewise, the difference in colors shows the cases from case number 1 to case number 10. For example, case number 10 shows the color blue, while case number one is green.

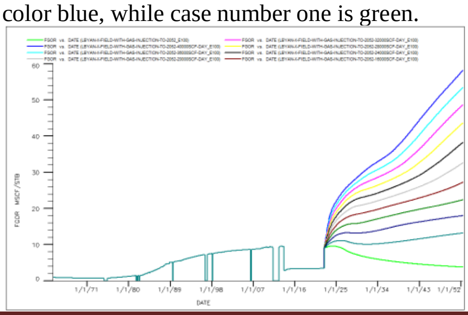

Figure 29: Field Gas-Oil Ratio Results at different Gas Injection Rates

The following figure shows the field gas production rate results at different gas injection rates. We note that the blue color represents case number 10, while the green color represents case number one.

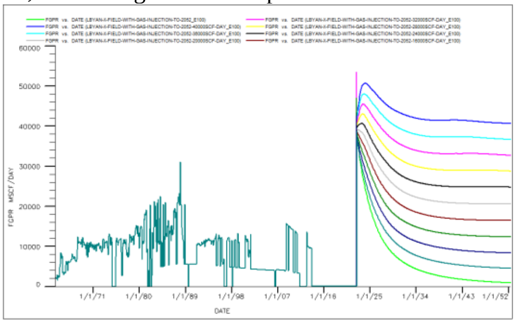

Figure 30: Field Gas Production Rate Results at different Gas Injection Rates

The following figure shows the field gas production total results at different gas injection rates. As the previous ones, the blue color is case No. 10 with a gas injection rate of 40 million standards.

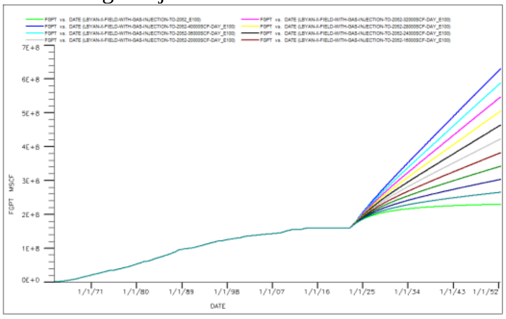

Figure 31: Field Gas Production Total Results at different Gas Injection Rates

The following figure shows the FOE results at different gas injection rates. We notice that the recovery factor is increasing. We also notice that the green color is case number 10 with an injection rate of 40 million, while the blue color is case number 9 and the rate of increase is actually 36 million. We notice that here the more the rate really increases the recovery increases.

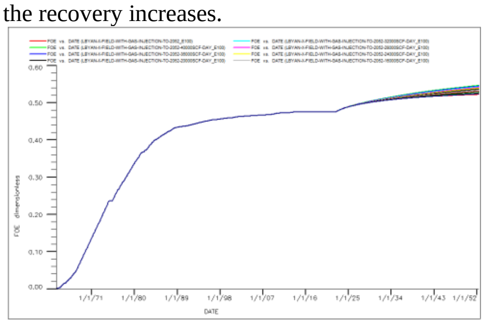

Figure 32: FOE Results at different Gas Injection Rates

The following figure shows the field oil-gas ratio results at different gas injection rates. because it is noted that the green color is case. 10, while the red color is without gas injection, while the black color is when the gas was injected at a rate of 20 million barrels.

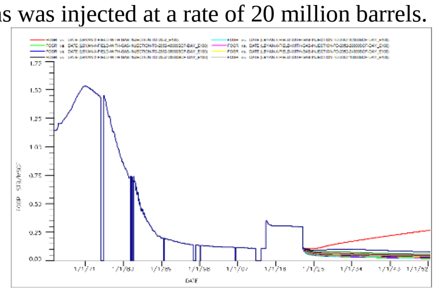

Figure 33: Field Oil-Gas Ratio Results at different Gas Injection Rates

This figure is shown the field oil production rate results at different gas injection rates. The red color shows the production case without gas injection, while the green color is case number 10, when gas was injected at a rate of 40 million barrels, and the blue color is case number 9, when gas was injected at a rate of 36 million barrels. We notice that here, the higher the gas injection rate, the higher the oil rate.

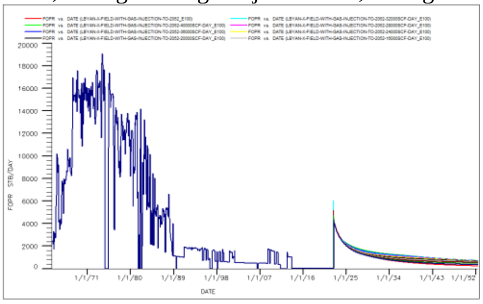

Figure 34: Field Oil Production Rate Results at different Gas Injection Rates

The following figure shows the field oil production total results at different gas injection rates. The red color shows the situation of production without gas injection, while the green color shows case No. 10, when gas was granted at a rate of 40 million barrels per day, followed by all of them. The blue color shows case No. 9, when gas was granted at a daily rate of 36 million, and the black color is when it is prevented. Gas injection at a rate of 20 million barrels.

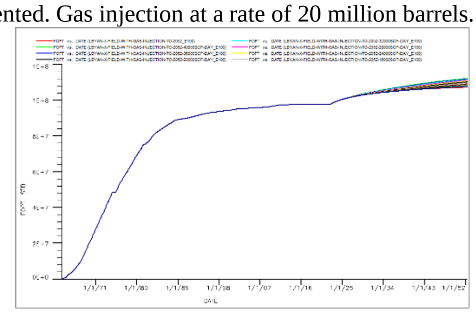

Figure 35: Field Oil Production Total Results at different Gas Injection Rates

The following figure shows the field pressure results at different gas injection rates. We note that case number 10, which is when 40 million gas was injected, and the green color represents the highest rate of pressure rise, while the blue color, which is case number nine, when a gas rate of 36 million was injected, is better than the red color, and the red color, which is a pressure drop, represents the case without gas injection.

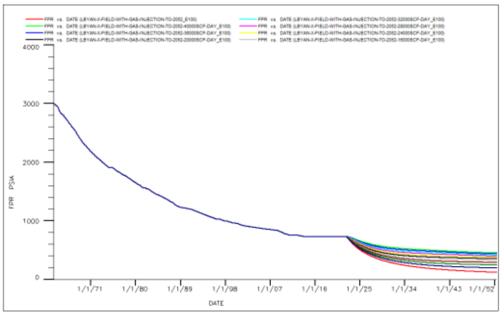

Figure 36: Field Pressure Results at different Gas Injection Rates

The following figure shows the field water cut results at different gas injection rates. We notice from the figure that water production was controlled. We notice that when the rate of the gas field increased, the rate of access to the entire gas field decreased. The blue colored curve represents the situation without gas injection, and here it is high, while the rate below them is for gas. The more we increase here the rate of the gas field, the more preservation of water production.

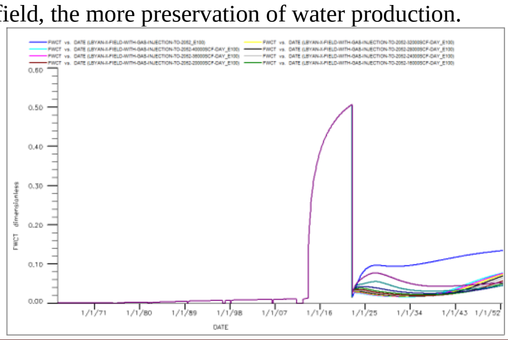

Figure 37: Field Water Cut Results at different Gas Injection Rates

The following figure shows the field water production total results at different gas injection rates. The curve in blue represents the case without water injection, while the curve in gray represents the least amount of water while the most water was injected. Case No. 10, when water was injected, when gas was injected at a rate of 40 million, which was the least water production.

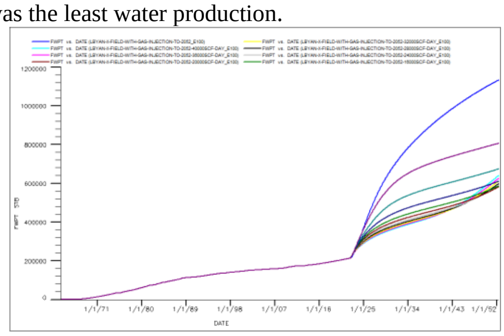

Figure 38: Field Water Production Total Results at different Gas Injection Rates

The following figure shows the oil saturation layer 1 for prediction gas injection. The oil saturation varying from 0 to 76%, and the average was 38%.

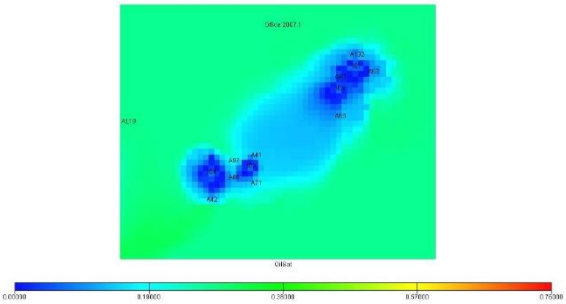

Figure 39: Oil Saturation Layer 1 for Prediction Gas Injection

The following figure shows the water saturation layer 1 for prediction gas injection. We note that water saturation ranges from 12% to 73%, and the average is 42%.

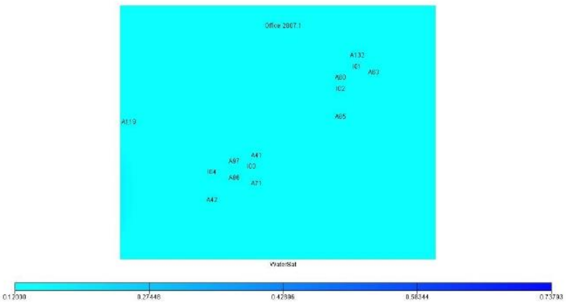

Figure 40: Water Saturation Layer 1 for Prediction Gas Injection

The following figure shows the gas saturation layer 1 for prediction gas injection. The gas saturation ranges from 12% to 97%, and the average saturation is 54%, and this is in layer number one only.

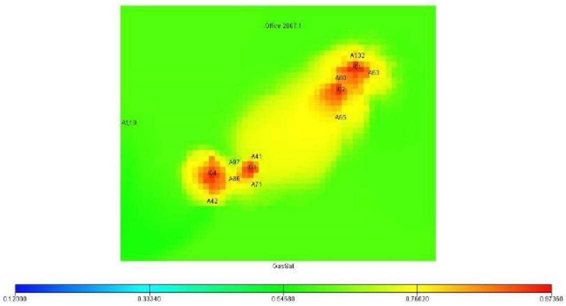

Figure 41: Gas Saturation Layer 1 for Prediction Gas Injection

The following figure shows the comparison of FWPT results at different rates of gas injection. We notice from the figure that as the gas injection rate increases, the total water production of the field decreases. We notice that after the injection rate increases, the water production increases at a slight rate. To solve this problem, we can change the location of the perforation of the well to reduce this phenomenon.

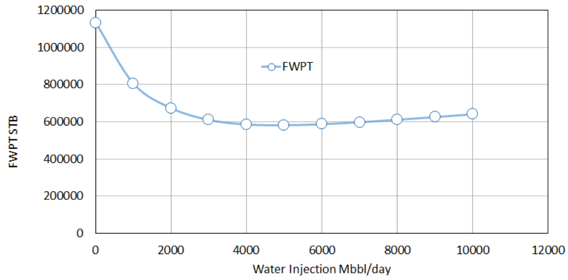

Figure 42: Comparison of FWPT Results at different Rates of Gas Injection

The following figure shows the comparison of FWCT results at different rates of gas injection. we notice that water decreased during the gas injection process, but when we increased the daily gas injection rate, the amount of water produced increased. We also solve this problem, which is to change the location of perforating the traces to reduce the amount of water produced

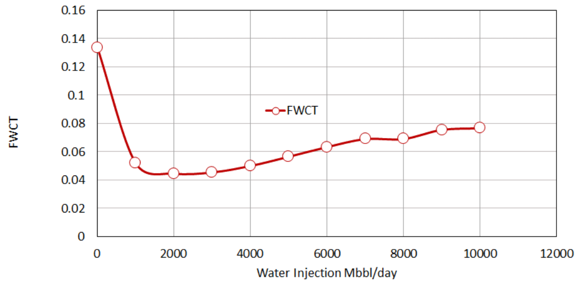

Figure 43: Comparison of FWCT Results at different Rates of Gas Injection

The following figure shows the comparison of FPR results at different rates of gas injection. We notice from the figure that there is a good and excellent increase in the pressure of the machine. As the gas injection rate increases, the pressure increases. We notice that the pressure increase reached 450 PSI in case No. 10, which is when 10 million were injected into the well and 40 million into the entire field in one day.

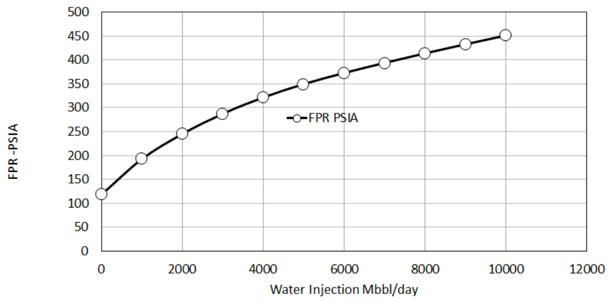

Figure 44: Comparison of FPR Results at different Rates of Gas Injection

The following figure shows the comparison of FOPT results at different rates of gas injection. We note that the higher the rate of the gas field injection, the greater the cumulative production of oil.

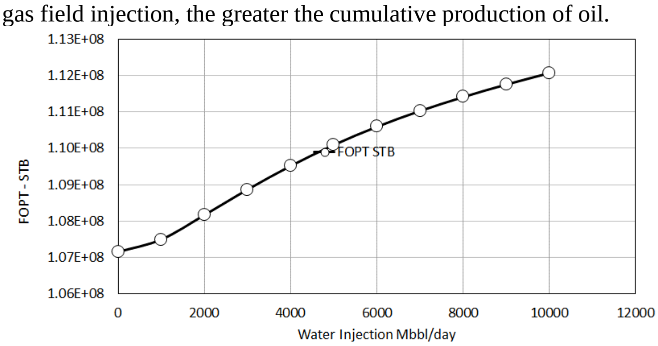

Figure 45: Comparison of FOPT Results at different Rates of Gas Injection

The following figure shows the comparison of FOE results at different rates of gas injection. We notice that there is a continuous increase due to the increase in gas injection.

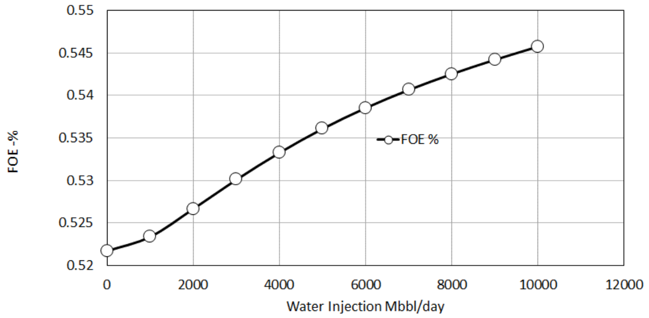

Figure 46: Comparison of FOE Results at different Rates of Gas Injection

The following figure shows the comparison of FGPT results at different rates of gas injection.

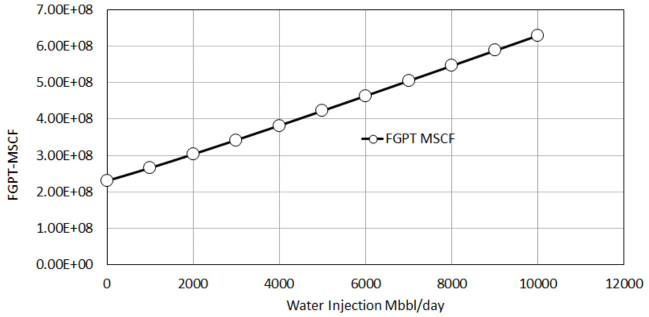

Figure 47: Comparison of FGPT Results at different Rates of Gas Injection

The following figure shows the comparison of FGOR results at different rates of gas injection. We notice that there is an increase in the gas injection, which causes an increase in the gas production rate.

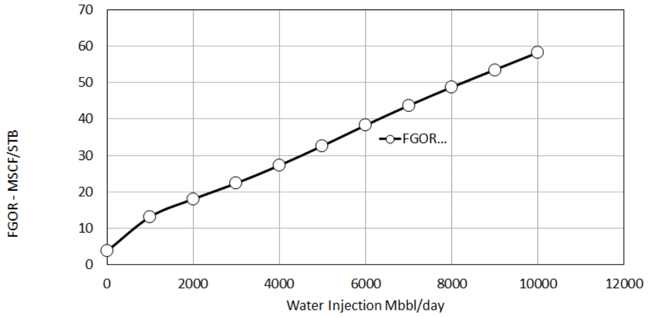

Figure 48:Comparison of FGOR Results at different Rates of Gas Injection

The following table shows the gas injection results at different rates of gas injection. A figure showing the results of gas injection for all cases from case number 1 to case number 10. The rate of gas was injected at a MSCF per day, and the total number of injections was 4 million, while for the 4 wells was 40 million. The following table shows the comparison of results of water injection and gas injection at 32000000scf. Results for gas injection were presented for case No. 9, when a gas rate of 32 million was injected, and here we will make a comparison between gas injection and water injection.

Table 8: Comparison of Results of Water Injection and Gas Injection at 32000000scf

Secondary Recovery	Gas Injection	Water Injection
FGOR (MSCF/STB)	48.63015	5.9184203
FGPT (MSCF)	5.47E+08	2.10E+08
FOE (%)	0.54252785	0.54990506
FOPT (STB)	1.11E+08	1.13E+08
FPR (PSIA)	0.069122888	435.59274
FWCT (%)	412.97729	0.90286547
FWPT (STB)	610604.69	42435192

The following figure shows the comparison of FWCT results at different rates of gas and water injection. We notice from the figure that the amount of water produced when water was injected into the field increased, while when the field was injected with gas, it decreased. The reason is due to the water field and gas injection.

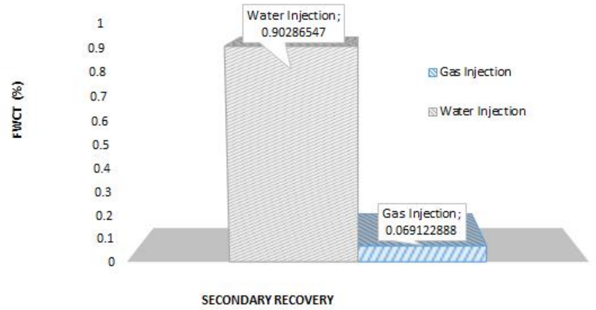

Figure 49: Comparison of FWCT Results at different Rates of Gas and Water Injection

The following figure shows the comparison of FPR results at different rates of gas and water injection. We notice from the figure that the pressure in the field increased when water was injected and the pressure increased to 435.5 psi, while when gas was injected it increased to 412.9 psi. Here, water injection into the field is considered the best for increasing pressure.

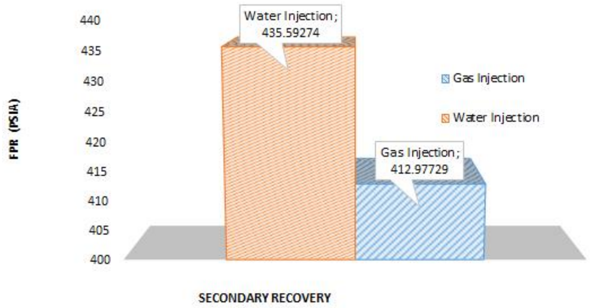

Figure 50: Comparison of FPR Results at different Rates of Gas and Water Injection

The following figure shows the comparison of FOPT results at different rates of gas and water injection. We note that the total amount of production output when the field was injected with water was greater than when the injection with gas.

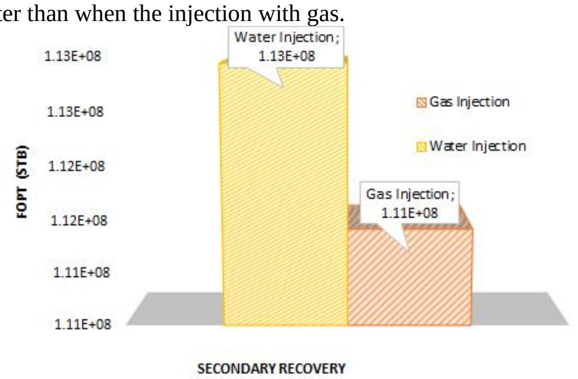

Figure 51: Comparison of FOPT Results at different Rates of Gas and Water Injection

The following figure shows the comparison of FOE results at different rates of gas and water injection. We note from the figure that the oil recovery factor was high with water, unlike when the field was injected with gas.

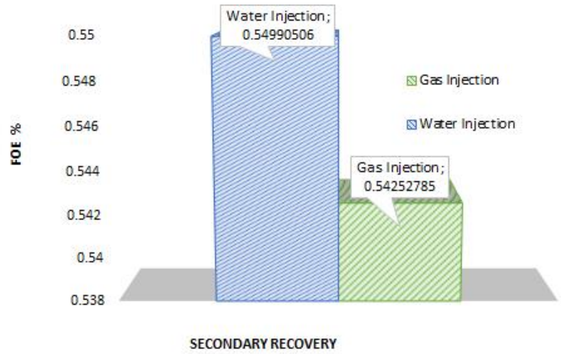

Figure 52: Comparison of FOE Results at different Rates of Gas and Water Injection

The following figure shows the comparison of FWPT results at different rates of gas and water injection. We also note that the increase in the amount of water produced due to water injection is much greater than when gas was injected.

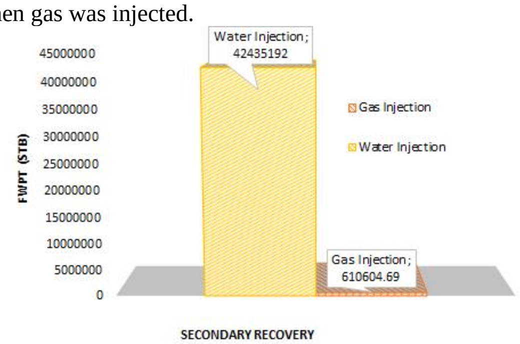

Figure 53: Comparison of FWPT Results at different Rates of Gas and Water Injection

The following figure shows the comparison of FGOR results at different rates of gas and water injection. From this it can be seen that the ratio of gas to oil was very high when the gas was injected, while it was low when the water was injected.

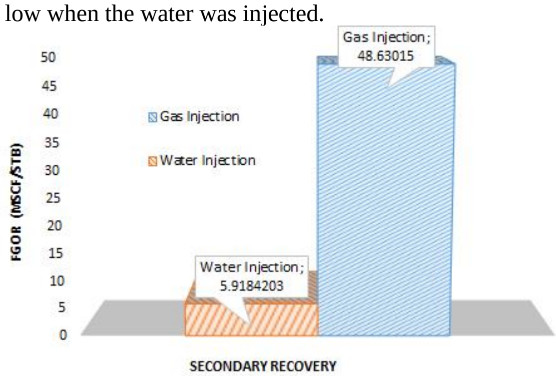

Figure 54: Comparison of FGOR Results at different Rates of Gas and Water Injection

The following figure shows the comparison of FGPT results at different rates of gas and water injection. We notice from this figure that the increase in gas production is greater in the case of gas injection and less in the case of water injection.

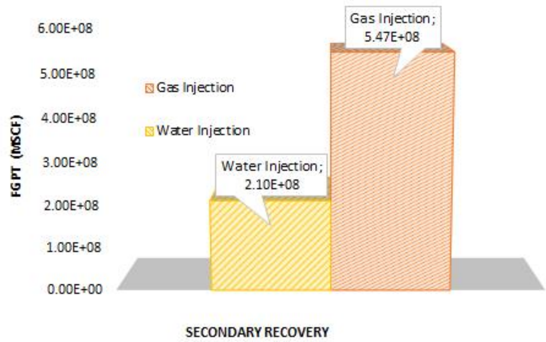

Figure 55: Comparison of FGPT Results at different Rates of Gas and Water Injection

2.10 Gas Injection and Water Injection

In this section, the results of gas injection and water injection will be presented. The following figure shows the field gas-oil ratio results at water injection and gas injection and both. We note that the highest increase was in Gas Oil Ratio, which was when the gas was injected alone into the field at a rate of 32 million standard cubic meters, and it decreased when water and gas were injected together, and it was lower when only water was injected.

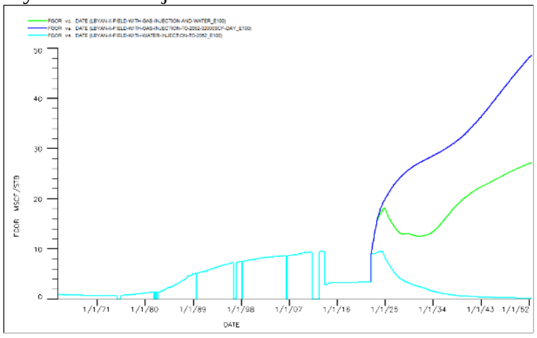

Figure 56: Field Gas-Oil Ratio Results at Water injection and Gas injection and both

The following figure shows the field gas production rate results at water injection and gas injection and both. We notice from the figure that the largest amount in the gas production rate was when the gas was injected alone into the field at a rate of 32 million barrels, and it was less than when water and gas were injected together, and it was much less when only water was injected.

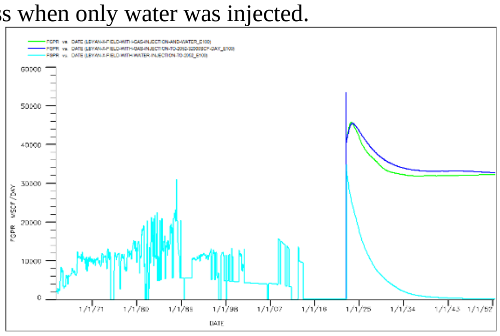

Figure 57: Field Gas Production Rate Results at Water injection and Gas injection and both

The following figure shows the field gas production total results at water injection and gas injection and both. We notice from the figure that the highest increase in gas production was in case No. 2 when gas was injected at a daily rate of 32 million, while it was less than that when water and gas were injected together, and it was much lower when gas and water were injected only.

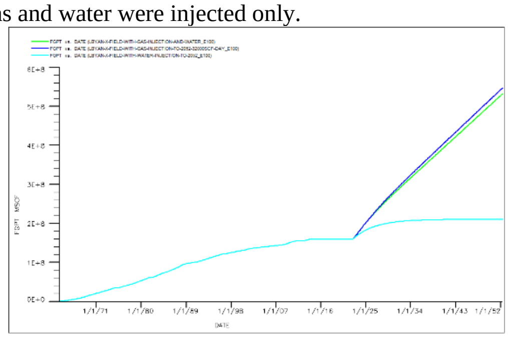

Figure 58: Field Gas Production Total Results at Water injection and Gas injection and both

The following figure shows the FOE results at water injection and gas injection and both. We notice from the figure that it was more when the water and gas were injected together, and less than when the water was injected and less than when the gas was injected, and we notice that more oil recovery was when the gas and water were injected together.

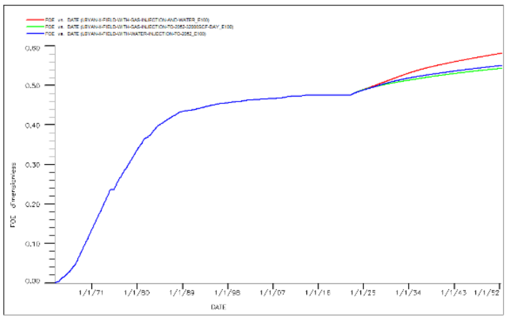

Figure 59: FOE Results at Water injection and Gas injection and both

The following figure shows the field oil-gas ratio results at water injection and gas injection and both. From the figure we notice that the increase in gas production was when water was injected and the curve was blue, while the injection of water and gas or the injection of gas alone was at the same level.

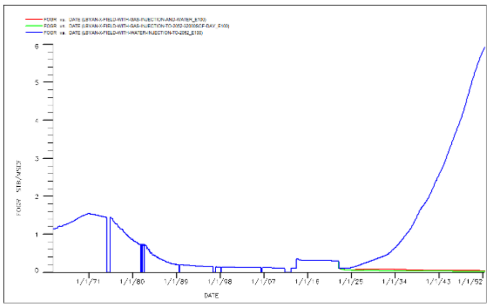

Figure 60: Field Oil-Gas Ratio Results at Water injection and Gas injection and both

The following figure shows the field oil production results at water injection and gas injection and both. We notice that the red color is the injection of water and gas, while the blue color is the injection of water alone into the field, and the green color is the injection of gas only. Oil production was high when water and gas were injected into the field.

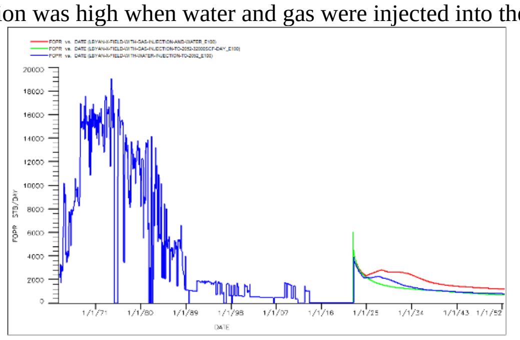

Figure 61: Field Oil Production Results at Water injection and Gas injection and both

The following figure shows the field oil production results total at water injection and gas injection and both. The red curve shows the total oil production when water and oil were injected into the field, the blue color when water was injected, and the green color when gas was injected, and it was best when water and gas were injected together.

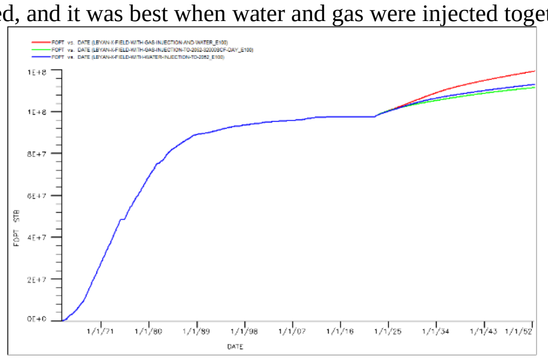

Figure 62: Field Oil Production Results Total at Water injection and Gas injection and both

The following figure shows the field pressure results at water injection and gas injection and both. The red curve shows the total oil production when water and oil were injected into the field, the blue color when water was injected, and the green color when gas was injected, and it was best when water and gas were injected together.

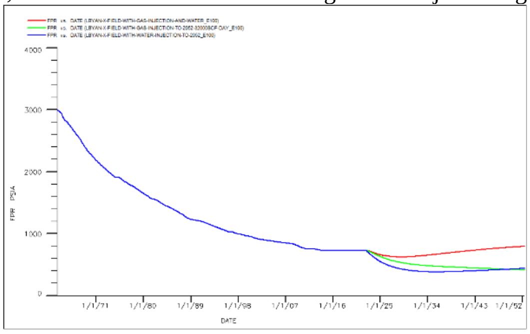

Figure 63: Field Pressure Results at Water injection and Gas injection and both

The following figure shows the field water cut results at water injection and gas injection and both. The red curve shows the total oil production when water and oil were injected into the field, the blue color when water was injected, and the green color when gas was injected, and it was best when water and gas were injected together.

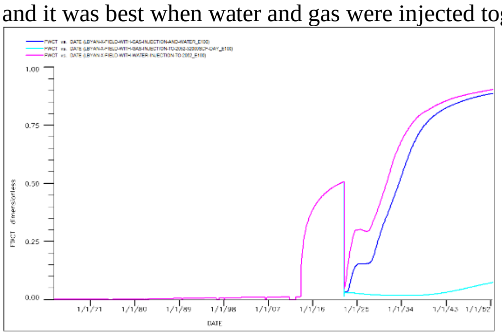

Figure 64: Field Water Cut Results at Water injection and Gas injection and both

The following figure shows the field water production rate results at water injection and gas injection and both. The blue curve represents the water production rate when water, and gas were injected together, the green color when only gas was injected, and the pink color when only water was injected.

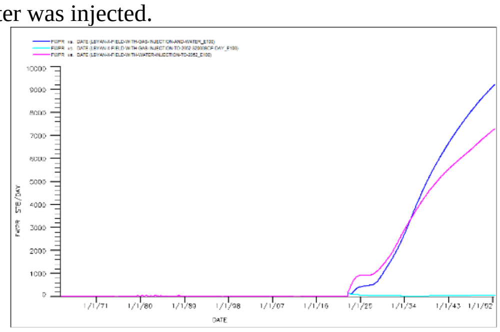

Figure 65:Field Water Production Rate Results at Water injection and Gas injection and both

The following figure shows the field water production total results at water injection and gas injection and both. The blue curve, which is the result of water, represents the injection of water and gas, while the green represents the injection of gas, and the bink represents the water injection.

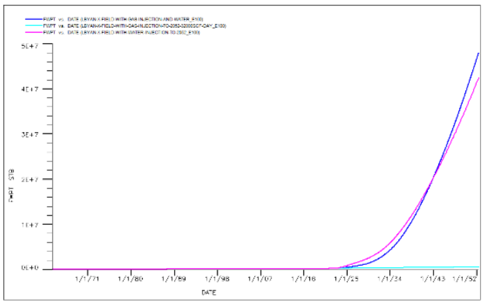

Figure 66: Field Water Production Total Results at Water injection and Gas injection and both

The following table shows the comparison of results of water injection and gas injection and both. The following table shows the final results of gas injection, water injection, or gas and water injection together in the field.

Table 9: Comparison of Results of Water injection and Gas injection and both

Secondary Recovery	FGOR	FGPT	FOE	FOPT	FPR	FWCT	FWPT
	MSCF/STB	MSCF	%	STB	PSIA	%	STB
Gas Injection	48.63015	5.47E+08	0.54252785	1.11E+08	412.97729	0.069	610604.69
Water Injection	5.9184203	2.10E+08	0.54990506	1.13E+08	435.59274	0.903	42435192
Gas and Water Injection	27.160583	5.32E+08	0.58078438	1.19E+08	792.75159	0.886	47958088

The following figure shows the comparison of FOPT results water injection and gas injection and both. We notice from the figure that the most oil production was when water and gas were injected into the field, then when only water was injected, and then when only gas was actually injected.

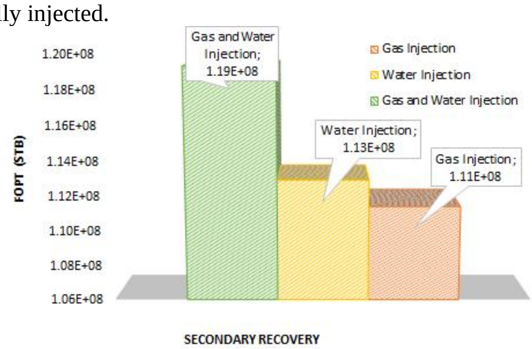

Figure 67: Comparison of FOPT Results Water injection and Gas injection and both

The following figure shows the comparison of FGOR results water injection and gas injection and both. We note that the FGOR was greater when the field was injected with gas only, less than when the field was injected with water and gas, and less than when the field was actually injected with water only.

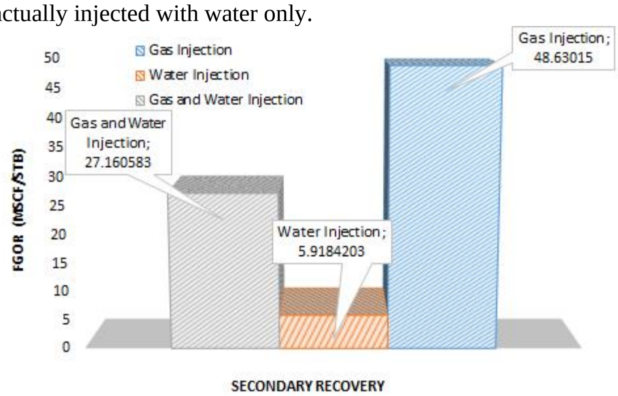

Figure 68: Comparison of FGOR Results Water injection and Gas injection and both

The following figure shows the comparison of FOE results water injection and gas injection and both. We notice that the highest percentage was when the water and gas were injected and it reached 58%, then when the water was injected and it reached 54%, and then when the gas was actually injected and it reached 54%.

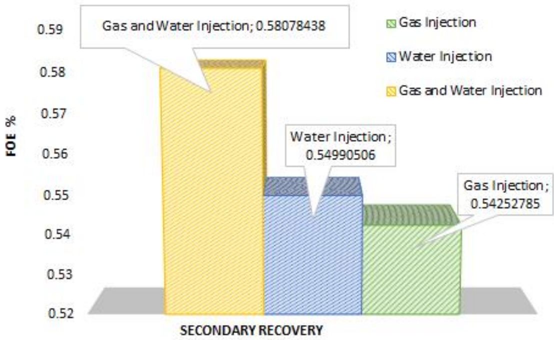

Figure 69: Comparison of FOE Results Water injection and Gas injection and both

The following figure shows the comparison of FGPT results water injection and gas injection and both. We note that the total amount of gas production was more when only gas was injected, less than when water and gas were injected, and less than when water was injected.

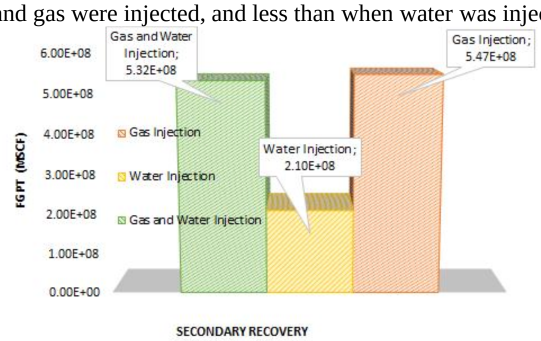

Figure 70: Comparison of FGPT Results Water injection and Gas injection and both

The following figure shows the comparison of FWPT results water injection and gas injection and both. We note that the amount of water produced was much higher when water and gas were injected, and less than when only water was injected, and a lot was changed when the head was actually injected.

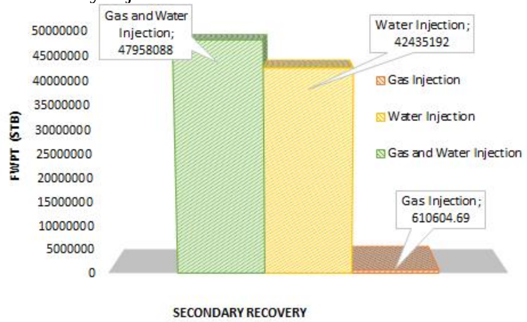

Figure 71: Comparison of FWPT Results Water injection and Gas injection and both

The following figure shows the comparison of FPR results water injection and gas injection and both. We notice that the pressure rise was greater when water and gas were injected, and the pressure reached 792 psi, while it was less when only water was injected, reaching 435.5 psi, and when only gas was injected, it reached 412.9 psi.

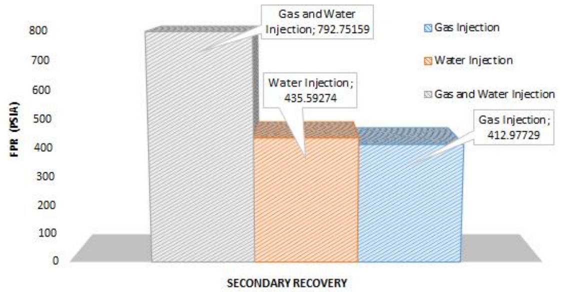

Figure 72: Comparison of FPR Results Water injection and Gas injection and both

The following figure shows the gas saturation at the end of water injection and gas injection. We notice that gas saturation starts from 12% to 96%, with an average of 54%.

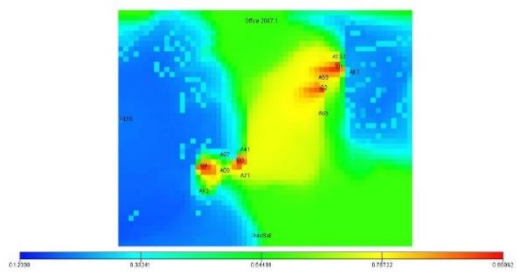

Figure 73: Gas Saturation at the end of Water injection and Gas

injection

The following figure shows the water saturation at the end of water injection and gas injection. Likewise, this figure shows the chord from 11% to 88%, with an average of 50%.

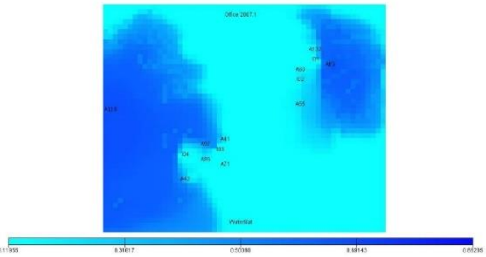

Figure 74: Water Saturation at the end of Water injection and Gas injection

The following figure shows the pressure distribution at the end of water injection and gas injection. The pressure starts from 464 PSI to 300 psi and averages is 1733 psi

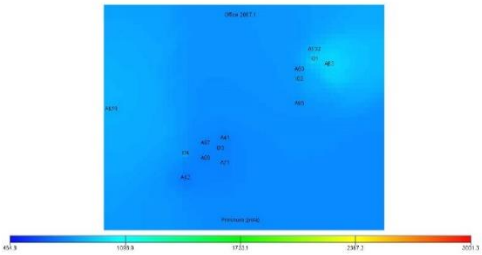

Figure 75: Pressure distribution at the end of Water injection and Gas injection

The following figure shows the oil saturation at the end of water injection and gas injection. Oil saturation starts from 0 to 76% with an average of 36%.

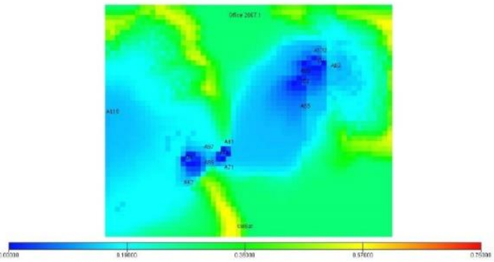

Figure 76: Oil Saturation at the end of Water injection and Gas injection

3 Conclusion and Recommendation

A study to comprehensive reservoir study for X Field plan of development. This study covered analyses and evaluation on areas of geophysics, geology reservoir engineering, water injection, and gas flooding. In this study, we know some conclusion as shown below:

1. The driving mechanism for all those reservoirs it comes from three natural forces, which are fluid expansion, PV compressibility, and water influx.
2. It has been started with the fluid expansion from 0 to 0.47, with the PV compressibility from 0.47 to 0.80, and with the water influx from 0.80 to 1 is water influx.
3. The simulator results show the reservoir pressure history curve is matching to the stimulation curve, this gives a good indication of the input data that has been entered to the model.
4. Material balance was utilized in reservoirs where enough adequate data were available for History matching and Performance prediction.
5. The best method to choose as secondary recovery for this oil field is water and gas Injection.
6. Water and gas Injection have the largest Total Field Recovery.
7. Water and gas Injection have the highest Reservoir Pressure at the end of the project.
8. Also, the Water Flooding method has the lowest value of Producing GOR.
9. Gas Injection has the lowest Field Oil Recovery. As we mentioned before, Gas Injection is almost use as Pressure Maintenance Method.
10. The Hurst van Everdingen water influx model Radial Aquifer best describe the reservoir.
11. The highest percentage of oil recovery was when the water and gas were injected and it reached 58%, then when the water was injected and it reached 55%, and then when the gas was actually injected and it reached 54%.
12. The field pressure rise was greater when water and gas were injected, and the pressure reached 792 psi, while it was less when only water was injected, reaching 435.5 psi, and when only gas was injected, it reached 412.9 psi.
13. Finally, central objective of this master thesis with the help of reservoir simulation fulfilled to produce future prediction that will lead to optimize reservoir performance which meant reservoir developed in the manner that brings utmost benefit to the commercial business.

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