A New Practical Method for Determination of Critical Flow Rate in Fahliyan Carbonate Reservoir

A .Hassani[1]*, S. A. Mortazavi[2], J. Gholinezhad[3]

[1,2]Drilling and Well Completion Technologies and Research Group Dept., Center for Exploration and Production Studies and Research, Research Institute of Petroleum Industry (RIPI), Tehran, Iran, West Blvd. of Azadi Sports Complex, Po. Box: 14665-137

[3]Reservoirs Productivity and Production Technologies and Research Group Dept., Center for Exploration and Production Studies and Research, Research Institute of Petroleum Industry (RIPI), Tehran, Iran, West Blvd. of Azadi Sports Complex, Po. Box: 14665-137

Abstract

In this study, a series of core flooding experiments have been carried out to determine the critical injection flow velocity in the porous media of the Fahliyan carbonate formation. For this purpose, a new practical method is employed and applied in two steps. First, a base-line permeability corresponding to a base rate is adopted and the injection rate is then returned to the base rate after each incremental stage in order to recalculate the permeability. Then a predefined parameter called 'degree of formation damage' is calculated at the base-line permeability at each stage. Experimental data shows that there is a linear relationship between the flow rate and the degree of formation damage. The critical injection rates corresponding to different degrees of formation damage, reported only as estimation in other works, are also calculated accurately in this study.

Keywords

Critical flow rate, Core flooding, Formation damage, Carbonate formation, Base-line permeability

* Corresponding author. Tel.: +98 21 48253352.
E-mail address: hassania@ripi.ir (A. Hassani)

1. Introduction

For most oilfield operators it is crucial to reach a high production rate. This is usually achieved by using such techniques as stimulation and EOR. However, the negative impacts of extreme fluid velocities in the porous media including excessive pressure drops and/or formation damage should be properly predicted. The latter could occur in the form of physical, chemical, biological and thermal damage (Miranda and Underdown, 1993; Civan, 2007; Renpu, 2011; Moghadasi et al, 2002). It could both be temporary, e.g. exceeding the turbulent limit of fluids in porous media and permanent, e.g. fine and sand production or fissure and fracture activation.

Most reservoirs contain small-diameter colloidal particles in contact with reservoir fluids. During drilling, completion, stimulation, workover, water injection and oil production operations different type of fluids interact with these uncemented particles and in some cases force and dislodge them from their original locations (Amaefule et al., 1988; Egbogah, 1984; Rahman et al., 1994). Miranda and Underdown (1993) reported that high fluid flow rate in the porous media was the main reason for fine migration in certain reservoirs. The minimum flow rate at which small particles detach and migrates within the pores of the formation is called ″critical flow rate″ (Gabriel and Inamdar, 1983; Leone and Scott, 1988; Amaefule et al., 1988; Miranda and Underdown, 1993; Mueke, 1979).

Type, location, size and concentration of fines in the pore network are physical factors determining the hydrodynamic conditions required for fine migration (Porter, 1989; Ohen and Civan, 1991; Zeinijahromi et al., 2011). On the other hand, Read (1989) stated that the pore geometry and the moving fluid viscosity are the important parameters for the determination of critical flow rate (CFR) in porous media (Read, 1989). According to Amaefule et al. the ionic strength and the pH of the injecting fluid, interfacial tension, pore geometry and morphology, and the wettability of rock and fine particles are the dominant factors that control the critical velocity (Amaefule et al. 1987). The critical flow rate/velocity may suspend fines or force them to move and precipitate in the pore spaces and result in pore plugging (Sharma, 1985; Wojtanowicz et al., 1987; Nguyen et al., 2012; Zeinijahromi et al., 2012). Consequently, the pressure drop along the porous media will become higher and cause a reduction in the permeability. In some cases a reverse phenomenon could occur where the permeability would show an abrupt increase due to a possible fracture opening (stimulation). Also there might be occasions where the permeability has a slight increase even at lower flow rates. This is due to core cleaning where fines smaller than the pore size are detached and entrained within the flow to the outlet. According to Khilar and Fogler, this phenomenon is called piping or washout of fines (Khilar and Fogler, 1998). Both of these phenomena causing the permeability to increase are also referred to as formation damage in this work.

There are not many published works on the effect of flow rate on permeability damage. Nevertheless, a few experimental techniques have been proposed for the determination of CFR through core-flooding tests (Amaefule et al., 1987; Forchheimer, 1914; Miranda and Underdown, 1993; Leone and Scott, 1988; Renpu, 2011). One method that was introduced by Forchheimer (Forchheimer, 1914), is to calculate the differential pressure across the core divided by flow velocity and then plot it as a function of flow velocities (DP/U vs. U). According to this theory, the ratio DP/U remains constant when there is no fine migration. But for velocities higher than the critical velocity the pressure drop across the core will increase gradually leading to a decrease in the calculated permeability value. So, the ratio should lie on the original value; otherwise the formation damage caused by fine migration for elevated pressure drops is likely to occur.

Leone and Scott conducted a comprehensive test series for a high clay content reservoir using two brines named as A and B (Leone and Scott, 1988). In their work, severe permeability damage was observed when decreasing the flow rate from 2 cc/min to 0.5 cc/min in a step-wise manner. The permeability damage was determined to be about 70% during the test. The results of the tests by different non-damaging brines confirmed the occurrence of mechanical fine migration as primary damage mechanism.

Miranda and Underdown proposed a method for the determination of CFR in core samples at reservoir conditions (Miranda and Underdown, 1993). According to this approach, the fluid is injected at a very low injection rate called base-line permeability. Then, the rate is increased in a step-wise manner and then returned to the initial rate (base-line permeability) after each incremental stage. Experimentally derived flow rate and permeability data are converted to bottom hole and wellhead production rates using completion data and well geometry (Miranda and Underdown, 1993).

Renpu (2011) used a parameter called degree of formation damage, D_k, in order to evaluate the sensitivity of core permeability to the flow rate. D_k is defined as below:

$$D_k = \frac{K_{i-1} - K_i}{K_{i-1}} \times 100 \quad (1)$$

Where:

K_{i-1} = permeability at flow rate Q_{i-1}

K_i = permeability at flow rate Q_i

D_k = degree of formation damage

The value of D_k calculated by this equation depends on the permeability change caused by the changes in flow rate. As long as $D_k \leq 5$, there will be no damage in the core sample. The different formation damage boundaries are defined in Table 1.

Table 1. Evaluation Criteria for Degree of Rate Sensitivity Damage

Formation Damage Degree (%)	$D_k \leq 5$	$5 < D_k \leq 30$	$30 < D_k \leq 50$	$50 < D_k \leq 70$	$D_k > 70$
Scale of Damage	None	Weak	Medium to Weak	Medium to Strong	Strong

The above definition that is derived from a Chinese Standard (SY/T5358-2002) was employed by Renpu (2011) who used the results of flooding tests on 10 core samples to quantify the formation damage. He increased the flow rate by injecting kerosene to quantify the degree of formation damage in linear and radial flow. In his tests, however, he did permeability calculations at increased flow rates and not at the base rate as he did not return to a predefined initial rate after raising the rate at each step. The problem with this approach is that any permeability reduction is interpreted as formation damage.

In core-flooding experiments, after increasing the injection rate the differential pressure normally goes up due to the turbulency. As a result, the calculated permeability will be slightly lower. In these cases, if the rate is returned to the baseline rate, the permeability will also get back to its initial value indicating no formation damage. In this work, in order to avoid misjudgment on the occurrence of formation damage, degree of formation damage is determined only at base rate and comparison is made based on the values obtained at baseline. Therefore a combination of two approaches, i.e Miranda and Underdown (Miranda and Underdown, 1993) and Renpu (Renpu, 2011), is employed here to do the permeability measurements and to calculate the degree of formation damage. In other words, a base rate hence a base-line permeability is adopted and the injection rate is returned to the base rate after each incremental stage. Then the degree of formation damage is determined through equation (1) at consecutive base-line permeabilities. Since the positive and negative signs are only an indication that the permeability goes up or down, the absolute value of D_k is used here to show the magnitude of permeability alteration and formation damage. An accurate and reliable quantification of formation damage and corresponding critical flow rates in plug samples taken from Fahliyan formation are carried out by the proposed technique in this work.

2. Material and Methods

2.1. Core Samples

The plug samples used in this work were obtained from Fahliyan carbonate formation in one of Iranian oil wells. Yadavaran Oilfield is located around 70 km to the southwest of Ahwaz and near the Iran-Iraq border in SW of Iran, and spreads out over a large geographical area stretching some 45 km from north to south and 15 km from east to west. In Yadavaran field, there are three main oil-bearing formations, namely Sarvak, Gadvan and Fahliyan.

After cleaning by methanol for a period of time and measuring the petrophysical properties such as porosity and air permeability, core samples were saturated by 4% KCl (synthetic brine) under sufficient vacuum pressure. Table 2 shows the specifications of plug sample used for flooding experiments. Plugs were selected from upper, middle and lower parts of Fahliyan formation.

Table 2. Description of the Plug Sample from Fahliyan Carbonate Formation

Plug No.	Depth (m)	Porosity (Ø)	Air Permeability (md)	Plug Dimensions	
				D (cm)	L (cm)
1	4134.84	21.70	5.308	3.81	5.10
2	4202.39	20.34	4.9	3.81	5.14
3	4280.53	15.88	12.45	3.81	5.13

Fahliyan formation is mostly composed of calcite and dolomite. The composition of the selected plugs (obtained from XRD data) is presented in Table 3:

Table 3. Composition of plugs obtained from XRD analysis

Plug No.	Calcite ($CaCO_3$)	Dolomite ($CaMg(CO3)_2$)	Kaolinite	Quartz (SiO_2)
1	98%	2%	---	---
2	79%	18%	1%	2%
3	85%	14%	---	1%

2.2. Injection Fluid

Injection fluids were synthetic brine (4% KCl prepared from distilled water) and gas oil. The viscosity of gas oil was measured by a rolling ball viscometer. Due to the limitations of the viscometer, the measurements here are restricted to temperatures up to 220 ^{o}F and laboratory pressure. The viscosity of gas oil at elevated temperatures was extrapolated. Figure 1 shows the results of viscosity estimation at elevated temperatures.

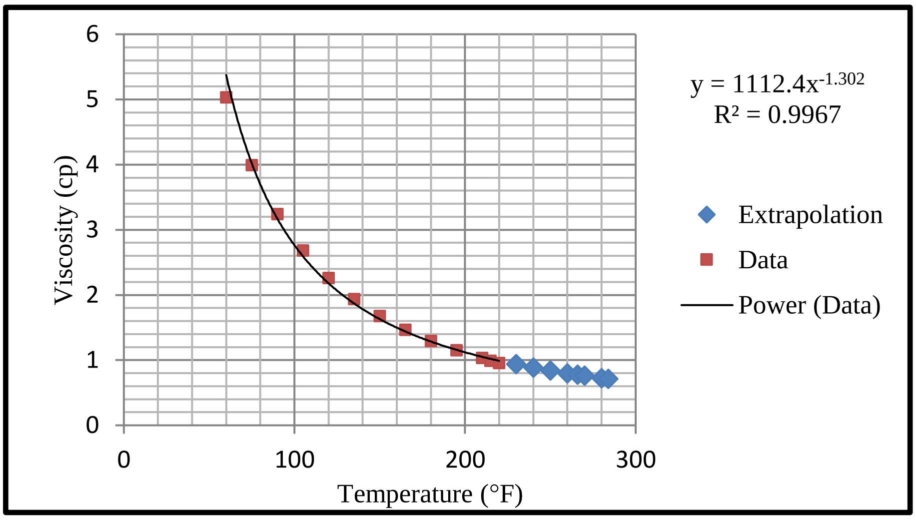

Figure 1. Viscosity Extrapolation at Elevated Temperatures

Accordingly, the viscosity is 0.77 and 0.71 cp at 266 ^{o}F (130 ^{o}C) and 284 ^{o}F (140 ^{o}C), respectively.

2.3. Experimental Setup

The core testing setup consists of a core holder, a pressure transducer measuring the overall pressure drop across the core and the pressure drop across the sections along the core, an annulus pump to apply an overburden pressure over the rubber sleeve containing the core sample, a back-pressure system and an effluent fluid collection container (Figure 2). To avoid formation damage caused by clay-water interactions, the core was initially saturated with a 4 wt. % KCl aqueous solution. At this point, the absolute liquid permeability was established and measured. The injection fluid used in all experiments is gasoil. This fluid is selected because it has relatively low compressibility as well as similar properties as the formation fluid.

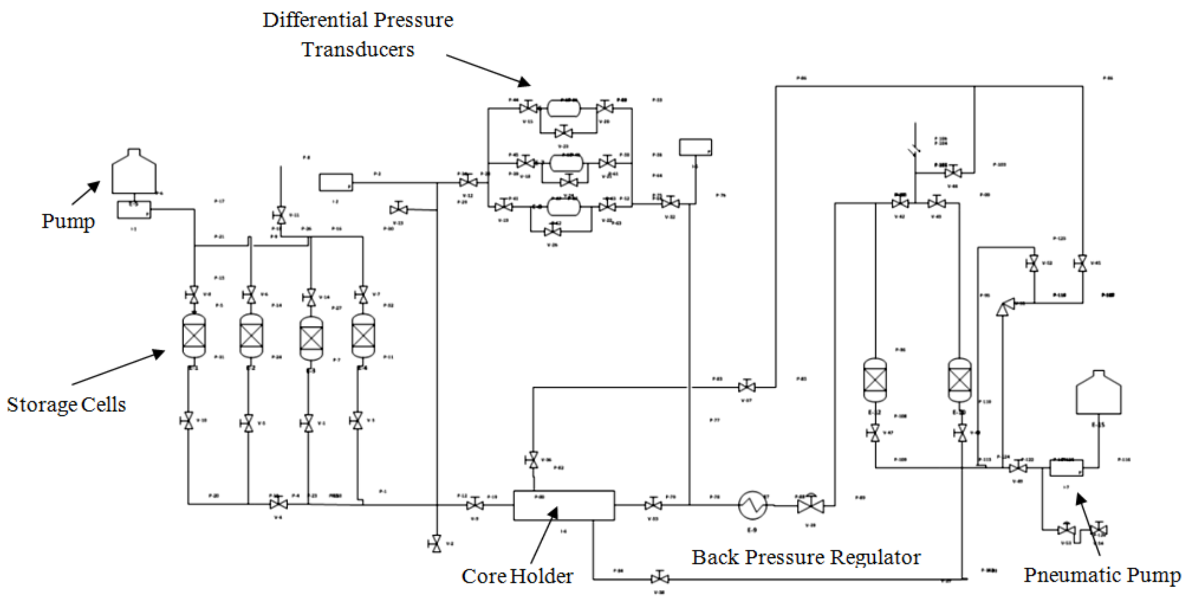

Figure 2. Schematic of experimental setup used for flooding experiments

2.4. Experimental Procedure

The plugs are mounted in plug holder and kept at reservoir temperature and pressure for 24 hours to simulate the reservoir condition. Brine (4wt.% KCl aqueous solution) is initially injected to restore the saturation status of plug. Then, the plug is flooded with gas oil for a period of time to reach a constant ΔP (Inlet minus Outlet pressure), i.e. steady state conditions. The flooding setup is manipulated to operate in the conditions depicted in Table 4.

Table 4. The Flooding Device Operating Conditions

Oven Temp. (°F)	Overburden Pressure (bar)	Back Pressure (bar)	Inj. Flow Rate (cc/min)
284	20-30 bars > Inlet Pr.	60-65 bars	Variable

The flooding tests include measuring the relative permeabilities for different flow rates at reservoir conditions. The tests begin with a base value of 0.5 cc/min for flow rate and subsequently, it increases to higher values in the next steps. After each incremental stage, the flow rate is returned to the base flow rate (0.5 cc/min) to recalculate the permeability and evaluate the formation damage.

The permeability at each flow rate is measured and the degree of formation damage is calculated at the successive baseline permeabilities. Then the CFRs corresponding to each formation damage boundary are determined. The designed flow rates for the tests are dependent on the permeability of the plug at the initial rate of 0.5 cc/min.

3. Results and Discussion

3.1. Plug No. 1

The injection starts with the base rate of 0.5 cc/min and proceeds with higher flow rates (Figure 3). Obviously, ΔP rises as the flow rate is increased and the overburden pressure should therefore be manipulated to higher values.

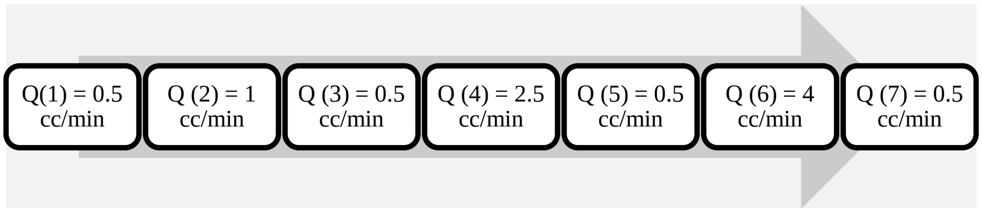

Figure 3. Sequence of different injection rates used in Plug No.1

The flooding schedule consisted of 7 stages as depicted in Figure 3. The test started with the injection rate of 0.5 cc/min considered as base rate for measuring permeability and consequently the degree of formation damage (D_k). Prior to testing, about 10 pore volumes of gas oil were injected to reach the pressure stability (S_{wi}). During the flooding experiments, no water was observed in the effluent.

The permeability alteration during different injection rates are shown in Figure 4. As it can be seen, several permeability measurements have been done following increasing the flow rate and waiting for a certain amount of time to reach steady state condition.

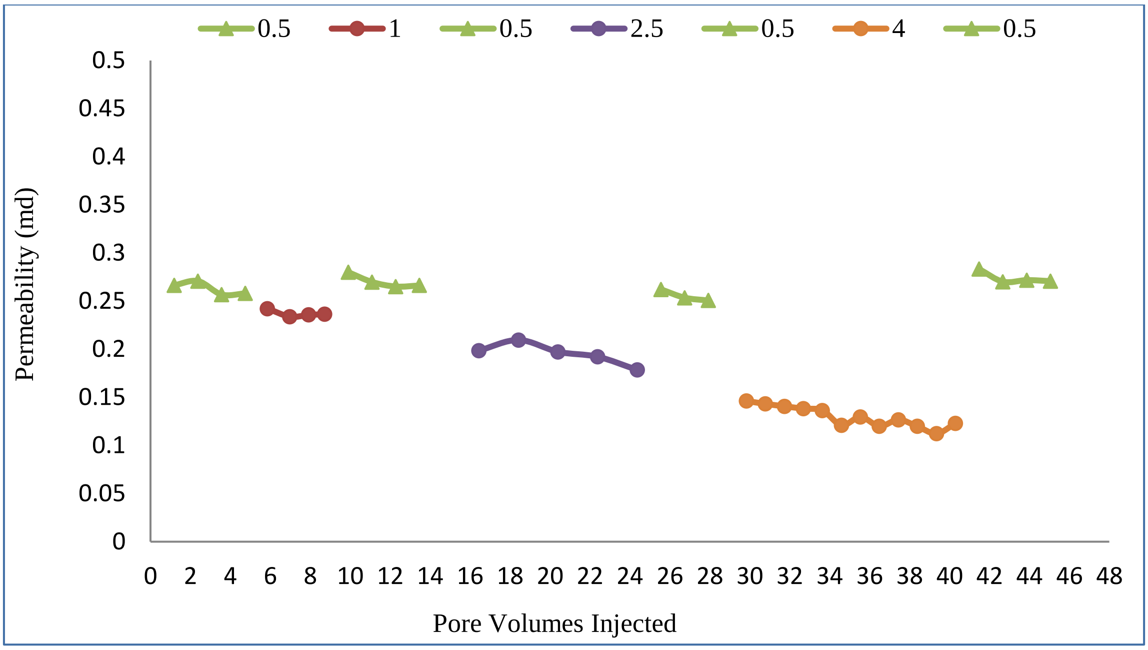

Figure 4. The Permeability Change in Different Injection Rates of Plug No. 1

The average values of end point oil relative permeability at different injection steps are listed in Table 5.

Table 5. Average End Point Oil Relative Permeability Value at Different Injection Steps of Plug No.1

Step	Flow Rate (cc/min)	Average Permeability (md)
1	0.5	0.263
2	1	0.232
3	0.5	0.272
4	2.5	0.203
5	0.5	0.255
6	4	0.130
7	0.5	0.279

The average permeability is the average of permeabilities at each flow rate after reaching steady state condition. For example this value for plug No. 1 and at flow rate of 0.5 cc/min (stage No. 1) is:

$$Perm_{average} = (0.266+0.271+0.0.257+0.258)/4=0.263$$

It can be seen that in some rates the system has not reached the steady state condition (the permeability has a decreasing trend). As a matter of fact, this is a proof that the measurements at these rates cannot be considered for the calculation of D_k or for interpretation and the results of the base rate should be taken into account. In other words, although the permeability determination has been done for all the rates, the permeability values only at the base rate are used for calculation of D_k and the interpretation of the results. In addition, at a very high rate, the pressure difference is sometimes so high that it is not possible to continue flooding in that rate due to the limitations in flooding equipment.

In order to evaluate the magnitude of induced damage, the degree of formation damage (D_k) were calculated at the injection rate of 0.5 cc/min (Steps 1, 3, 5 and 7). The calculated values are listed in Table 6.

Table 6. Evaluation of the Degree of formation Damage (D_k) for Plug No. 1

Steps	Flow Rate (cc/min)	Parameter	Calculated Amount
1 and 3	0.5	$D_{k\,(1,3)}$	3.422
3 and 5	0.5	$D_{k\,(3,5)}$	6.250
5 and 7	0.5	$D_{k\,(5,7)}$	9.412

The measured end point oil relative permeabilities at the stages of 2, 4 and 6 decreased gradually (especially at q = 4 cc/min) but when the rate returned to the base value (q = 0.5 cc/min), only small change in the permeability value was observed, meaning no formation damage.

The averaged end point oil relative permeability at step 3 increases but no sign of permanent formation damage in the plug is observed ($D_{k\,(1,3)} \leq 5$). According to Khliar and Fogler, this increase in the permeability could be explained by 'piping or washout of fines' where the small fines are detached and moved out within the fluid (Khilar and Fogler, 1998). Turbulent flow has mentioned as a phenomena to occur when the flow rate increases at each step, it is not considered for the permeability change at successive base rates. For instance, the permeability has decreased from 0.263 to 0.237 md when the flow rate has increased from the base rate to 1 cc/min. There was no turbulancy effect when the flow returned to the base rate after each incremental stage.

According to the data in Table 6, there is a linear relationship between D_k and flow rate from which the exact value of CFR can be extracted.

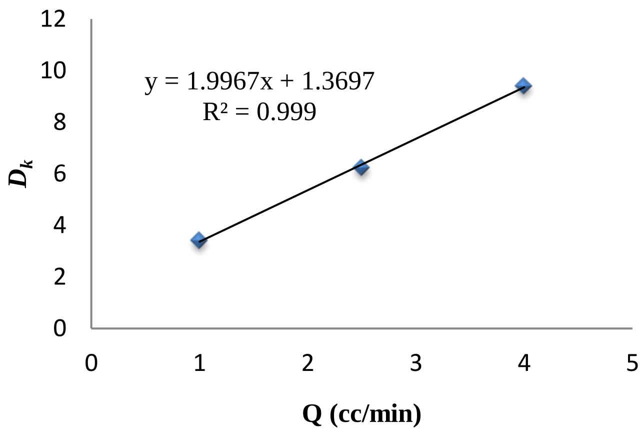

Figure 5. Linear Relationship between the Degree of Formation Damage and the Injection Rate

It has been stated that flow rates corresponding to medium and medium to strong damages will cause serious formation damage and must be avoided during injection or production (Renpu, 2011). So the main objective of this work is to determine the weak ($5 < D_k \leq 30$) and weak to medium ($30 < D_k \leq 50$) damages.

From the linear regression data, the lower and upper boundaries of critical flow rate corresponding to different types of damage are calculated (Table 7).

Table 7. The critical flow rate limits for Plug No.1

Type of Damage	Critical Flow Rate (cc/min)	
	Lower Limit	Upper Limit
None	0	1.82
Weak damage	1.82	14.34
Medium to Weak	14.34	24.36
Medium to Strong	24.36	34.37
Strong	34.37	---

To create medium to weak or medium to strong damage, injection rates higher than 4 cc/min should be tested. However, if rates higher than 4 cc/min are used; the difference between the outlet pressure and overburden pressure becomes higher than 50 bars exceeding the equipment pressure limit. Therefore, the linear extrapolation is employed to estimate the rates leading to medium to strong damages ($D_k \geq 30$).

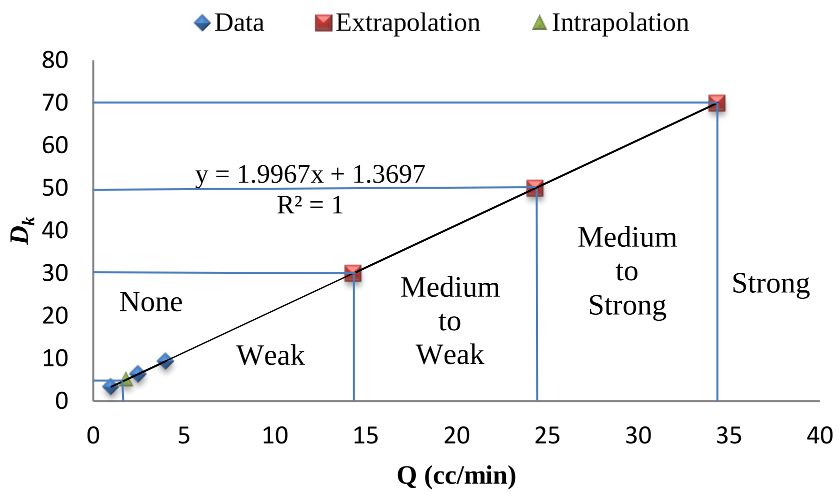

Figure 6. Lower and upper limits of formation damage indicated by different flow rate values

3.2. Plug No. 2

The injection starts with 0.5 cc/min and proceeds to higher flow rates. Initial ΔP is about 1.5 bars for 0.5 cc/min which subsequently increases to about 17.5 bars for 3 cc/min. The permeability alteration during different injection flow rates are shown in Figure 7. The calculated permeability values for all flow rates are also presented in Table 8.

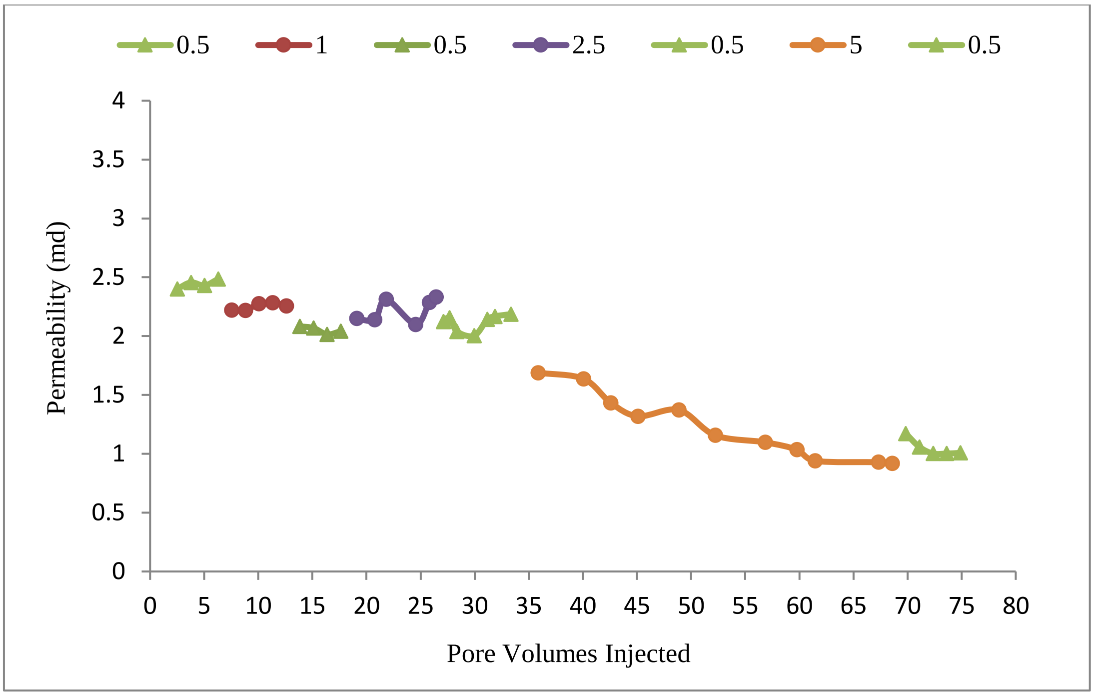

Figure 7. The Permeability Change in Different Injection Rates of Plug No. 2

Table 8. Average Permeability Value at Different Injection Steps of Plug No.2

Step	Flow Rate (cc/min)	Average Permeability (md)
1	0.5	2.329
2	1	2.251
3	0.5	2.164
4	2.5	2.187
5	0.5	1.897
6	4	1.146
7	0.5	1.232

It can be seen that the end point relative permeability at incremental stages (steps 2, 4 and 6) exhibits a decreasing trend. Also the permeability values at the base rate (0.5 cc/min) decreases continuously. In this case, the decreasing trend is more likely due to fine migration where the pores have been plugged with fines detached from loosely rocks. There is about one percent of Kaolinite (XRD analysis, Table 3) in the rock which is the primary suspect for fine migration.

As in plug No. 1, the degree of formation damage (D_k) was calculated at the base rate of 0.5 cc/min (Steps 1, 3, 4 and 7). The resulting values are listed in Table 9.

Table 9. Evaluation of the Degree of formation Damage (D_k) for Plug No. 2

Steps	Flow Rate (cc/min)	Parameter	Calculated Amount
1 and 3	0.5	$D_{k\,(1,3)}$	7.091
3 and 5	0.5	$D_{k\,(3,5)}$	12.340
5 and 7	0.5	$D_{k\,(5,7)}$	35.069

Similar to plug No.1, there is a linear relationship between the degree of formation damage and the injection rate. By applying a linear regression, the position of flow rates corresponding to particular degrees of damage has been determined as shown in Figure 8.

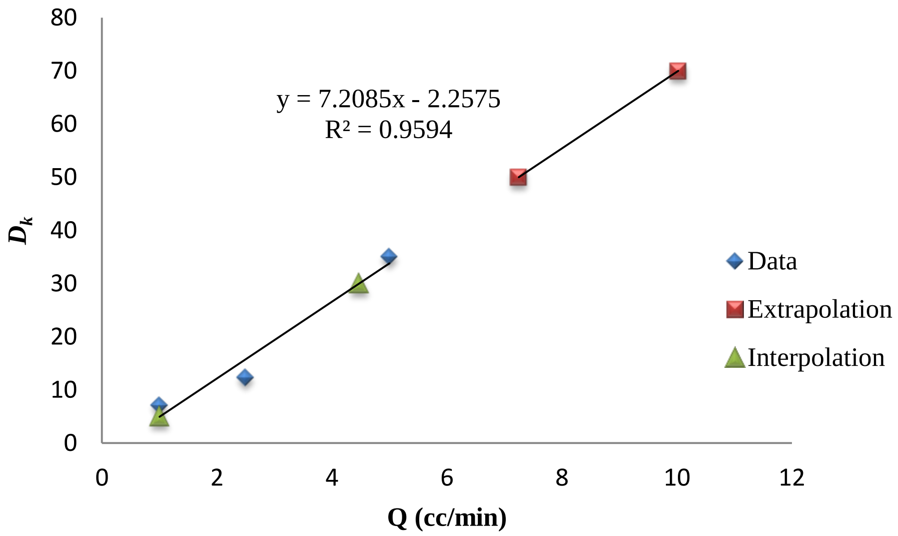

Figure 8. Linear relationship between the degree of formation damage and the injection flow rate of plug No. 2

The plug reaches the first formation damage boundary, i.e. weak damage, at a rate higher than 1 cc/min. Flow rates below the boundary of medium to strong damage are interpolated from the regression ($D_k \leq 50$). The test could not be continued to see the strong damage because of the limitations in flooding equipment. Table 10 shows the estimated values of the CFR corresponding to a certain type of damage.

Table 10. Estimation of the CFR by Linear Regression Method for plug No. 2

Type of Damage	Critical Flow Rate (Linear Regression) (cc/min)	
	Lower Limit	Upper Limit
None	0	1.007
Weak damage	1.007	4.475
Medium to Weak	4.475	7.249
Medium to Strong	7.249	10.024
Strong	10.024	---

3.3 Plug No. 3

The operating conditions for this plug are the same as other plugs. But the injection has been extended to 11 steps to capture the medium and medium to strong boundaries taking into account the setup limitations. The results of permeability measurements at different rates are summarized in Figure 9 and Table 11.

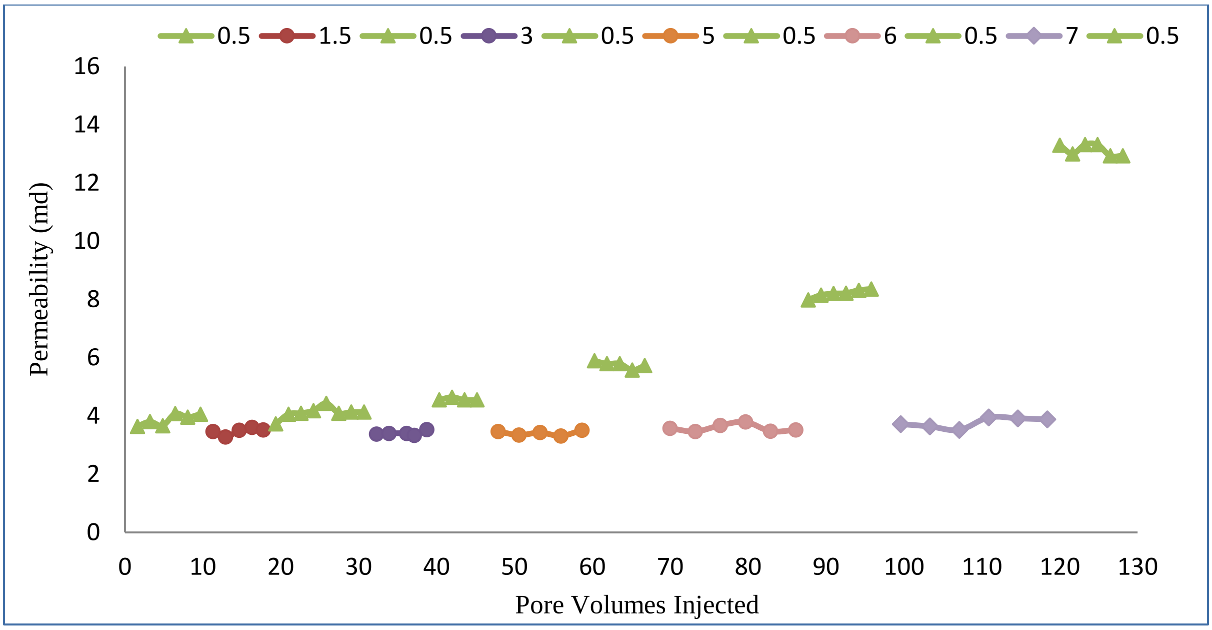

Figure 9. The Permeability Change in Different Injection Rates of Plug No. 3

It can be seen that the difference between baseline permeabilities (q = 0.5 cc/min) is significant especially after the flow rate of 7 cc/min. At the final injection stage, the pressure difference decreases considerably resulting in higher permeability (q=constant). This drastic increase in the permeability might be due to fracture activation. The XRD analysis for plug No. 3 shows no clay content. Also it was mentioned in Archie analysis (a qualitative method for routine classification of core samples) that there is a fracture on the inlet face of the sample. The fracture is activated due to higher flow forces which may cause some particles to detach from the pore wall and migrate to specific sites on fracture faces resulting in continuous fracture opening. This happens when the flow rate changes to higher values and returns to the base flow rate afterwards (the overburden pressure was maintained constant during injection).

Table 11. Average Permeability Value at Different Injection Steps of Plug No.3

Step	Flow Rate (cc/min)	Average Permeability (md)
1	0.5	3.849
2	1.5	3.486
3	0.5	3.922
4	3	3.450
5	0.5	4.544
6	5	3.485
7	0.5	5.750
8	6	3.543
9	0.5	8.204
10	7	3.766
11	0.5	13.124

Although the flooding can be continued to see the different boundaries of formation damage, the setup limitations prevents the pressure difference to be greater than 50 bars. The results of measurements and calculations for plug No. 3 are summarized in table 12.

Table 12. Evaluation of the Degree of formation Damage (D_k) for Plug No. 3

Steps	Flow Rate (cc/min)	Parameter	Calculated Amount
1 and 3	0.5	$D_{k\,(1,3)}$	1.894
3 and 5	0.5	$D_{k\,(3,5)}$	15.870
5 and 7	0.5	$D_{k\,(5,7)}$	26.524
7 and 9	0.5	$D_{k\,(7,9)}$	42.690
9 and 11	0.5	$D_{k\,(9,11)}$	59.968

An interesting point of the test is that the estimated rates for the boundaries of damages are extended to the strong damage and the trends could be generalized to different plugs of Fahliyan carbonate formation. It means that by having the linear relationship between the injection rate and the degree of formation damage, the exact value of critical rates can be calculated.

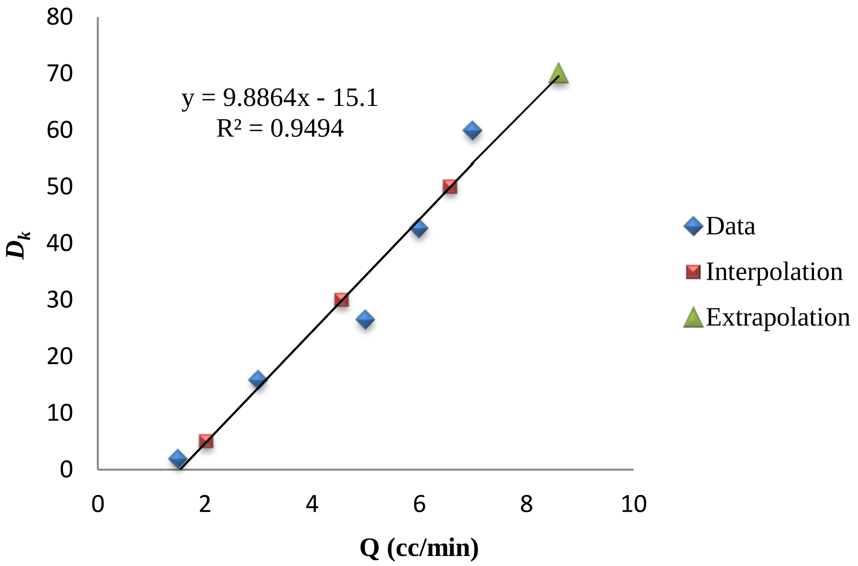

Figure 10. Linear relationship between the degree of formation damage and flow rate for plug No. 3

The proposed method has a high capability to identify formation damage boundaries at base-line permeabilities. Indeed, the exact value of flow rate at which a particular type of damage occurs could be determined.

Table 13. Estimation of the CFR of plug No.3 by linear regression

Type of Damage	Critical Flow Rate (Linear Regression) (cc/min)	
	Lower Limit	Upper Limit
None	0	2.033
Weak damage	2.033	4.562
Medium to Weak	4.562	6.585
Medium to Strong	6.585	8.608
Strong	8.608	---

In the chart below, changes of CFR at different depths based on the results of experimental work are illustrated. It should be mentioned that these results have been obtained from linear core flooding tests and care should be taken before upscaling the results to well and reservoir dimensions.

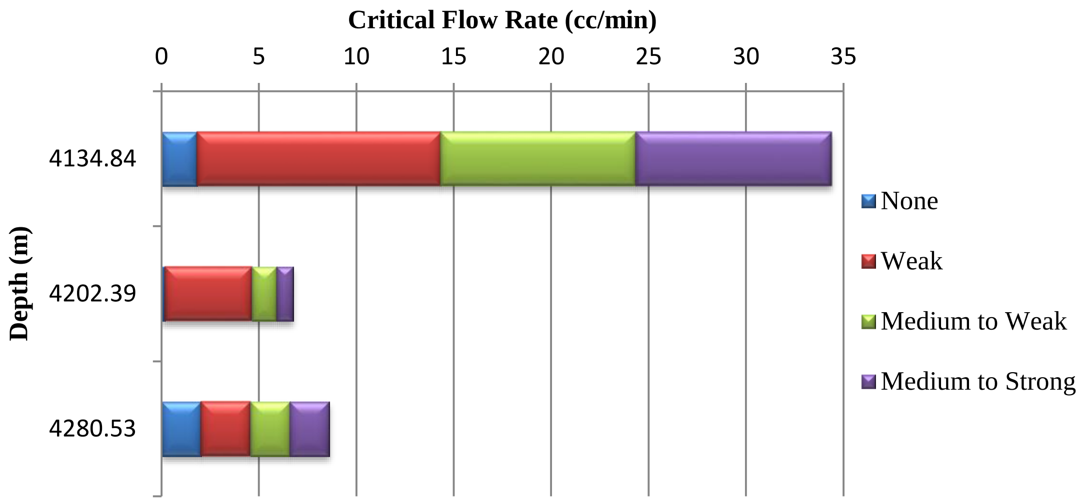

Figure 11. Estimated Critical Flow rates at Different Depths for Fahliyan Formation

4. Conclusions

Core flooding experiments were conducted using gasoil as the injection fluid. The test was carried out in a step-wise manner and the amount of permeability loss is determined using linear Darcy law in each step. A new method for quantifying CFR is established. The proposed technique is applied in two different steps. The first step uses a base-line permeability and returning the injection rate to the base rate after each incremental stage. The second step includes determining the degree of formation damage using the calculated permeabilities.

Based on the results of tests on three plugs from Fahliyan formation, the dynamic behavior of formation at different production and injection rates can be obtained. According to the results, there is a linear relationship between the injection rate and the degree of formation damage. Hence the exact values of critical injection rates can be estimated by applying a linear regression. In addition, if there is no restriction while conducting experiments, the higher boundaries of formation damage, as occurred in plug No. 3, are reached and the corresponding flow rates could be measured.

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