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Optimum matrix acidizing: How much does it impact the productivity

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Abstract. Formation damage is one of the big challenges for oil and gas oilfields development. Several types of formation damage most likely exist during the entire life of producing wells. Formation damage can occur during the drilling or coring operations, well completion, work-over and production. The most important problems that affect formation during drilling operations are mud filtrate and fines invasion. There are different damage mechanisms affect reservoirs for instance pore blocking by solids, clay swelling and dispersion and liquid block which all reduce effective permeability to hydrocarbons. The reduction in production and an excessive build up pressure in injection wells indicate the formation. Many techniques are developed to remove the formation damage and to improve the productivity of wells. Matrix acidizing is one of these method which depend on injecting acids into the formation below fracturing pressure to eliminate the damage around the well. In this study, comprehensive design procedures for the acid treatment have been introduced. The procedures include the determination of the damage type and the mineralogy of the formation. Accordingly, the selection of the appropriate acid for the treatment and the optimum volume of injected acid are explained in the study. Additionally, the research presents several models for the pre-flush volume and the main acid volume based on the radius of the damaged zone and the height of the formation. New technique has been proposed for determining the final permeability improvement ratio based on current and proposed productivity index. It has been found the pre-flush volume increase as the carbonate percentage in the formation increases while the main acid volume conversely proportional with the clay content in the formation.

Keywords: matrix acidizing, productivity index, formation damage

1.Introduction

One of the big challenges that typically occurred throughout production process starting from the beginning is the formation damage in the vicinity of the wellbore. Wellbore and the surrounding formation may undergo several physical and chemical changes with time which in turn reduce its permeability. These changes are caused by different activities that the well is experienced in its entire life. Some of these changes might be developed by the drilling process in which drilling fluid may contaminate the sand face. Others might be resulted from completion process or even the stimulation process such as the fracturing and acidizing treatment. Production process may also be the reason for different changes that are usually represented by fine and scale deposits resulted from the interaction between reservoir fluids and the wellbore or generated inside the formation due to drag forces created by the fluid flow. Fines are usually introduced into the formation from drilling operations also. Such physical and chemical changes during the producing life of the well and the reservoir reduce the deliverability or productivity. The term “Formation Damage” is frequently used to describe the impact of such physical and chemical changes in the rock formation.

Acidizing is considered one of the oldest stimulation technique still in modern use. This method has been established since the description of the first acid treatment in 1895 given by Herman Frasch [1]. He described the reaction of hydrochloric acid with limestone to produce soluble products which are removed as the well stars producing. The commercial use of the acidizing as a stimulation technique became widespread around 1930s. Since then, researches have been in constant technical efforts to extend application to more complex reservoir. In 1933, Halliburton attempted to make hydrofluoric acid applicable in oil fields. However; the results were disappointing because acid left in the wellbore a large quantity of unconsolidated sand. Therefore, Halliburton did not offer hydrofluoric-hydrochloric acid mixture for commercial use until the middle of 1950's. Hydrofluoric acid has been widely used in stimulation treatment and extensive research has been mad to improve treatment fluid until now [2].

Acid system and acid volume are the most important parameters in the design of the acid treatment. [3] proposed guidelines for acid system used in sandstone matrix. These guidelines are based on reservoir mineralogy and permeability. He explained [4] that successful acidizing treatment depends on several parameters which are: 1) Good evaluation of candidate wells by using completion and production histories, production well flow analysis, and formation composition analysis 2) Design for effective coverage for the damaged area, 3) Selection of solvents, acids and acid compositions to prevent or reduce incompatibility, and 4) Effective well preparation.

Several researches have given great attentions to the effect of temperature and mineral sensitivity in the estimation of the acid volume needed for a specific treatment. Treatment volumes are used based on experience or using mathematical simulation. Usually the optimum volume of regular mud acid system ranges from 125 to 200 gal/ft of formation. This is based on the experience. But successful treatment however, does not need, always, such high range of volume. Recent work by [5] shows that actual volume needed for a successful treatment is much smaller than used in oil industry, 125-200 gal/ft.

[6] stated several reasons for the formation damage such as asphaltic deposits, sand production, bacterial growth, and scale deposits. Formation damage is generally due to fine solids in movement that plug the pores. These fine solids either come from the formation itself or solids have been transported by the invasion or the injection of other fluids during different operations on the wells such as drilling, cementing and previous treatments (workover). Damage could be illustrated at different levels as shown in Figure 1. Damages can be classified according to the location such as: inside the well and on the sides of the well. There are several types of formation damage mechanisms, for instance: damage due to drilling operation, casing and cementing, and production operations [7], [1], [8].

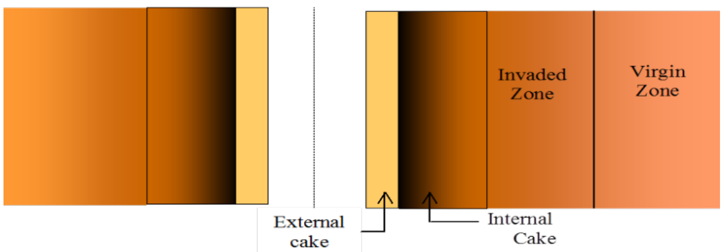

Figure 1. Damage illustration.

Formation damage has different impacts on reservoir properties. In general, formation damage caused increasing the pressure drop required to push reservoir fluid toward the wellbore. The extra pressure drop is required to overcome the resistance resulted by the damage. Not only increasing the pressure drop, but also the flow rate is reduced by the damage. Both changes in turn lead to significant loss in the productivity index of the wells. Mathematically, Darcy law can be written for the wells with damaged zone as shown in Figure 2 as follows:

$$P_e - P_w = \frac{141.2Q\mu B}{h}\left[\frac{1}{k_d} ln\left(\frac{r_d}{r_w}\right) + \frac{1}{k} ln\left(\frac{r_e}{r_d}\right)\right] \tag{1}$$

while the change in productivity index, describing the relationship between inflow rate and pressure draw dawn, resulted from the existence of damaged zone is given by:

$$\frac{J}{J_d} = \frac{ln(r_e/r_w)}{\frac{k}{k_d}ln(r_d/r_w)+ln(r_e/r_d)} \tag{2}$$

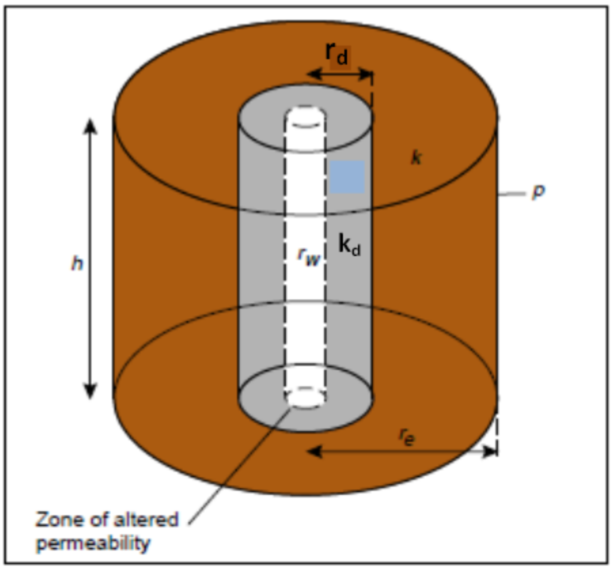

Figure 2. Damaged zone around wellbore.

2. Acid solution types

Several acid solutions are available to use for carbonate reservoir stimulation. The most common acids for the treatment to remove the damage zone or the skin effect are:

2.1. Hydrochloric Acids

HCl acid is used to clean the tubing, the bottom of the well, and the perforations. It is used to dissolve carbonate minerals. HCl reacts with carbonates as follow:

2.1.1. Calcite ($CaCO_3$)

$$2\ HCl + CaCo_3 \longrightarrow CaCl_2\ \text{(calcium chloride)} + H_2O + CO_2 \tag{3}$$

2.1.2. Dolomite ($CaMg(CO_3)_2$)

$$4\ HCl + CaMg(CO_3)_2 \longrightarrow CaCl_2 + MgCl_2 + 2\ H_2O + 2CO_2 \tag{4}$$

2.2. Hydrofluoric-Hydrochloric acid (HF, HCl)

Called Mud acid, Hydrofluoric-Hydrochloric acid is the basic acid solution used for treating sandstone formations. HF-HCl mixtures exist in different formulations such as regular HF acid contains 3% HF-12% HCl, half strength HF acid contains either 1.5% HF-7.5%HCl or 1.5%HF-13.5%HCl, double strength HF acid contains 6%HF-9%HCl. The different reactions that can take place when mud acid is in contact with matrix are:

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2.2.1 Reaction with silica (quartz)

$$SiO_2 + 4HF \rightleftharpoons SiF_4 \text{ (silicon tetrafluoride)} + 2H2O \quad (5)$$

$$SiF_4 + 2HF \rightleftharpoons H_2SiF_6 \text{ (fluosilisic acid)} \quad (6)$$

2.2.2. Reaction with calcite

$$CaCo_3 + 2\ HF \rightarrow CaF_2 \text{ (calcium fluoride, precipitate)} + H_2O + CO_2 \quad (7)$$

2.2.3. Reaction with silicates (Na_4SiO_4)

$$Na_4\ SiO_4 + 8\ HF \rightleftharpoons SiF4 + 4NaF + 4H_2O \quad (8)$$

$$2NaF + SiF_4 \rightleftharpoons Na_2SiF6 \text{ (precipitate)} \quad (9)$$

$$2HF + SiF_4 \rightleftharpoons H_2SiF_6 \quad (10)$$

2.2.4. Reaction with Albite

$$NaAlSi_3O_8 + 22HF \rightleftharpoons 3H_2SiF_6 + AlF_3 + 8H_2O \quad (11)$$

2.2.5. Reaction with kaolinite

$$Al_4Si_4O_{10}\ (OH)_8 + 24HF + 4H^+ \rightleftharpoons 4AlF_2^+ + 4SiF_4 + 18H_2O \quad (12)$$

2.2.6. Reaction with montmorillonite

$$Al_4Si_8O_{20}\ (OH)_4 + 40HF + 4H^+ \rightleftharpoons 4AlF_2^+ + 8SiF_4 + 24H_2O \quad (13)$$

2.3. Organic acid

The principal reasons for using the organic acids are their lower corrosively and easier inhibition at high temperatures. Among the most common organic acids are acetic acid and formic acid. Additives are used to ameliorate stimulation efficiency and to reduce secondary effects as well as to protect surface and bottom equipment of the wells.

2.3.1. Corrosion Inhibitor*:* It is a chemical used to protect drill pipe, tubing or any other metal that can be in contact with acid during treatment.

2.3.2 Tensioactive Agents: They are used to reduce surface and interfacial tension, ameliorate acid rock contact and acid penetration by reducing capillary pressure, breaking emulsion and dispersing formation fines liberated by acid.

2.3.3 Iron Control Additives: Iron can be generated either from corrosion deposits formed on the surface of the tubing or soluble formation minerals after injection. Iron precipitation problems occur when pH increases toward 7.

2.3.4 Diverting Agents: Diverting agent is used with acid and foam to form a relatively low-permeability filter cake on the formation face. This filter face increases the flow resistance and diverts the acid to other parts of the formation where less diverting agent has been deposited

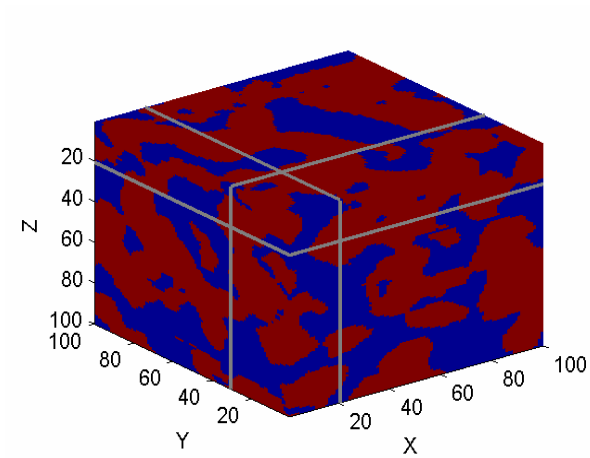
3. Experimental Procedures

3.1. X-Ray Diffraction

X-ray diffraction is an analysis, which allows the determination of the crystalline materials content in the sample [9]. The principal is to shoot an X-ray at a pulverized sample. Then, the diffraction pattern is recorded and the angle of diffraction indicates the crystalline structure of the sample, and hence the mineral content of the sample. Recently CT-Scan, shown in Figure 3, is used for to determine the plugged core sample that can be an indication for the formation damage problems in the porous media. CT-scan produces multiple 2D slice-images of a rock that can then be used to reconstruct the 3D volume. Therefore, it is important to obtain consecutive CT scan slices at high enough resolution to generate a dense array of 2D images. For example, features of interest, i.e., pore throats and cracks, can only be digitally described if the resolution is much smaller than their size. CT scanners can be generally grouped into four categories based on their spatial resolution and the size of an object suitable for scanning, with the most common type being the conventional scanner with resolution on the order of a millimeter. While the ultra-high resolution is in the order of 10 microns and can handle rock samples of up to a few centimeters in diameter.

CT scan employs a micro-focal X-ray source. The system's magnification increases with the specimen's proximity to the X-ray source. The system uses a fixed pixel size in the video image, which allows the user, by varying the magnification, to achieve the needed spatial resolution. In addition, the ability of the micro-focal source to provide a stable X-ray output, even at mean energies of 30-50 keV, permits high-quality discrimination among materials even with significant radiation attenuation. As a result, the mineral grains and epoxy can be easily discriminated from the pore space in the images of the prototypes. Images from CT scanners have been widely used in geosciences, soil sciences and petroleum engineering for direct imaging of fluid flow in pores, as well as for detailed characterization of pore morphology. Figure 3 shows the front and back view of CT scan while Figure 4 shows typical CT scan images for sand prototype.

Figure 3. CT-Scan system.



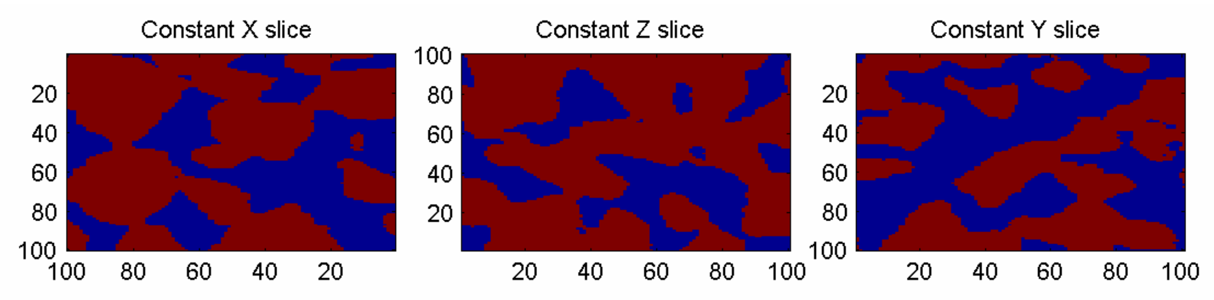


Figure 4. CT scan images.

3.2 Solubility Test

Solubility test is designed to apprehending the reactivity of the formation with acid solution. This test involves drying, crushing, and weighing a portion of 2 gm core sample (W_1). Then the portion of the core sample is treated by 100 ml of acid at T=80°C. The solution is filtrated after one hour and the insoluble material is dried and weighted (W_2). The difference in weights determines the solubility expressed in percentage as follows:

$$S = \frac{W_1 - W_2}{W_1} \tag{14}$$

3.3. Damage Test

Damage test is run to determine the potential of the acidizing process by measuring the clean formation permeability, damaged formation permeability, and the permeability of the formation after acidizing treatment. This test is conducted in 3 stages:

3.3.1. Initial permeability measurement*:* After washing and drying, a core is saturated with inert oil. After draining the inert oil, the measurement of rate is recorded after flow stabilization. The permeability is determined using Darcy law as follow:

$$k = 887.3\,\frac{Q\mu L}{A\Delta P} \tag{15}$$

3.3.2. Damage Test: The damaging fluid (drilling mud) is injected into the core at a pressure of P = 30 Kg_f/cm^2 until the mud filtration seizes. A counter pressure at the outlet of the core is fixed at 10 Kgf/cm^2. After 3 hours of filtration, core sample is cleaned using inert oil.

3.3.3. Final Permeability Measurement*:* Final permeability (k_f) is measured in this test using same conditions as in the initial permeability test. Then, the damage coefficient is given by:

$$C = \frac{k_f - k}{k} \tag{16}$$

3.4. Acidizing Test

The acidizing test is used to investigate the effect of several acid systems on the permeability. The acid flooding system used for this purpose is shown in Figure 5. The test consists of injecting certain volume of acid solution each stage of treatment. Flow rate is recorded after certain part of the total injecting acid volume to calculate the permeability to acid (k_a). The acid response curve (ARC) using (k_a) or (k_a/k) versus injected acid volume is then established as shown in Figure 6. Finally, at the end of the procedure, the final permeability to the inert oil (k_f) is determined under the same conditions used in the determination of the initial permeability. The change of permeability before and after acidizing is expressed by:

$$k_r = \frac{k_f}{k} \tag{17}$$

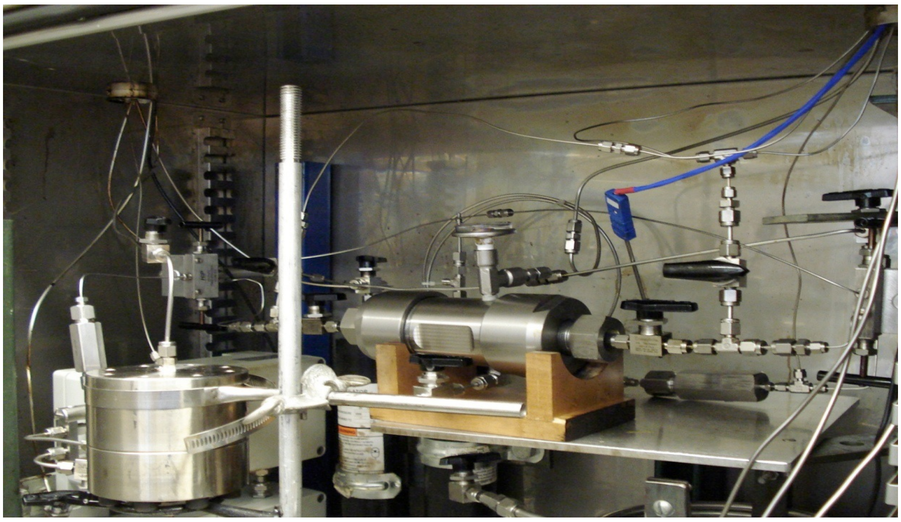


Figure 5. Core acidizing system.

Acidizing test (damage and acidizing tests) system consists of: Core holders (Haussler sleeve) as shown in Figure7, 2-duplex pumps to deliver test fluids, hydraulic pump to provide confining pressure, which prevents the fluid movement around the core, and control system for temperature and pressure.

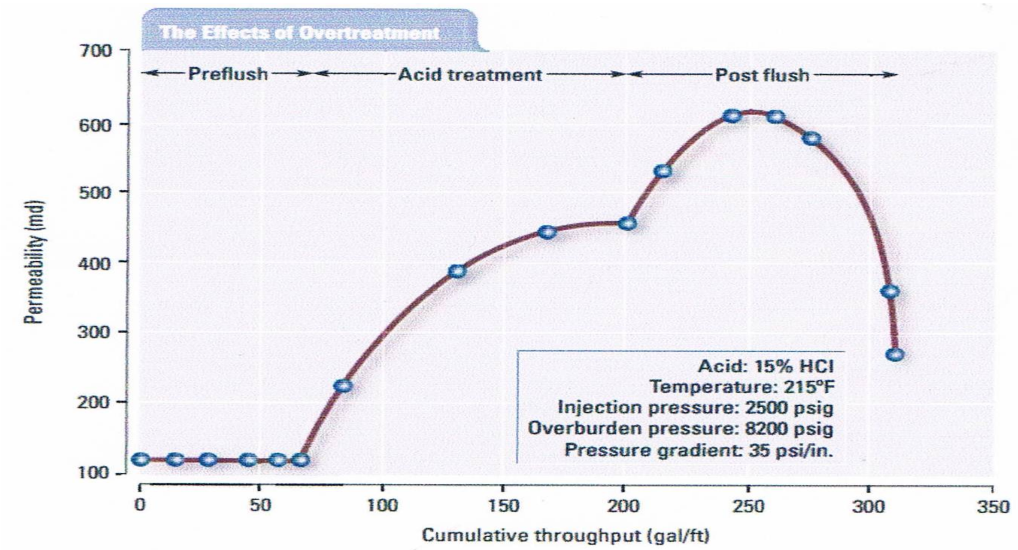


Figure 6. Acid response curve.

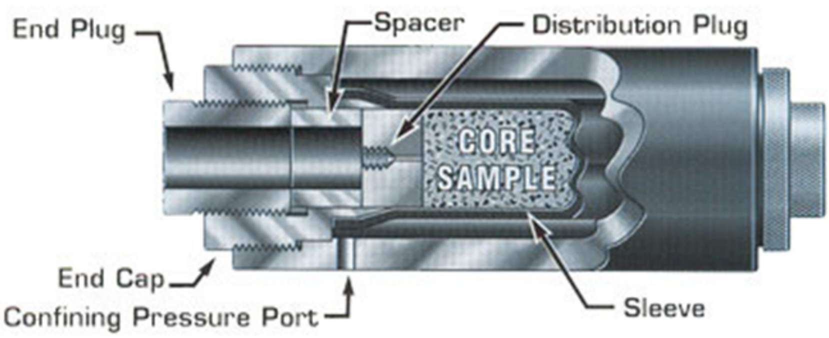


Figure 7. Core holder.

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4. Predicting Optimum Treatment Volume:

After knowing the most appropriate acid system from laboratory study, acid volumes are determined from the acid response curve (ARC) tests of this system. The common method consists of determining the volume of acid per core section from the acid response curves for a certain permeability improvement ratio. Then, by analogy, the required volume for field application can be calculated based on estimated depth of the damage.

4.1. Pre-Flush Volume

This process is used to dissolve minerals and remove iron-based scales from tubulars. It acts as a buffer between the main acidizing fluid and the formation brine. This volume can be determined from the acid response curve (ARC). When ARC tests are not available, pre-flush volume is equal to the half of the main treating acid volume. The pre-flush volume typically is calculated based on one square foot of damaged area; therefore, the total required volume of acid for this process is calculated as follows:

$$A = 2\pi r_d h \tag{18}$$

where:r_d is the damaged area radius. Then, pre-flush volume is obtained by multiplying the area obtained by equation 18 by pre-flush volume. It can be calculated also using the following equation:

$$V_{HCL} = \pi(r_d^2 - r_w^2)h(1-\emptyset)\frac{S}{X} \tag{19}$$

where*:* S = Rock solubility by HCl determined from the solubility tests. X = Dissolving power defined as the volume of rock dissolved per volume of acid reacted.

The dissolving power is calculated as follows:

1- Calculate (β) as the mass of rock dissolved per unit mass of acid reacted:

$$\beta = \frac{(M_w)_m(Sc)_m}{(M_w)_a(Sc)_a} \tag{20}$$

where (Sc) in the above equation is the stoichiometric coefficient obtained from the chemical reaction equation of the mineral (m) and acid(a). For example, the reaction of 100% HCl with dolomite ($CaMg(CO_3)_2$) defined by equation 4:

$$\beta_{100} = \frac{184.3*1}{36.47*4} = 1.263$$

2- For acid concentration less than 100%:

$$\beta_x = \beta_{100}^x \tag{21}$$

where: x is the acid concentration.

3- The dissolving power for the acid concentration of interest is calculated as follows:

$$X = \frac{\rho_a \beta_x}{\rho_m} \tag{22}$$

The pre-flush volume is determined from equation 18 and shown in Figure 8 for one foot of the matrix height $\left((1-\emptyset)h\right)$.

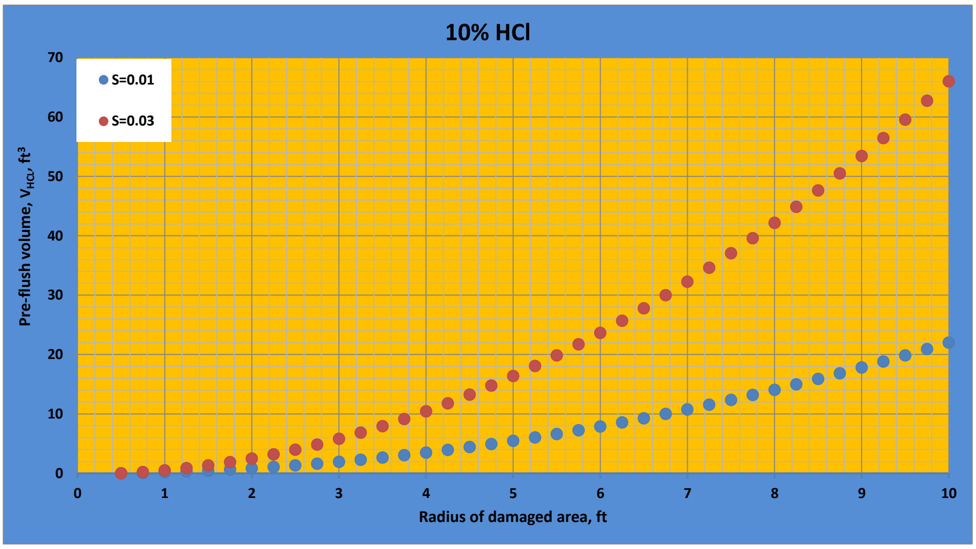

Figure 8: Pre-flush volume for dolomite.

4.2. Treatment volume (Main volume)

The treatment volume is determined based on the permeability ratio. Typically, it is determined from the second stage (Acid treatment) of the ARC. For this purpose, the final permeability of formation after the acidizing process should be determined. Therefore, different permeability ratios for different injected acid volumes are recorded for each acid system throughout the acidizing test. This can be done for different types of formation lithology (mineralogy). Then, several mathematical models might be derived based on formation lithology for each acid system and permeability improvement ratio so that:

$$V = C r_d h \tag{23}$$

where (C) is constant depends on formation lithology and acid system. The treatment volume can also be calculated using the following model:

$$V = \pi\left(r_d^2 - r_w^2\right) h \emptyset \tag{24}$$

The volume of acid required for the main treatment given by equation 24 always less than the volume obtained using ACR. The ACR technique gives more accurate acid volume as it takes into account the type of formation lithology, formation temperature, and acid concentration. However, the ACR technique requires knowing the final permeability of formation after acidizing. Lab test can be used to determine this permeability.

In this study, new technique, shown in Figure 9, is proposed to determine the final permeability. This technique uses current permeability damage ratio (k_D) and current productivity index ratio for the damaged formation (J_d/J) to determine the dimensioned damaged radius (r_{dD}). Then, based on the determined (r_{dD}) and the prospective productivity index ratio for the stimulated formation (J_{st}/J) , the permeability ratio after acidizing is determined (k_r).The required parameters in this techniques are defined as follows:

$$\frac{J_d}{J} = \frac{k_D \ln{(r_{eD})}}{\ln(r_{dD}) + k_D \ln{(r_{DD})}} \qquad \frac{J_{st}}{J} = \frac{k_r \ln{(r_{eD})}}{\ln(r_{dD}) + k_r \ln{(r_{DD})}}$$

$$k_D = \frac{k_d}{k}, \qquad r_{eD} = \frac{r_e}{r_w}, \qquad r_{dD} = \frac{r_d}{r_w}, \qquad r_{DD} = \frac{r_e}{r_d}$$

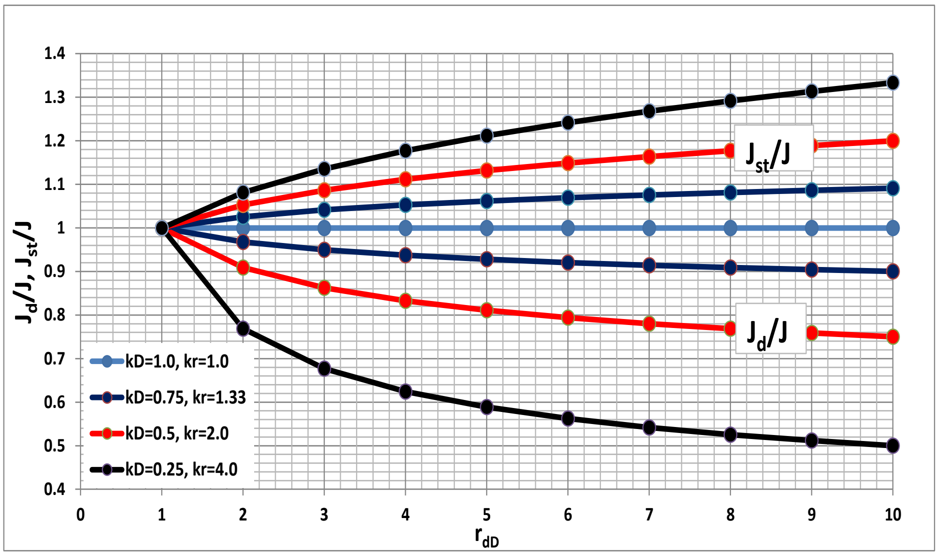

Figure 9: Permeability ratios before and after acidizing.

It can be inferred from Figure 9 that productivity index after acidizing process can be increased significantly. For the same radius of damage, the great improvement in wells productivity can be more than double assuming that damage ratio in permeability before acid stimulation is (0.25). The permeability in this case can be increased more than 16 times from the damaged or initial permeability before treatment.

5. Conclusions

Matrix acidizing is suitable stimulation tool for damaged formations. It is more applicable for carbonate reservoirs where HCl acid systems and HCl-HF acid solutions can be used effectively to remove the damage reasons. In this process, pre-flush volume can be estimated using the ARC or some mathematical models provided in the research paper. These models depend on the damage area radius, lithology of the formation, and acid system. Main treatment volume is estimated also from the ARC or calculated from mathematical models derived for several lithologies, acid system and damage area radius. Main treatment volume depends on the permeability improvement ratio that can be determined experimentally for different acid systems. This study proposed new technique for calculating this ratio.

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