The Effects of kv/kh on Gas Assisted Gravity Drainage Process

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ABSTRACT

Gelama Merah field is located in offshore west Sabah, Malaysia. Gas Assisted Gravity Drainage (*GAGD*) was proposed to overcome the gravity segregation effect from continuous gas injection in the conventional horizontal flooding patterns as well as water shielding, decreased in oil relative permeability and reduced in gas injectivity which happened in Water-Alternating-Gas (*WAG*) process. This research was done based on heterogeneous reservoir, which has not yet been attempted by any published *GAGD* research. The objectives of the research are to investigate the effect of k_v/k_h on gravity segregation in the visual physical model; to study the effect of operating parameters on the oil recovery (*RF*) and breakthrough time; to visualize and understand the development of the downward movement towards the horizontal producer; to study the relationship of k_v/k_h to oil recovery and breakthrough time at their respective gravity number (N_G); to scale up the production time to real reservoir condition; to compare the simulation results with laboratory results. Investigations have been done by using Schlumberger ECLIPSE 100 which have been prior history-matched with laboratory results. Results show that for heterogeneous reservoir, k_v/k_h of 0.8 show the highest *RF* (64.73 %*ROIP*). Since the gas density did not show a significant change in *RF*, it was suggested that compress gas might can be apply for *GAGD* process.

***Index Terms*— Enhanced oil recovery (*EOR*), gas-assisted gravity drainage (*GAGD*), vertical and horizontal permeability (k_v/k_h), Water-Alternate-Gas (*WAG*)**

I. INTRODUCTION

GAGD process makes full use of gravity segregation, in which it is a nature problem to *WAG* method [1-3]. Recently, there is still no published paper that included reservoir heterogeneity in *GAGD* investigation. Thus, it is worth to conduct a research to investigate the effect of k_v/k_h that might affect the performance of *GAGD* process. ECLIPSE 100 was used to simulate the reservoir performance. ECLIPSE is reservoir simulation software by Schlumberger that offers the industry's most complete and robust set of numerical solutions for fast and accurate prediction of dynamic behavior, for all types of reservoirs and degrees of complexity—structure, geology, fluids, and development schemes.

The objectives of this study are:

i. To investigate the effect of k_v/k_h on gravity segregation in the visual physical model.

ii. To study the effect of operating parameters (pressure and injection rate) on the *RF* and breakthrough time.

iii. To visualize and understand the development of the downward movement towards the horizontal producer.

iv. To study the relationship of k_v/k_h to oil recovery and breakthrough time at their respective N_G.

v. To scale up the production time to real reservoir condition.

vi. To compare the simulation results with laboratory results.

The concept behind this gas displacement will be further explained by a series of theories [4-7].

II. BACKGROUND

Field study also confirms that GAGD appears to be an effective alternative to the *WAG* [3]. Recoveries as high as 85–95% have been observed in field tests and nearly 100% recovery efficiency has been observed in laboratory core floods [3].

In *GAGD* process, gas is injected from top of reservoir and provides a gravity stable displacement of oil towards the horizontal well at the bottom (Figure 1) [8].

Information from Gelama Merah was used as a base for calculation and reservoir model design. A total of nine targeted sand units were available, namely 3.2 (Figure 2), 4.0, 5.0, 6.0, 7.0, 8.0, 9.0, 9.1, and 9.2, respectively [14-16]. After interpreted all the available contour map, a West-East cross section of the Gelama Merah reservoir is shows in Figure 13.

Table I summarizes Gelama Merah field properties which was then used in time scaling calculation.

k_v and k_h was calculated by applied arithmetic average permeability and reciprocal average permeability, respectively (Figure 3 (a) and (b)).

Wyllie and Gardner correlation was used to generate the relative permeability data needed for simulation (Figure 4) because the respective data can be generated after connate water saturation is known [19].

Imaging method was applied in wettability determination [18 & 20]. Refer to Equation 6 for calculation.

Simulation is a faster method to investigate *GAGD* performance compared to laboratory method. However, simulation results have to be validated and history-match with laboratory results [21]. This research has done history-match on pressure profile and *RF*.

III. METHODOLOGY

The overall process flow diagram of the research is shows in Figure 5. The research consists of laboratory investigations and simulations. History matching was done to validate the simulator.

The flow phenomena were investigated by visual physical model (Figure 6) whiles the properties such as permeability and porosity was measured by measurement model (Figure 8). Detail on conducting the visual physical model and measurement model are summarized in Figure 7 and 9, respectively.

Steps in Figure 10 were straightly followed to yield the same initial condition before conduct the desired investigations.

The static model given by PETRONAS GARIGALI SDN. BHD consist of 53 blocks, 44 blocks, and 104 blocks in X, Y, and Z-direction, respectively. The conceptual model was scaled down by a factor of 6.56 and only take X and Z-direction into account. The simulation model consists of 18, 3, and 36 blocks in X, Y, and Z-direction, respectively (Figure 11). The dimension of one block is 1 ft × 0.1 ft × 1 ft.

Well's location and condition are show in Figure 12. Both of the wells were perforated horizontally.

IV. RESULTS & DISCUSSION

After interpreted all the available contour map, West-East cross section of Gelama Merah is produced (Figure 13). The Gas Oil Contact (*GOC*) and Potential Oil Water Contact (*POWC*) were found to be at 4905 ft True Vertical Depth Sub-Sea (*TVDSS*) and 5020 ft *TVDSS*, respectively.

The *GOC* and *POWC* of Gelama Merah were determined from correlation between well logs and pressure plot (Figure 14 (a) and (b)). Butterfly Effect in Neutron and Density cross plot was used to determine the gas zone while Resistivity log and Gama Ray log was used to determine the potential hydrocarbon and type of formation, respectively. Based on the pressure gradient finger print, pressure plot was used to confirm the *GOC* and *PWOC* in well logs.

Results from measurement model were validated with Helium Porosimeter test (Figure 15). The maximum different was 2.01 %, which is acceptable.

After the validation test, the ϕ and k for each range of glass beads size which were measured by measurement model are summarized in Table II. This information was then used to pack different k_v/k_h value of porous media in visual physical model.

Table III shows the porosity for reservoirs that have been packed according to the desired k_v/k_h ratio.

Figure 16 (a) and (b) show the relative permeability curve for Oil-Water and Oil-Gas system, respectively. The connate water saturation in all visualization models happened to be the same (12%). The reason may due to the fabrication of porosities were almost the same for all models (refer to Table III). This information was then input to ECLIPSE 100 under PROPS section.

Figure 17 and 18 show the wells pressure profile and recovery factor for the model with different k_v/k_h, respectively. For all the three cases, the steady state *WBHP* profiles were established after 1.1 *PV* of CO_2 has been injected. This may due to the similar in their porosity, viscosity, and formation compressibility. For heterogeneous cases, a dominant in k_v will yield a higher recovery. For homogeneous reservoir (k_v/k_h=1.0), the vertical and horizontal permeability were the same. Thus, gas sweeps the reservoir more uniform and resulted in a higher recovery.

Figure 19 (a), (b), and (c) show the fluid displacement for model with k_v/k_h of 0.8, 0.9, and 1.0, respectively. A dimmer colour indicates that there was a higher liquid saturation while a lighter colour indicates that gas has invaded the respective zone. For homogeneous model, the front displacement is stable (near horizontal displacement). However, for heterogeneous model, the front displacement is different for both cases. For k_v/k_h=0.8, a long tongue-like displacement can be observed, gas tends to move vertically downward than horizontally. As the k_v/k_h increase to 0.9, a more stable displacement can be observed. However, gas tends to bypass the side area across the area. It was proven that gas will always displace the higher permeability zone first. For homogeneous model, there are a few spots that were not fully sweep by the gas. Naami and his friends stated in their research in 1999 that this can be caused by the local heterogeneities in homogeneous model [23].

When gas move from a lower permeability layer to a higher permeability layer, multiple viscous fingering will be observe (Figure 20). The capillary force is reduced when gas flow from a smaller to bigger pore size. Thus, gas is more dominant to move downward [22].

For cases where gas move from high to low permeability layer, the back pressure encountered has caused the gas to move sideway rather than downward (Figure 21). During this mechanism, the unswept area will reduce [22].

In this research, sensitivity test was the first thing that has been done in simulating process. Figure 22 shows sensitivity of recovery factor to uncertainties in the reservoir characters and operating parameters (gas density, net-to-gross (*NTG*), injector pressure, and injector rate). It clearly highlights injector pressure as the most important input quantity (of those considered) and has the most impact on the result.

Results from sensitivity test show that injector pressure has the highest weight on recovery factor. Thus, it was important to match the injector pressure with the laboratory results. Injector pressure of 20 psia gave the closest fit to history data (Figure 23). An error bar of 1% was applied to history data for error correction.

Since the main objective is to investigate the impact of all the parameters on recovery factor. Thus, it has to be history matched so that the reading is reliable. An error bar of 1% has been applied to the history data for error correction. Results show that injector pressure of 20 psia gave the best fit (Figure 24).

The wells orientation (injector and producer) were investigated to make sure the best orientation was used for the candidate (reservoir investigated). Types of orientation that have been investigated were (Figure 25 (a), (b), (c), and (d)):

1. Two vertical wells.
2. Shallow vertical injector with horizontal producer.
3. Deep vertical injector with horizontal producer.
4. Two horizontal wells.

Effect of gravity effect can be clearly observed in heterogeneous reservoir when two vertical wells were used (Figure 27 (a)-(d)). Non-uniform displacement (Figure 27 (a)-(d)), early breakthrough (Figure 27 (d)), and late production (Figure 30) were some of the weakness if vertical wells are used in this candidate. However, this kind of wells orientation gave the highest ultimate recovery factor on the applied candidate.

For vertical injector with horizontal producer combination, a tongue-like displacement can be observed as the gas expands downward (Figure 27 and 28). The gas has move to the next layer before actually fill up the current layer. For these kinds of well orientations, the gas has a higher tendency to move downward than horizontally. For the same pore volume injected, a deeper injector will yield a higher and faster recovery (Figure 30). It is suggested that for a candidate with a higher k_v, the injector can be set at a deeper depth. Provided that the gas has the time and opportunity to migrate upward.

Two horizontal wells combination yield the most stable displacement front compared with the previous three types (Figure 30 (a)-(d)). However, this Toe to Heel in *GAGD* oil recovery did not perform as expected. Mahmoud (2006) also encounter the same problem, the reason given was CO_2 gas did not rise to the top of the pay zone; instead, it found a path of least resistance to the horizontal well [9].

Figure 30 shows the recovery factor for different well arrangement over every pore volume injected. The results can be explain in three period:

i. Phase I, a deep vertical injector with horizontal producer (Figure 25 (c)) give the highest recovery. The gas was injected nearer to the producer, due to the lower density, gas will then migrate to the top part of the reservoir.

ii. Phase II, two vertical wells (Figure 25 (a)) start to show an increase in recovery. However, deep vertical injector with horizontal producer (Figure 25 (c)) still shows a higher recovery. The design with two horizontal wells shows that gas sweep the reservoir more stable front (refer to the colour different between Figure 26-29).

iii. Phase III, two vertical well combination (Figure 28 (a)) shows the highest ultimate recovery (63.89% *ROIP*).

For well orientation design, two important points can be highlighted:

i. Well design was fully depended on the candidate characterization.

ii. Desired well design will be chosen based on the objective.

Previous researcher [1] [9] [10] used CO_2 as the injection gas. CO_2 was used due to its miscibility with the oil. Since *GAGD* can be apply under immiscible condition and density different play an important role in *GAGD* successfulness, investigation has been done to investigate the effect of gas density on the recovery factor.

Results from simulation shows that the density different did not resulted a severe change in recovery factor (Figure 31). Since *GAGD* make use of gravity force and pressure gradient of respective fluids to recover the oil in place [18], it was suggested that compress gas can be use as an alternative to CO_2 gas.

Figure 32 shows the density of Nitrogen (63% of air was made of Nitrogen) compared to the density of CO_2 at different pressure [24]. It was very obvious that Nitrogen was lighter than CO_2. Taking all the factors into account, it was suggested that compress gas may be use as a replacement to CO_2.

Equation 7 was used to scale the time in laboratory into the time in Gelama Merah field. One second in laboratory will be equivalent to five minutes in Gelama Merah. For the most optimum case (k_v/k_h=0.8), the time required in field to achieve 64.73% *ROIP* in laboratory was 5.8493 hr, which is equivalent to 73 days in Gelama Merah. This result was reasonable when compared to the result from Mahmoud (2006) [9] and Sharma (2005) [1] which range from 69-975 days.

After analyzed the results (Figure 33), it seem like there is no relationship between gravity number and recovery factor. The same out come was found by Mahmoud in 2006 [9]. However, it was believe that the experimental range was not wide enough to be able to establish a clear relationship.

V. CONCLUSIONS

The results from this research can be summarized as follow:

1. Different k_v/k_h have been created by vary the glass beads size. Laboratory investigation found that a lower k_v/k_h will resulted in a slightly higher recovery (64.73% *ROIP*) in heterogeneous reservoir due to a more dominant of vertical permeability.
2. ECLIPSE 100 simulator was used to investigate the effect of operating parameters (injector pressure, injection rate, and injected gas density) on *GAGD* process. From the sensitivity test, it was found that the injection pressure was there most important parameter (among the parameters that have been taken into consideration) that influent the recovery. However, the injector pressure has a negative effect. Too high of injector pressure will caused the gravity force to lose its domination and thereby allow the viscous force to be stronger.

3. A 2D visual physical model and a measurement model have been used to visualize the fluid front displacement during *GAGD* process. Experimental results have indicated the usefulness of visual physical model as a tool to investigate the performance of new process such as *GAGD*. The measurement model was also proved to be an acceptable technique after been compared with Helium Porosimeter Test (error 2.01%).
4. The experimental run time has been scaled to real time in field by the use of a dimensionless time expression. It was found that 1s in laboratory was equivalent to 5 minutes in Gelama Merah. Thus, it required around 73 days to achieve 64.73% *ROIP* in Gelama Merah.
5. Vertical injector and vertical producer was found to be the best combination for a higher ultimate recovery (63.89% *ROIP*) while a horizontal producer with a deeper injector resulted a higher recovery in the early production time.
6. The packing technique will give a higher impact on permeability than porosity. The permeability different between a tightly packed and loosely packed model is 25% but the porosity just differ to a maximum of 4.09%.

VI. SUGGESTIONS

Further *GAGD* visualization is recommended to explore some unanswered questions. The important recommendations are:

1. Sensitivity test show that compress gas may be used to replace CO_2 during *GAGD* implementation. Thus, it was suggested that laboratory investigation should be conduct by replace CO_2 with compressed gas.
2. A higher strength and thermal resisted glass based visual physical model should be constructed to investigate all the parameters in miscible *GAGD*. Temperature may affect the physical and chemical properties of the fluids and gas in place.
3. Study should be done to investigate the effect of fracturing on the recovery.
4. Grid refinement should be apply in simulation to give a more detail visualization on the viscous fingering.
5. A wider experimental range is required to investigate the relationship between gravity number and recovery factor.

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APPENDIX A

Pore Volume Calculation

$$PV = \frac{m_{m+w} - m_{m+p}}{\rho_w - \rho_p} \qquad (1)$$

Where,

m_{m+w} and m_{m+p} : Weight of model fill with water, paraffin, g

ρ_w and ρ_p : Density of water, paraffin, g/cm^3

PV : Pore volume of model, cm^3

Porosity Calculation [6]

$$\phi = \frac{PV}{BV} \times 100\% \qquad (2)$$

Where,

ϕ : Porosity of the model, %

BV : Bulk volume of the model, cm^3

Permeability Calculation

$$k = \frac{Q\mu L}{A\Delta P} \qquad (3)$$

Where,

k : Permeability, Darcy

Q : Displacement flow rate, cc/min

μ : Viscosity of injected fluid, cp

L : Length of the porous media, cm

A : Area of cross section of the porous media, cm^2

ΔP : Pressure different across the porous media

Gravity Number Calculation [1]

$$N_G = \frac{\Delta \rho g K}{\Delta \mu v_d} \tag{4}$$

Where,

v_d : Darcy Velocity, 0.0000641 ms^{-1}

Diffusivity constant, D

$$D = \frac{k}{\phi \mu c} \tag{5}$$

Wettability Determination [20]

$$\theta = 2 \tan^{-1}\left(\frac{2H}{D}\right) \tag{6}$$

Where,

H = Height of the droplet, mm

D = Diameter of the droplet, mm

if , θ<62°9 (Water-wet); θ=62-133° (Intermediate-wet); θ>133° (Oil-wet)

Time Scaling

$$t_d = \frac{k k_{ro}^{o} \Delta \rho g t}{h \phi \mu g_c \left(1 - S_{or} - S_{wi}\right)} \tag{7}$$

Where,

t_d is the dimensionless time

t is the real time, s

k is the absolute permeability of the porous media, m^2

k_{ro}^{o} is the end-point relative oil permeability

$\Delta \rho$ is the density contrast between the displaced and displacing phase, kg/m^3

g is the gravitational force, 9.81 m/s^2

g_c is the gravitational force conversion factor, 1

μ is the oil viscosity, Pa.s

h is the height of the porous media, m

ϕ is the porosity of the porous media, fraction

S_{or} is the residual oil saturation, fraction

S_{wi} is the initial water saturation, fraction

Set-up for Laboratory Investigation

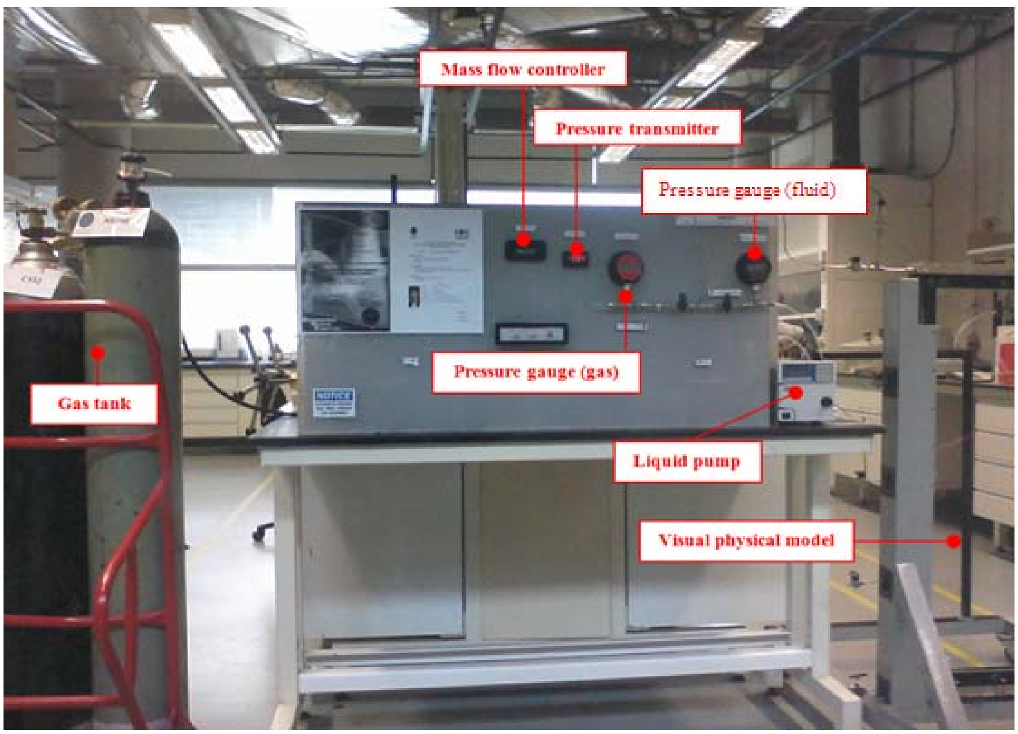


Fig. I: Flooding Test Set-up

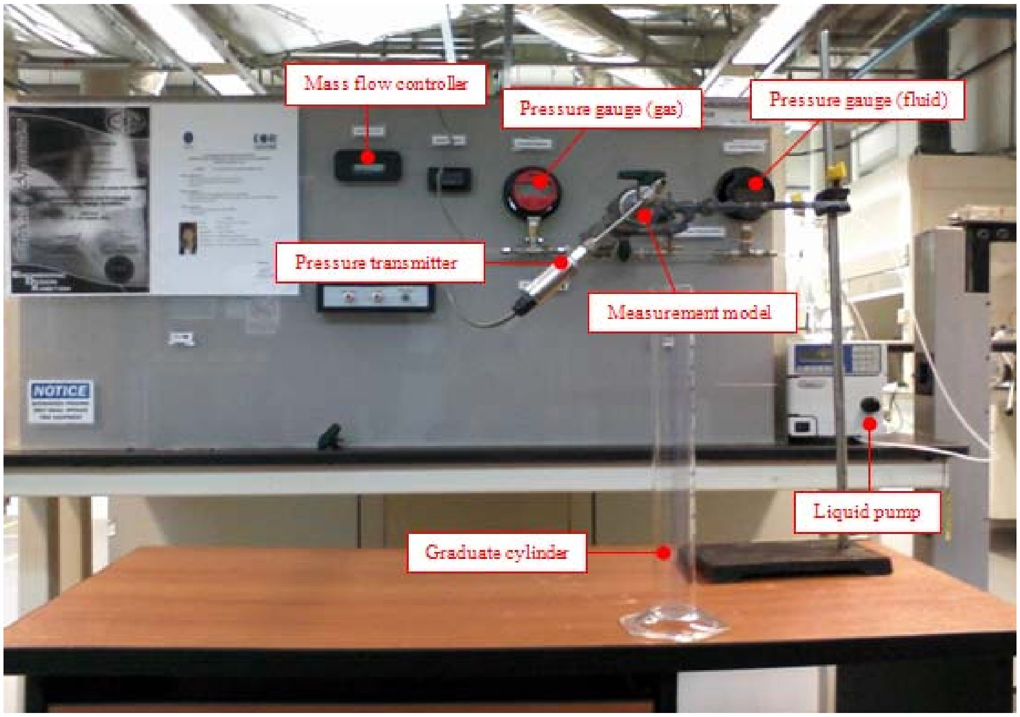


Fig. II: Measurement Model Set-up

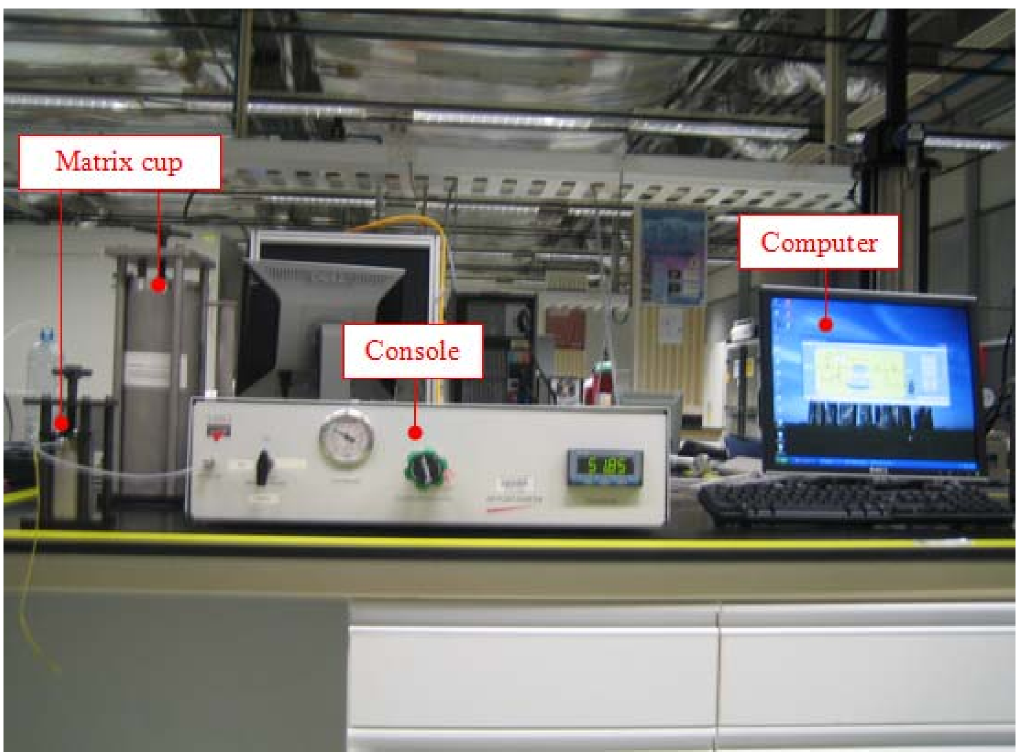


Fig. III: Helium Porosimeter Test Set-up

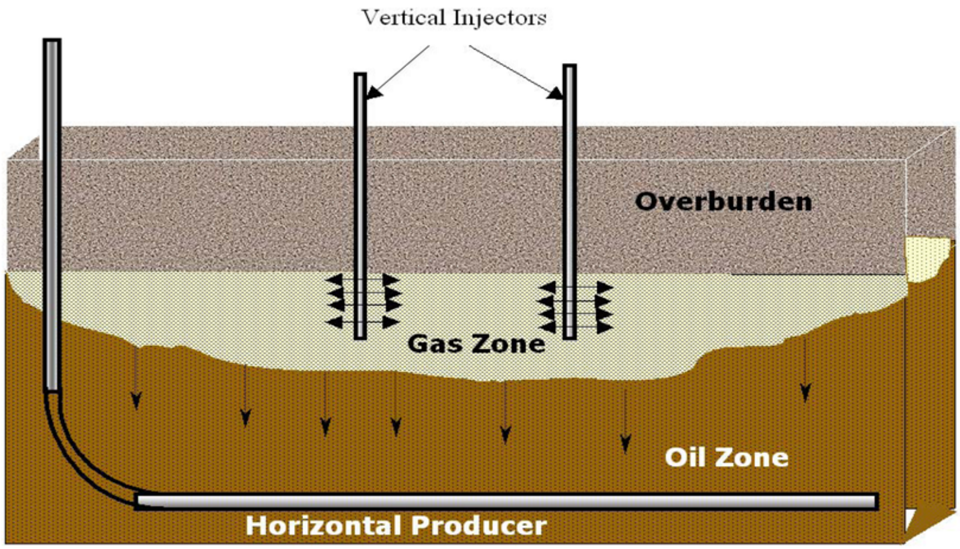


Fig. 1: Schematic of the *GAGD* Process [8]

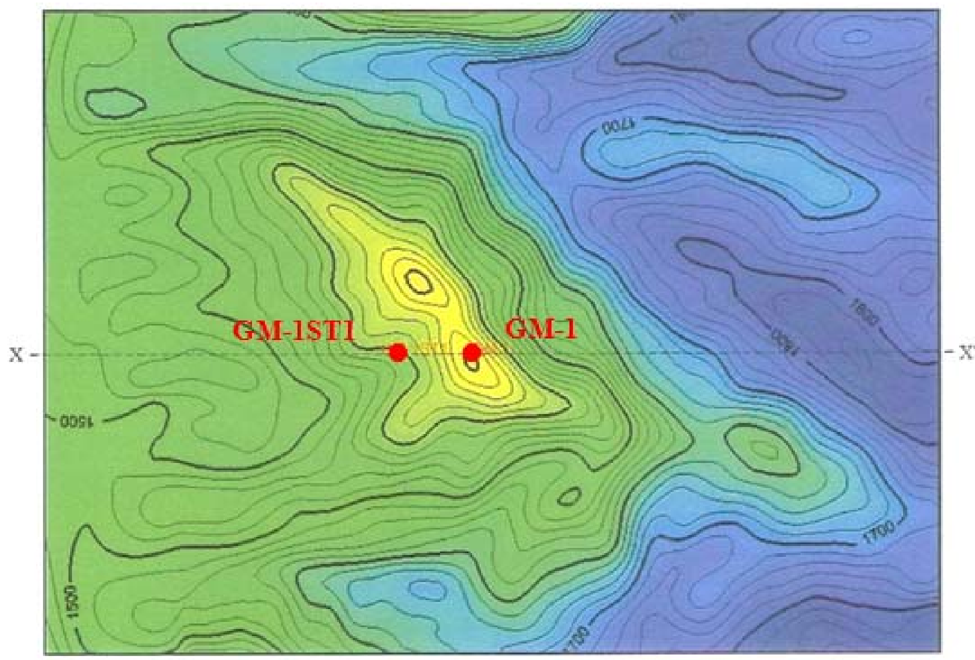
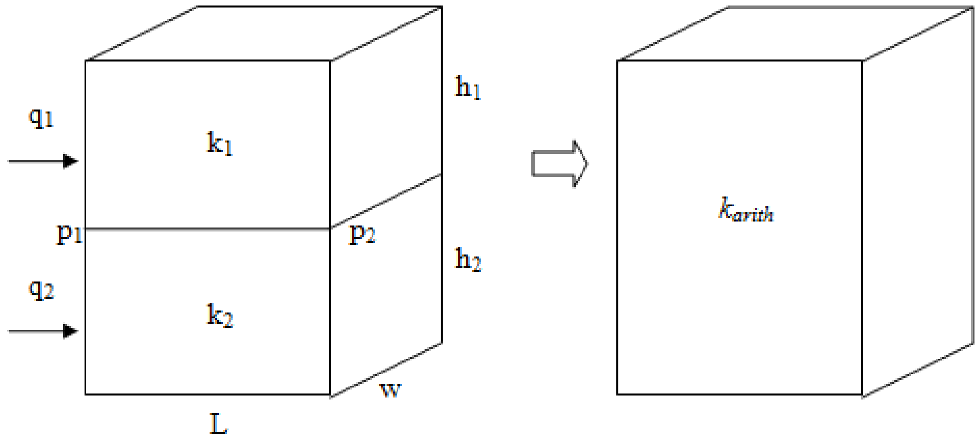
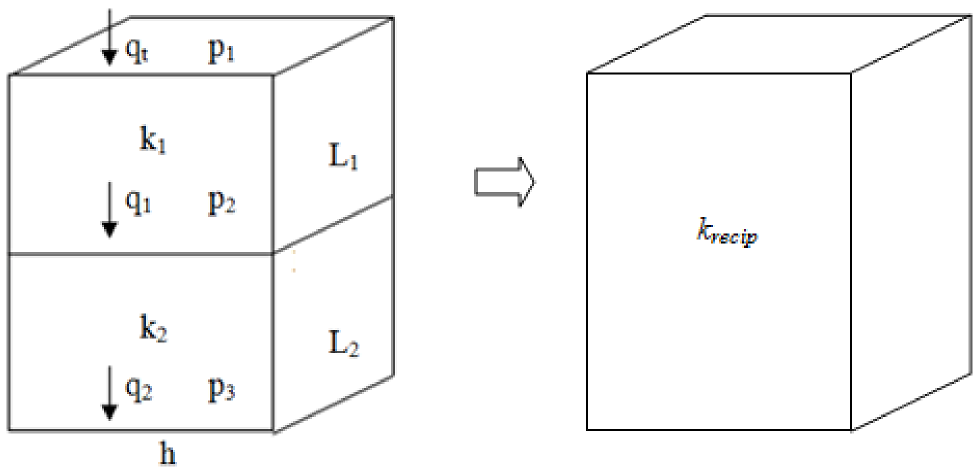


Fig. 2: Top of Sand Contour Map for Unit 3.2 [14-16]



(a)



(b)

Fig. 3 (a) (b): Arithmetic and Reciprocal Average Permeability [18]

Drainage Oil-Water Relative Permeabilities

Type of formation	k_{ro}	k_{rw}	Equation
Unconsolidated sand, well sorted	$(1 - S_w^*)$	$(S_w^*)^3$	(5-4)
Unconsolidated sand, poorly sorted	$(1 - S_w^*)^2 (1 - S_w^{*1.5})$	$(S_o^*)^{3.5}$	(5-5)
Cemented sandstone, oolitic limestone	$(1 - S_o^*)^2 (1 - S_w^{*2})$	$(S_o^*)^4$	(5-6)

Drainage Gas-Oil Relative Permeabilities

Type of formation	k_{ro}	k_{rg}	Equation
Unconsolidated sand, well sorted	$(S_o^*)^3$	$(1 - S_o^*)^3$	(5-7)
Unconsolidated sand, poorly sorted	$(S_o^*)^{3.5}$	$(1 - S_o^*)^2 (1 - S_o^{*1.5})$	(5-8)
Cemented sandstone, oolitic limestone, rocks with vugular porosity	$(S_o^*)^4$	$(1 - S_o^*)^2 (1 - S_o^{*2})$	(5-9)

Fig. 4: Relative Permeability Calculation [19]

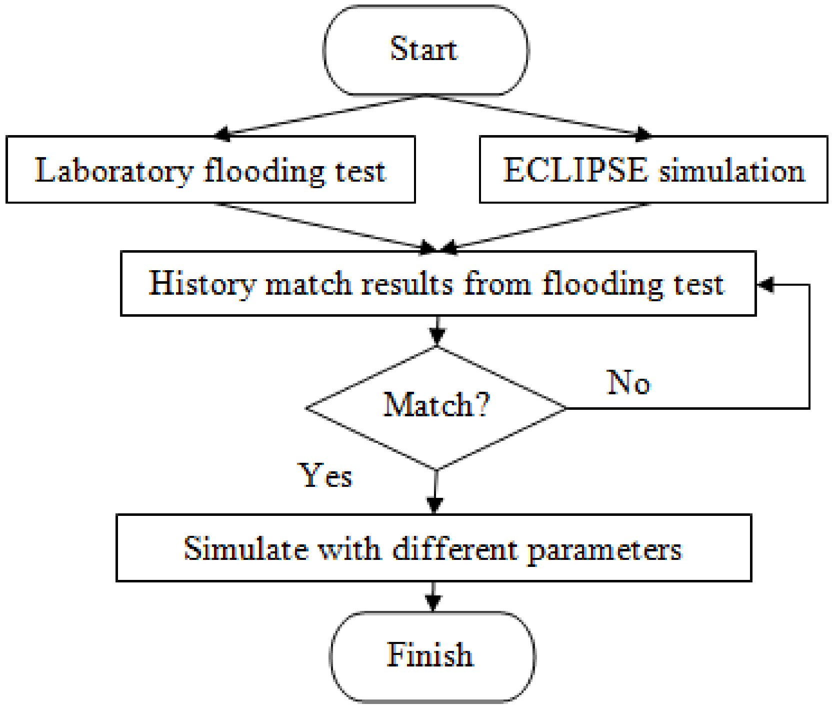


Fig. 5: Overall Process Flow Diagram

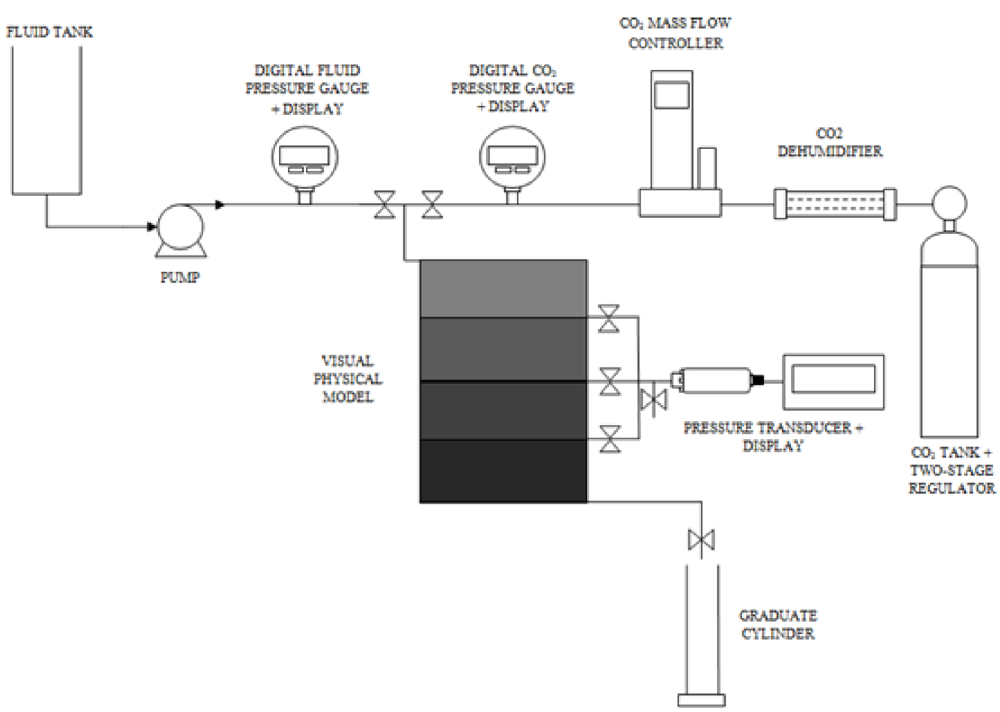


Fig. 6: Process Flow Diagram for Visual Physical Model

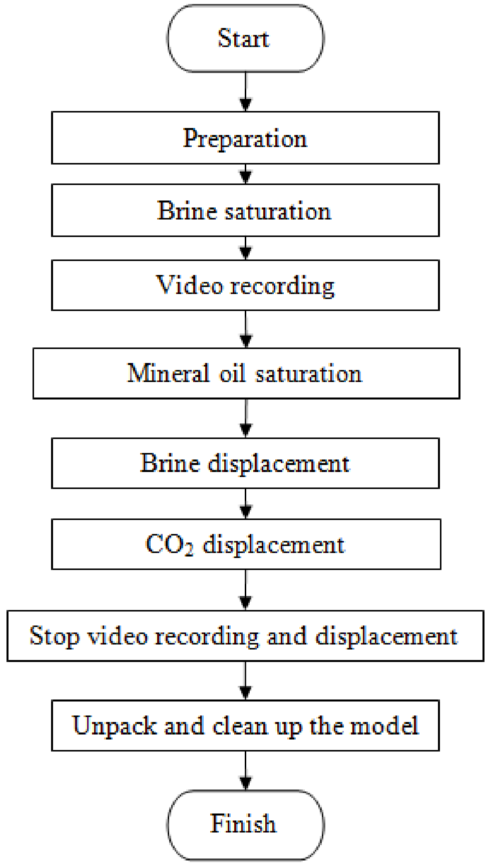


Fig. 7: Process Flow for Visual Physical Model

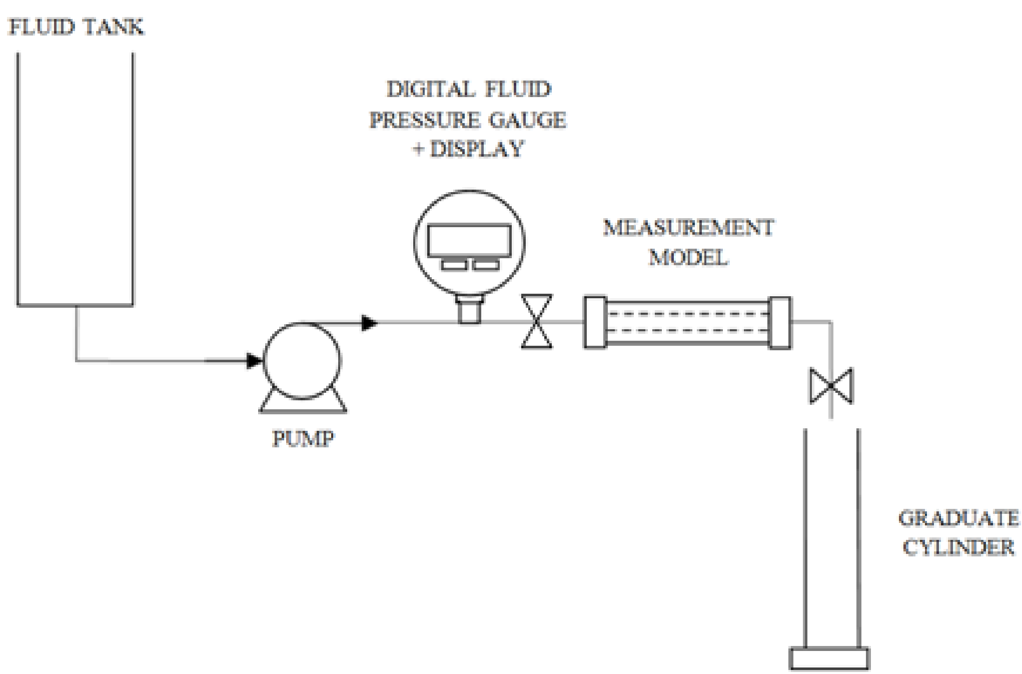


Fig. 8: Process Flow Diagram for Measurement Model

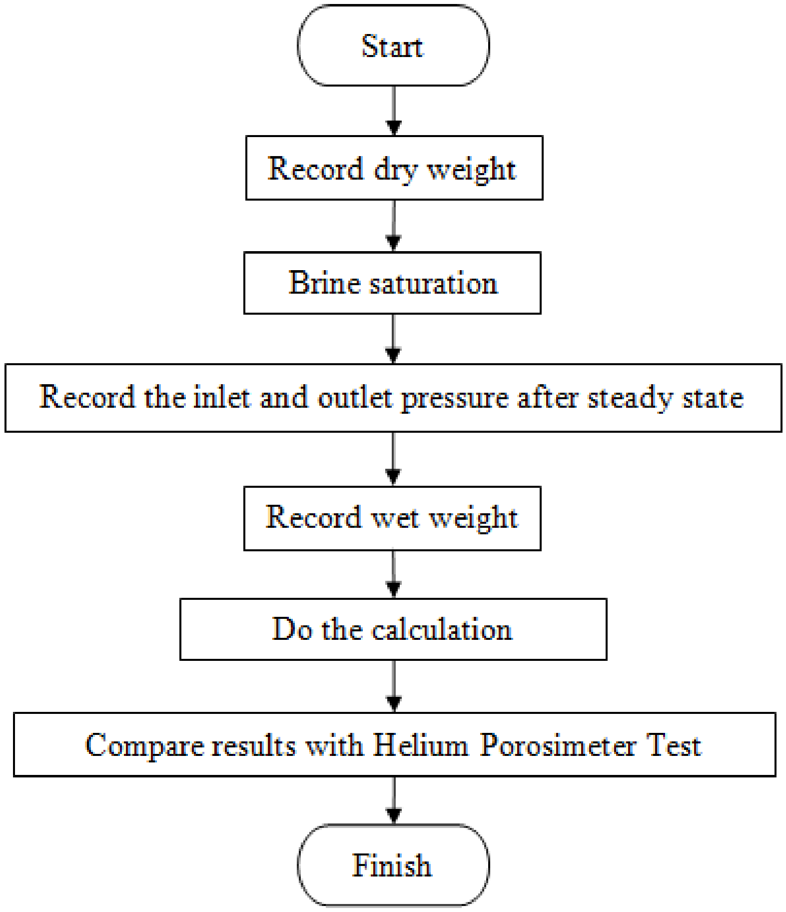


Fig. 9: Process Flow for Measurement Model

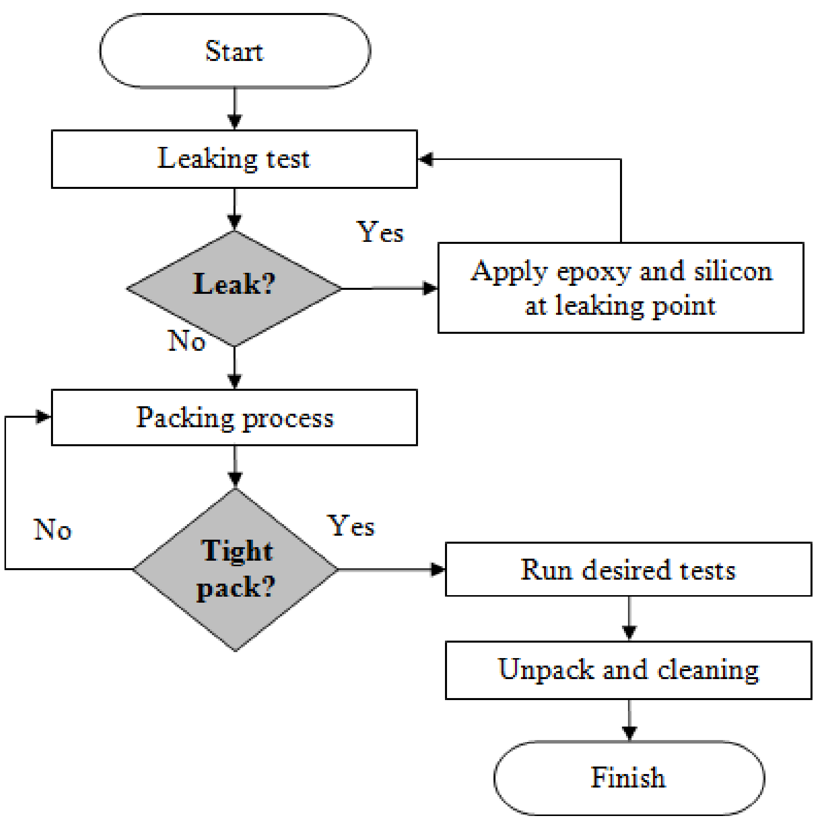


Fig. 10: Process Flow for Packing, Cleaning, and Repacking

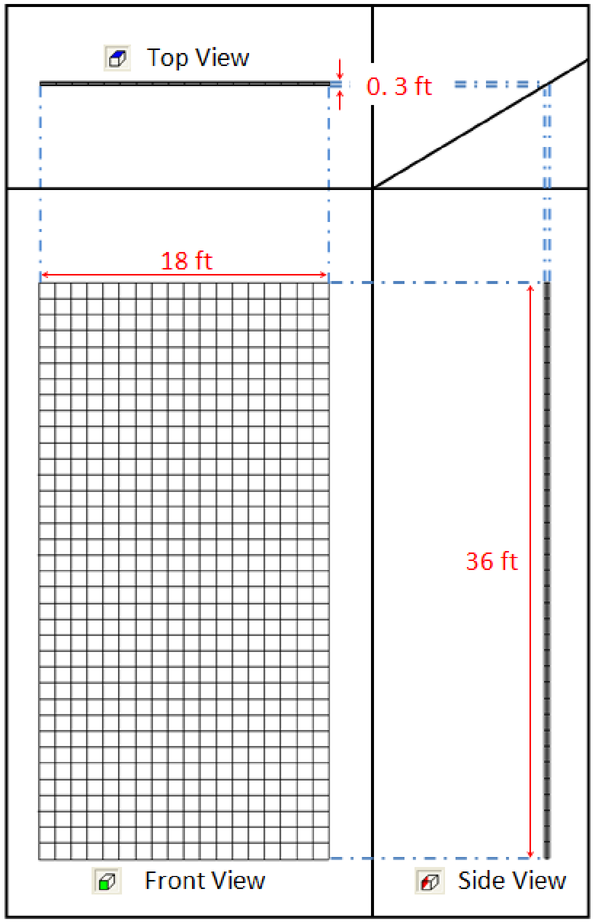


Fig. 11: Dimension of Simulation Model

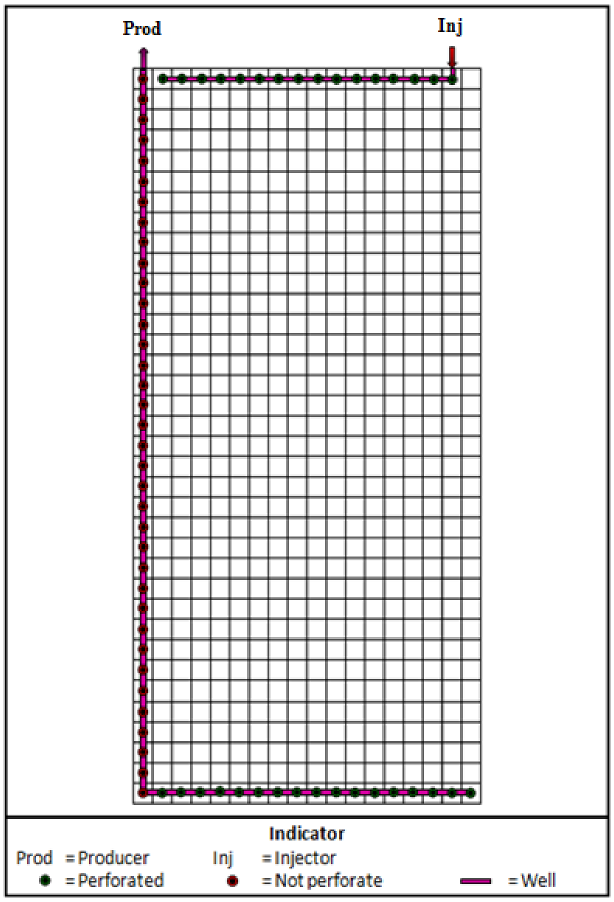


Fig. 12 Well's Location and Condition of Simulation Model

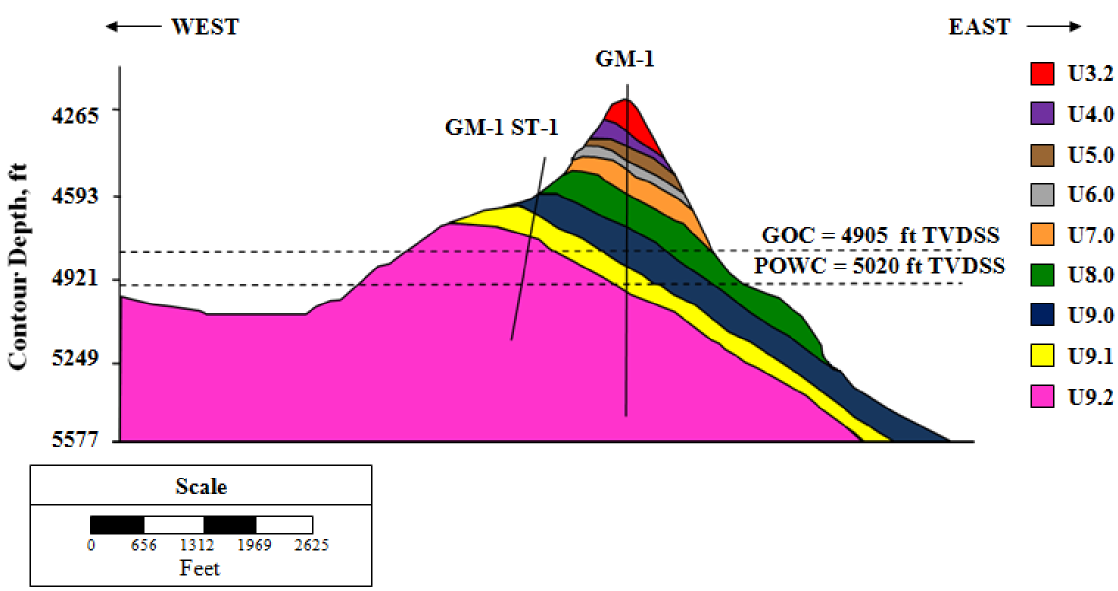
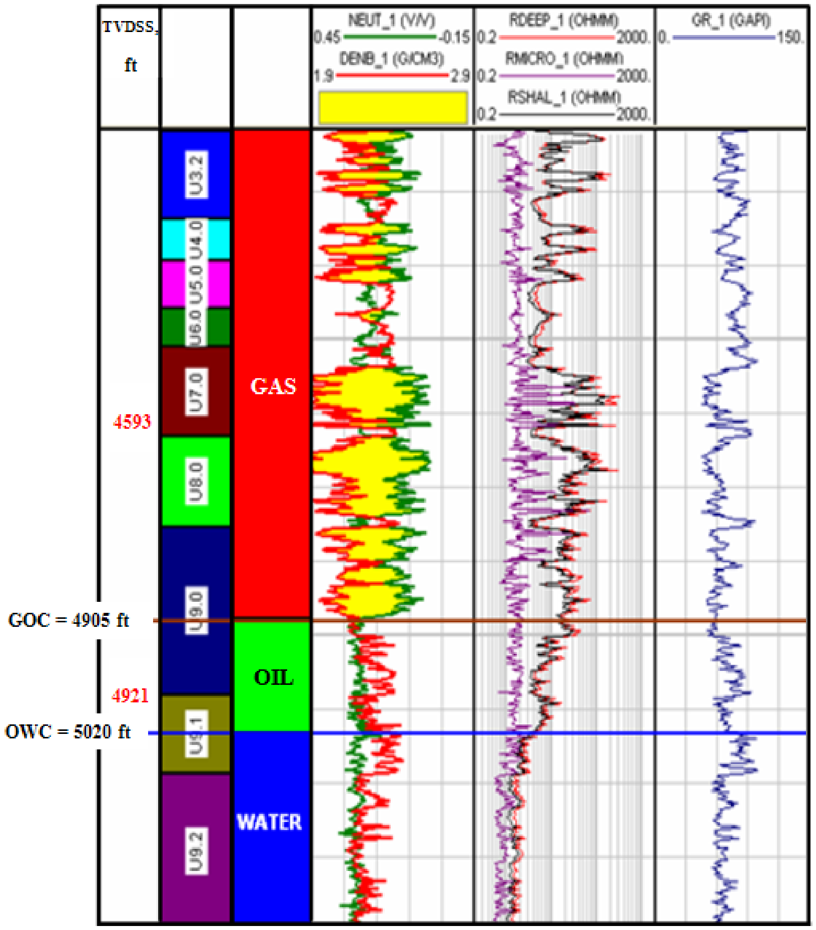
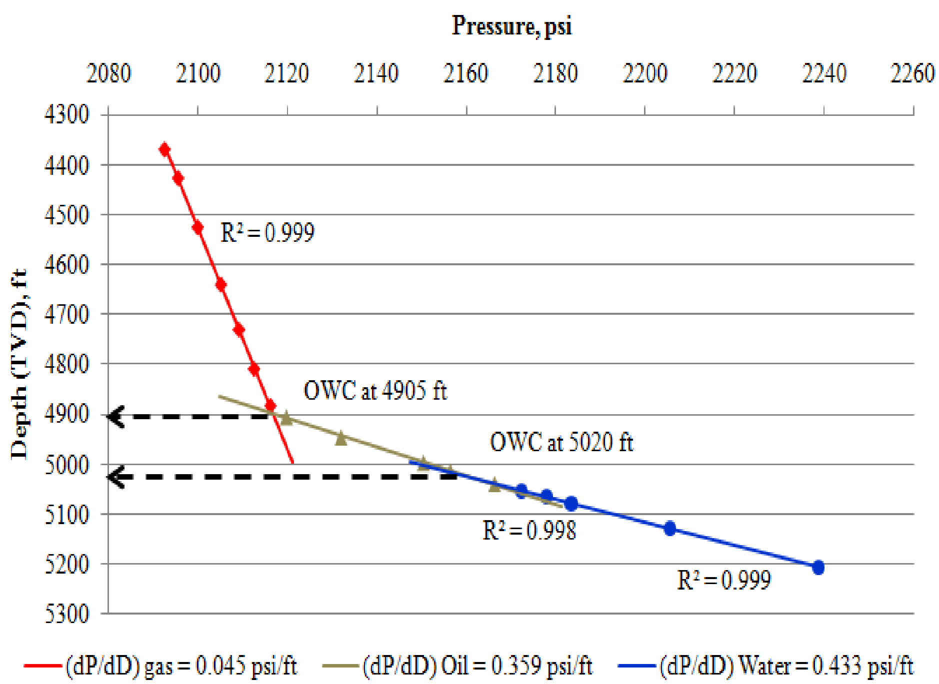


Fig. 13: West-East Cross Section of Gelama Merah



(a)



(b)

Fig. 14: (a) and (b) Correlation of Fluid Contact between Well Log and Pressure Plot

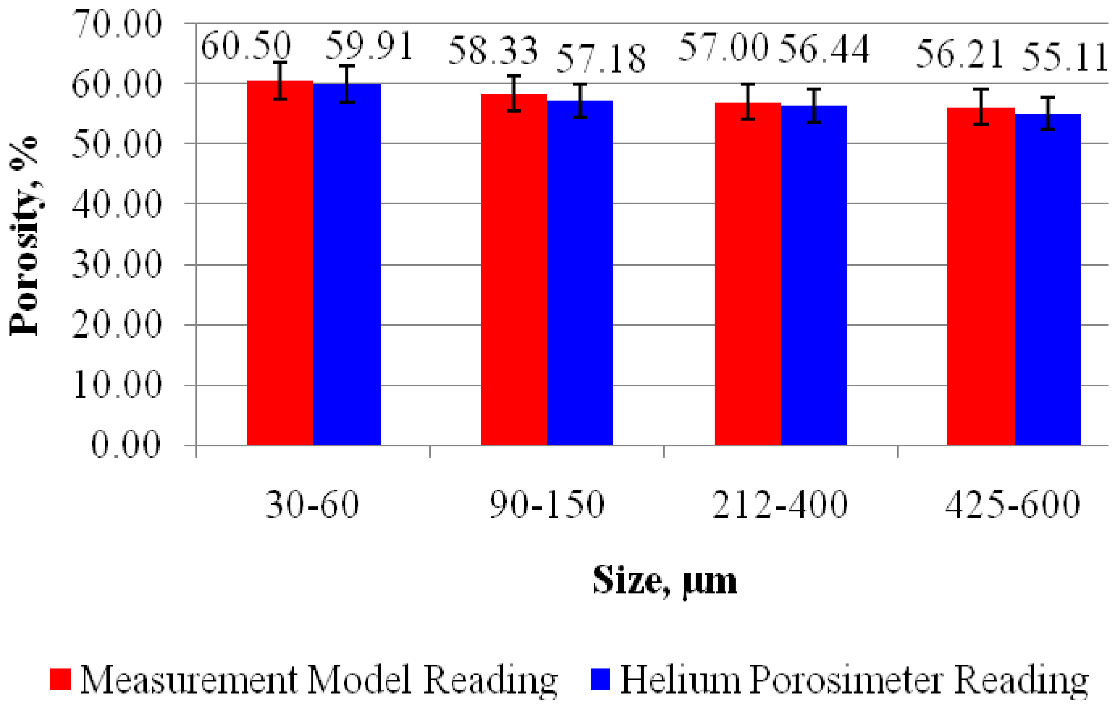
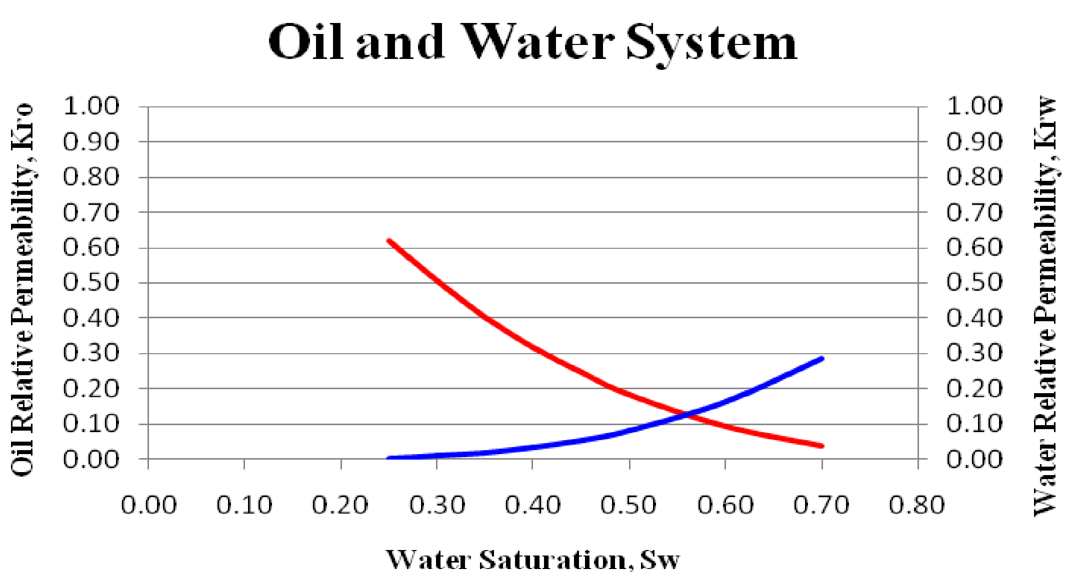
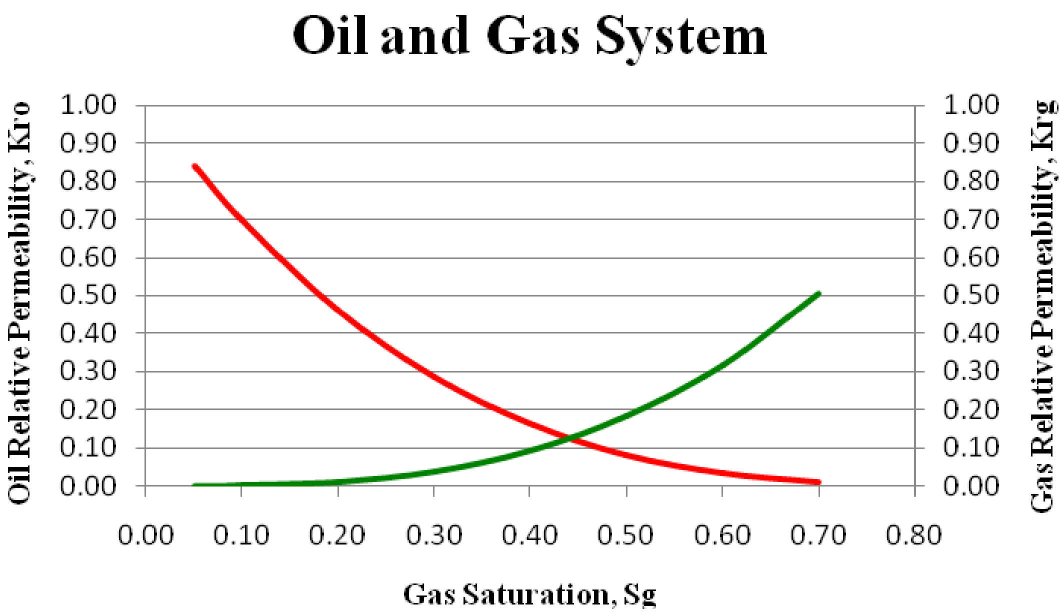


Fig. 15: Porosity Measurement from Measurement Model and Helium Porosimeter



(a)



(b)

Fig. 16: (a) (b) Relative Permeability Curve for Oil-Water and Oil-Gas System

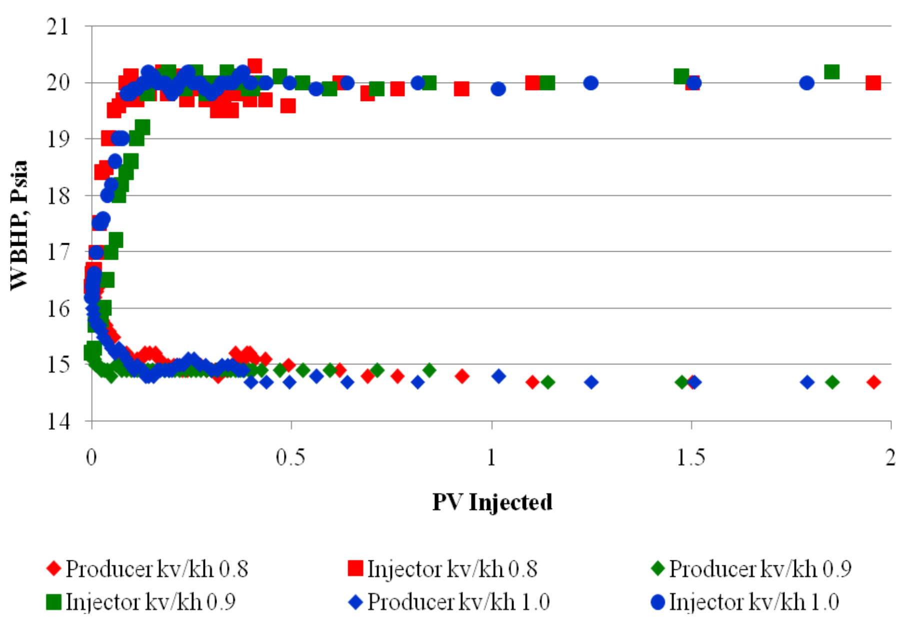


Fig. 17: Bottom Hole Pressure Profile for Different k_v/k_h

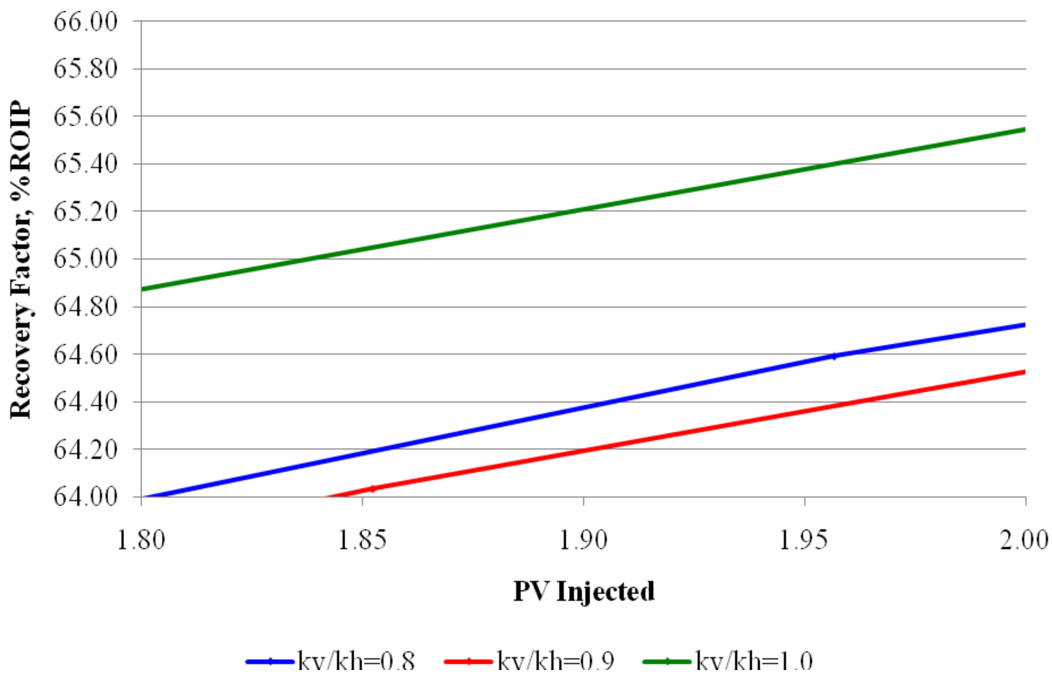


Fig. 18: The Effect of Different k_v/k_h on Recovery Factor

(a) k_v/k_h=0.8 (b) k_v/k_h=0.9 (c) k_V/k_h=1.0

Fig. 19: The Fluid Displacement for Different k_v/k_h

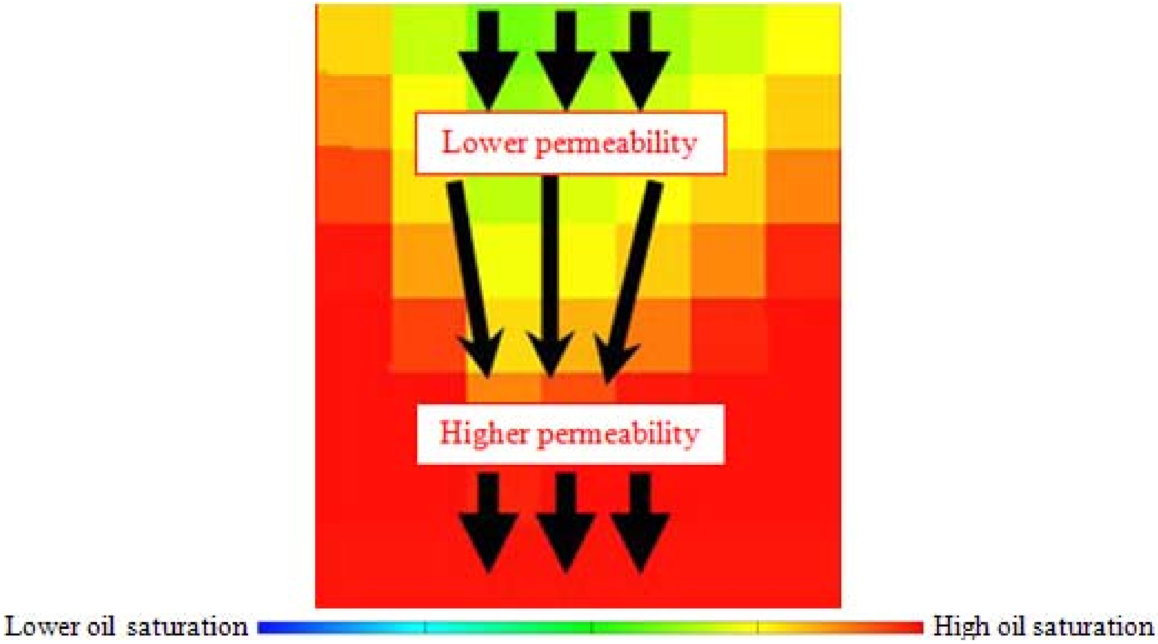


Fig. 20: Flow Mechanism from Low to High Permeability [22]

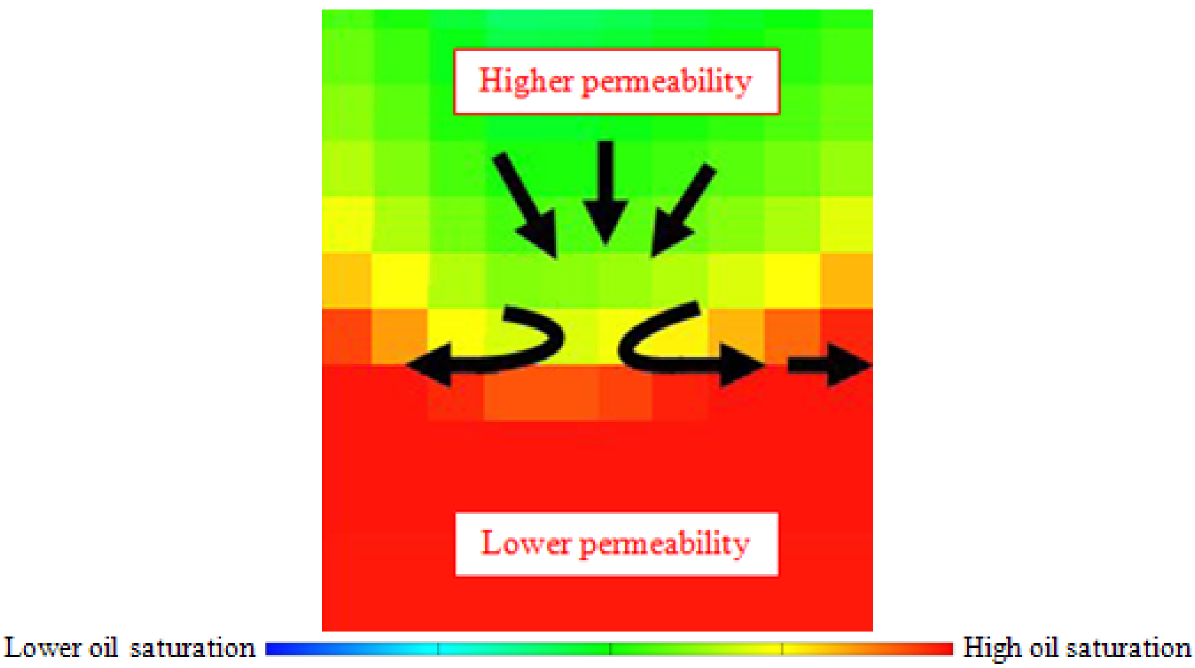


Fig. 21: Flow Mechanism from High to Low Permeability [22]

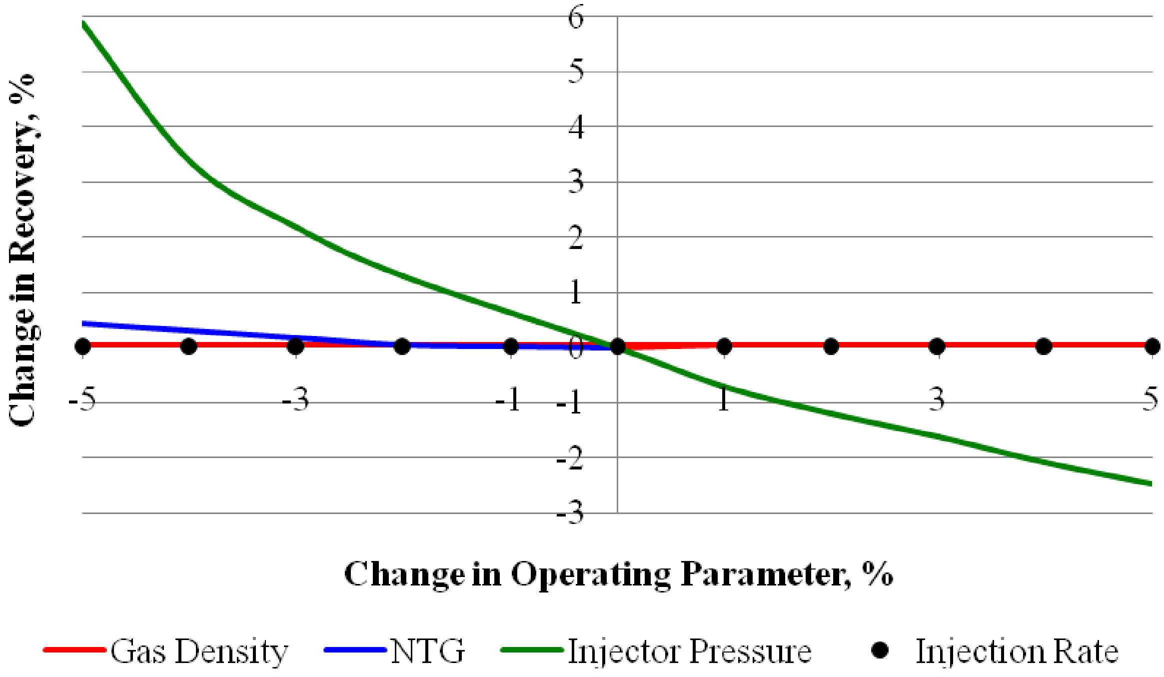


Fig. 22: Spider Diagram Evaluation Sensitivity Test

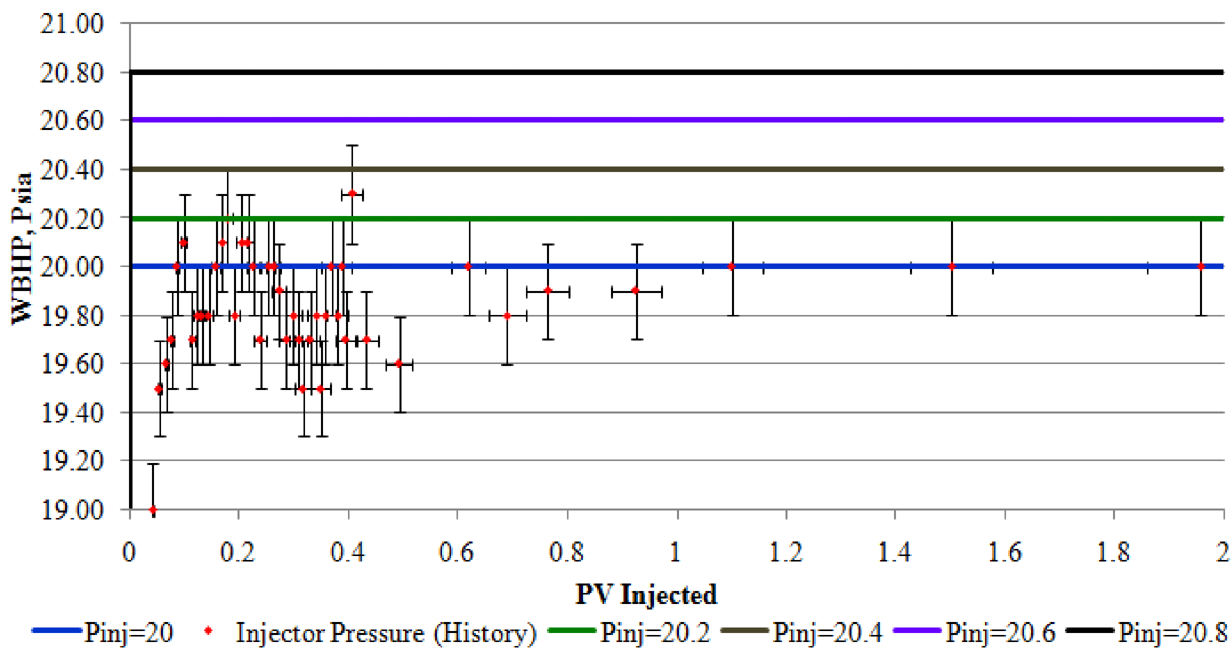


Fig. 23: Matching the Well Bottom Hole Pressure

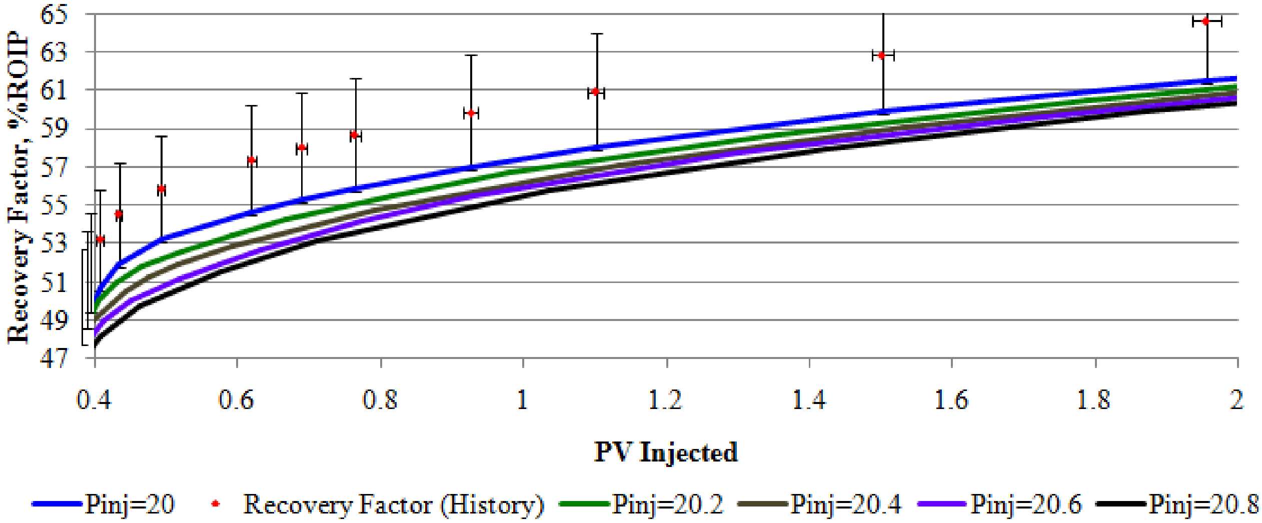
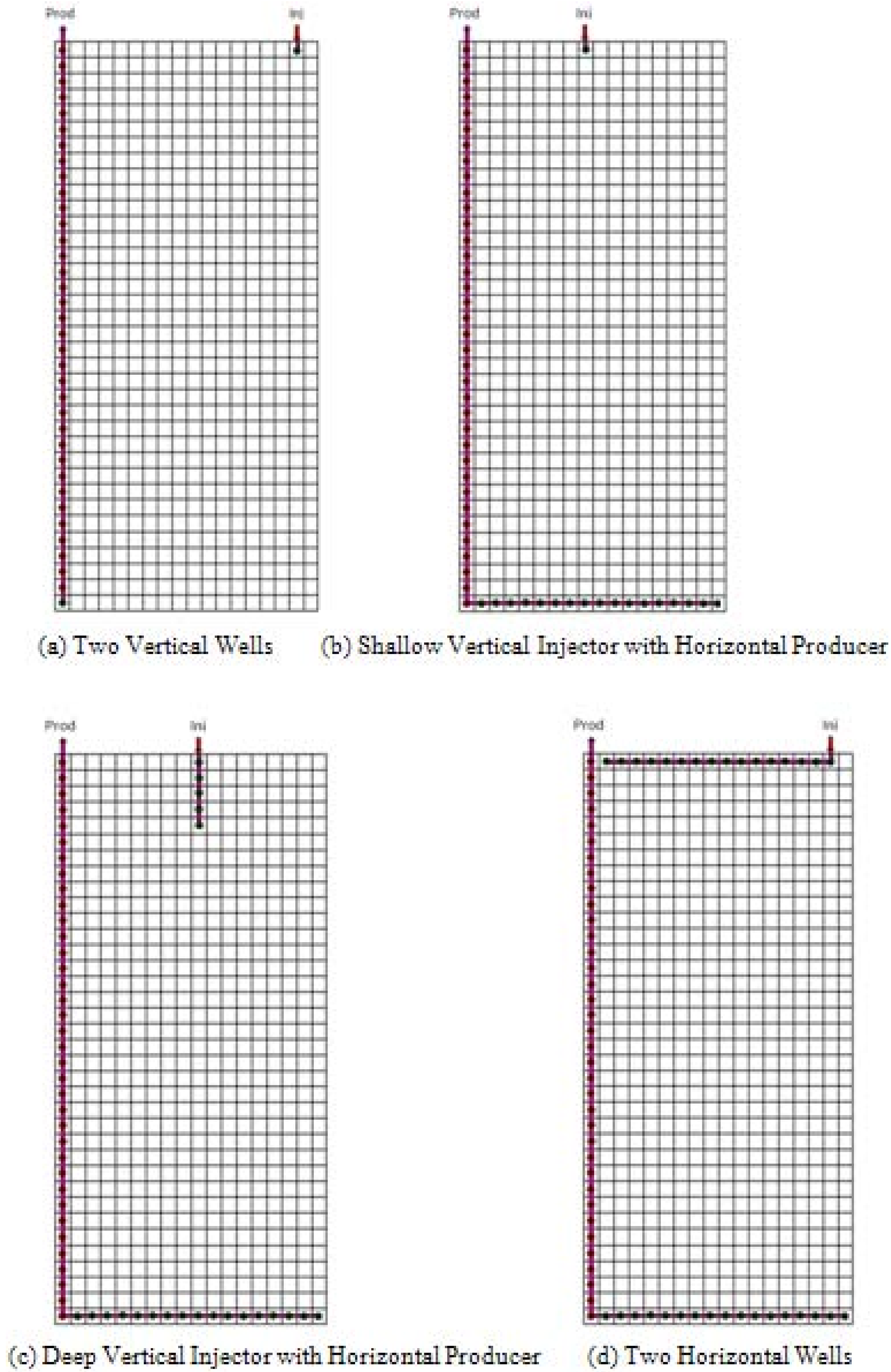


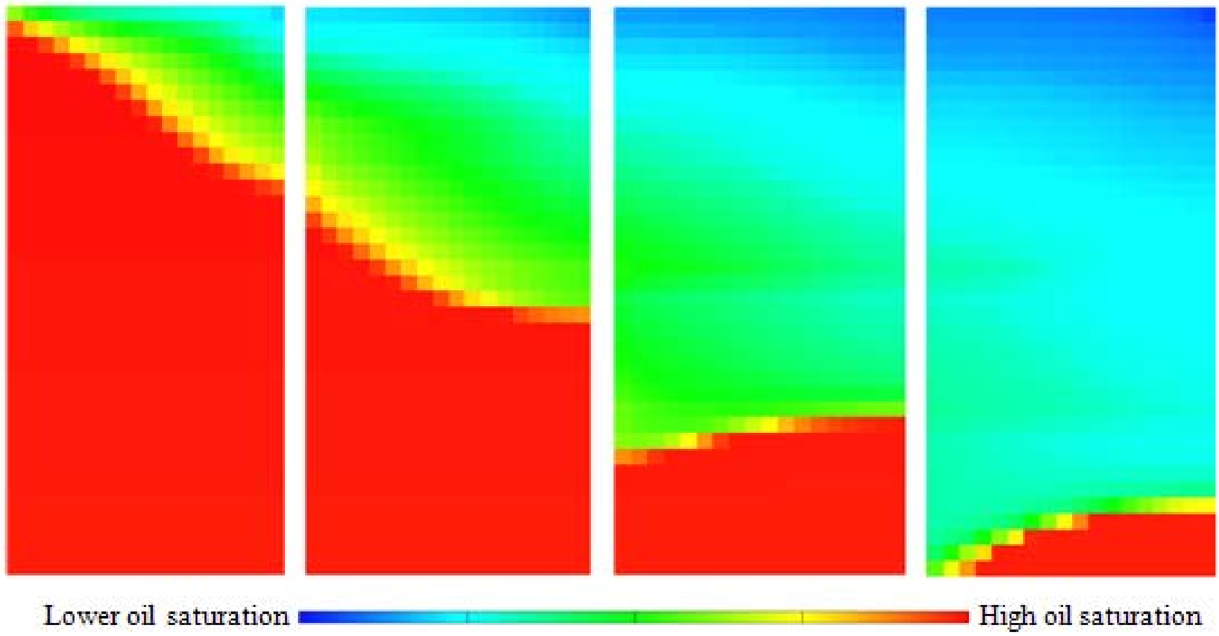
Fig. 24: Matching the Recovery Factor



(a) Two Vertical Wells (b) Shallow Vertical Injector with Horizontal Producer

(c) Deep Vertical Injector with Horizontal Producer (d) Two Horizontal Wells

Fig. 25: Schematic of Wells Orientation



(a) Across 1st layer (b) Across 2nd Layer (c) Across 3rd Layer (d) Across 4th Layer

Fig. 26: Fluid Front Displacement for Two Vertical Wells

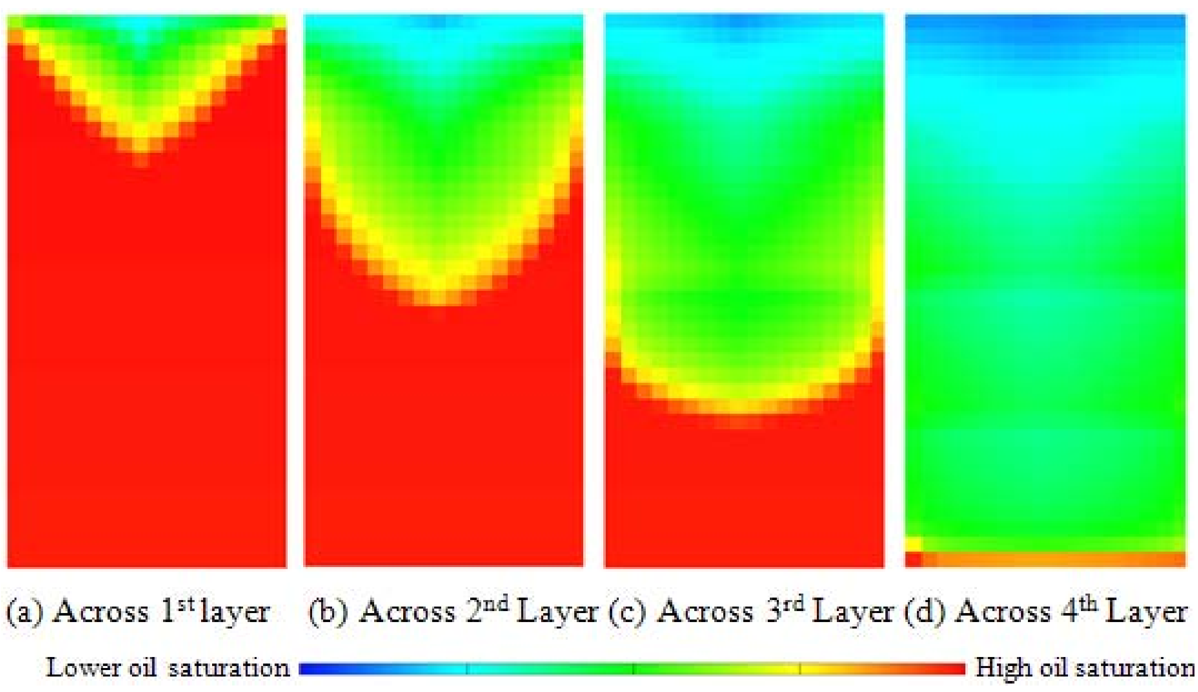


Fig. 27: Fluid Front Displacement for Shallow Vertical Injector

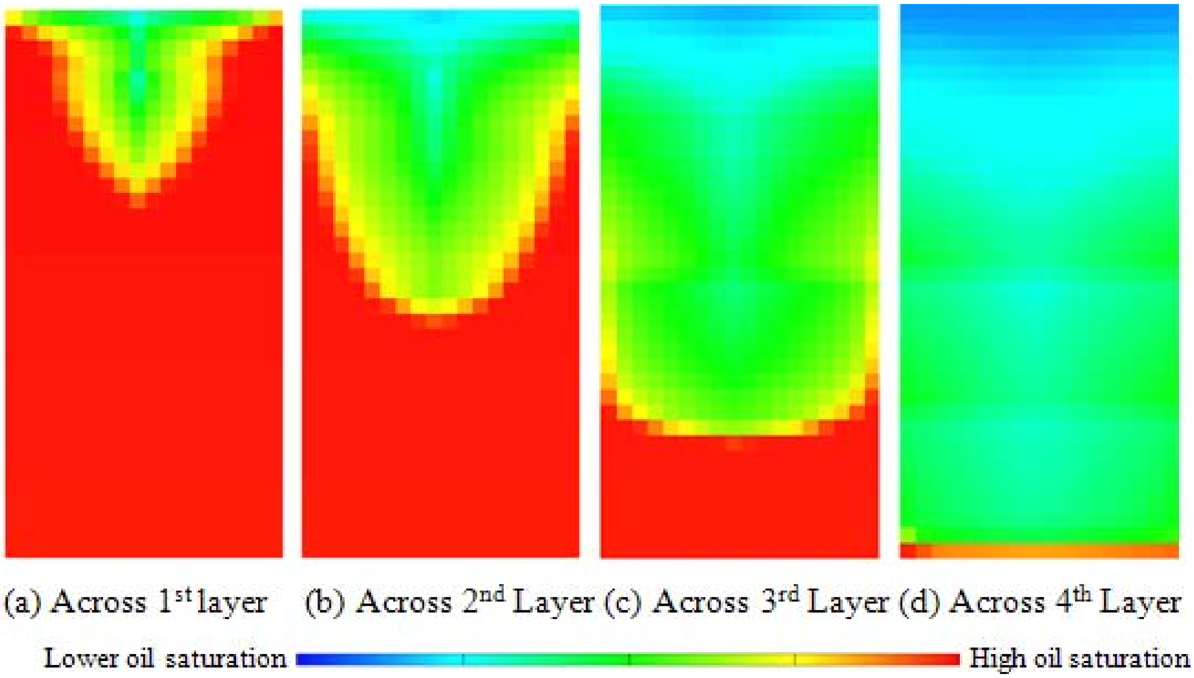


Fig. 28: Fluid Front Displacement for Deep Vertical Injector

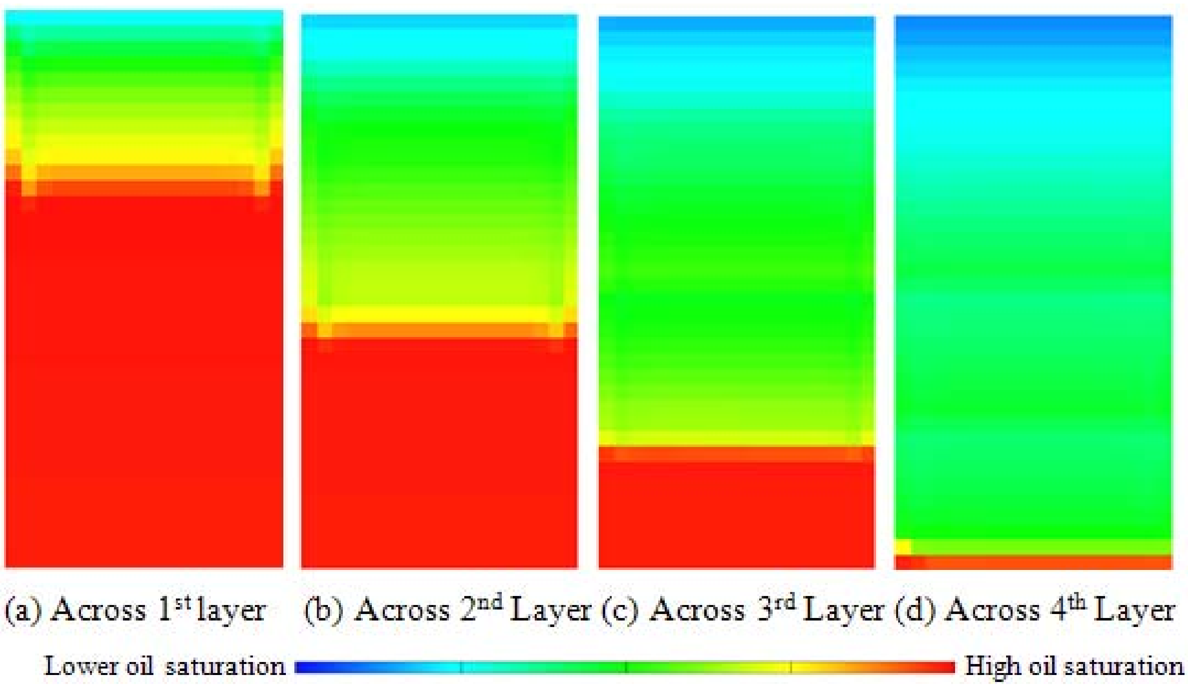


Fig. 29: Fluid Front Displacement for Horizontal Injector and Horizontal Producer

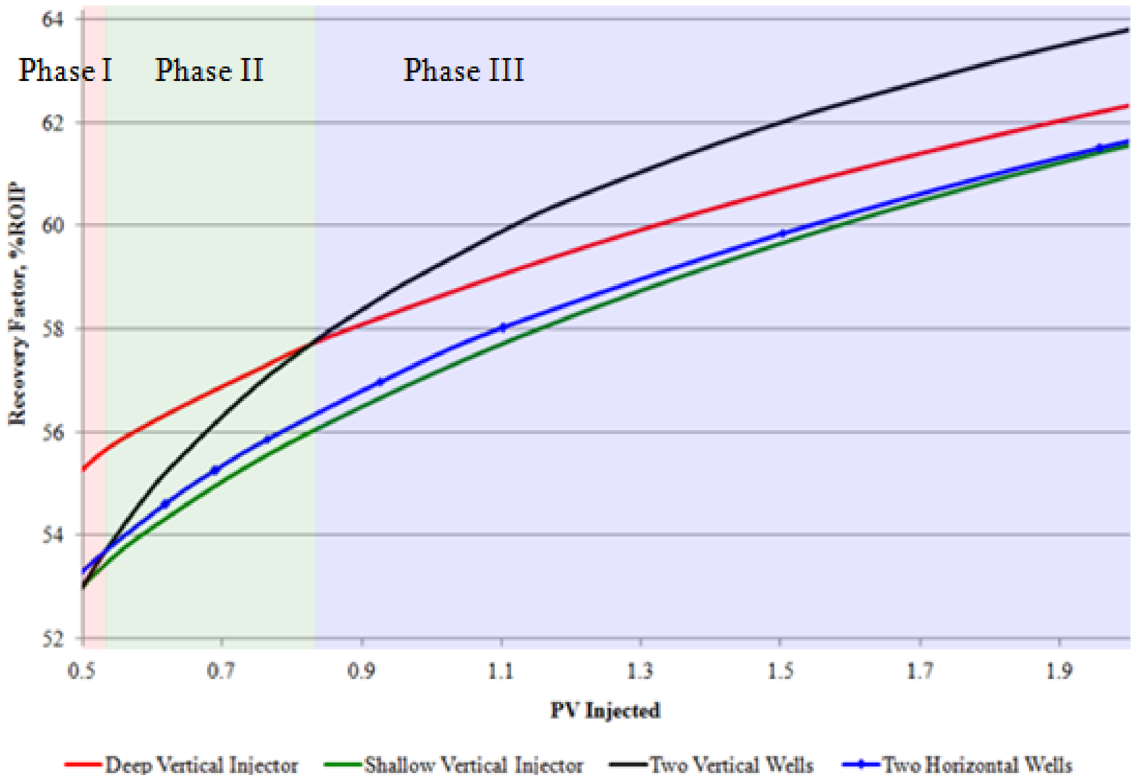


Fig. 30: Recovery Factor for Different Well Arrangement over Pore Volume Injected

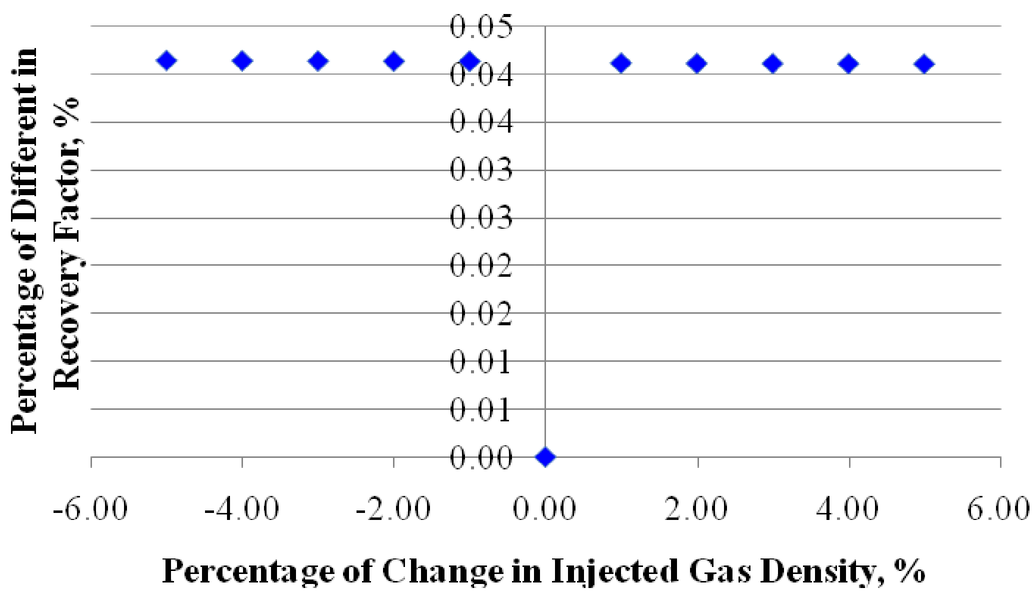


Fig. 31: Change in Recovery Factor with Different Injected Gas Density

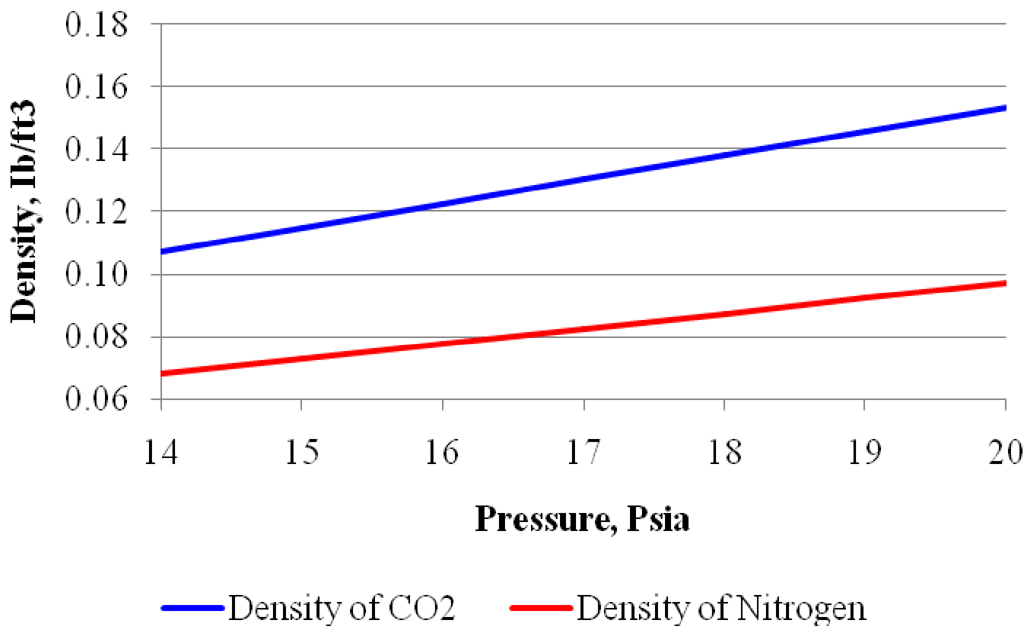


Fig. 32: Density of CO_2 and Nitrogen at Different Pressure

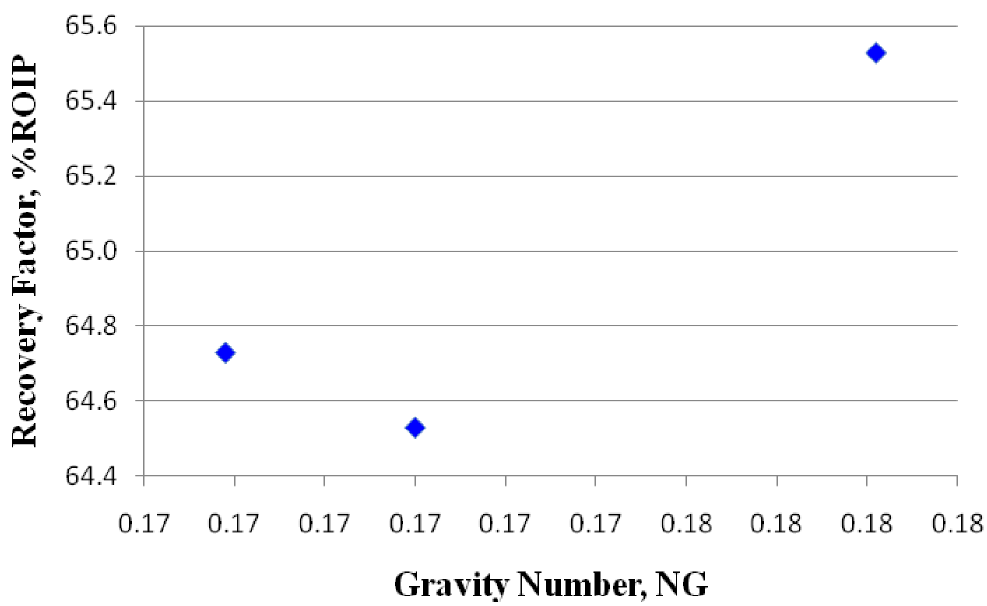


Fig. 33: The Effect of Gravity Number on Recovery Factor

TABLE I: Gelama Merah Field Properties [14-16]

Property	Value
K	4130 m-Darcy
k_v	140 m-Darcy
k_{ro}	0.48
Φ	27 %
Height	115 ft
ρ_{oil}	51.69 Ib/ft^3
Proposed *GAGD* pressure	2500 psi
CO_2 density	8.73 Ib/ft^3
S_{wi}	36 %
S_{or}	20 %
μ_{oil}	1.36 cP

TABLE II: Porosity and Permeability of each Range of Glass Beads

Size, µm	ϕ, %	*k*, mD
30-60	60.50	12482.74
90-150	58.33	14979.29
212-400	57.00	24965.48
425-600	56.21	37448.22

TABLE III: Properties for Three Different Packing

kv/kh	Average Porosity, %
0.80	58.01
0.90	56.61
1.00	56.21