Effects of EDTA and Phosphate Concentrations on Sandstone Permeability: A Multiple Linear Regression Analysis

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Abstract.
Permeability determines how readily fluids can move through reservoir rock, and any reduction caused by formation damage may directly affect well productivity. This study examined the effect of a completion fluid containing EDTA (ethylenediaminetetraacetic acid) and sodium phosphate (Na_3PO_4) on sandstone permeability and evaluated the experimental results using multiple linear regression. Laboratory tests were performed on two sandstone core plugs, S-1 and S-2, with initial effective oil permeabilities (Ko) of 9.9784 mD and 13.4409 mD and porosities of 19.52% and 19.23%, respectively. Three fluid formulations were tested: CF-1 (5% phosphate + 10% EDTA), CF-2 (10% phosphate + 10% EDTA), and CF-3 (15% phosphate + 10% EDTA). After each injection, the samples were aged for 24 hours, and permeability was measured with a Hassler Core Holder using a modified form of Darcy's law. The regression analysis produced the model $Y = 0.148 + 1.476X_1 + 5.447X_2$, with $R^2 = 0.9794$ and an F-statistic of 71.37 ($p < 0.0001$). Within the model, phosphate accounted for an estimated 78.7% of the permeability improvement, while EDTA accounted for 21.3%. The highest Ko values were obtained with CF-3: S-1 increased from 9.9784 to 19.4885 mD (+95.31%), and S-2 increased from 13.4409 to 26.0651 mD (+93.92%). Incremental improvement decreased from an average of 40.15% at CF-1 to 23.71% at CF-2 and 12.26% at CF-3, indicating diminishing marginal gains at higher phosphate concentrations. Porosity remained unchanged during the injection sequence, suggesting that the increase in permeability was associated with the removal of material restricting pore throats rather than an increase in pore volume. These results support the potential use of the phosphate-EDTA system for formation treatment and completion-fluid optimization within the tested concentration range.
Keywords: *EDTA; phosphate; sandstone permeability; formation damage; multiple linear regression; completion fluid and pore throat cleaning.*

I. INTRODUCTION

Permeability is a central parameter in petroleum reservoir engineering because it describes the ability of a rock to transmit fluids under a pressure gradient. During drilling, completion, and production, this property may decline as a result of formation damage. Such damage can arise from secondary mineral precipitation, invasion of drilling-fluid filtrate, fine-particle migration, or clay swelling after contact with injected aqueous fluids [1]. When these processes restrict the pore network, well productivity and hydrocarbon recovery can also decrease. Chemical stimulation is therefore commonly considered when permeability needs to be restored. EDTA (ethylenediaminetetraacetic acid, $C_{10}H_{16}N_2O_8$) is a chelating agent that forms stable, water-soluble complexes with polyvalent ions such as Ca^{2+}, Mg^{2+}, Fe^{3+}, and Al^{3+} [2]. By binding these ions, EDTA can help dissolve scale and mineral deposits that obstruct fluid-flow paths. Sodium phosphate (Na_3PO_4), meanwhile, can help regulate pH and limit the re-precipitation of secondary deposits during treatment [3, 4].

Previous laboratory studies have reported permeability increases of approximately 30-95% after EDTA-based treatment, although the response depends on the rock mineralogy, chemical concentration, and contact time [2, 5, 6]. Mahmoud [7] found that EDTA reacted selectively with sandstone minerals, particularly carbonate cement, while leaving the silica-grain framework largely unaffected. Shafiq et al. [5] also showed that the performance of chelating agents during acidizing varied with the mineralogical characteristics of conventional and tight sandstones. Similar observations were reported by Hassan et al. [6], who identified improved oil recovery from sandstone reservoirs treated with chelating-agent salts.

Although these studies provide useful evidence, many report the experimental response descriptively and do not develop a statistical relationship between chemical concentration and permeability improvement. This limits their direct use when selecting treatment concentrations for field applications. The present study addresses this need by applying ordinary least squares multiple linear regression to laboratory core-flooding data. The study has three objectives: (1) to examine the effect of phosphate concentration on sandstone permeability while EDTA is maintained at 10% as a pH-control component; (2) to estimate the relative contributions of EDTA and phosphate in the regression model; and (3) to develop the empirical relationship $Y = \beta_0 + \beta_1 X_1 + \beta_2 X_2 + \varepsilon$ as a basis for evaluating completion-fluid formulations in oil and gas well operations.

II. LITERATURE REVIEW

2.1. Permeability and Formation Damage in Sandstone Reservoirs

Darcy's law defines permeability (K) as the proportionality factor that relates fluid flow to the pressure gradient across a porous medium [1]:

$$\mathbf{K = (Q \times \mu \times L) / (A \times \Delta P)} \quad \dots (1)$$

where K is permeability (mD), Q is the volumetric flow rate (cm^3/s), μ is fluid viscosity (cp), L is sample length (cm), A is cross-sectional area (cm^2), and ΔP is the pressure difference (atm). In sandstone, permeability is influenced by pore geometry, grain-size distribution, cementation, and the degree of connection between pore throats. The Kozeny-Carman relationship, $k = (\Phi^3 / [S^2(1-\Phi)^2]) \times C$, illustrates why porosity alone does not determine permeability: a rock may contain substantial pore volume but still transmit fluid poorly when its pore throats are narrow or weakly connected [1].

2.2. Chemical Stimulation with EDTA and Phosphate

EDTA is a multidentate chelating agent that can form stable 1:1 complexes with divalent and trivalent metal cations through six coordination sites. In sandstone treatment, it can react with carbonate cements, including calcite and dolomite, as well as iron-bearing scale such as $Fe(OH)_3$ and FeOOH that may obstruct pore throats [7]. Unlike conventional hydrochloric-acid systems, the chelation process does not depend on the direct release of corrosive protons. Parhizgar Keradeh and Tabatabaei-Nezhad [8] reported that EDTA/seawater flooding improved oil recovery in sandstone while also reducing problems associated with scale re-precipitation.

Sodium phosphate (Na_3PO_4) may contribute to permeability improvement in two ways. First, phosphate-mineral interactions can assist in removing siliceous and calcareous material from pore spaces. Second, the solution can buffer the pH at approximately 6, a condition intended to support EDTA chelation while reducing the likelihood of secondary carbonate precipitation [3, 4]. Earlier work has associated combined EDTA-phosphate treatment with permeability improvements of 30-50% in carbonate-bearing sandstone at moderate concentrations [9]. Larger gains may occur when the initial cores contain more extensive mineral deposits or other forms of formation damage.

2.3. Multiple Linear Regression in Experimental Reservoir Studies

Multiple linear regression (MLR) is used to estimate the relationship between one dependent variable and two or more predictors [10]. Under the ordinary least squares (OLS) approach, model coefficients are selected by minimizing the sum of squared residuals. When the Gauss-Markov assumptions are satisfied, the resulting coefficients are interpreted as Best Linear Unbiased Estimators (BLUE). Model performance is commonly described using the coefficient of determination (R^2), which indicates the proportion of variation in the response explained by the predictors, and the F-statistic, which evaluates the overall regression. In core-flooding experiments, this approach can provide an empirical link between treatment variables and the observed rock-fluid response [11].

III. METHODS

3.1. Sample Characteristics and Experimental Design

Two sandstone core plugs, designated S-1 and S-2, were obtained from the Reservoir Rock Analysis Laboratory, Department of Petroleum Engineering, Universitas Trisakti. Their dimensions were measured using digital calipers, and porosity-related properties were determined with a helium porosimeter. The initial physical properties of the two samples are summarized in Table 1.

Table 1. Initial Physical Characteristics of Sandstone Core Samples

Parameter	Unit	S-1	S-2
Length	cm	3.70	4.20
Diameter	cm	2.60	2.60
Bulk Volume	cc	19.64	22.30
Pore Volume	cc	3.83	4.29
Porosity (φ)	%	19.52	19.23
Dry Weight	gr	40.73	45.89
Grain Density	gr/cc	2.58	2.55
Initial Ko (oil permeability)	mD	9.9784	13.4409
Initial Kw (water permeability)	mD	7.4257	8.3635
Porosity Classification	—	Very Good	Very Good

3.2. Completion Fluid Composition

Three completion-fluid formulations were prepared by setting the sodium phosphate (Na_3PO_4) concentration at 5%, 10%, and 15% for CF-1, CF-2, and CF-3, respectively. EDTA was maintained at 10% in all formulations and used as a pH-control additive, with a target pH of approximately 6. Table 2 lists the measured fluid properties. The crude oil used for the permeability measurements had a viscosity of 5.049 cp and a specific gravity of 0.864.

Table 2. Physicochemical Properties of Completion Fluid Scenarios

Fluid Scenario	Phosphate (%)	EDTA (%)	Viscosity (cp)	Specific Gravity
CF-1 (5% PO_4 + 10% EDTA)	5	10	1.01	1.090
CF-2 (10% PO_4 + 10% EDTA)	10	10	1.04	1.112
CF-3 (15% PO_4 + 10% EDTA)	15	10	1.05	1.178
Crude Oil (reference)	—	—	5.049	0.864

3.3. Experimental Procedure

The experiment was carried out in four stages. First, each core was dried at 80°C for 24 hours. Baseline oil and water permeabilities (Ko and Kw) were then measured with a Hassler Core Holder at a pressure differential of 20 psi and an overburden pressure of 200 psi; 12 flow-rate readings were recorded for each stage. Second, the completion fluid was injected in the reverse-flow direction at low pressure to minimize the risk of mechanical damage to the core. Third, the treated samples were aged in the injected fluid for 24 hours. Finally, Ko was measured again under the same operating conditions used for the baseline test. Permeability was calculated using the modified Darcy equation:

$$\mathbf{K = (14700 \times Vol \times \mu \times L) / (\Delta t \times \Delta P \times A)} \quad \dots (2)$$

3.4. Multiple Linear Regression Analysis

The response variable, Y, was defined as the cumulative percentage recovery of oil permeability relative to the baseline value: $Y = [(Ko_2 - Ko_1)/Ko_1] \times 100\%$. The predictors were X_1, representing EDTA concentration, which was fixed at 10%, and X_2, representing phosphate concentration at 5%, 10%, or 15%. The dataset contained six observations, obtained from two core samples tested at three phosphate concentrations. OLS regression was performed using the Data Analysis ToolPak in Microsoft Excel. The model was evaluated using R^2, adjusted R^2, the F-statistic, and individual t-tests with $\alpha = 0.05$.

IV. RESULTS AND DISCUSSION

4.1. Permeability Response to Phosphate-EDTA Injection

Table 3 compares the oil-permeability measurements obtained before and after each completion-fluid treatment. Both core samples showed a consistent increase in Ko as the phosphate concentration increased, indicating that the phosphate-EDTA formulations improved fluid flow through the tested sandstone samples.

Table 3. Oil Permeability (Ko) Before and After Completion Fluid Injection

Scenario	Ko S-1 Initial (mD)	Ko S-1 Final (mD)	Ko S-2 Initial (mD)	Ko S-2 Final (mD)	ΔKo S-1 (%)*
Baseline	9.9784	—	13.4409	—	—
CF-1 (5%)	9.9784	14.1645	13.4409	18.5946	41.95
CF-2 (10%)	9.9784	17.4865	13.4409	23.0521	75.24
CF-3 (15%)	9.9784	19.4885	13.4409	26.0651	95.31

** Cumulative ΔKo (%) calculated from baseline. S-2 cumulative values: CF-1: 38.34%, CF-2: 71.51%, CF-3: 93.92%.*

The highest oil permeability was measured after treatment with CF-3. For S-1, Ko increased from 9.9784 mD to 19.4885 mD, corresponding to a 95.31% increase. For S-2, Ko increased from 13.4409 mD to 26.0651 mD, or 93.92%. These values are above the 30-50% range reported by Al-Hadhrami et al. [9]. One possible explanation is that the test cores initially contained a greater degree of formation damage, allowing more obstructing material to be removed during treatment. The stronger response may also be related to the buffering effect of the 15% phosphate formulation. Although S-2 retained the higher absolute Ko throughout the experiment, its percentage increase at CF-1 was slightly lower than that of S-1 (38.34% compared with 41.95%). This suggests that the lower-permeability sample responded somewhat more strongly to the first treatment stage.

Porosity did not change during the injection sequence and remained at 19.52% for S-1 and 19.23% for S-2. This observation suggests that the permeability increase was primarily associated with improved pore-throat connectivity, most likely through the removal of mineral deposits at flow constrictions, rather than an increase in total pore volume. The interpretation is consistent with the findings of Sa'adah et al. [12] and with the general concept of percolation-threshold behavior in porous media.

4.2. Incremental Efficiency and Diminishing Marginal Returns

Table 4 shows the incremental improvement in Ko between consecutive treatment stages. The percentage recovery for each stage was calculated as $\%Recovery = [(Ko_2 - Ko_1)/Ko_1] \times 100\%$, where Ko_1 is the permeability measured after the preceding stage.

Table 4. Incremental Ko Enhancement per Injection Stage

Injection Stage	ΔKo S-1 (%)	ΔKo S-2 (%)	Average (%)	Mechanism
CF-1 vs. Baseline (5%→0%)	41.95	38.34	**40.15**	Soft damage dissolution
CF-2 vs. CF-1 (10%→5%)	23.45	23.97	**23.71**	Resistant mineral layer
CF-3 vs. CF-2 (15%→10%)	11.45	13.07	**12.26**	Pore saturation threshold

The incremental response decreased as the phosphate concentration increased. The mean gain was 40.15% for CF-1, 23.71% for CF-2, and 12.26% for CF-3. This pattern can be understood in terms of the progressive removal of formation damage. At 5% phosphate, the treatment may preferentially remove loosely bound carbonate deposits and drilling-fluid residues that are relatively easy to dissolve. After this material has been removed, the remaining obstructions are likely to contain more resistant mineral phases, such as kaolinite and illite, which may explain the lower incremental response at 10% phosphate. By the 15% stage, many of the accessible pore throats may already have been cleared, leaving less material available for further removal and producing a smaller hydraulic gain [12]. From an operational perspective, the 5% formulation provided the largest increase per treatment stage, whereas the higher concentrations produced additional, but progressively smaller, improvements.

Water permeability followed a similar trend. After CF-3 treatment, Kw increased from 7.4257 mD to 13.2363 mD for S-1 (+78.25%) and from 8.3635 mD to 15.0643 mD for S-2 (+80.12%). The response in both oil and water permeability indicates that the treatment improved the connected flow paths available to both fluids.

4.3. Multiple Linear Regression Model

The six observations used to construct the OLS model are presented in Table 5.

Table 5. Regression Dataset: Independent Variables and % Recovery Ko (Y)

Obs.	X_1: EDTA (%)	X_2: Phosphate (%)	Sample	Y: % Recovery Ko (cumulative)
1	10	5	S-1	41.95
2	10	10	S-1	75.24
3	10	15	S-1	95.31
4	10	5	S-2	38.34
5	10	10	S-2	71.51
6	10	15	S-2	93.92

The OLS analysis produced the following empirical model:

$$\mathbf{Y = 0.148 + 1.476\ X_1 + 5.447\ X_2 \quad \ldots (3)}$$

A summary of the regression results is provided in Table 6.

Table 6. Statistical Summary of the Multiple Linear Regression Model

Statistical Parameter	Value	Std. Error	t-stat	p-value	Interpretation
β_0 (Intercept)	0.148	4.888	0.030	0.977	Intercept not statistically significant
β_1 (EDTA coefficient, X_1)	1.476	0.489	3.028	0.054	Significant at $\alpha = 0.10$; estimated relative contribution 21.3%
β_2 (Phosphate coeff., X_2)	5.447	0.456	11.948	<0.001	Statistically significant; estimated relative contribution 78.7%
R^2	0.9794	—	—	—	Model explains 97.94% of observed variance
R^2 Adjusted	0.9657	—	—	—	Adjusted for the number of predictors
F-statistic (ANOVA)	71.37	—	—	<0.0001	Overall regression statistically significant

The regression produced an R^2 value of 0.9794, meaning that the model accounted for 97.94% of the observed variation in permeability recovery. The overall F-statistic was 71.37 ($p < 0.0001$), indicating a statistically significant relationship between the predictors included in the model and the response variable [10]. The phosphate coefficient ($\beta_2 = 5.447$) was larger than the EDTA coefficient ($\beta_1 = 1.476$). On the basis of the model, phosphate was assigned an estimated relative contribution of 78.7%, while EDTA accounted for 21.3%. In the proposed treatment mechanism, EDTA supports the process by binding metal ions released during mineral dissolution and reducing their potential to precipitate again within the pore network [6, 7].

The interpretation of the EDTA coefficient requires caution because X_1 was fixed at 10% in every observation. As a result, the coefficient represents a model-estimated effect at that fixed formulation rather than a response derived from experimentally varying the EDTA concentration. The reported 21.3%

contribution should therefore be understood as a baseline estimate associated with the presence of 10% EDTA. A fully crossed factorial design, in which both EDTA and phosphate concentrations are varied independently, would be needed to assess the EDTA effect more directly [5].
The residual differences between the measured and predicted values ranged from -3.80 to +5.86 percentage points and did not show an evident systematic pattern, which is consistent with the assumption of homoscedasticity [10]. The model should nevertheless be applied only within the conditions represented by the experiment: phosphate concentrations of 5-15%, EDTA at 10%, sandstone porosity of approximately 19%, and initial Ko values of about 9-14 mD. Predictions outside these ranges would require further laboratory validation.

V. CONCLUSION

This study examined changes in sandstone permeability after treatment with phosphate-EDTA completion fluids and used multiple linear regression to describe the experimental response. The main findings are summarized below:
(1) The regression model $\mathbf{Y = 0.148 + 1.476X_1 + 5.447X_2}$ produced $\mathbf{R^2 = 0.9794}$ **and** $\mathbf{F = 71.37}$ **(**$\mathbf{p < 0.0001}$**),** accounting for **97.94%** of the observed variation in **Ko** recovery.
(2) Within the fitted model, sodium phosphate **(**$\mathbf{Na_3PO_4}$**)** had an estimated relative contribution of **78.7%,** while **EDTA** accounted for **21.3**% in its role as a chelating and pH-control component.
(3) The greatest improvement was obtained with **CF-3 (15% phosphate + 10% EDTA). Ko** increased by **95.31%** in **S-1 (9.9784 to 19.4885 mD) and by 93.92%** in **S-2 (13.4409 to 26.0651 mD).**
(4) The average incremental improvement decreased from **40.15%** at **CF-1** to **23.71%** at **CF-2** and **12.26%** at **CF-3.** Thus, the **5%** phosphate formulation produced the largest gain per treatment stage, while higher concentrations provided smaller additional improvements.
(5) Porosity remained unchanged at **19.52%** for **S-1** and **19.23%** for **S-2.** This supports the interpretation that the increase in permeability resulted mainly from improved pore-throat connectivity rather than expansion of the total pore volume.
(6) The empirical model may be used as an initial reference for completion-fluid optimization under conditions similar to those tested, namely phosphate concentrations of **5-15%, EDTA at 10%,** and sandstone porosity of approximately **19%.**

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