Experimental Study and Modeling of Gravity Drainage during WAG Process in Fractured Carbonate Rocks

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ABSTRACT: *The experimental study and modeling of gravity drainage during Water Alternative Gas Injection, WAG process, in carbonate rock for one of the Iranian off-shore reservoir at lab-scale were carried out. The mechanism of gravity drainage during the WAG process, and its contribution to the oil recovery in the fractured carbonate reservoirs were also studied. In the WAG process alternatively gas is injected during the process and gravity drainage could be happened. Changes in the block dimensions, rock properties, oil properties, gas properties, and fractures properties and their effect on the amount of oil recovered during the gravity drainage mechanism were studied. It would be worth mentioning that Methane, as major constituent of natural gas, was used as injection fluids within the experiments. Also carbonate rock was used as block sample in the physical model within the experiments. The results obtained from the experiments were compared with those obtained from the simulation and the comparison confirmed fair agreement between the results. It was found out that from 1 to 6 percent of oil can be recovered by gravity drainage during WAG process.*

KEY WORD: *Gravity drainage, WAG, Fracture, Gas invaded zone, GOC, Ultimate recovery, Single block, Carbonate rock, Physical model.*

INTRODUCTION

Nearly twenty percent of the oil reserves around the world can be found in the fractured reservoirs [1]. More than two-thirds of the major reserves in the Middle East are carbonate reservoirs [2]. The Gravity drainage mechanism plays an important role in the recovery of oil from tight matrix blocks into the fracture network. The matrix blocks provide the storage and the fractures provide the flow path for the liquid produced from the matrix. In a fractured reservoir, as production begins and reservoir pressure drops, the gas oil contact in the fracture goes down below that in the matrix, and some of the oil matrix blocks become surrounded by gas.

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When the gravitational forces exceed the capillary forces, those matrix blocks in the gas-invaded zone (surrounded by gas) will undergo a gravity drainage process. Gravity caused downward movement of oil in the presence of gas has been referred to as gravity drainage. It is a gas-oil displacement in which gravity forces are dominating. The density difference between the oil in the matrix and the gas in the fracture is the main driving force which is counteracted by the matrix capillary pressure. The performance of a fractured reservoir depends on the intensity of fracturing, the fracture volume and the degree of fracture communication. In its depletion period, a fractured reservoir may be divided vertically into several distinct zones. These zones are mainly; gas cap, gas invaded, gassing, undersaturated oil, water invaded and aquifer.

The presence of vertical fractures causes the gas-oil contact inside the fracture network exceeds the corresponding contact in the matrix block, where the gas invaded zone (GIZ) is formed. When the gravitational forces exceed the capillary forces, causes the fluid in the matrix block become unstable and thus producing oil from the blocks. The oil recovery in this zone is therefore dominated by gravity drainage mechanism, which is one of the most efficient recovery mechanisms in fractured reservoir. The main issue in understanding the flow behavior in fractured porous media is the block-to-block interaction that is capillary continuity and infiltration. When the gravity force is the only driving force, the process is called free gravity drainage (FGD). In free gravity drainage the ultimate saturation distribution inside the matrix block is governed by the capillary pressure curve of the block.

Gravity Drainage

The gravity drainage takes place mainly when gas from gas saturated fractures displaces the oil of the matrix. In each case the only driving force is the gravity force and without any external force, is called free gravity drainage (FGD). The matrix capillary pressure, connate water saturation and oil relative permeability are key factors to control the recovery rate and ultimate recovery from a single block. The flow rate and ultimate recovery from stack-blocks depend on capillary continuity, re-infiltration, and fracture transmissibility. As production starts, the oil in the fracture is first recovered and then gas from the gas cap or the free gas or injected gas replaces it. The oil in the matrix needs longer time to be drained by gravity to the fractures.

It causes fractures to become saturated with gas, and matrix to contain mainly oil. Therefore the gas-oil contact (GOC) in fracture advances ahead of that in the matrix block. This difference in the contacts elevation in addition to the density difference between the oil in the matrix and the gas in the fracture provides the pressure difference required for the oil recovery from the matrix [3]. The final recovery from the matrix is determined by the balance between the capillary pressure and gravity forces.

The final saturation distribution in the matrix block can be thought of as a transition zone where at each height the capillary pressure is $P_c = \Delta\rho.g.h$ It was found that oil relative permeability and capillary pressure are the key factors for efficient recoveries of oil under gravity drainage process [4]. When the quantities of interstitial water increases, the recovery of oil decreases. Less viscous oil and thicker oil formation have better drainage [5]. The rate of gravity drainage is controlled by the fluid and rock properties.

It was also found that by dropping the GOC the amount of oil that is produced from the upper matrix is sucked by the lower matrix. This process is known by re-infiltration process. In the WAG process during cyclic gas injection, some blocks in the reservoir surrounded by gas, and thus gravity drainage process will be started. *Barenblatt*, proposed a dual-media approach for modeling naturally fractured systems [6]. *Kazemi* and *Rossen* presented simulators for modeling fluid flow in naturally fractured reservoirs [7,8]. *Reiss* and *Van Golf-Racht* analyzed fluid segregation in detail for the matrix and fracture systems to identify matrix-block production rates and ultimate recoveries [9,10].

Saidi accounted for both radial and vertical variations by subdividing each matrix block into a cylindrical set of grid cells and simulating the varying saturation and pressure profiles [11]. Laboratory studies of gravity drainage from uncon-solidated sands were performed by *Higgings* and *Shea* [12]. The results of *Hagoort* suggest that oil recovery from the gravity drainage mechanism is dependent on three factors: the magnitude of gravitational forces relative to viscous forces, the shape of oil relative permeability curve, and the reservoir geometry and heterogeneity [4]. Two laboratory experiments were conducted on immiscible gas-oil flow, one is non-fractured with matrix permeability of $K_m = 1$ md and the other in fractured media with fractured permeability of $K_{ff} = 500$ md [1].

The matrix properties are the same as the non-fractured media. The rate of drainage in the fractured system was lower. The re-infiltration and the contrast in capillary pressure of the matrix and the fractured delayed the oil drainage process. Re-infiltration is influenced by capillary and gravity forces. There is disagreement in literature with respect to the effectiveness of water imbibition in fractured reservoirs for oil recovery. *Saidi* believes that water imbibition in fractured reservoirs is ineffective in water-wet and oil-wet rocks [3].

Firoozabadi suggested that water injection can give a very efficient recovery in fractured reservoir of water-wet and weakly water-wet matrix rocks [13]. In fractured reservoir the major forces are capillary and gravity forces, while in non-fractured reservoir the viscous forces are dominant. The reason is that the presence of a high permeability fractured network will lead to low pressure drop. Even for high injection/production rates the pressure drop will remain low. Therefore, the oil production from the matrix is controlled by gravity and capillary forces.

The assumption of zero capillary pressure for the fractured network has been proved to be an incorrect assumption [14,15]. *Firoozabadi* and *Hauge* showed that the fracture capillary pressure is influenced by characteristics of fractured medium such as fracture aperture, fracture roughness and the number of contact points between the fractures faces [14]. It was shown that the fracture capillary pressure is inversely proportional to fracture aperture. Both in laboratory and in many field applications, it has been found that high oil recovery can be achieved by application of gravity drainage process. For instance, *Kantzas et al.* reported gravity drainage laboratory experimental results using unconsolidated media [16].

Most of the available experimental studies in literature deal with immiscible displacement in fractured porous media. Few experimental lab scale studies can be found on immiscible displacement in fractured porous media [13, 15, 17-21].

Effect of changes in gas-water relative permeability

In the WAG process there are changes in saturation during each injection period. The non-wetting face is trapped in a discontinuous immobile state when is left behind by the wetting phase. When the volume of the trapped face increase the relative permeability of the injected fluid decrease [22, 23]. Fig. 17 shows a three-phase diagram indicating the performance of two cycles of water and gas injection in a WAG process. During the first cycle beginning at Swc gas is injected until reach saturation Sg1 at Swc, then start the water injection displacing the gas up to gas saturation Sgr1 at water saturation Sw1, ending the first cycle.

The second cycle start at those conditions increasing the gas saturation up to Sg2 displacing the water to Swc, observe the reduction in Krg during this new cycle, then during the water injection the gas saturation is reduced to Sgr2 increasing the water saturation to Sw2, leaving a trapped gas volume of approximately 20-30 %. This process is repeated until reach the total number of WAG cycles. For a realistic prediction of the reservoir performance, it is required a correct treatment of the effect of the three phases flowing in the reservoir and the history of dependent saturation functions for the imbibition and drainage process. The trapped gas process plays an important role on the residual oil displaced by water during each WAG cycle [24].

EXPERIMENTAL PROCEDURE

In this research experiments were fluid flow in fractured porous media under immiscible conditions. The important experimental parameters i.e. matrix permeability, fracture width and flow rate were selected according to carbonate reservoirs. The experiments of immiscible displacement were conducted at atmospheric conditions. The basic fractured reservoir model was one block of rock representing the matrix, surrounded by fractures on its faces. This study begins with a 1-D model (vertical physical model) that considers a block of matrix initially saturated with oil at irreducible water saturation. Methane (CH_4) was used for injection into top of vertical physical model consist of a carbonate block, which were saturated with separator oil, from SIRRI field.

The vertical physical model considered the matrix as one medium and the fracture as another medium. The matrix boundaries (fractures) were initially filled with gas.

Flow thus only occurred in the vertical direction inside the matrix by gravity segregation at a constant low rate and low pressure.

Oil flows to the fracture at the bottom of the matrix and gas fills from the top. Experiments on physical model can be used to investigate the effect of changes in many variables properties such as block dimensions, rock type, rock properties, oil properties, gas properties, experiment conditions, atmospheric and reservoir conditions, and etc. The effect of rock type and changes in the block dimensions at atmospheric and reservoir conditions on the amount of oil recovered during the gravity drainage mechanism was studied.

The displacing direction is positive downward. The physical model include fractured porous media was designed using the carbonate block. The block dimensions is 15 cm in width, 15 cm in length and 100, 66 and 33 cm in height as matrix and placed into vertical core holder. The space between the matrix and the walls of core holder acts as the fracture. The top and the bottom of the matrix and fracture system had a flow path of thickness 0.2 cm. The flow path covered the matrix and the connection at the top was connected to the CH_4 injection pump.

The bottom was connected to a collection vessel on a balance. The online balance was connected to a computer and the data were collected with Lab-view software (as shown in Fig. 1). The matrix porosity was measured and found to be 0.124. The fracture width was 0.2 cm, of the spacer. Where matrix permeability was 8.2 md. Gravity drainage experiments were conducted in single carbonate block through RGD-1, RGD-2, and RGD-3 samples. The physical block and fluid properties are given in tables 1, 2 and 3. The cumulative oil production, recovery factor was measured for each experiment.

MODELING OF GRAVITY DRAINAGE

The gas gravity drainage process in carbonate rock was modeled by Eclipse100 simulator. A 1-D model was constructed and run for each experiment using Eclipse100 at atmospheric and reservoir conditions. The model was in the vertical direction with gravity drainage for oil and gas phases including capillary and gravity forces. The matrix cells will typically have a gas-oil capillary pressure, while the fracture cells will usually have zero capillary pressure.

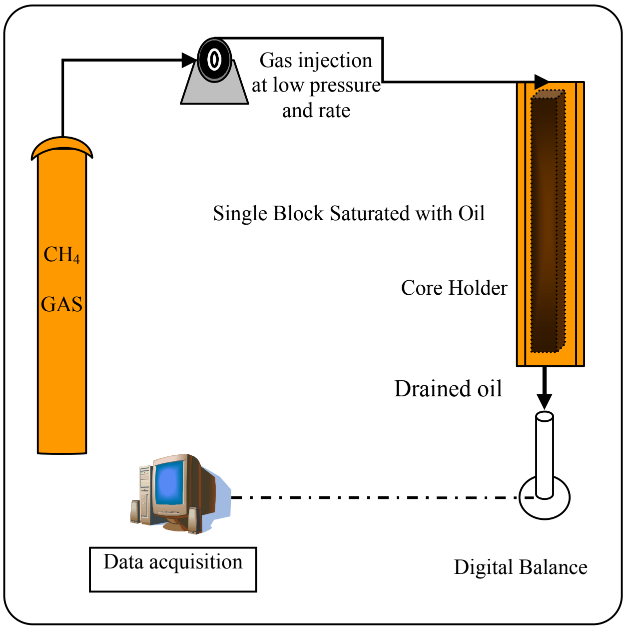

Fig. 1: Schematic diagram for the gravity drainage process used in experiments.

In gas-oil systems the oil will be the wetting phase and will tend to imbibe into the matrix. In practice this means that if the gravity drainage model is not active then no oil production will occur from a matrix block when the associated fracture block full of gas. The total oil recovery factor, total oil produced, oil production rate, average residual oil saturation and average pressure can be estimated using this model for each block height. Comparison of the modeling and experimental results using the plots of oil production, oil recovery factor and etc. versus time was done.

RESULTS AND DISCUSSION

Tables 1, 2 and 3 show respectively the physical properties of block samples and reservoir fluid used in this work at reservoir and atmospheric conditions. As seen from table 1 three blocks of carbonate rocks, RGD-1, RGD-2 and RGD-3 have the same physical properties with different length of 33, 66 and 100 cm respectively were used in the experiments. Table 2, shows physical properties of live oil as well as dead oil at reservoir and atmospheric conditions. Table 3 shows the reservoir live oil composition used in the model at reservoir conditions. It represents the analysis for the reservoir fluid composition, molecular weight and specific gravity of the hexane plus fraction.

Table 1: Physical properties of block samples used in the experiments.

Block Sample	Rock type	length (cm)	dimension	Ave. Porosity (%)	Ave. Ka (md)	Ave. Swi (%)
RGD-1	Carbonate	33	15*15	12.4	8.20	0.15
RGD-2	Carbonate	66	15*15	12.4	8.20	0.15
RGD-3	Carbonate	100	15*15	12.4	8.20	0.15

Table 2: Physical properties of live oil at reservoir conditions and dead oil a atmospheric conditions.

Gas solution in oil (RS)	SCC/RCC	53
Oil volume factor (BO)	Res Vol./ Std Vol.	1.27
Bubble point pressure	Atm	106
Fluid viscosity @ Atm. cond.	Cp	2.30
Oil density @ Atm. cond.	Gr/cc	0.857
Fluid viscosity @ Res. cond	Cp	1.8
Oil density @ Res. cond	Gr/cc	0.779
API		31.5
Gas density @ Res. cond.	Gr/cc	0.00127

Reservoir conditions: Temperature = 207 °F, Pressure = 280 atm. Atmospheric conditions: Temperature = 60 °F, Pressure = 1 atm.

Table 3: the reservoir live oil composition used in the model at reservoir conditions.

COMPONENT	Mole per cent
Methane	23.45
Carbon Dioxide	2.05
Ethane	7.26
Propane	8.02
Iso Butane	1.92
Normal Butane	3.99
Iso Pentane	1.85
Normal Pentane	2.57
Hexane Plus	48.89
Total	100.00

Molecular weight of Hexane Plus = 260, Specific gravity of Hexane Plus = 0.8976.

Table 4 shows experimental and simulation results for the oil recovery factor after implementation of the gravity drainage with dead oil at atmospheric conditions. Table 5 shows simulation results for the oil recovery factor after implementation of the gravity drainage with live oil at reservoir pressure of 280 atm. From tables 4 and 5 could be compared the experimental and simulation results for the oil recovery factor after implementation of the gravity drainage with dead oil at atmospheric and reservoir conditions. As seen from tables 4 and 5, the simulation results are in good agreement with those obtained from experiments.

As seen from table 6, experimental and simulation results for the amount of oil recovery factor, oil production and oil initial oil in place after implementation of gravity drainage at atmospheric and reservoir conditions. Table 6, compares the results obtained from the experiments with those obtained from the simulation using the simulator employed in this study. As can be seen the oil recovery factor obtained after implementation of gas gravity drainage changes with time and various with different height.

Also in table 6 the whole experimental and simulation results obtained from all block height in this work can be compared at the same time.

As shown the maximum experimental and simulation oil recovery factor is attained using the gravity drainage with height equal 100 cm. As mentioned before the block height is important and can be affected on the oil recovery. As seen maximum oil recovery factor for block with height equal 100 cm is more than others.

Table 4: Experimental and Simulation results for the oil recovery factor after implementation of the free-gravity drainage with dead oil at standard conditions.

Oil Recovery Factor / Block Length (cm)	Laboratory Oil Recovery (%)	Simulation Oil Recovery (%)
100	3.96	4.21
66	1.47	2.50
33	0.26	0.81

Table 5: Simulation results for the oil recovery factor after implementation of the gravity drainage with live oil at reservoir pressure of 280 atm.

Oil Recovery Factor / Block Length (ft)	Simulation Oil Recovery (%) injection at 280 atm
100	5.30
66	2.90
33	0.90

Table 6: Experimental and simulation results for the mount of oil recovery factor, amount of oil recovered and OIP after implementation of gravity drainage at atmospheric and reservoir conditions.

Block Height (cm)	Lab-Oil Recovery (%)	Lab-Oil Prod (SCC)	SIM-Oil Recovery (%)	SIM-Oil Prod (SCC)	
	0.00	0.00	0.00	0.00	Initial conditions
100	3.96	93.5	4.200	99.748	Atmospheric conditions
66	1.47	22.90	2.500	38.526	
33	0.26	2.00	0.800	5.975	
100	-	-	5.30	114.5	Reservoir conditions
66	-	-	.2.9	41.9	
33	-	-	0.9	7.2	

As shown minimum oil recovery with height equal 33 cm is observed using the gas gravity drainage on the core scale. Because more oil recovery depend on amount of difference in the contacts elevation in addition to the density difference between the oil in the matrix and the gas in the fracture. Table 7 shows standard deviation of experimental and simulation results for the amount of oil recovery factor after implementation of the gas gravity drainage mechanism with different height.

Table 8 shows experimental and simulation results for the mount of oil drained at atmospheric conditions. Figs. 2 to 13 show respectively variation of the cumulative oil recovered, oil recovery factor, block residual oil saturation, and block average pressure versus time obtained after implementation of gas gravity drainage processes on the core scale at reservoir conditions through simulation and atmospheric condition through experimental.

Figs. 2 to 4 show that data of experiments are little less than simulation model results. This is because difference between real gravity drainage mechanism in experimental studies and simulator results.

As seen the oil recovered through gravity drainage mechanism with height equal 100 cm is more than others. Figs. 5 to 7 show the oil recovery factor of experimental and simulation model for different block height. Figs. 8 to 10 show that average oil saturation decreased after implementation of gas gravity drainage processes in block. As seen Figs. 11 to 13 show the average block pressure. As seen outlet pressure is nearly constant and equal one atmosphere. Figs. 14 to 16 show respectively variation of the cumulative oil recovered, block average pressure and oil recovery factor versus time obtained after implementation of gas gravity drainage processes on the core scale at reservoir conditions through simulation results. As shown the oil recovery factor at

Table 7: Standard deviation of experimental and simulation results for the mount of oil recovery factor after implementation of the gas gravity drainage mechanism with different height.

Standard Deviation / Block Length	Laboratory	Simulation
3 ft	0.992725	1.357087
2 ft	0.220866	0.699888
1 ft	0.028351	0.039970

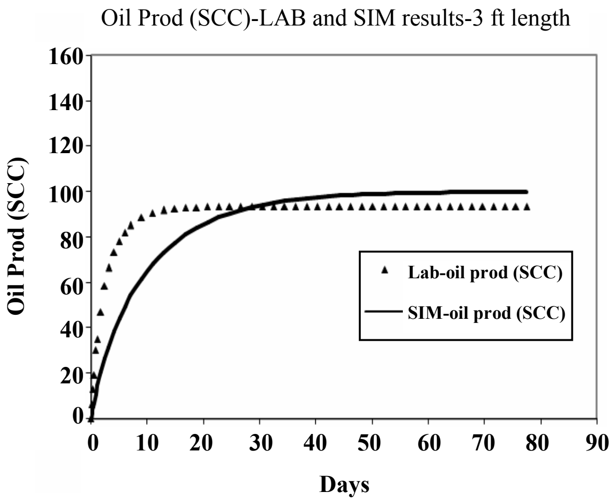

Fig. 2: variation of the amount of cumulative oil recovered through experimental and simulation results at atmospheric conditions.

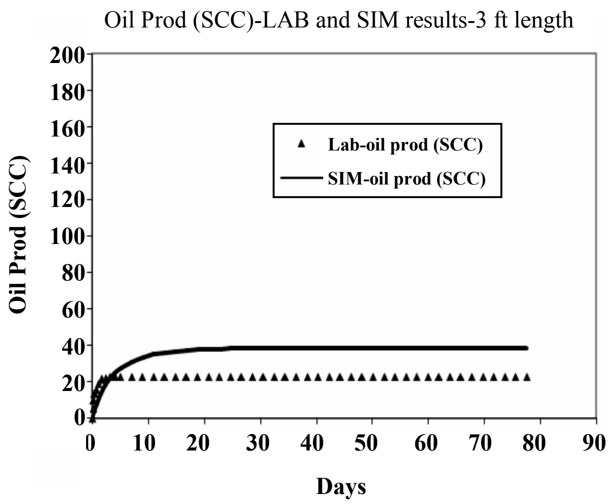

Fig. 3: variation of the amount of cumulative oil recovered through experimental and simulation results at atmospheric conditions.

Table 8: the mount of oil drained through experimental and simulation results for block height equal 3 ft at atmospheric conditions.

Time (hours)	Laboratory Oil drained (SCC)	Simulation Oil drained (SCC)
0.0	0.0	0.000
4.0	6.5	2.513
7.5	13.0	4.286
14.0	19.2	6.901
20.9	30.4	10.843
28.0	35.2	14.500
41.5	47.2	20.743
58.5	58.5	26.453
75.0	66.4	31.639
98.5	73.3	38.359
122.0	78.3	44.310
145.5	81.9	49.551
169.0	85.0	54.217
216.0	88.7	61.763
263.0	90.4	68.020
310.0	91.7	73.140
357.0	92.4	77.356
404.0	92.8	80.978
451.0	93.1	83.917
498.0	93.2	86.455
545.0	93.3	88.596
592.0	93.4	90.347
639.0	93.4	91.799
686.0	93.4	93.020
733.0	93.4	94.179
780.0	93.4	95.126
921.0	93.4	97.069
968.0	93.5	97.515
1015.0	93.5	97.889
1156.0	93.5	98.684
1203.0	93.5	98.869
1297.0	93.5	99.153
1344.0	93.5	99.262
1438.0	93.5	99.430
1485.0	93.5	99.494
1579.0	93.5	99.594
1720.0	93.5	99.690
1861.0	93.5	99.748

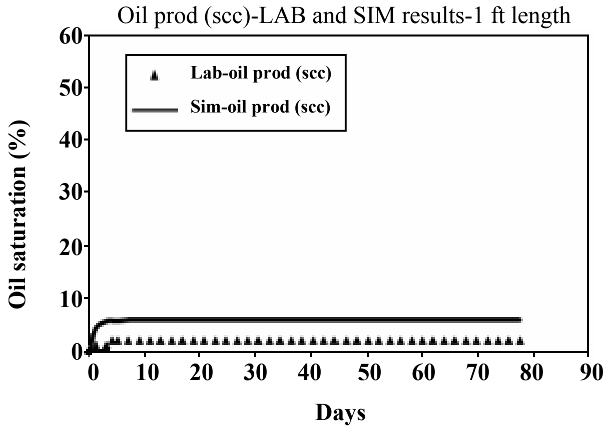

Fig. 4: variation of the amount of cumulative oil recovered through experimental and simulation results at atmospheric conditions.

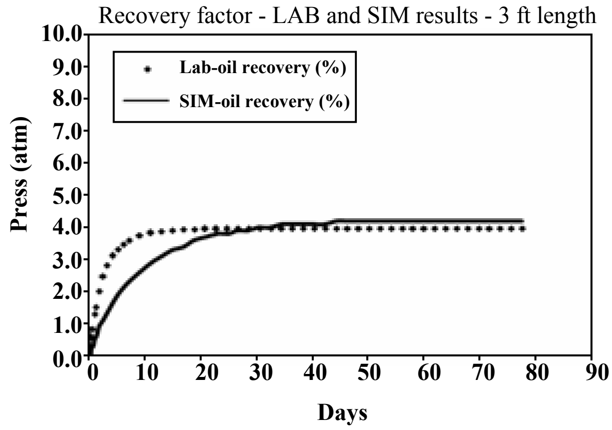

Fig. 5: variation of the amount of oil recovery factor through experimental and simulation results at atmospheric conditions.

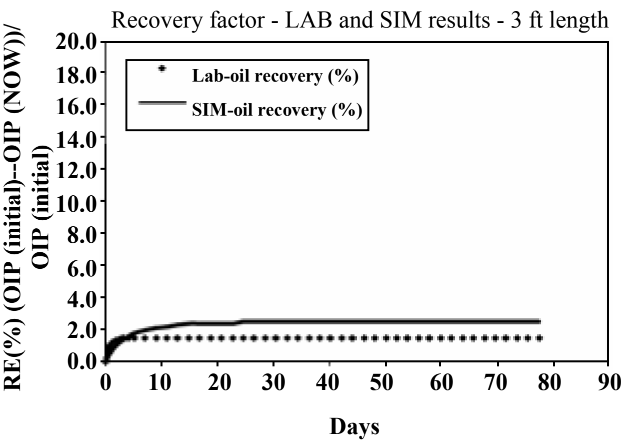

Fig. 6: variation of the amount of oil recovery factor through experimental and simulation results at atmospheric conditions.

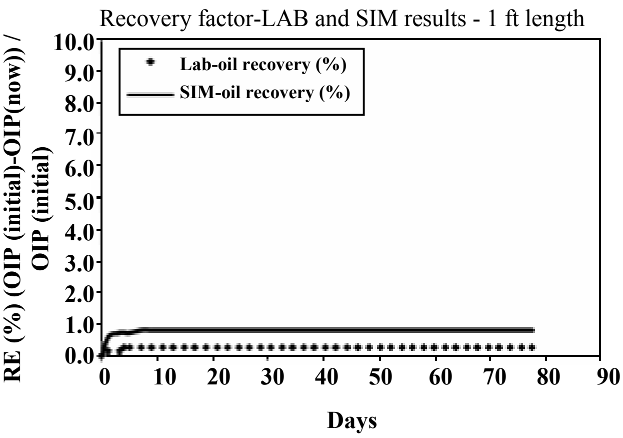

Fig. 7: variation of the amount of oil recovery factor through experimental and simulation results at atmospheric conditions.

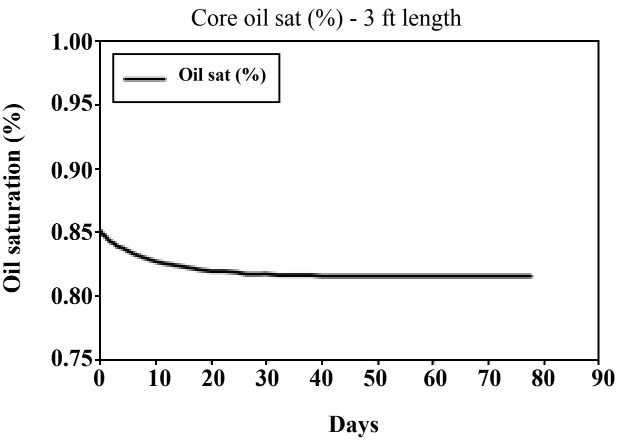

Fig. 8: variation of the block residual oil saturation through simulation at atmospheric conditions.

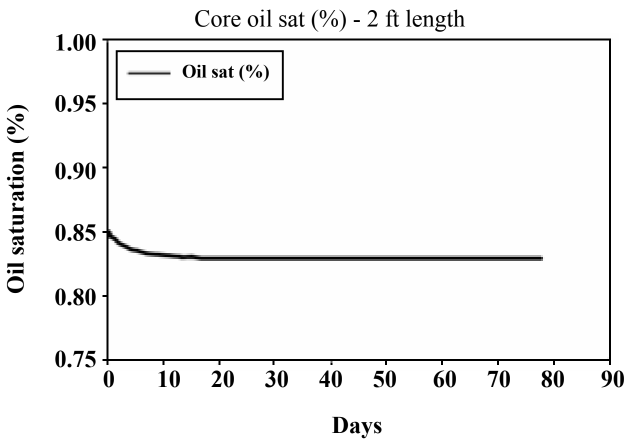

Fig. 9: variation of the block residual oil saturation through simulation at atmospheric conditions.

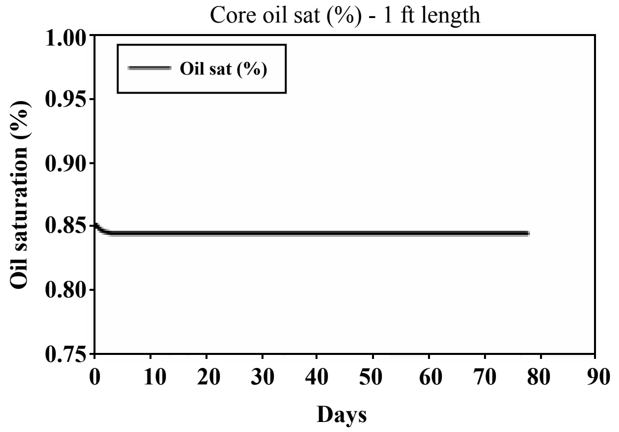

Fig. 10: variation of the block residual oil saturation through simulation at atmospheric conditions.

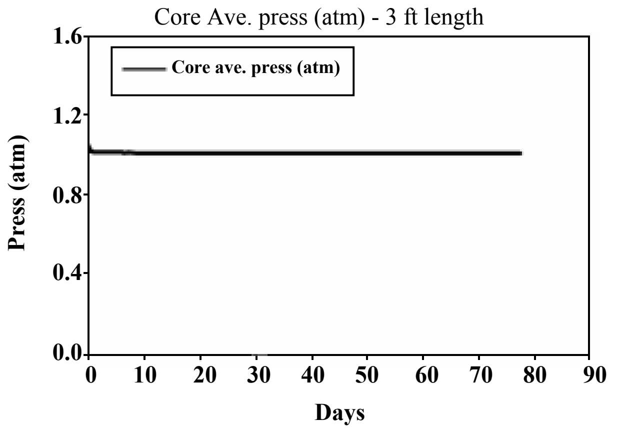

Fig. 11: variation of the block average pressure through experiments at atmospheric conditions.

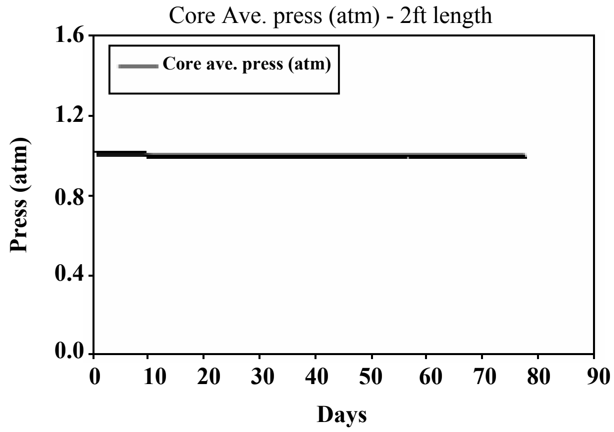

Fig. 12: variation of the block average pressure through experiments at atmospheric conditions.

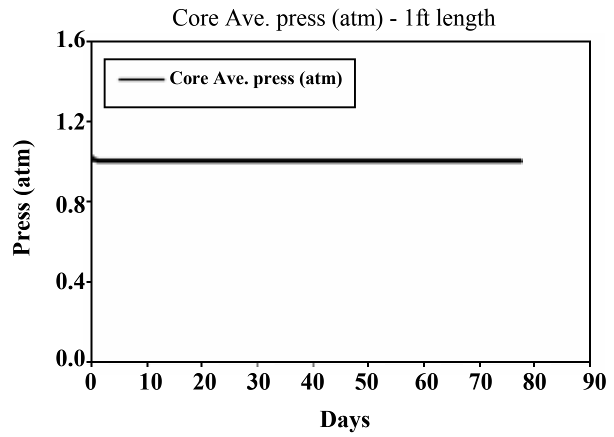

Fig. 13: variation of the block average pressure through experiments at atmospheric conditions.

reservoir conditions are more than atmospheric conditions. This is because of solution gas that helps to increase of oil drained in downward. The pressure difference in the block in both scenarios is low and gravity drainage could be as dominant mechanism for oil production. Figs. 11 to 13 and 15 shows respectively variation of the average core pressure at atmospheric and reservoir conditions during experiments. Those are horizontal straight line and show nearly same pressure through core. It means only free gravity drainage without any external force, high pressure difference between core inlet and out let, is as dominant mechanism and caused downward movement of oil in the presence of gas.

Fig. 17 shows a three-phase diagram indicating the performance of two cycles of water and gas injection in a WAG process. During the first cycle beginning at Swc gas is injected until reach saturation Sg1 at Swc, then start the water injection displacing the gas up to gas saturation Sgr1 at water saturation Sw1, ending the first cycle. The second cycle start at those conditions increasing the gas saturation up to Sg2 displacing the water to Swc, observe the reduction in Krg during this new cycle, then during the water injection the gas saturation is reduced to Sgr2 increasing the water saturation to Sw2, leaving a trapped gas volume of approximately 20-30 %. As seen good agreement between experimental and simulation can be obtained using the Eclipse 100 at reservoir and atmospheric conditions.

CONCLUSIONS

The gas gravity drainage both theoretically and experimentally studied on a block scale for an Iranian offshore reservoir. The results showed that implementation

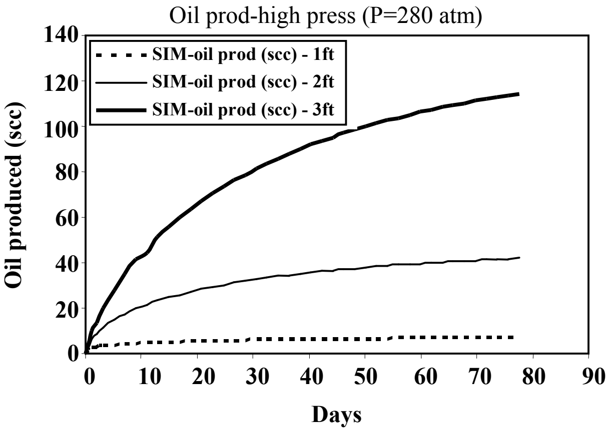

Fig. 14: variation of the amount of cumulative oil recovered through simulation at reservoir conditions.

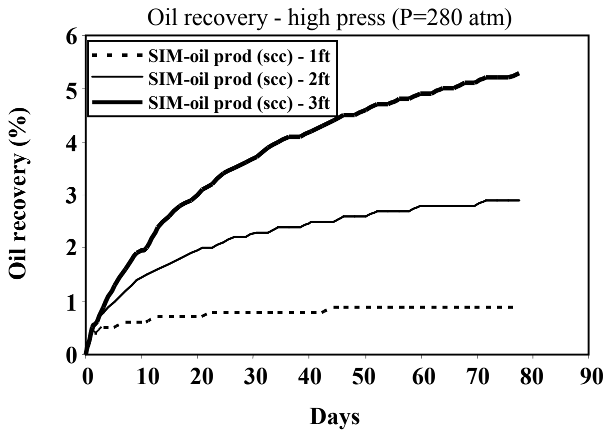

Fig. 16: variation of the amount of oil recovery factor through simulation results at reservoir conditions.

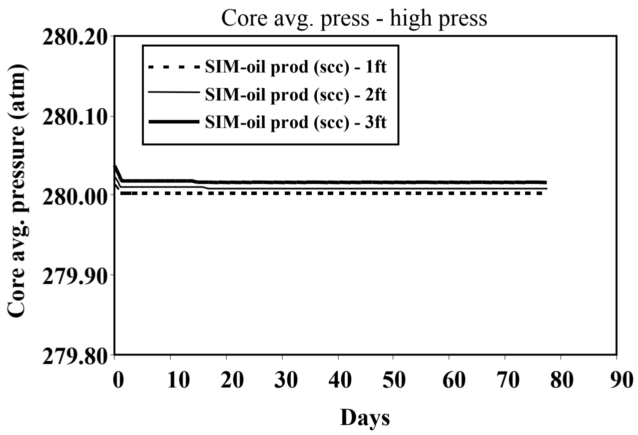

Fig. 15: variation of the block average pressure through simulation results at reservoir conditions.

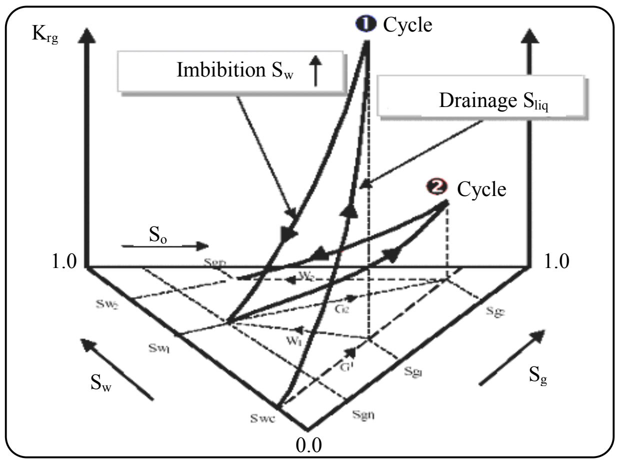

Fig. 17: WAG process, Gas 3-phase relative permeability Hysteresis.

of the gas gravity drainage process with high block height and solution gas can lead to a higher oil recovery comparing to small block height and without any solution gas. It found that the oil recovery factor and the amount of oil recovered is more than that in atmospheric conditions. The block height can be considered as one of the most important factors that could significantly affect the oil recovery. If the block height is more than the critical height then gas gravity drainage processes could start. The experimental results were compared with the results obtained from a numerical black oil simulator. It was concluded that good agreement can be attained between the results of the simulation and those of experiments collected in this work.

Nomenclatures

GIZ	Gas invaded zone
OIP	Oil initial in place
GOC	Gas-oil contact
FGD	Free gravity drainage
RF	Oil Recovery Factor
μo	Oil viscosity
μg	Gas viscosity
Pc	Capillary pressure
Δρ	Density difference between oil and gas
h	Elevation between oil and gas contact

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