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Effect of water alternating gas (WAG-N_2) after water or gas flooding on crude oil recovery in sandstone reservoirs

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Abstract. Previous studies showed that nitrogen injection could recover oil up to 45-90 % of the Original Oil in Place (OOIP) of the reservoir. Additionally, when applying Water Alternating Gas (WAG-N_2), recovery can be improved by combining gas and water and having better gas mobility control by reducing viscous fingering and density tonging, as well as contacting the un-swept zones, leading to an improved microscopic displacement. The objective of this study is to determine the total Oil Recovery Factor (ORF) of WAG-N_2 process either after Water Flooding (WF) or after Gas Flooding (GF) in sandstone reservoirs. The results showed that with the following conditions: 38.8° API gravity oil, injection rate of 0.6cm^3/m, injection pressure of 2000 psi (1378.59 kpa), WAG rate of 1:1, and Sand pack temperature of 70°C, the maximum ultimate ORF was 71.2 % in WAG after WF and 52.42 % of WAG after GF. On the other hand, WF provided ORF of 65.6 % when compared with GF recovery (29.03 %).

1. Introduction

The decline in oil production and the rise in oil prices in the last few years have made the producers think much about the large amount of oil which is still trapped in reservoirs even despite the application of the common enhanced oil recovery (EOR) methods. Although the process of gas injection has attracted more attention, it has major problems of poor sweep efficiency and inefficient displacement of oil in low-pressure reservoirs [1]. Nitrogen is used in both miscible and immiscible gas injection processes in oil reservoirs. In heterogeneous formations, gas tends to breakthrough early due to overriding and fingering [2]. The process of alternative injection of water and gas helps to control gas mobility.

The first reported WAG injection was in 1957 in Canada. It was originally proposed as a method to improve sweep of gas injection mainly by using water to control the mobility of the displacement and to stabilize the front. WAG injection has been applied since the early 1960s. Oil recovery by WAG injection has been attributed to contact of un-swept zones, by exploiting the segregation of gas to the top or the accumulation of water toward the bottom. Because the residual oil after GF is normally more than the residual oil after WF, and three-phase zones may obtain lower remaining oil saturation, WAG injection has the potential for increased microscopic displacement efficiency. Therefore, WAG injection can lead to improved oil recovery by combining better mobility control and contacting un-swept zones, thereby leading to improved microscopic displacement. Nitrogen solubility in crude oil is less than carbon dioxide; thus, poor evaporation and oil swelling efficiency will not be unexpected. The minimum miscibility pressure of carbon dioxide is lower than nitrogen, which makes miscible nitrogen flooding suitable for light oil reservoirs with high pressure [3]. Nitrogen as an immiscible gas in low pressures will lower oil viscosity more than carbon dioxide because of its lower density relative to carbon dioxide [4]. In this paper, a comparison between WAG-N_2 after WF and after GF was performed. Before starting WAG after WF, water was flooded initially prior to WAG, and in case of WAG after GF, gases were flooded prior to WAG.

2. Water alternating gas- nitrogen (WAG-N_2)

2.1 Nitrogen injection (flooding)
Nitrogen has emerged as an alternative injection gas for gas-based enhanced oil recovery processes in the past two decades [5]. Nitrogen as a substitute for inert gas came became significant by the development of large scale nitrogen plants using cryogenic air separation, which could be located in the oil field to provide a ready source of compressed nitrogen [6]. In the 1960s and 1970s, operators began seeking non-hydrocarbon sources of gas because natural gas was unavailable in some geographic areas or was becoming too expensive for reinjection. Later, carbon dioxide and nitrogen started to emerge as substitutes for natural gas. The first nitrogen projects emerged in the 1970s and until 1977, all the nitrogen was sourced from on-site inert gas plants [7]. During the 1980s, inert gas projects were converted into cryogenic nitrogen projects, and as the early nitrogen injection projects began to mature, nitrogen rejection also became a necessity [6].

Advantages of nitrogen injection

1. Corrosion in injection and production wells in the offshore environment is a critical problem; therefore, the injection of a chemically-inert dry substance such as cryogenically-produced nitrogen delays or prevents the advent of corrosion [7].
2. The costs and limitations on the availability of natural gas and CO_2 have made N_2 an economical alternative for oil recovery in EOR applications and is not corrosive [8].
3. On-shore costs of carbon dioxide are rarely quoted under 2 US$/Mscf whereas cryogenic nitrogen is available at less than 1 US$/Mscf [9].
4. Nitrogen is harmless compared to other gases (not flammable) [10].

2.1.1 Main problems of gas injection

2.1.1.1 Gravity Overriding: It is one of the problems of the continuous gas injection process; it is usually called density tonging or overriding of gas. The problem is that, after some time and distance, the reservoir fluid mixture is separated by gravity. The gas goes to the top of the reservoir and overrides the oil. This phenomenon leads to the early breakthrough of the injected gas and reduces the vertical sweep efficiency [11], see Figure 1.

2.1.1.2 Viscos fingering: When a low-viscose gas displaces higher viscose oil, viscous fingering will occur due to high values of mobility ratio (*M*). The mobility ratio is the ratio of the mobility of the displaced fluid to the mobility of the displacing fluid. When the values of *M* are greater than 1, it is referred to as viscous fingering but if less than 1, the mobility is stable [12], see Figure 2.

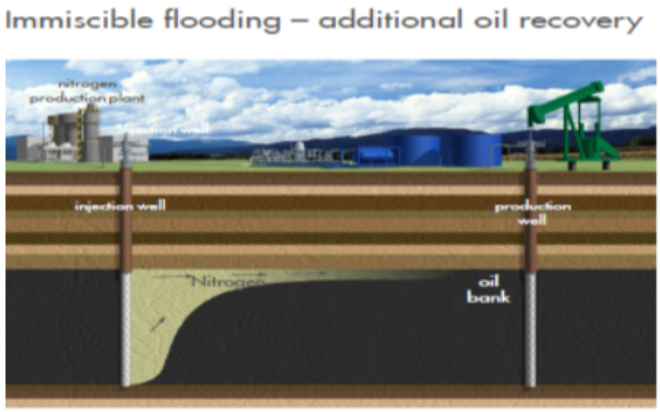

Figure 1. Nitrogen overriding (tonguing)

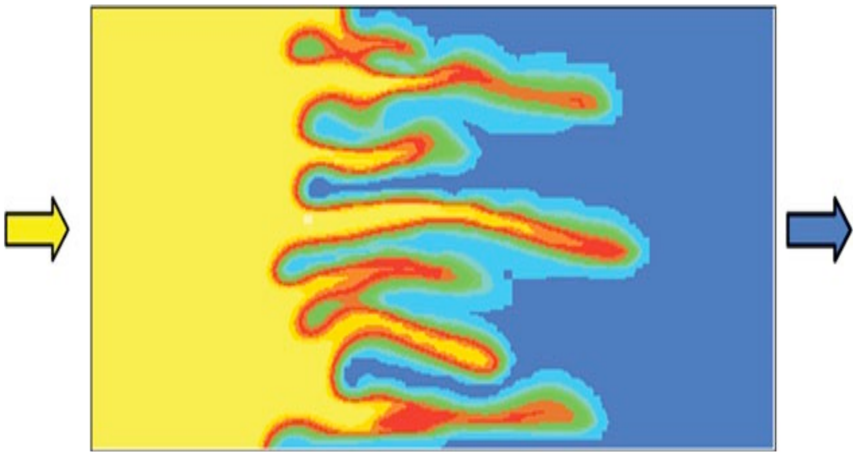

Figure 2. Viscosity fingering: The viscosity ratio in this simulation is 10; flow is from left to right [12]

2.2 Water alternating gas (WAG)

Due to the problems that occur during gas injection, the WAG process was first introduced by Caudle & Dyes to solve such problems [13]. Since 1958, authors and companies have been developing and devising methods and techniques to resolve the problems associating with the WAG process. Water Alternating Gas (WAG) is a process of injecting water, followed by gas, then more water and more gas, etc., see Figure 3. When the gas mixes with water ahead of it, there will be a reduction in gas mobility. This is why WAG can improve the recovery factor [11]. WAG injection is a combination of two conventional EOR techniques: water flooding and gas injection. WAG process consists of the injection of water and gas either at alternate slugs or simultaneously in the wellbore with the objective of reducing the impact of viscosity fingering [14].

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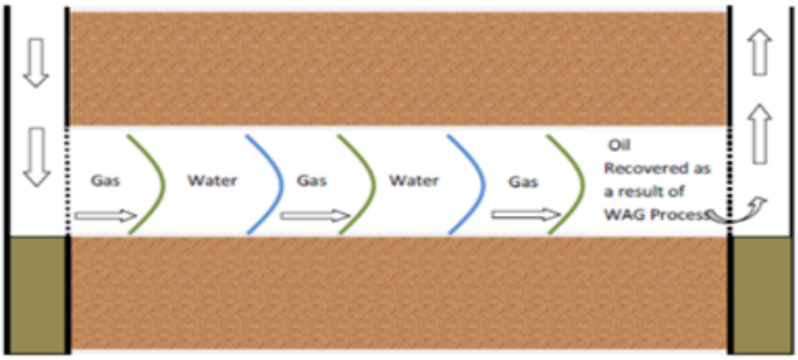

Figure 3. A schematic illustration of the WAG process

In 1958, Caudle & Dyes applied the first WAG process which was achieved by injecting water with gas. This water reduces the relative permeability to gas in this area and thus, lowers the total mobility. Although Caudle & Dyes suggested a simultaneous injection of oil and gas to improve mobility control, the field reviews show that they are usually injected separately [15]. The main reason for this injection pattern is better injectivity when only one fluid is injected. If too much gas is injected, the process can only approach the mechanism of the gas-driven displacement. However, if too little gas is injected, the worst that can happen is that the reservoir will be subjected to a water drive displacement [16]. Syed et al. (2011) applied several EOR methods, such as CO_2 and N_2, enriched hydrocarbon gas, and WAG on a model. They discovered nitrogen injection as the least oil recovering process as it recovered about 53 % of oil for 19 years. They also found that nitrogen injection has the best pressure maintenance. The screening criteria of the nitrogen show that the depth should be at least 6000" to have miscible displacement.

2.2.1 Problems of implementing WAG

Although water and gas are injected in the water alternating gas injection process to solve the problems of tonging and fingering, the result is that the injected water moves towards the bottom and the gas moves towards the top of the reservoir due to their density and difference with oil in the reservoir. This causes the under-riding and overriding phenomena, leaving a large amount of oil in the un-swept zone [17].

During the application of the originally-designed WAG technique via the alternate injection of water and gas, two cases are faced: During the gas cycle, the flow direction will be to the top of the reservoir; however, when the water cycle is implemented, the flow will be to the bottom due to fluids segregation under gravity [15]. In addition to these problems, there are some disadvantages or problems that might occur during the WAG process. These may include corrosion, especially when applying WAG CO_2 [18], early breakthrough [18], as well as the existence of an un-swept zone which makes a large amount of oil unrecoverable due to gravity segregation [17].

2.2.2 Classification of WAG process

Although significant researches have been put forward to increase tertiary recoveries by WAG technique, there is a necessity for more developments that will ensure better oil recovery. The modification of the conventional water and gas injection method could ensure more oil recovery [19]. WAG can be generally classified to miscible (MWAG) and immiscible (IWAG) processes. There is also hybrid WAG (HWAG) and simultaneous WAG (SWAG) processes as well [20].

Miscible WAG Injection: This is experienced when the reservoir is re-pressurized to bring its pressure above the minimum miscibility pressure (MMP) of the fluids. In many cases, a multiple-contact gas/oil miscibility may be obtained, but much uncertainty remains about the actual displacement process [18].

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Immiscible WAG Injection: Even when the gas cannot develop miscibility with oil, there are still some compositional exchanges between gas and oil which are important for the fluid characterization and oil recovery [20].

*Simultaneous WAG (SWAG) injection: S*WAG injection occurs when water and gas are injected in the reservoir at the same time through a single injection well. However, when the water and gas are mixed at the surface and then injected into the reservoir, the process is referred to as SWAG injection [21,18, 22].

Selective Simultaneous Water Alternating Gas (SSWAG) Injection: SSWAG is referred to the process of pumping gas and water separately using a dual completion injector without mixing the two phases on the surface [23-25].

3. Methodology

3.1 Experimental setup

This setup was designed for all injection processes, such as WF, GF, WAG, and SSWAG, where three inlets were needed to inject brine and gas at the same time in different positions. The upper and lower valves were shut during this experiment, see Figure 4.

Injection pumps: There are two injection pumps; one pump was used for gas and the other one was used for brine. The injection pumps were connected to the oil/water/gas supply accumulators. These pumps were referred to in the sketch as Labels 17 and 18 as shown in Figure 4.

Brine/oil/nitrogen gas supply: The brine/gas nitrogen accumulators were filled to provide the core with a certain fluid during the injection process. These accumulators were referred to as numbers 12, 13 and 14 in Figure 4. Each accumulator has a volume of 680 cm^3.

Nitrogen supply cylinder: Label 11 in Figure 4 represents the gas cylinder. The nitrogen accumulator was connected to the nitrogen supply cylinder of pressure = 200 bar (20000Kpa).

Core holder: The core flood holder (labeled 6 in Figure 4) was made of stainless steel that could withstand a maximum confinement pressure of 3000 psi (206.84 bar). The experimental injection pressure did not exceed 2000 psi (13789.5 Kpa) at 200F (93.34ºC). It accommodated a core of 35.29 cm in length and 3.80 cm in diameter.

Oil/water production separator: The produced fluids were collected in a separator connected to the core holder. This separator is a sight graded glass. The produced gas was vented from the top of a glass separator and the volumes of the two liquids (water/oil) were read from a graded cylinder. This separator was labeled 2 in the setup shown in Figure 4.

Pressure regulator: Label 3 in Figure 4 shows the location of the regulator. The pressure regulator was mainly used to maintain the reservoir (Sand pack core) at the designed pressures (2000 psi (137.89.5Kpa) in all processes.

Oven (system temperature maintenance): This oven was used to generate the designed reservoir temperature. The temperature of this oven was set at 70ºC (calibrated using a manual thermometer) and was fixed in all the experiments. Label 1 in Figure 4 represents the equipment border in the oven.

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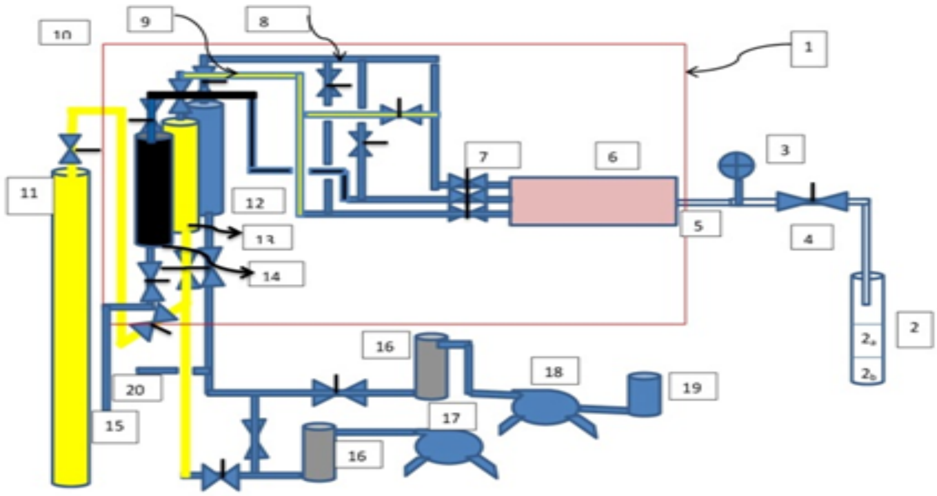

Lab experimental Setup Components

1- Oven border (all these equipment are in the oven to control Temperature)
2- Oil, water, and gas production graded cylinder. 2_a : produced oil, 2_b: produced water
3- Pressure Regulator, RP
4- Outlet valve
5- Sand pack core holder outlet
6- Sand pack core holder contains sandstone or carbonates
7- Core holder inlet valves
8- Water line
9- Gas line
10- Oil saturating line
11- Gas supply cylinder
12- Water accumulator
13- Gas accumulator
14- Oil accumulator
15- Oil supplier
16- Mercury cylinder
17- Mercury pump
18- Water pump
19- Water resource for pump
20- Brine resource

Figure 4. Sketch of the experimental setup

Pipes and valves: All the components of the setup were connected to each other using 1/8" stainless steel pipes and valves which could withstand the designed injection pressure of below 2500 psi (17236.89 Kpa).

3.2 Sand pack core sample preparation
Sandstone was chosen as the rock reservoir due to the nitrogen injection reservoir criteria where sandstone rocks are preferred. The sand pack core was made of sandstone grains and was placed in the core holder. The sandstone grains size was between 90-150 micron meters. After cleaning the sand pack in toluene, it was carefully placed in the core holder and the cover was closed tidily before starting the experiments.

3.3 Calculation of porosity and permeability for both sandstone samples

The following steps were carried out to calculate porosity:
1. Sand pack core was cleaned in toluene.
2. The sandstone grains were dried and weighed before placing in the core holder space.
3. The pack core was saturated with pure water by pushing water into the core using the compressor.

4. Two to three PVs of pure water were injected to ensure complete saturation.
5. The core's porosity was calculated using the weight of dry and saturated core and water density.
6. The effective porosity is the volume of the pores connected to each other divided by the total volume of the core. Therefore, the amount of water retained in the core can represent the volume of the core pores. See Table 1.

Table 1. The results of the porosity of the reservoir

Rock type	**Sandstone**
Core diameter, cm	3.8
Core length, cm	35.29
Core bulk volume, cm3	400
Pore volume, cm^3	151
Porosity, %	37.75

After taking the porosity measurements of the sandstone sample, permeability was also calculated. The sand pack was subjected to a differential pressure between water flow inlet and outlet. It was estimated by recording the differential pressure between the inlet and outlet points of the sand pack at different flow rates. Then, Darcy law was applied as follows:

$$Q = -\frac{K A \Delta P}{\mu L} \qquad \text{(Eq.1)}$$

Q = flow rate, cm^3/s, μ = viscosity of saline, cp, A = crosssectional area, cm^3, ΔP = differential pressure, atm, L = core length, cm, K= sand pack permeability, Darcy.
Then;

$$K = \frac{Q \mu L}{A \Delta P} \qquad \text{(Eq.2)}$$

K was calculated several times with different values of Q and the average K was recorded in Table 2.

Table 2. Calculation of the permeability of the sand pack

Properties	**Values**
Core diameter, cm	3.8
Area, cm^2	11.335
Length, cm	35.29
Average ΔP, atom	0.128979
Flow rate, Q, cm^3/s	0.1525
Water viscosity, at 25C, cp	0.89
K, md	3276

3.4 Experimental procedure

3.4.1 WAGN$_2$ after WF

The objective of this injection is to evaluate how much oil a wetting phase (WF) can produce. This run involved injecting water continuously into the oil-saturated core (secondary recovery mode) to produce OOIP until 1 PV of brine was injected (248 min). After ending the WF process, Water Alternating Gas (WAG-N_2) was applied to produce the remaining oil (OIP). This run involved injecting nitrogen in alternating cycles with water (WAG process) into the remaining oil core (tertiary recovery mode) until 2 cycles were performed. Each fluid lasted 0.25 PV (60 min).

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Procedure steps

1. The sand pack core was cleaned in toluene and saturated with reservoir water by pushing water into the core using the injection pump.
2. Then, the sand pack core was saturated with light oil to reduce the water saturation to irreducible water saturation (S_{wi}).
3. Sand pack core was flooded with brine until 1 PV was injected (248 min.).
4. The recovered oil was recorded at the cylindrical glass.
5. The ORF percentage was calculated for the WF process.
6. Then, WAG-N_2 injection process was initiated using water to gas injection rate of 1:1 for 0.25 PV for each injection fluid.
7. Two cycles were applied, starting with N_2 gas.
8. The recovered oil by the WAG process was recorded and the ORF percentage of the WAG process was calculated, and then the total ORF for both WF and WAG was calculated.

3.4.2 WAG after GF

The purpose of this process is to evaluate how much oil GF can produce. This run involved injecting nitrogen continuously into the oil-saturated core (secondary recovery mode) to produce OOIP until 1 PV of brine was injected (248 min). After ending GF, the WAG-N_2 process was initiated to produce the remaining oil (OIP). This run involved injecting brine in alternating cycles with nitrogen (WAG process) into the remaining oil core (tertiary recovery mode) until 2 cycles were performed. Each fluid lasted 0.25 PV (60 min).

Procedure steps

1. The sand pack core was cleaned in toluene and saturated with reservoir brine by pushing water into the core using the injection pump.
2. Sand pack core was saturated with light oil to reduce the water saturation to irreducible water saturation (S_{wi}).
3. Sand pack core was flooded by water until 1 PV was injected (248 min.).
4. The recovered oil was recorded at the cylindrical glass before calculating the ORF % for the GF process.
5. The WAG-N_2 injection process was initiated using water to gas injection rate of 1:1 for 0.25 PV for each injection fluid.
6. Two cycles were applied, starting with brine.
7. The recovered oil by WAG process was recorded before calculating the ORF %.
8. Then, the total ORF for both GF and WAG was calculated.

The sandstone sand pack and fluid properties corresponding to experiments are recorded in Table 3.

Table 3. Sand pack rock and fluid properties for sandstone.

Properties	Values
Reservoir pressure (Bar)	2000 psi (13789.51 Kpa)
Reservoir temperature, ^{0}C	70C
Oil density at 70 ^{0}C, g/cm^3	0.79
Oil viscosity at 70 ^{0}C, cp	2.4
Oil density at 25 ^{0}C, g/cm^3	0.812 g/cc
Oil viscosity at 25 ^{0}C, cp	3.3 cp
Water salinity, PPM	35,000
Water viscosity at 70^{0}C, cp	0.4413
Water density at 70^{0}C, g/cm^3	1.003215
API gravity, at 25 ^{0}C, API	38.77

4. Results

WAGN$_2$ after water flooding: In WF, water breakthrough occurred at 125 min. By the end of the WF process, the oil recovered was 82 cm^3, representing 65.60 % of the original oil in place (OOIP). After water breakthrough, water was produced in small volumes before becoming highly produced. However, oil production started declining as presented in figure 5.

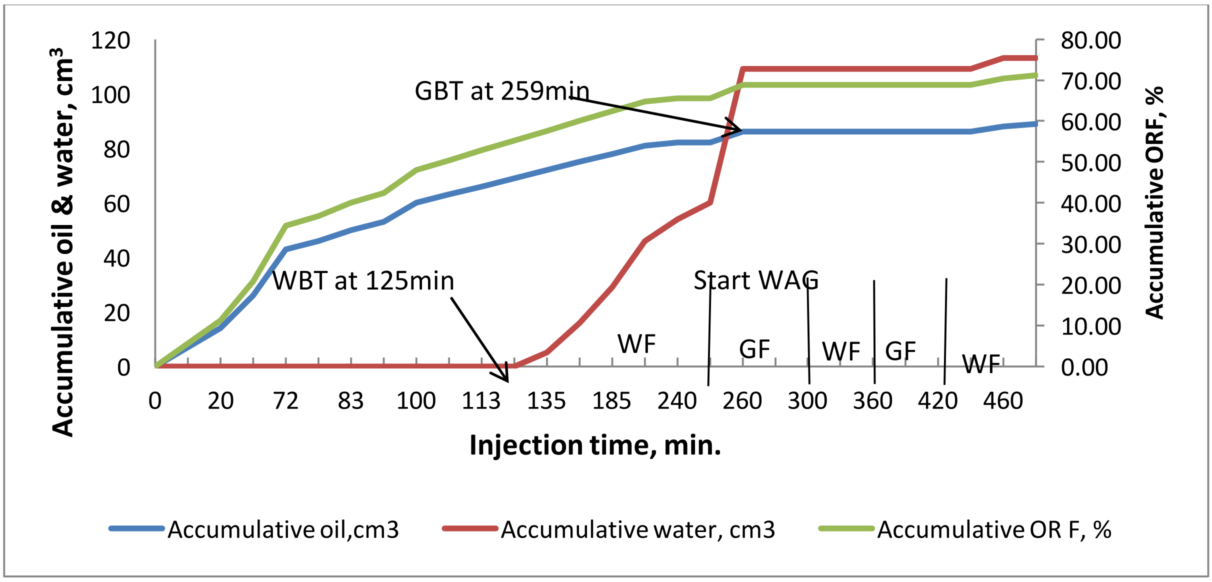

Figure 5. The whole process of WAG-N2 after WF

Only 4 cm^3 of oil was produced in the first cycle of WAG; however, after 11 min of starting WAG, the gas breakthrough (GBT) was observed in the production vessel. During the next two floodings of water and gas, there was no water production. Neither oil nor water was produced except in the last cycle where 3 cm^3 of oil was recovered and 4 cm^3 of water was seen in the production vessel. The WAG process was terminated at 480 min and the resulted ORF was only 5.60 %, indicating an extra recovery. It is important to note that, in the 1st cycle of gas injection, the gas pushed a huge volume of water (49 cm^3); therefore, it took much time to replace the voids left during the GF. The remaining oil in place (OIP) was 43 cc and the produced oil by WAG was 7 cm^3. This oil represented 16.28 % of the OIP and 5.60 % of the OOIP. Eventually, the total oil recovery factor was 71.20 %, representing the whole process (WF and WAG) as shown in Table 4 and 5.

WAGN$_2$ after Gas Flooding: It was observed that oil was highly recovered initially until GBT at 50 min before declining until the end of the GF process (reaching almost zero). The total oil recovered from this process was only 36 cm^3 out of 124 cm^3, representing 29.03 % of the OOIP (Table 4). WAG nitrogen was started using brine, then N_2. The process was conducted in two cycles for each fluid. Each fluid was injected for about 60 min to extract the remaining oil in place (OIP). Table 4 shows the main results of the WAG process, where an extra 29 cm^3 of oil was produced. WAF after GF is shown in Figure 6.
This amount of oil represents 23.29 % of the OIP and 42.95 % of the OOIP. The total process produced 52.42 % of the OOIP. It is important to notice that in the first slug of brine followed by the slug of gas, neither oil nor water was produced but during the second slug of brine and gas, 11cm^3 and 18 cm^3 of oil were recovered, respectively. See Table 4 and 5.

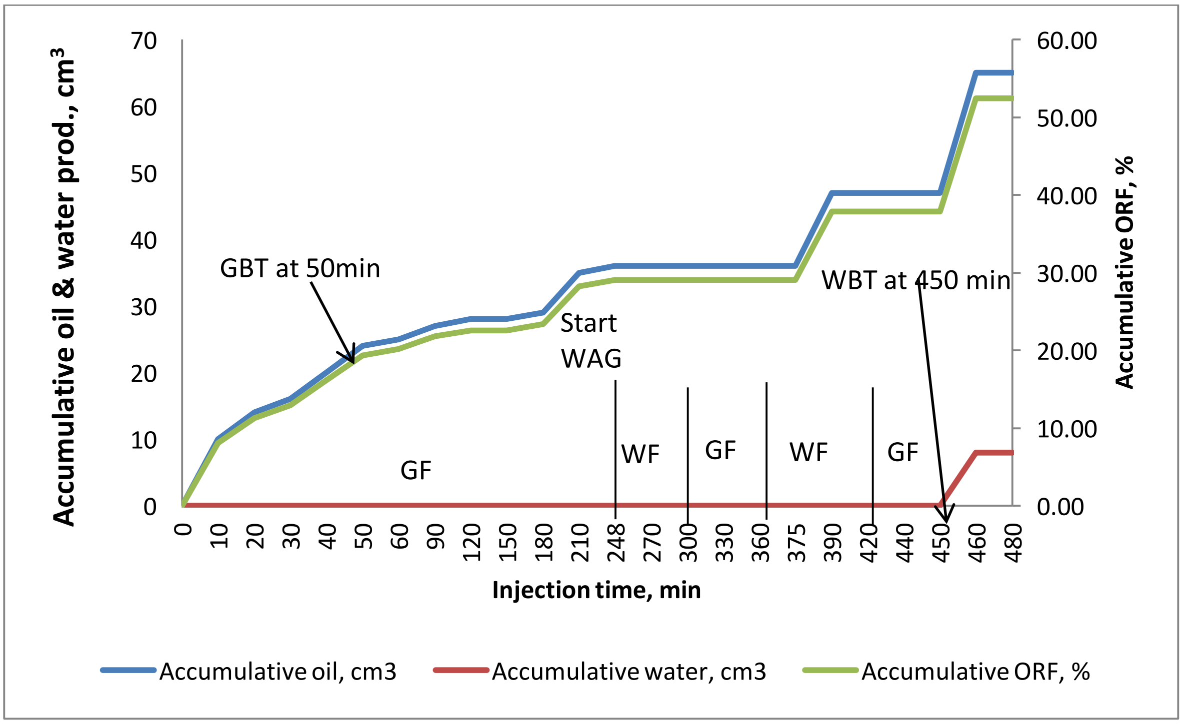

Figure 6. The whole process of WAG-N_2 after GF

Table 4. WF and GF

Parameters	WF	GF
S_{wi}, %	17.21	17.88
Pore Volume (PV), cm^3	151	151
Oil Original In Place (OOIP), cm^3	125	124
Water Injection rate, cm^3/min	0.6	0.6
Injection Time, min.	248	248
Recovered oil Volume, cm^3	82	36
ORF, %	65.6	29.03

Table 5. WAG process after WF and after GF

Parameters	WAG after WF	WAG after GF
OIP (oil remaining in place), cm^3	43	88
Gas injection rate, cm^3/min	0.6	0.6
Water injection rate, cm^3/min	0.6 cc/min	0.6 cc/min
Water Injection Time, min.	60 (2 cycles)	60 (2 cycles)
Gas injection time, min.	60 (2 cycles)	60 (2 cycles)
Recovered oil, cc	7	29
ORF (with respect to OOIP), %	5.6	23.39
ORF (with respect to OIP), %	16.28	32.95
Total ORF, %	71.2	52.43

Comparison between *WAG-N_2 after WF and GF:* Tables 4 and 5 showed the detailed results of the experiments for WAG after WF and WAG after GF. WF recovered 65.6 % of the OOIP while only 29.03 % was recovered by GF after keeping all the other injection parameters constant. According to

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Table 5, Process of WAG after WF recovered only 7cm^3 of the 43cm^3 of OIP, during cycles 1 and 2. This volume represents 5.6 % of the OOIP and 16.28 % of the OIP. Contrarily, WAG after GF recovered 29 cm^3 of OIP during cycle 2, representing 32.95 % of the OIP and 23.39 % of the OOIP.
Table 6 illustrates the results of the whole process of WAG after WF and after GF, including the water and gas breakthrough times.

Table 6. Different ORF% for all the processes

Processes	After WF (%)	After GF (%)
WF	65.6	
GF		29.03
WAG related to OIP	16.27	32.95
WAG related to OOIP	5.6	23.95
The whole process of WAG	71.2	52.42
WBT in WF, min.	125	
GBT in GF, min.		50
WBT in WAG, min.		450
GBT in WAG, min.	259	

Figure 7 compares the WAG after WF and WAG after GF. The figure showed the start of the processes to be almost identical; however, GF began at a higher rate.

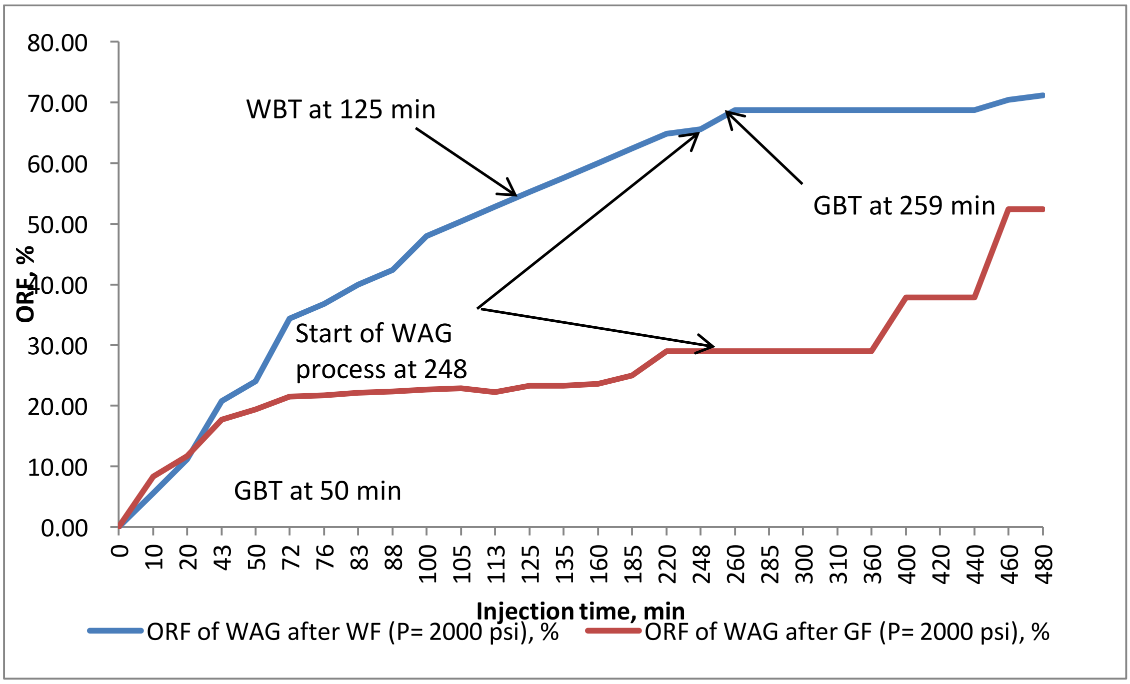

Figure 7. WAG-N_2 process after WF and after GF

In WF, the accumulative ORF continued rising until the WBT after which the ORF rate began to decline gradually until almost the end of the WF process. For GF, the production started to decline as soon as GBT occurred, and the recovery rate became low until almost near the end of the GF where oil recovery resumed with gas bubbles due to unsteady flow.
In WAG after WF, the ORF during the two cycles was not as high as the ORF obtained by WAG after GF. ORF of 32.95 % out of 88 cm^3 (OIP) was obtained only in WAG after GF while 16.27 % out of 43 cm^3 (OIP) was obtained by WAG after WF. From Figure 6, an improved ORF was achieved in WAG after GF during cycle 2 only.

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5. Discussion and analysis

Water Alternating Gas after WF: Figure 6 and 7 show the progress of the WAG after WF process during the 480 min of the experiment. At the beginning of WF, the accumulative oil production highly increased until the 72nd min and slightly decreased when the time reached 105 min. In the last 30 min of WF, only 1 cm^3 of oil was recovered; conversely, water was highly produced as 11 cm^3 was produced in the last 30 min of WAG. Moreover, WBT occurred due to the water fingering and water under-riding that had occurred previously. During fingering, water moves faster than oil along the paths or fingers due to the difference in the viscosity of water and oil. This leaves an amount of un-swept oil. After WBT at 125 min, the accumulative water production values increased hugely due to the increase in the numbers of water fingers which moved rapidly to the wellbore area. When WBT had occurred, it formed continuous paths (fingers) through the sand pack which consisted of narrow throats fully filled with water and pores that contain oil bounded by water. After injecting 1 PV of water at 248 min, the WF process was terminated and 65.60 % of the OOIP was recovered.
During the WAG process, the water and gas combination mechanism were used to control the mobility of gas in the displacement. During the 1^{st} GF in WAG, GBT occurred and the gas pushed 49 cm^3 of water and 4 cm^3 of oil; therefore, the ORF highly increased, reaching 68.80 % in 12 min. This quantity of produced water occupied the pores during the WF process. From the 1^{st} WF to the 2^{nd} GF, neither oil nor water was produced due to the substitution of the 49 cm^3 of water. The whole water volume injected in the 1^{st} WF in the WAG was used to fill the pores. In the 2^{nd} cycle of the WAG process, 3 cm^3 of oil was recovered during the WF and 4 cm^3 of water was produced due to the complete filling of the pores in the previous cycle. It was notable that, during the period of 260 to 440 min, water and oil production had stopped because the injected water was used to fill the pores, which were emptied during GF.

Water Alternating Gas after GF: Figure 6 and 7 show the plot of the accumulative ORF % versus the injection time. Although the recovered oil volume was not equal to the volume of the injected gas in the first 50 min of GF, however, the oil production was almost smooth except in the first 10 min. The reason was that the gas mobility was higher than oil and water. When the gas was injected in GF, it pushed a larger amount of oil; oil recovery declined and remained almost close to each other. In the immiscible gas injection process, the portion of the injected nitrogen dissolved in the oil reduces the oil viscosity. In addition to reducing viscosity, the dissolved gas also swells the oil. At 50 min, GBT occurred due to gas gravity problems, known as gas tonging or gravity over-ride due to differences in density between nitrogen and oil. In addition, viscous fingering is another problem that usually occurs during gas injection. Mobility ratio plays a significant role in viscous fingering; however, the mobility ratio is a function of the viscosity of the injected fluid and fluid displaced, which is oil. The viscosity of N_2 is low compared with oil; therefore, gas will move very fast to the production zone, causing what is known as "fingering phenomenon". During the period after GBT until the end of the GF process, the oil production was discontinuous (not stable, i.e. frequent slugs of oil was recovered associating the gas bubbles). After the gas breakthrough, some minor gas fingering occurred through the oil channels, leaving un-swept oil. The oil production for gas injection was at a slower rate than for WF. The injected gas followed the oil channels through the sand pack and distributed everywhere.
At 248 min, WAG started to recover the remaining oil in place. In fact, the quantity of water flooded was almost enough to fill the voids that had already been emptied from oil in GF process. The oil recovered in GF was 36 cm^3; therefore, 1 h of WF was almost enough to fill the pores in the sand pack. By the 1^{st} GF and the 2^{nd} WF in WAG process, the sand pack was able to resume oil production. The filling of the pores using water and the following of the process using gas caused the gas to search for paths to recover some oil before the reoccurrence of fingering and over-ride. On the other hand, sandstone is water-wet; therefore, some water adhered to the rock, consequently expelling some oil from the voids. As a result, in the 2^{nd} GF of the 2^{nd} cycle, the gas was able to make new fingers and tonging and recovered a reasonable amount of oil (18 cm^3) and 8 cm^3 of water during the period of 450 to 460 min when WBT occurred.

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Substantially, 29.03 % of the OOIP was produced by the GF process. This small ORF % highlighted the problem that always occurs during gas flooding (which is fingering and/or gravity over-ride). Moreover, during the WAG which began at 248 min for WF and GF in cycle 1, neither oil nor water production was recorded because the process was only able to fill the empty pores of the core during the 1st cycle. On the other hand, ORF was 8.87 % and 14.52 % in cycle 2 for WF and GF, respectively. The total oil produced at the end of the WAG run was 28 cm^3, representing 23.39 % of the OOIP and 31.82 % of the OIP. During WF, the production rate was smooth until WBT where water flow creates fingers or channels due to the viscous fingering phenomena that usually occurs during WF or GF. After a distance from the injection point, water tends to travel downward under the influence of under-ride gravity. This early under-ride causes early WBT and consequently affects the oil recovery. After WBT, some fingers are suppressed, and the flow became towards the bottom, leaving a substantial amount of oil in place. On the other hand, the WAG process controls water and gas mobility after applying WAG as a tertiary recovery by combining between two injecting fluids and reducing water under-ride. Therefore, more oil was produced during WAG after WF.
Relevant literature review on Water Alternating Gas Nitrogen: A review of WAG injection was provided by Arne Skauge et. al. in the 72 field cases reported. The majority of these projects have resulted in a significant increase in oil recovery, generally about 5-10% in sandstone. They concluded that the average improvement in non-inert gas was 6.4% [26].

6. Conclusion
WAG-N_2 can increase oil recovery before gas and water segregation occurs. The gas flooding process recovered less oil compared to water flooding due to early GBT. The ORF for WAG after WF was higher than ORF in WAG after GF. Although WAG after WF resulted in better total ORF% than WAG after GF, however, WAG after GF with respect to OIP yielded good results compared to WAG after WF. The most significant problems encountered during GF application is the tonging and viscous fingering; however, for WF, the major problem is gravity under-ride. Water and gas segregation is associated with WAG processes.

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