Petroleum & Coal
ISSN 1337-7027

Available online at www.vurup.sk/petroleum-coal
Petroleum & Coal 56(2) 175-181, 2014

LABORATORY STUDY FOR WATER, GAS AND WAG INJECTION IN LAB SCALE AND CORE CONDITION

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Received January 15, 2014, Accepted April 14, 2014

Abstract

In this research experimental and simulation studies have done for WAG, Water injection and Gas injection. The WAG results compared to water injection and gas injection. Plan of all three types injection were designed and, lots of tests were performed by the core flooding system. Immiscible Methane injection was used in WAG process and gas injection. The core and fluid samples were prepared from Iranian carbonated reservoirs. Injection pressure and temperature were selected according to reservoir condition. The wettability of system was nearly oil wet; because generally carbonate rocks are oil wet. It was found which the results of numerical simulation are more than experimental tests. So it was found that WAG tests with injection rate 0.2 cc/min has recovery factor more than about 6 and 10 percent compare to water injection and gas injection. It means WAG process increases oil recovery factor compare to water injection and gas injection.

Keywords: Oil recovery; immiscible; carbonate; simulation; recovery factor.

1. Introduction

A common trend for the successful injections is an increased oil recovery in the range of 5-10 percent of the IOIP (initial oil in place). One of the new methods for improved oil recovery is WAG (water alternating gas injection). Since the residual oil after WAG process is normally lower than the residual oil after water injection and gas injection. Three phase zones may obtain lower remaining oil saturation. WAG has potential for increased macroscopic displacement efficiency in immiscible displacement, microscopic displacement efficiency (in miscible displacement), and improved oil recovery by better mobility control with, combining water and gas front. The first reported WAG in 1957 in Canada and then in Kansas and North Sea. Both onshore and offshore projects have been included, as well as WAG with hydrocarbon or nonhydrocarbon gases. Improved oil recovery by WAG is discussed as influenced by rock type, injection strategy, miscible/Immiscible gas, and well spacing. Managing WAG injection projects requires making decisions regarding to the WAG ratio, half-cycle-slug size, and ultimate solvent slug size for each WAG injector in the field. WAG has resulted in improved recovery (compared to a pure water injection and gas injection). WAG injection results in a complex saturation pattern since two saturation (gas and water) will increase and decrease alternatively. This gives special demands for the relative permeability description for the three phases (oil, gas and water).

2. Theory

Incremental oil that can be economically produced over that which can be economically recoverable by conventional primary and secondary methods. The main goals of any IOR method are increasing the capillary number and providing favorable mobility ratios (M<1.0). The capillary number is defined as the ratio of viscous to capillary forces.

$$Nca = \frac{ViscousForce}{CapillaryForce} = \frac{v\mu}{\sigma\cos\theta} \qquad (1)$$

where σ is the interfacial tension, θ is contact angle.

The overall efficiency of any Improved Oil Recovery (IOR) process depends on both the microscopic and macroscopic sweep efficiencies. While the fluids density difference and rock heterogeneity affect the macroscopic efficiency, the microscopic displacement efficiency is influenced by the interfacial interactions involving interfacial tension and dynamic contact angles. The mobility ratio, which controls the volumetric sweep, between the injected fluid and displaced oil bank in flooding processes, is typically highly unfavorable due to the relatively low viscosity of the injected phase. This difference makes mobility and consequently flood profile control the biggest concerns for the successful application of this process. These concerns led to the development of the WAG process for flood profile control. The higher microscopic displacement efficiency of gas combined with the better macroscopic sweep efficiency of water significantly increases the incremental oil production.

WAG review showed that this process has been applied to rocks from very low permeability to high permeability cores. The major design issues for WAG are reservoir characteristics and heterogeneity, rock and fluid characteristics, composition of injection gas, injection pattern, WAG ratio, three-phase relative permeability effects and flow dispersion [1]. Stratification and heterogeneities strongly influence the oil recovery process. Reservoirs with higher vertical permeability are influenced by cross flow perpendicular to the bulk flow direction. Viscous, capillary, gravity and depressive forces generally influence this phenomenon. Cross-flow may influence to increase the vertical sweep, but generally the effects are detrimental to oil recovery, mainly due to the gravity segregation and decreased flow velocity in the reservoir. This leads to reduce frontal advancement in lower permeability layer. WAG recoveries and continuous gas injections are more strongly affected by these phenomena. Reservoir heterogeneity controls the injection and sweep patterns in the flood. The reservoir simulation studies [1] for various kv / kh (vertical to horizontal permeability) ratios suggest that higher ratios adversely affect oil recovery in WAG process. Gorell [1] reported that the vertical conformance of WAG displacements is strongly influenced by conformance between zones. In a non-communicating-layered system, vertical distribution of C1 is dominated by permeability contrasts. Flow into each layer is essentially proportional to the fractional permeability of the overall system (average permeability * layer thickness (k*h)) and is independent of WAG ratio, although the tendency for C1 to enter the high permeability zone with increasing WAG ratio cannot be avoided. Due to the cyclic nature of the WAG, the most permeable layer has the highest fluid contribution, but as water is injected it quickly displaces the highly mobile C1 and all the layers attain an effective mobility nearly equal to the initial value. These cause severe injection and profile control problems. The higher permeability layer(s) always respond first. WAG will reduce mobility not only in the high permeability layer but also in the low permeability layer, resulting in a larger amount of the C1 invading in the highest permeability layer. The ratio of viscous to gravity forces is the prime variable for determining the efficiency of WAG injection process and controls vertical conformance of the flood. Cross-flow or convective mixing can substantially increase reservoir sweep even in the presence of low vertical to horizontal permeability ratios. Heterogeneous stratification causes physical dispersion, reduces channeling of C1 through the high permeability layer, and delays breakthrough. This is attributed to permeability and mobility ratio contrasts [3]. This is unfavorable and greatly influences the performance of the flood. However, the effects are reservoir specific and the overall effect is dependent on various parameters like permeability, porosity, reservoir pressure, capillary pressure and mobility ratio [1,3-5] Rock and Fluid Characteristics

Fluid characteristics are generally black-oil or compositional PVT properties obtained in the laboratory by standardized procedures [1]. Very accurate determination of fluid properties can be obtained with current techniques. However, rock-fluid interactions such as adhesion, spreading and wettability affect the displacement in the reservoir. In reservoir simulators all these rock-fluid interactions are generally lumped into one parameter – relative permeability. The relative permeability is the connecting link between the phase behavioral and transport properties of the system. Relative permeability is an important petrophysical parameter, as well as a critical input parameter in predictive simulation of each floods. Relative permeability data are generally measured in the laboratory by standardized procedures with actual reservoir fluids and cores and at reservoir conditions [1]. Capillary pressure is usually present unless the flood is miscible. The capillary pressure depends on local curvatures of the fluid/fluid interfaces, which in turn depend on saturation, saturation history, wettability and pore geometry [1,9].

Laboratory displacement processes are affected by viscous instabilities and discontinuities at the inlet and, more importantly, the outlet of the core, which is referred to as the end effect. Using large core lengths and pore volume can minimize end effects. The scaling criterion of Leas and Rappaport has been used to remove the dependence of oil recovery on injection rate and core length. The use of this scaling criterion helps the capillary pressure gradient in the flow direction to be smaller than the imposed pressure gradient. The scaling criterion is given by Eq-2.

$$L.V.\mu \geq 1 \qquad (2)$$

where L is the core length (cm), μ is viscosity of displacing phase (cp) and V is fluid velocity (cm/min).

2.1 Main Parameters

The optimum WAG ratio is influenced by the wetting state of the rock [2]. WAG ratio of 1:1 is the most popular for field applications [6]. However, gravity forces dominate water-wet tertiary floods while viscous fingering controls oil-wet tertiary floods. High WAG ratios have a large effect on oil recovery in water-wet rocks resulting in lower oil recoveries. Tertiary C1 floods controlled by viscous fingering had a maximum recovery at WAG ratio of about 1:1. Floods dominated by gravity tonguing showed maximum recovery with the continuous C1 slug process. The optimum WAG ratio in secondary floods was a function of the total C1 slug size.

The WAG injection results in a complex saturation pattern as both gas and water saturations increase and decrease alternatively. This results in special demands for the relative permeability description for the three phases (oil, gas and water). There are several correlations for calculating three-phase relative permeability in the literature [7], but these are in many cases not accurate for the WAG injection since the cycle (water/gas) dependant relative permeability modification and application in most models are not considered. Stone II model is the most common three-phase relative permeability model used in commercial reservoir simulators today; however, it is necessary to obtain experimental data for the process planned.

2.2 IOR Method-Gravity effect

Green and Willhite [7] suggest that the same density difference, between injected gas and displaced oil that causes problems of poor sweep efficiencies and gravity override in these types of processes can be used as an advantage in dipping reservoirs. Gravity determines the gravity segregation of the reservoir fluids and hence controls the vertical sweep efficiency of the displacement process. Gravity stable displacements of oil by gas injection or WAG in dipping reservoirs as secondary or tertiary process results in very high oil recovery. This has been confirmed by laboratory tests, pilot tests as well as field applications [1,8-10,11-13]. Although the purpose of WAG injection is to mitigate the gravity segregation effects and provide a stable injection profile, WAG in down dip reservoirs have shown better profile control and higher recoveries. Hence the gravity considerations in WAG design are necessary.

3. Apparatus and setup

This research is directed towards an evaluation and ability of the WAG process. WAG parameters and rock-fluid interactions in a laboratory were investigated. This project aims to study the flooding characteristics of WAG and continuous gas and water injection in core scales at reservoir pressure (3100 - 3400 psi) and reservoir temperature (200 ^{o}f). So need design and make the experimental setup. In SUT (Sharif University of Technology), it was made and able to tested each injection types. The high-pressure (more than 5000 psi) coreflood apparatus was setup to conduct unsteady state coreflood experiments. It consists of a high-pressure pump injecting at desired flow rate (minimum less than 0.1 cc/min) and pressure (maximum 10000 psi) to the bottom part of the floating piston transfer vessel. The transfer vessel is filled with the fluid to be injected into the core. Three types of experiments: continuous gas injection water injection and WAG process were performed. In order to accomplish the proposed objectives, core flooding experiments were conducted in 31.5 cm long and 3.8 cm diameter with carbonate cores (table1 & 2), using brines as aqueous phases along with pure C1 as the immiscible injecting gas. Injection rate 0.1, 0.2, and 0.5 cc/min were performed in continuous gas injection, water injection and WAG process. These experiments were conducted in immiscible mode. Oil recoveries were determined in these floods to evaluate the effectiveness of WAG process against continuous gas injection in immiscible and water injection cases. All the experiments consisted of the following steps: Saturation with brine, determination of pore volume and absolute permeability, oil flood to connate water saturation. The core filled with brine solution after core cleaning to determine pore volume and absolute permeability. It is brought to connate water saturation by flooding with oil sample at high flow rates. Based on injection type the core is then water or gas flood to water injection and gas injection residual oil saturation also with WAG process.

Table 1 Core properties

Core Sample	Porosity	Permeability md	Swi	Rock type	Core length cm	Core diameter cm
S1,S2,S3	12.5	8	0.20	carbonate	31.5	3.8

Table 2 Fluid properties

μo (cp)	μw (cp)	Oil Gravity (API)	SW	SG	Density ρo (cm^3/g)	Pg (cm^3/g)	Pw (cm^3/g)	Bo	Bw
0.5	0.9	31.05	1.07	0.815	0.891	0.000708	1.013	1.28	1.043

4. Lab results

It was found that optimum injection rate for WAG process with 1.2P.V (total injection volume) is 0.2cc/min compare to 0.1cc/min and 0.5cc/min that used for all three types in reservoir condition.

During experimental tests, it was found that WAG process have recovery factor 51.9 % OIIP and during numerical simulation 53.45% OIIP with injection rate equal 0.2 cc/min.

Continuous water injection experimental tests 46.25% OIIP and with numerical simulation 48.91% OIIP in 0.2 cc/min.

Continuous immiscible C1 injection experimental tests 42.03% OIIP and with numerical simulation 44.06 % OIIP in 0.2 cc/min.

WAG tests with injection rate 0.2 cc/min has recovery factor more than 5.65 and 9.87 percent compare to water injection and gas injection. WAG numerical simulation with injection rate 0.2 cc/min has recovery factor more than 4.54 and 9.39 percent compare to water injection and gas injection.

5. Conclusions

1. WAG process able to push and produce oil from unswept zones.
2. The oil recovery factor with WAG process appeared to be better than water injection and immiscible C1 injection.
3. Basic parameters for WAG process are Injection Rate, Slug Size, WAG Ratio and etc.which in this research found optimum injection rate is 0.2 cc/min.
4. Increasing the oil recovery factor by WAG process between 4-9.5 % OIIP based on experimental and numerical simulation for carbonate core in this research.

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Fig. 1, 2, 3 Oil recovery factor with numerical study for injection rate = 0.1, 0.2, 0.5 cc/min

Fig.1 q_{inj} =0.1cc/min

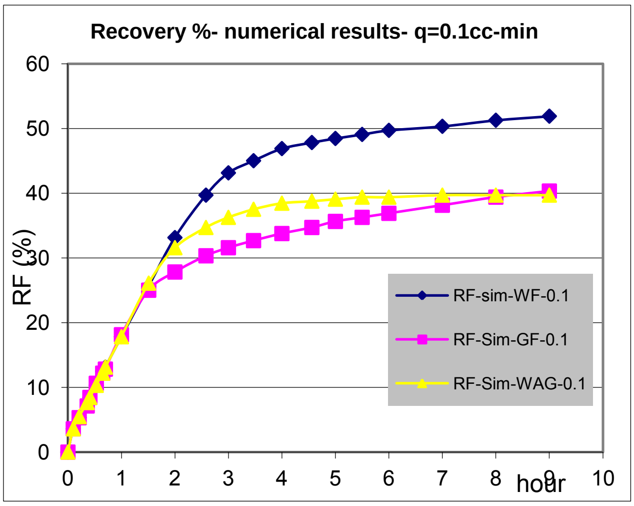

Fig.2 q_{inj} =0.2cc/min

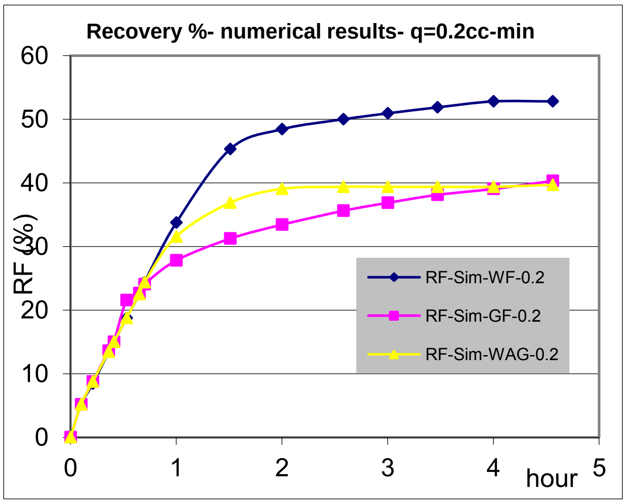

Fig. 4, 5, 6 Oil recovery factor with experimental study for injection rate = 0.1, 0.2, 0.5 cc/min

Fig.3 q_{inj} =0.5cc/min

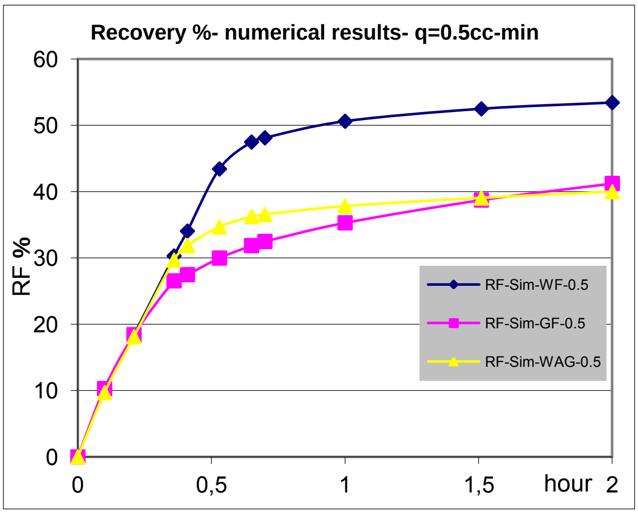

Fig.4 q_{inj} =0.1cc/min

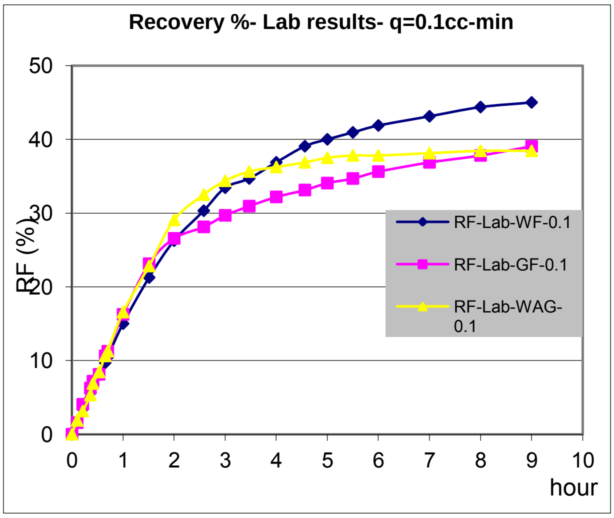

Fig.5 q_{inj} =0.2cc/min

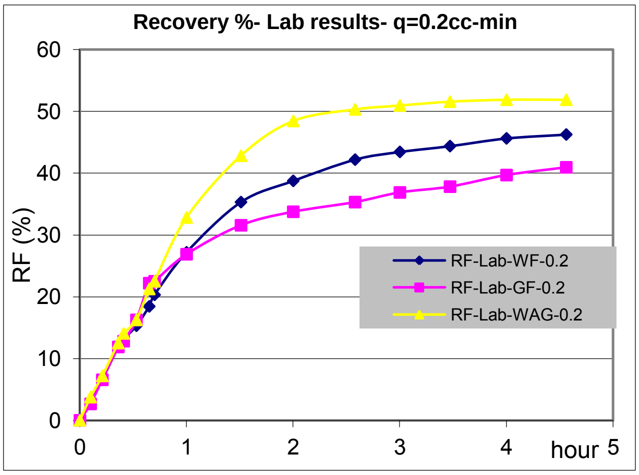

Fig.6 q_{inj} =0.5cc/min

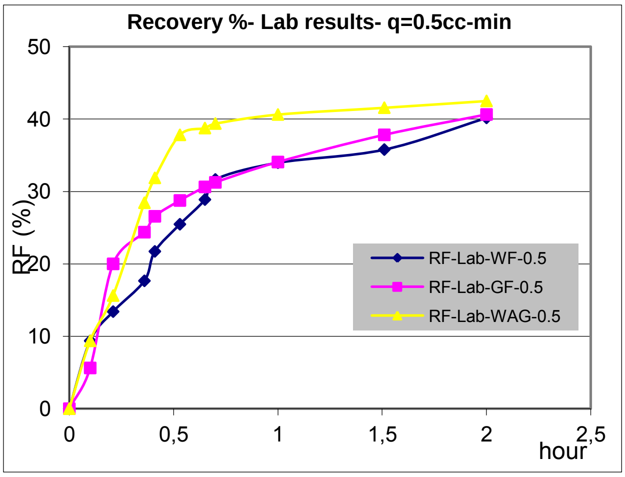

Fig. 7, 8, 9 comparing of oil recovery factor during experimental study and numerical study for injection rate = 0.1, 0.2, 0.5 cc/min

Fig.7 q_{inj} =0.1cc/min

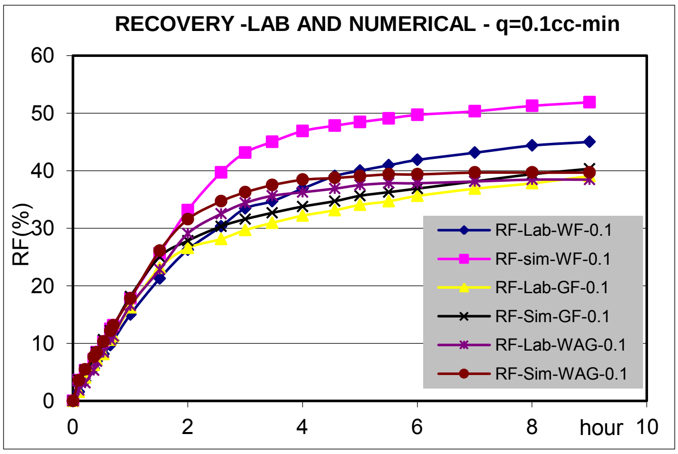

Fig.8 q_{inj} =0.2cc/min

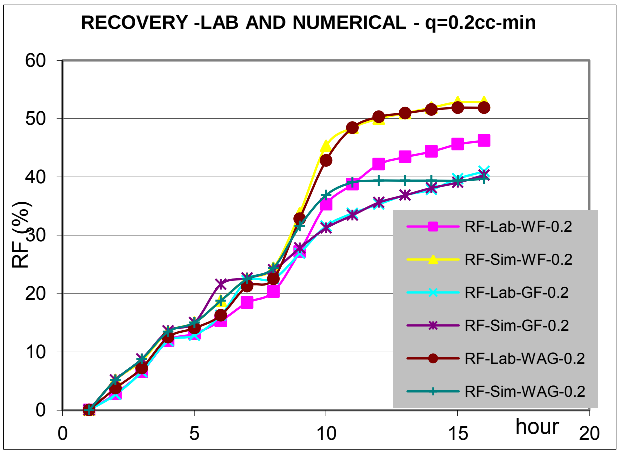

Fig. 10, 11, 12 comparing of oil recovery factor during experimental study and numerical study only for each injection type

Fig.9 q_{inj} =0.5cc/min

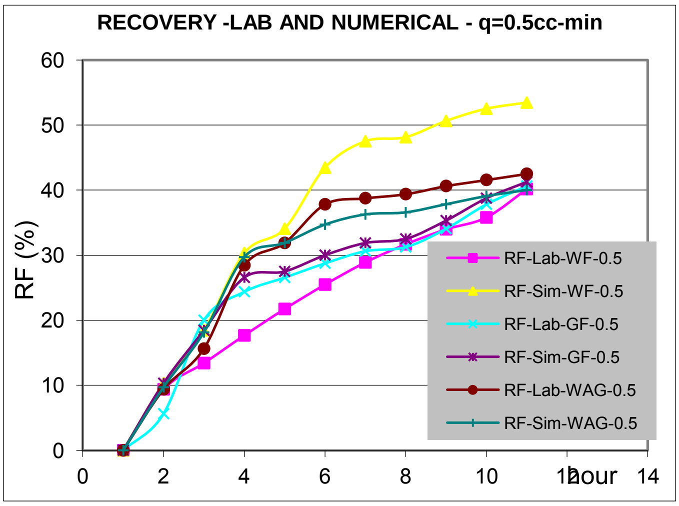

Fig.10 Water injection scenario

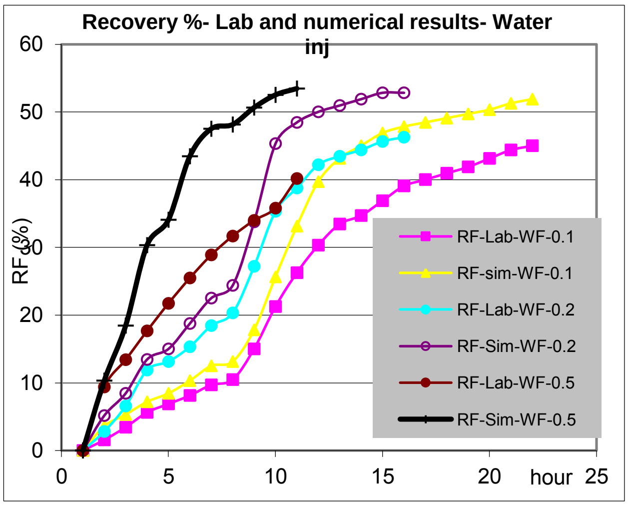

Fig.11 Gas injection scenario

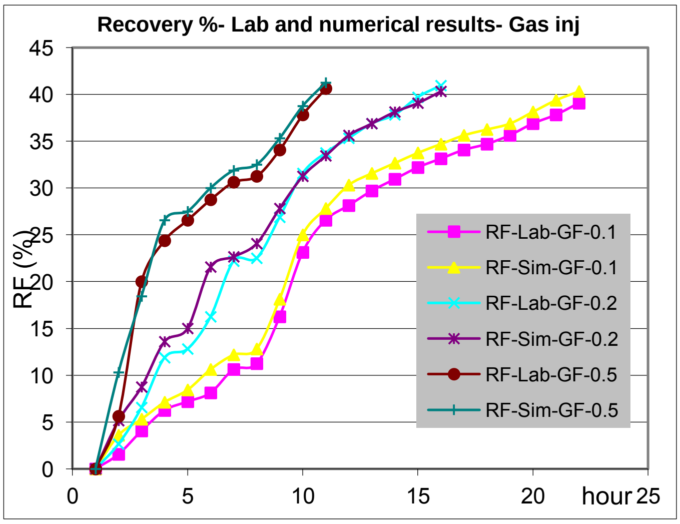

Fig.12 WAG process scenario