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New Equations of Water Block in Oil Wells

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Abstract
Water block or invasion of water into the pores of reservoir forms during the operations of water-based drilling, injection, many perforations, completion fluids and some other particular processes in the reservoir (such as fingering and conning). Under these circumstances, the deformation of the fine particles such a clay (water-wet solids) in the flow path of second phase can decrease the permeability of reservoir. Therefore, the solvents such as surfactants (as demulsifiers) are utilized to lower the surface tension as a phenomenon associated with intermolecular forces (known as capillary action) during flowback, avoiding the formation of emulsions and sludges in the mostly near-wellbore zone or under-treatment and under-injection radii of the reservoir. However, besides surging or swabbing the wells to decrease the surface tension, the use of these solvents as the agent changing of wettability along with base fluid is a common method in removing water block from the wellbore, especially in the low permeability reservoirs or the reservoirs latter confronted with average pressure less than bubble point. For an optimum result of these solvents after using them in the wells with various reservoir characterizations, it needs determining the trend of their behavior variations in the different lithologies and evaluating the removed damages. The previous findings on this subject are only a couple of experimental investigations and so far have not been introduced any equation for this type of damage in the water, oil and gas reservoirs. As a result, the limitations are an integrated methodology in order to interpret the interactions of fluid and rock after injecting acids and other fluids for estimating the removed water block. In these evaluations has been applied the acid expanding ability (I_k) for a definite oil layer around the wellbore using the full characteristics of reservoir (including overburden pressure correlations), producing well history and the acidic and alkaline solvents properties. Afterwards, the equations incorporated in the framework of the petrophysic and geologic data of field and the different geologic elements based on core flooding displacement experiments have separately obtained for two groups of the wells with the oil-wet and water-wet wettability for calculating the removed water block (B_k). Finally, the rate of forming water block (q) is also calculated using the value calculated for the removed water block and also the trend of using these solvents is determined for different lithologies using these set of equations. The entire of these acceptance criteria are based on the nature of the rock and fluid in the reservoir circumstances. These equations as a fast and cost effective approach are also introduced so as to provide computational methods so that determine how much and how the blocked fluid is removed from the definite strata around the wellbore after injecting acids and solvents with the various acidities to different lithologies during the acidizing operations.

Key Words and Phrases
Defined Oil Layer, Overburden Pressure, Fundamental Equations of Water Block, Experimental and Field Data, Solvents in Acidizing.

1. Investigation Background

The compatibility of lithology with the acid needs to be handled before the process of acidizing, in which base fluids mixed with additive solvents are injected, avoiding a net loss in well productivity. In the procedure of additives, use of mutual solvents such as alcohols and surfactants (as wetting agents for decreasing surface tension of the acid and subsequently better penetration in the matrix of the rock) should to be conducted according to the previous determined percents for any lithology of the reservoir so that wettbility changes provide the stable conditions for existing phases and control losing of oil–based phases to the formation. The work on water block in the previous literature is in the form of experimental investigations [1], [2], [3], [4] and an integrated method needs to predict the outcome of the interactions of fluid and rock after injecting acids and other fluids mixed with the wetting agents that aimed at dissolving the water blocked in the oil wells. For this goal, it is imperative finding the exact rock characteristics and the injected and in-situ fluids behavior data in the reservoir. In other words, investigation is also introduced so as to provide computational methods so that determine how much and how the blocked fluid is removed from the definite strata to the specific lithology during injecting solvents. In Fig. 1, the quantitative and qualitative studies of layer structural characteristics such as inter-granular space (IGS), inter-fracture space (IFS) and fracture width (FW), which have been already applied in a definite layer's equation of overburden pressure, are also utilized in this research to conclude on the equations of removed water block (B_k). Therefore, in the theory of investigation, the effects of various variables on the water block and overburden pressure are presented that each of them represents the fluid and rock behavior. As denoted in Fig.1, for this goal, first, quantitative-structural characteristics classification is summarized, second, the overburden pressure as a function of the subsurface physical parameters that demonstrated its own role in making water block is presented, third, the theory of the subject matter of water block in the reservoir is discussed and immediately the experimental and field information (including experimental theory, experimental tests, field tests) are presented to be concluded the novel equations of water block, and finally, the role of the minerals of the reservoir rock on the injected fluids and the quantity of each variable are discussed.

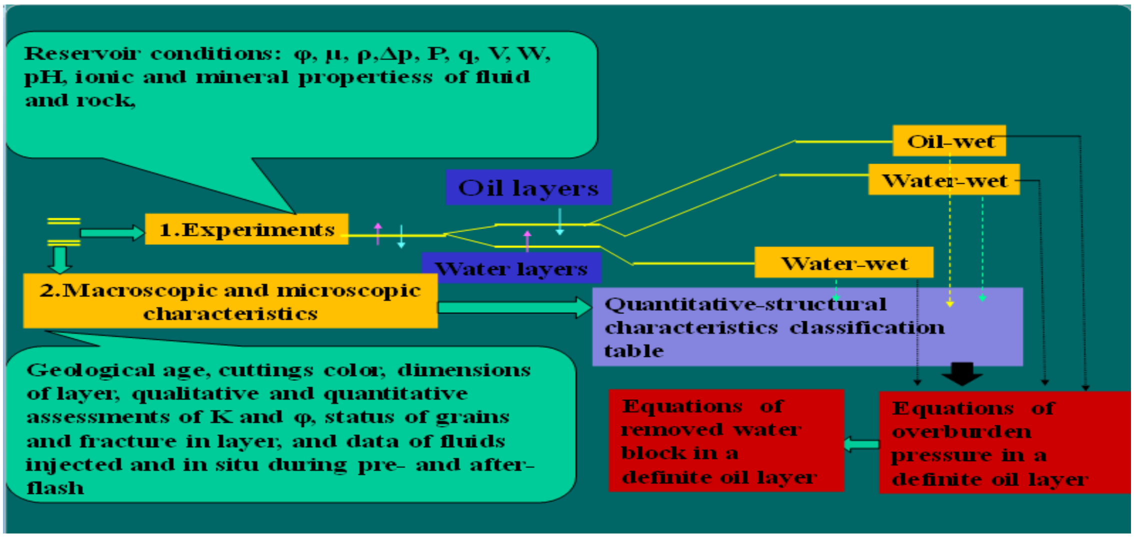


Fig. 1 The total process of equations of the removed water block in the oil wells.

2. Quantitative-Structural Characteristics Classification Table in Reservoir

These physical quantities of the inter-granular space (IGS), inter-fracture space (IFS) and fracture width (FW) according to Table 1 have been applied in the equation of overburden pressure that we intend to briefly explain the method of using it in various lithologies. These quantities in the framework of the three structural classifications can also take into account the effect of the severity of particles migration in different porosities. Additionally, in these quantities is considered the effect of the present of carbonate cement or clay in the layer on the damages such as water block, phase trapping and any other obstacle caused by rock and fluid. [5].

Table1 Estimation of IGS (d_1), IFS (d_2) and FW (d_3) in hydrocarbon reservoirs.

ID	Lithology	IGS, m	ID	Lithology	IGS, m	
1	Coarse particles	5×10^{-2} to10^{-2}	5	L/ D	6.5×10^{-5} to 7.5×10^{-6}	
2	Fine S	10^{-2} to 2.5×10^{-3}	6	S with SH	7.5×10^{-6} to 10^{-7}	S:sand
3	S with L / D	2.5×10^{-3} to 5.5×10^{-4}	7	SH/clay	$< 10^{-7}$	D:dolomite
4	S with L/ D/SH	5.5×10^{-4} to 6.5×10^{-5}	Inter-granular space: (IGS) or d_1			L:limestone
						SH:shale
ID	Lithology	IFS, m	ID	Lithology	IFS, m	-------------
1	Coarse particles	2.5×10^{-2} to 10^{-2}	5	L/ D	10^{-5} to 10^{-6}	-Inter-granular
2	Fine S	10^{-2} to 10^{-3}	6	S with SH	10^{-6} to 10^{-7}	space: (IGS) or d_1
3	S with L / D	10^{-3} to 5.5×0^{-4}	7	SH/clay	$< 10^{-7}$	-Inter-fracture
4	S with L/ D/SH	5.5×10^{-4} to 10^{-5}	Inter-fracture space: (IFS) or d_2			space: (IFS) or d_2.
						-Fracture width:
ID	Lithology	FW ,m2	ID	Lithology	FW ,m	(FW) or d_3,
1	Coarse particles	$<10^{-7}$	5	S with L/D	10^{-4} to 10^{-5}	-------------------
2	Coarse S	10^{-6} to 10^{-7}	6	S with SH	10^{-3} to 10^{-4}	
3	Fine S	5.5×10^{-5} to 10^{-6}	7	L/D	10^{-2} to 10^{-3}	
4	S with L/ D/SH	5.5×10^{-4} to 10^{-5}	8	Sh/clay	$> 10^{-2}$	
			Fracture width: (FW) or d_3			

*d_1 and d_2 are the average of per range in each ID. For d_3 have : d_3= 100%(0.1M) $5<\varphi\leq 15.5$, d_3= 30 %(0.1M) $20.5<\varphi\leq 25$, d_3= 50 %(0.1M) $15.5<\varphi\leq 20.5$, $M=(d_{max}-d_{mim}/d_{max})$

3. Equation of Overburden Pressure in a Layer with Dimensions Defined and Formation Damages

This section summarily describes how overburden pressure, as expressed in equation below, affects the formation damages. The overburden pressure can influence the types of physical quantities (e.g., porosity and permeability) in the rock types during underground interactions. Due to the great variability of the carbonate rocks, these rocks are the most difficult to understand and interpret. On the other hand, in these rocks the pressure can range in various levels and change the fluids distribution in the pores with various sizes. Hence the overburden pressure influences on these physical parameters, especially, as the fluids movements and tectonic displacements occur in the under pressure depths. The experimental results of the overburden pressure effect on these physical parameters show a decrease in porosity and permeability with increase in overburden pressure of reservoirs [6], [7], as these variations are observed in the equation of overburden pressure in the next sections. Overburden pressure can provide the forming of water block to altering the media and its fluid contained. For example, in the dual medium reservoirs, permeability reduction due to reservoir overburden pressure can give rise to the appropriate media for forming the water block [8], [9] or during the drilling operations the invasion depth of fluid injected increases with overbalance pressure [10]. But how these forces change the physical characteristics of the exposed section of formation adjacent to the wellbore, it relates to the subsurface processes that displace the particles while flowing fluids through which and could be determined through the laboratory values profiles (eg., density and porosity versus depth). These subsurface forces exerted of fluid and rock on the small drilled or damaged point or on the major underground dimensions could naturally alter the layers pressure and other physical characteristics [11], [12}. Therefore, the classification of overburden pressure based on porosity (section 3 of paper) has been used in the equations of the removed water block.

This equation has been defined for the overburden pressure of a definite and delimited sectional area that here are applied in the calculations of the removed water block (B_k) in the oil wells. Therefore, the removed water block is a function of the overburden pressure of a definite and delimited sectional area according to the subsequent sections. The detailed and accurate information on the equation of overburden pressure can be found in reference [13].These pressure variations for three groups of rocks given by (3.1) as follows:

$$P_{ob} = \frac{1}{A}\left|\frac{C_1\sqrt{W_d}\sqrt{\rho_r g}h\sqrt{(\frac{\mu_o+\mu_w}{\mu_w})}\sqrt{\frac{t_1+t}{(t_1-t)}}}{d_1\sqrt{\frac{d_1^{\,2}}{d_2}}}\right| + \frac{1}{A}\left|C_2(W_W+W_o)\frac{d_2}{d_1 d_3^{\,2}}\right| + \frac{1}{A}\left|\frac{C_3 W_d}{d_3^{\,2}}\right| \qquad (3.1)$$

Where: $C_1 = 0.2;\ C_2 = 1.10;\ C_3 = 4.6\times10^{+2}\quad d_3 = 100\%(0.1M);5<\varphi\leq 15.5$

$C_1 = 0.17; C_2 = 1.15; C_3 = 4.4\times10^{+2}\qquad d_3 = 50\%(0.1M);15.5<\varphi\leq 20.5$

$C_1 = 0.15;\ C_2 = 1.20;\ C_3 = 4.3\times10^{+2}\qquad d_3 = 30\%(0.1M)\quad ;20.5<\varphi\leq 25\qquad M = \left(\frac{d_{\max}-d_{mim}}{d_{\max}}\right)$

$$\text{If } T<176^0\text{F then } \mu_o@T^0 = \mu_0 - 22pH_0@60^0F\times\frac{(176^0F-T^o)}{60^0F}[(\rho_o@60^0 - \rho_o@T^0)/\rho_o@60^0] \text{ and } \mu_0 = \mu_o@60^0F, \qquad (3.2)$$

$$\text{If } T\geq 176^0\text{F then } \mu_o@T^0 = \mu_0 - 17pH_0@60^0F\times\frac{(T^0-176^0F)}{60^0F}[(\rho_o@60^0 - \rho_o@T^0)/\rho_o@60^0] \text{ and } \mu_0 = \mu_o@176^0F, \qquad (3.3)$$

Units in the equation of overburden pressure: Where P_{ob} is overburden pressure (bar), C_1, C_2 and C_3 are the constants in which the C_1 and C_3 relate the W_d (dry layer weight) and their values and also their effect on P_{ob} is maximum in the oil layers with low porosity, but C_2 relates the fluids weight (W_w+W_o) and its value and also its effect on P_{ob} is minimum in the low porosity oil layers. Therefore, the constants values would change with the different sets of rocks in the determined porosities at above. A is a unit conversion factor from kg_f to bar, and equals to 10197.162. φ is porosity (%) and g is the acceleration of gravity(kg/m^3). ρ_r is the rock density (kg/m^3), and the ρ_o and ρ_w are the oil and water densities (kg/m^3), respectively. $\rho_r = W_d/(V_b-V_p)$ at which V_b=bulk volume (m^3), V_p=empty spaces volume (m^3) and W_d=dry weight of desired sectional area (k_{gf}). h is the depth of layer from the earth surface (m) and t is the geological age of favorite layer on the million years (my), at which t_1 is the lower layer age. d_1 and d_2 are, respectively, inter-granular space and inter-fracture space (matrix media or distance between fractures) on the meter, whereas the d_3 is fracture width (m). d_{max} and d_{mim} in (3.1) are maximum and minimum of the fracture width in each lithilogy which obtain from table 1. μ_o in eqs (3.2) and (3.3) is the viscosity of oil (kg/m-sec) in an oil layer under reservoir temperature (^{0}F) and in which the pH is oil acidity which is usually constant.

4. Water Block and Formation

In this section are studied the characteristics of layer such as rock transmissibility, effect of pathways on the fluids conductivity and particles, and the other physical variables in underground conditions. The previously carried out studies discern the water block subject matter from the other damages. For example, in the initial studies on water block by [14] was developed a method in which the use of inexpensive chemical treatment lowered the surface tension in low permeability gas reservoir improving the damaged sandstone permeability from water block. In this method, the ranges of permeability before-blocking, after-blocking and after-treatment were 0.1-94md, 0.0-49md and 0.1-81md, respectively, a method that allows distinguishing the type of the blocking phase. Afterwards, the phase trapping index (*APT*i) known as a formation damage type by [15] with a formula, was developed by [16] with a new formula, and then was found by [4] that this index is based upon permeability and initial water saturation values in which the damage of (*APT*i) differs in oil-wet and water-wet conditions. He also determined that APT is different from the water block, and the evaluation of APT cannot use the permeability damage ratio which is often used to evaluate liquid sensitivity and water block. For removing these damages, [17] concluded the use of aqueous-based completion fluids in causing the water block near the wellbore and around the hydraulic fractures, [18] proposed using the non-polar hydrocarbon based fluids for reducing water block in the tight and dry gas reservoirs and also [19] investigated the flow of gas through the reservoir rock matrix and fracture in removing the blocking fluids and the displacement and evaporation in exacerbating the water block.

Therefore, in these studies has been investigated the effects of oil based fluids, dry gas injection, drawdown pressure, low surface tension and effect of displacement and evaporation on the blocking fluid near the fracture and matrix.

But in other studies on solvents and water block was revealed that in all water, oil and gas reservoirs, the underground processes such as different injection types, fingering and conning are caused by the emulsion of water and oil around the wellbore and lastly the increase of water saturation led to water block in the big pores, therefore, solvents mixed with de-emulsifiers are used [1], [20], [21]. However, the water block is mostly a major issue in the water injection wells in which the permeability damages more occur in sandy layers and the clay minerals in these distances can be sensitive to the salinity degree and pH of water injected [22]. When these distances in low permeability reservoirs contain of saturation salt and high asphaltene oil, then the salinity degree and pH development can displace the clay minerals [23]. By altering the wettability in these distances, the water block recovery improves, but hampers the oil productivity at early times [24] and for ensuring it a experimental work was designed and carried out to test the effect of wettability alterations on the liquids blocked at high temperatures (140^0C) [25]. But other important studies to discern the susceptibilities of rocks as opposed to solvents was needed to be carried out for the dense reservoirs which will more and more have confronted with the different damages while repetitive production. In this case, [2] investigated that low permeability limestones are much more susceptible to the variations in wettability both with brine and methanol than high permeability sandstones. In experimental results was determined once the length of flood path decreases, the amount of the solvent required for completely recovery lessens, as a result, a smaller water percentage is required to drive the solvent. Moreover, [3] demonstrated that in high porosity core plugs the severity of fines migration is high, cores wettability alterations with high carbonate cement is also more and the sensitivity of formation water is low in completely sandy samples.

The fine and coarse fractures in the reservoir effect on the water block, because of the pressures exerted on the pores and the liquid phase saturation alterations. But based on the modeling results on the fractured and unfractured water and oil reservoirs systems [26] and investigations on the late fractured reservoirs production times [27], the considerable water block is in the fractures that this is due to the less pressure difference between the capillary and drawdown states. Consequently, in case of the difference between static and flowing bottomhole pressures, the fracture effect has an important role in decision-making on the overburden pressure as well as the type and the percentage use of solvent used in the types of lithologies [28].

5. Experimental and Field Information

5.1. Experimental Theory

In this subsection, a full explanation of some aspects of the fluids and rocks above and a variety of the circumstances in the accepted knowledge below for explaining a specific set of models in the reservoir can direct us to accomplish the experiments and to deduce the relationships. Therefore, relationships or basic principles of the certain phenomena in form of the tests are applied to incorporate facts, concepts and assumptions to draw a totalized conclusion. Similarly, an ideally quantified set of the standard measures needs to determine whether the results of the procedure are of acceptable quality in the form of the equation. But some investigators have utilized a few experimentally and statistically especial procedures in their periodic tests to document the results of the procedures. We here mention a few of these assessing methodologies of the tests, but approaches other than these set in literatures may be applicable and acceptable in which the applicant should justify alternative approaches. Likewise, such justifications for a better planning of the well interventions should be based on the data derived from rock and fluid contained that deal with in thorough experiments and/or theoretical errors for a procedure given for acids or solvents.

Differences in these procedures could in some cases affect the quality or performance of the new incorporations, while using physicochemical measurements and techniques. Assessments in this case are different and few, for instance, as assessing the results by carefully averaging microscale properties over some representative physical properties, one can describe systems of interest using macroscale system properties and govern equations [29]. When the way of comparison these scales using the Darcy's law differs to other models, the other scales such a macro (usually captured in the pseudo functions like relative permeability) for resolving the dynamics which occur between individual grains of the porous medium are researched. For example, we here can refer to the model of the flow regimes of Forchheimers (e.g., determining productivities) in the magnitude of the fluid velocity and dimensionless measure of the flow behavior in a porous media. [30], [31]. Generally, according to studies conducted on the modeling and the mathematical methods, in the equations of motion the flow of a fluid through a porous media is modeled by the Darcy's law which is an expression of the conservation of mass. Additionally, when we are dealing with a continuum it is not so easy to specify the mass of individual elements for which we want to write dynamical balances. To conserve the mass, the rate of change of the mass in the fixed volume must be equal to the mass leaving or entering. Therefore, this equation which describes the condition of mass conservation is sometimes referred to as the continuity equation [32], [33], [34}. In this investigation, the methods of microscale and macroscale associated with the models of mass fluxes (mass flow rate per unit area per unit time) and continuum could assess the large and short length scales until the averaged properties relevant to composition are being ranged and then the total property of fluid is completely stabilized. At the macroscopic level (based on a continuum hypothesis and the existence of representative elementary volumes) were conserved both mass and momentum (e.g., a vector field like pressure), although the mass alterations are mostly negligible to the fluids surrounding the matrix porous. Therefore, the properties of heterogeneity change in a porous medium, especially, while displacing the particles alongside the flow in these heterogenous masses with large (meter scale) or short (centimeter scale) length scales.

But as finding an equation to describe a set of date, as our investigation here, we need a process of finding a more elaborated empirical equation to make an exact guess for the form of equation. The obtained form can be adjusted to yield the best result with the least difference between the experimental and field data, and those obtained by the equation. In the two-step procedure, first, we plot the raw data of variable in order to get a fit curve and then make an exact guess of the equation form through the accessible data. Second, we find the n-equation writing technique from undetermined parameters using the selected values of the averaged properties. Hence, for a final multi-variable equation needs to obtain several averaged properties using the data adjusted and incorporated. Definitely, such an equation for a reservoir, especially with heterogeneous structures, needs the information of well logs, geological outcrops, seismic surveys (where accessible), thin sections, core samples, well tests, production and injection data, core flooding and other laboratory experiments, etc.

It is crucial to know whether the heterogeneity changes that have been extensively studied and in certain time span monitored by reports in our equations have any effect on product performance in determining predominantly thresholds for each variable. The methods of averaging the properties associated with the models of mass fluxes and continuum in the in-process and periodic tests of inter-or intra-laboratory procedures are significant in cases where the new variables included in the new incorporations or when the common variables knowledge are dependent upon environment conditions. In some cases a loss on a procedure may be considered adequately, hence a detection procedure (e.g., qualitative information in form of the macroscopic and microscopic examinations in the field or laboratory) is most importantly preferred. Procedures and acceptance criteria simultaneously follow and present the blocking of water in the water, oil and gas reservoirs as well as water and oil reservoirs in our investigations that are main subject matter. Additionally, other procedures and acceptance criteria may be determined by other appropriate procedures, e.g., while applying the detailed characteristics of the water block in the gas reservoirs in the field scales. There may be a need to specify the coefficients of equations or the dimensionless numbers in which and/or to modify the equations using the gas reservoir information (e.g., compressibility as what in subsequent sections partially guided, accurate range of porosity in a gas reservoir, degree of the ions hardness and being salty and other changes necessary that show the sensitivities to certain parameters). However, the type of acceptance criteria should be based on (1) the nature of the rock and fluid in the reservoir circumstances, (2) the intended use of the wellhead product, and (3) most importantly the previously delimited area around the wellbore that injection in a great deal time slowly will improve it.

5.2. Experimental Procedure

According to the above-mentioned method of [14], here an experimental procedure designed to a water-oil system to reveal the range of the permeability in the three situations of before-blocking, after-blocking and after-treatment. The stepwise procedure in experiments more presents the trend of the changes of rate, pressure, production time, displacement of particles and ions, decrease of surface tension against increase of capillary number and tens other variables that have been included in equations under reservoir temperature using common apparatuses such as core flooding, surface tension, and so on. Therefore, for obtaining the accurate results, we have tried to ensure the results by comparing the data of the water-bearing rocks against the oil- bearing rocks in two oil-wet and water-wet groups in the experimental scale that the data of water-bearing rocks are out of the scope of this paper.

5.3. Experimental tests

In comparison between the experimental data of the oil–wet oil-bearing rocks (O.W.O.R), water–wet oil-bearing rocks (W.W.O.R) and water–wet water-bearing rocks (W.W.W.R), two properties of the acidic solvents or low viscous solvents (LVSs) and alkaline solvents or high viscous solvents (HVSs) at the time confronting to various lithologies are studied to measure the parameters of the wettability and the types of permeability (absolute (K_{ab}), damaged (K_d), relative (K_r)) in both states of oil-bearing and water-bearing of the rocks. Acidic and alkaline solvents are mixed with water or gasoil so that decrease the interfacial tension and remove the water blocked in the rocks saturated with water and oil, respectively. Typical experimental data for the three set of rocks (W.W.W.R, W.W.O.R and O.W.O.R) given in Table 2, evaluating the influence of the solvents. According to Table 2, to evaluate the damaged permeability (K_d) in three groups of rocks after occurring the water block, $(K_d)_A$% and $(K_d)_B$% are defined as the percentage increase of K_d in W.W.W.R to W.W.O.R and W.W.W.R to O.W.O.R, respectively. For example, $(K_d)_A$% as a comparing ratio for the damages between the first two set of rocks (W.W.W.R and W.W.O.R) before injecting LVSs and HVSs has had an increase up to 14 and 15% in the loose and dense rocks, respectively, while $(K_d)_B$% as a comparing ratio for the damages between the second two set of rocks (W.W.W.R and O.W.O.R) before injecting LVSs and HVSs has had a much more increase both in loose and dense rocks (16 and 17%, respectively),therefore, $(K_d)_B$% is much more than $(K_d)_A$%. This indicates that the percentage damage in the water-wet rocks saturated with water is more the oil-wet and water-wet rocks saturated with oil.

Moreover, to evaluate the relative permeability variations in three groups of rocks at above (W.W.W.R, W.W.O.R and O.W.O.R), two parameter of $(K_r)_A$% [ratio of K_r in (W.W.W.R) to K_r in (W.W.O.R)] and $(K_r)_B$% [K_r in (W.W.W.R) to K_r in (O.W.O.R)] are defined and compared. In evaluations, $(K_R)_A$% concludes on the average effect of the solvents in removing water block in loose and dense rocks in two groups of (W.W.W.R) and (W.W.O.R) in which water–wet water-bearing rock samples and water–wet oil-bearing rock samples saturated with water and oil, respectively. But $(K_r)_B$% concludes on the effect of the solvents in removing water block in loose and dense rocks in two groups of (W.W.W.R) and (O.W.O.R) in which water–wet water-bearing rock samples and oil-wet oil-bearing rocks saturated with water and oil, respectively.

In $(K_r)_A$% , as a index for the percentage of K_r improvement in the first two set of rocks (W.W.W.R and W.W.O.R), are determined that K_r improvement in the group of W.W.W.R (only dense types) in which the HVSs are injected, is much more than K_r improvement in the group of W.W.O.R to the same rocky properties (only dense types). But in the second two set of rocks (W.W.W.R and O.W.O.R), the effect of the HVSs improvement in the O.W.O.R increases, $(K_r)_B$% as a index for the percentage of K_r improvement decreases and also the percentage improvement of K_r using the LVSs (usually with the high acidity property) considerably decreases in last group of rocks (i.e., O.W.O.R). In effect, in both the loose and dense rocks during injecting low viscous solvents with the usually high acidity, the value of indexes $(K_r)_A$% and $(K_r)_B$% become high and this indicates that the performance of these solvents in the water–wet water-bearing rock samples is better of the water–wet oil-bearing rock samples. On the other hand, alkalinity performance in

W.W.W.R, W.W.O.R and O.W.O.R increases respectively, as this increase is meaningful in the dense rock samples the type of O.W.O.R. Nevertheless these changes, in loose rocks in both set the percentage of Kr improvement is more than the dense rocks.

Table2 A comparison between typical experimental data in the various absolute permeability ranges of the oil-bearing (oil-and water-wet) and water-bearing rocks.

(K_{ab})	W.W.W.R	L	9 to 17 md	1	litho	% of increase of $(K_d)_A$ before		
		D	0.9 to 4md			injection of	LVSs	HVSs
					L		14	14
					D		15	15
(K_{ab})	W.W.O.R	L	12 to 25 md		litho	% of increase of $(K_r)_A$ after		
		D	1.67 to 8md			injection of	LVSs	HVSs
					L		16	12
					D		11.5	8.5
(K_{ab})	W.W.W.R	L	9 to 17md	2	litho	% of increase of $(K_d)_B$ before		
		D	0.9 to 4.5md			injection of	LVSs	HVSs
					L		16	16
					D		17	17.3
(K_{ab})	O.W.O.R	L	10 to 20md		litho	% of increase of $(K_r)_B$ after		
		D	2.5 to 6md			injection of	LVSs	HVSs
					L		19	9.5
					D		5	5
	*D:dense		*L:loose			*litho:lithology;		

5.4. Field Tests

Under underground conditions after occurring the much partial tectonic changes and the fluids nature change, water invasion through cannels flows alongside of the matrix media and pushes the non-wet hydrocarbon phase within the main cannels, as this displacement finally modifies the capillary absorption. On the other hand, water back accumulates in the distances near or beyond the wellbore where the front of fluids injected affects the performance of what is previously stable. Therefore, as treating the penetration of the solvent in the oil molecules during the long run depending upon the rock type can move the blocked water into the main cannels. For this reason, the set of the most importantly physical quantities relevant to rock and fluid in these canals and matrices are researched. These physical quantities consist of variables based on field data such as pressure loss, maximum and minimum flow rates, injection time, permeability, porosity, hardness and/or brittleness testing, injected fluid volume, overburden pressure, injection and production pressure, flow rate of production before injection operations by which the oil has been producing and some other parameters of the rocks and fluids. As a result, the qualitative and quantitative review techniques of daily reports, inspection reports, learned lessons and well summary must be considered in the final review to conclude on the ongoing and future operations. However, it is critical that very early cycles and phases of the well are embedded in the research schemes and modified by the field based personnel. See a representative sample of these tests in Table 3. In all tests, the physical quantities relevant to three treatment processes of base fluid, solvent and base fluid mixed with solvent are considered. The experimental data are porosity, permeability and a few variables included in relationship P_{ob}^{C1}, mostly to point out the rock characteristics. But other information for fluids is largely provided from well's production and injection history. The P_{ob}^{C1} is observed as an attribute of goodness assessing practice of reservoir as well as of (B_k) outcome quality assurance that in other places may be applicable to calculate other variables in other operations (e.g., fracturing and stimulation a definite area in reservoir). The lowest specified concentration of the solvent in exponential correlation of C_1 should be determined to be effective in controlling damage. In this case, dissolution procedures using solvents and base fluids should be validated at the laboratory. Similarly, the multiple-point and multi–time samplings at the wellhead also can effectively help being better the results. However, quantitative and qualitative acceptance criteria and a procedure for determining the particles size distribution in time of dissolution address the situation of porosity and permeability that were considered in formulations of P_{ob}^{C1}. In this case, the addition of particle size distribution testing in the macro-and micro- scales is well thought out in place of dissolution testing. The maximum and minimum flowing rate set based on the observed range of variations is estimated and the production rate depending on the bubble point pressure status of the reservoir is estimated at flowing bottomhole pressure using the models determining the rate (e.g., Vogel, Rawlins and Schellhardt, Fetkovich, etc.). Using the expression for I_k, and also plot I_k vs P_{ob}^{C1} in the end of investigation, we can somewhat get the lithology type. The plot associated with the table is the final profile of the I_k in which the horizontal tangent line in the up and the down of each curve (i.e. inflection point) is maximum and minimum, respectively. Therefore, at any I_k of plot we cannot draw a tangent to the P_{ob}^{C1} in order to determine an exact amount of the I_k and its corresponding P_{ob}^{C1}, unless we use from the table determining the I_k and lithology. Hence, as the quantities such as the expending (I_k) changes smoothly during changing depth and temperature, then we can describe the variations of the I_k versus P_{ob}^{C1} that indicate the effects of the lithology and the type of solvent employed in which point of the reservoir during some time periods. Likewise, the two petrophysical properties of the rock and fluid in tests, i.e. porosity (φ) and permeability (k), have been determined previously using the equations of conversation of mass (such as Darcy or other than) and/or the experimental procedures. At last, the dimensionless expression of P_p/P_{ob}^{C1} included in the equations to reduce the number of true parameters and to understand the relative magnitudes of various processes in the different lithologies.

Table 3 Field data of the removed water block in the oil wells.

$(B_k)o.w$ in oil reservoir the type of oil-wet (O.W.O.R) with loose and dense rocks at T=176 to 250^{0}F										
q_{mam}, m^3/min	q_{mim}, m^3/min	q_i, m^3/min	P_1, bar	P_2, bar	P_p, bar	p_{ob}^C, bar	φ, %	K, md	V_{inj}, m^3	$(B_k)o.w$, $(m^3/min)(T^0m)^{-0.5}$
1.8	*0.86*	*0.30*	*80*	*139*	*55*	*2*	*24*	*27*	*162*	*71*
1.55	*0.77*	*0.25*	*71*	*119*	*47*	*2.35*	*20*	*23*	*134*	*59*
1.51	0.72	0.22	64.5	115.6	41	2.52	*18.7*	*23*	*123.2*	52.53
0.96	*0.46*	*0.16*	*42*	*75*	*32*	*2.9*	*16*	*14*	*114*	*44*
0.90	*0.43*	*0.14*	*40*	*68*	*26*	*3.14*	*15*	*13*	*96*	*35*
0.48	*0.25*	*0.09*	*21*	*37*	*14*	*6.7*	*7*	*6*	*43*	*16*
$(B_k)w.w$ in oil reservoir the type of water-wet (W.W.O.R) with loose and dense rocks at T=176 to 250^{0}F										
q_{mam}, m^3/min	q_{mim}, m^3/min	q_i, m^3/min	P_1, bar	P_2, bar	P_p, bar	p_{ob}^C ,bar	φ, %	K, md	V_{inj}, m^3	$(B_k)w.w$, $(m^3/min)(T^0m)^{-0.5}$
1.82	*0.74*	*0.34*	*92*	*150*	*57*	*1.95*	*24.5*	*29*	*166*	*59*
1.35	*0.68*	*0.27*	*67*	*120*	*44*	*2.24*	*21*	*22*	*142*	*50*
1.29	0.63	0.20	61	110	39	2.50	*19*	*21*	*127*	44
0.93	*0.43*	*0.17*	*42*	*81*	*30*	*2.87*	*16*	*15*	*108*	*40*
0.82	*0.37*	*0.13*	*40*	*70*	*26*	*2.96*	*14*	*13*	*93*	*29*
0.39	*0.22*	*0.07*	*21*	*36*	*13*	*5.75*	*8*	*6*	*51*	*14.5*

When (% solvent)$\uparrow \Rightarrow$ $q_{mim}\uparrow$ and $[(q_{max})-(q_{mim})]\downarrow \Rightarrow \sqrt{\dfrac{1}{q_{max}-q_{mim}}}\uparrow \Rightarrow B_k\uparrow$

5.5. Experimental and Field Findings

These findings have been extracted to incorporate the information of the wellhead and laboratory, while comparing them with salt water disposal wells. As the rock pore due to the water base fluids invasion is filled with water, the oil phase is pushed in along with the fractures because of rate, pressure drop and high capillary pressure. Under these conditions, oil is accumulated by strong water flow in the far radius of wellbore and subsequently water saturation is increased in the matrix. This situation is caused to change the rock wettability from water-wet to oil-wet in the curvature of invaded media, and provide the water block problem.

The high viscous solvents (HVSs) have a gradually development in the water wells, as this improvement is increased in high the temperatures, dense rocks and oil wells. Accordingly, the starting point of the HVSs in effecting on the permeability development occurs in the lower temperature. If the HVSs are used in the acidizing processes as after-or pre-flash, then should be given a great time for the better performance of the solvent, as this waiting time in the water wells is more than it in the oil wells. The filtration of the formation water has a positive influence reducing the surface tension during the use of solvents, especially mutual solvents, as this reduction becomes more in the HVSs. Similarly, in a general behavior the surface tension in the HVSs is less than the LVSs according to the surface tension experiments. For that reason, the better washing of the water injected to the salt water disposal/depleted wells in the desalting units can prevent or diminish the formation of water block and other formation damages in the porous media. For example, for solvents such as mutual solvents, the percent used in the base fluids is within the range of 5 to 10% accordance with factory's work instructions. But the percent can also be efficient in the lower ranges in the salt water disposal wells, paying attention to flow rate, lithology, permeability and overburden pressure during using mutual solvents. Since the increase of flow rate has the significant influence in pushing water block in the permeable rocks, in loose water-wet rocks the performance of the LVSs is more than the HVSs and in water-wet dense rocks the speed of treating the damages by solvent (mostly non-alcohol based type, foamed fluids, surfactants and transient wettability modifying agents) is lower. However, the effect of both HVSs and LVSs in loose rocks is averagely more than dense rocks. Sandy plugs are commonly uniform, brittle, salt and sensitive against the stresses and the chemical and mechanical forces, and the variety of particles and cements are less, as a result the space between the grains is less consolidated together. For example, in limestone/dolomite or shale these inter-granular distances are more cemented together and often exert the more pressure on the beneath and intermediate layers. This investigation is an incorporation of the geology, petroleum and petrophysics subjects in the major underground scales in the form of the fundamental questions and the empirical equations based on experiments. Therefore, concentrating on the paper introduction, section relevant to findings, example cited and the reservoir properties based on the data obtained from logging tools, methods and cuttings can follow the purpose of the investigation step by step until when achieving to the novel equations of water block. The factors changing the quantity of the B_k depend on the variables in the equations of B_k that contain length or progress amount of the injection front which is being predicted, sensitivity to wettability, percent of the salinity and the ions displacement, required solvent amount, severity of the particles migration in various porosities and percent of carbonate cement or clay in the layer. As a result, the equations obtained from a set of experimental data and empirical information could answer to very fundamental questions for types of anisotropic layers of the reservoir that rock's framework is multi-mineral with the various geometries of the pores, especially when flowing fluid through which.

General Methodology for Novel Equations: As indicated in Fig.1 in background, in the discussions below, first, the structural layer characteristics (IGS, IFS and FW) obtained from the experiments on the oil-and water-wet layers and the wellhead information mentioned (section 2), second, the equation of overburden pressure as a function of the physical parameters resulted from previous information indicates its own role in revealing parameters effecting on the water block (section 3), and finally, the following novel equations of water block are introduced for the oil-wet and water-wet layers of oil reservoirs (section 6).

6. Equations of Removed Water Block in Oil Reservoirs

6.1. Equations of Removed Water Block in the Oil-Wet Oil Reservoirs with Dimensions Defined

The equations obtained from a set of experimental data and empirical information could answer to very fundamental questions for anisotropic and isotropic reservoirs that their framework includes multi mineral with the various geometry of pores. These equations present solutions to contrast the types of oil layers and propose the alternatives to treat them when are confronted to the damage of water block in the porous media. These equations for oil-wet oil reservoirs with two ranges of porosity given in (6.1) and (6.2) below that will be discussed in the subsequent subsections.

$$(B_k)_{o.w} = \sqrt{k}\ q_p \sqrt{-\frac{I_k A_w \Delta P}{\frac{\rho_f V}{t}(q_{max} - q_{min})}} \sqrt{(\frac{pH_f}{pH_{ac2\%}}) - 1} \sqrt{(1 - \frac{D_s}{H_{Mg}})^2}$$

$$I_k = 6.5\times10^2 (T^0)\ (h)(1 - \frac{\mu_f}{\mu_{ac2\%}})^4 (\frac{P_p}{P_{ob}^{C_1}})^{-2} \quad C_1 = 0.10 - C_{mu};\ 0.05 < C_{mu} \le 0.10;\ 5 < \varphi \le 15.5 \qquad (6.1)$$

$$(B_k)_{o.w} = \sqrt{k}\ q_p \sqrt{-\frac{I_k A_w \Delta P}{\frac{\rho_f V}{t}(q_{max} - q_{min})}} \sqrt{(\frac{pH_f}{pH_{ac4\%}}) - 1} \sqrt{(1 - \frac{D_S}{H_{Mg}})^2}$$

$$I_k = 7.1\times10^2 (T^0)\ (h)(1 - \frac{\mu_f}{\mu_{ac4\%}})^4 (\frac{P_p}{P_{ob}^{C_1}})^{-2} \quad C_1 = 0.10 - C_{mu};\ 0.05 < C_{mu} \le 0.10;\ 15.5 < \varphi \le 25 \qquad (6.2)$$

6.2. Equations of Removed Water Block in the Water-Wet Oil Reservoirs with Dimensions Defined

The same above-mentioned variables for oil-wet reservoirs are also applied for the water-wet oil reservoirs equations. These equations for water-wet oil reservoirs with two ranges of the porosity given in eqs (6.3) and (6.4) as following:

$$(B_k)_{w.w} = \sqrt{k}\ q_p \sqrt{-\frac{I_k A_w \Delta P}{\frac{\rho_f V}{t}(q_{max} - q_{min})}} \sqrt{(\frac{pH_f}{pH_{ac2\%}}) - 1} \sqrt{(1 - \frac{D_S}{H_{Mg}})^2}$$

where: $I_k = 5.4\times10^2 (T^0)\ (h)(1 - \mu_f/\mu_{ac2\%})^4 (\frac{P_p}{P_{ob}^{C_1}})^{-2} \quad C_1 = 0.10 - C_{mu};\ 0.05 < C_{mu} \le 0.10;\ 5 < \varphi \le 15.5$ (6.3)

$$(B_k)_{w.w} = \sqrt{k}\ q_p \sqrt{-\frac{I_k A_w \Delta P}{\frac{\rho_f V}{t}(q_{max} - q_{min})}} \sqrt{(\frac{pH_f}{pH_{ac4\%}}) - 1} \sqrt{(1 - \frac{D_S}{H_{Mg}})^2}$$

where: $I_k = 5.9\times10^2 (T^0)\ (h)(1 - \frac{\mu_f}{\mu_{ac4\%}})^4 (\frac{P_p}{P_{ob}^{C_1}})^{-2} \quad C_1 = 0.10 - C_{mu};\ 0.05 < C_{mu} \le 0.10;\ 15.5 < \varphi \le 25$ (6.4)

Units in equations of removed water block: Where B_k or removed water block is the power of the damage removal by chemical and demonstrates a relationship between the expending of chemicals and the damage made. B_k is proportional to the rate of blocking the fluid (q_B) to the square root of the acid expanding ability ($\sqrt{I_k}$) in which q_B can be obtained from $q = \frac{Bk}{\sqrt{I_k}}$. In the B_k the volume of water block that in each minute has endured the temperature T^0 in depth of h after the injection of the acid and the solvents to different acidity properties, is measured and its unit is $\frac{m^3}{\min\sqrt{T^0 m}}$. I_k, expending or acid expending ability, which its unit is mK or T^0m, where 1 K = 1000mK. One K is the expending of an acid sample of 28% injected to a well with the previously-predicted pressure and rate of injection and production. And the well located in a layer L cm long (a length of zone around the wellbore which the front of the fluid injected covers which zone) with a cylindrical cross-sectional at depth h from earth surface which endures an overburden pressure of its upper layers column. And then depending on the favorite layer lithology, the injected acid is converted to acids 2 to 4% (ac2% to ac4%) under reservoir conditions. Ideally, under the conditions that the viscosity of base fluid mixed with solvent and the expended acid viscosity are assessed for the reservoir fluids displacement behavior. Practically, 1K measures the capacity of gradually expending of an acid that its variable indicated with I_k and its applications are for too large horizontal scales of the reservoir layers to an aim to treat, stimulate, fracture and/or drill them. On the whole, as acid expends, then the media has an ability to push the previously blocked fluid with a rate of $q_{B,}$ and in which the underground chemical expending is measured with I_k. C_{mu} is the percent of solvent used with base fluid that in the oil reservoirs is mainly gasoil, and the constant of C_1 is calculated by which. The percent of C_m that is commonly being used at wellhead and in relationship of C_1 is subtracted from maximum allowable amount that has been delimited by factory's product. At above-mentioned equations this maximum amount is 0.10 for mutual solvents. As a result, the superscript C_1 differs in value for the types of solvents that subsequently will change the I_k. P_{ob} is the overburden pressure (bar) and obtains from equations 1 to 6. K is permeability (md) and SI unit of K equals about 0.98692×10^{-12} or 10^{-12} m^2. q_p is last oil rate (m^3/min) in production well before the injection of fluids. P_p is last oil pressure (bar) in the production well before injecting fluids. ΔP is pressure loss of acid 28% and retarder acid with gasoil mixed in solvent (bar), and A_w is sectional area of wellbore (m^2). V is the entire volume of fluids injected to the well (m^3), excluding the volume of fluid mixed with solvent. t is the injection time of the entire volume of fluids injected to the well (min). ρ_f is density of base fluid (kg/m^3) that mutual solvent is mixed with it at wellhead. μ_f is the μ of base fluid mixed with solvent that equals to the average of viscosity of the base fluid (in here is gasoil) and viscosity of the solvent (kg/m-s) under reservoir conditions. $\mu_{ac4\%}$ is the viscosity of acid 27% and retarder acid (kg/m-s) that have endured the conditions of reservoir. pH of the base fluid mixed with solvent is the average of the acidity percent of the base fluid and mutual solvent under reservoir conditions. $pH_{ac4\%}$ is the acidity of acid 27% and retarder acid that have endured the reservoir conditions in a sandy layer and have been converted to acid 4%, as this amount in most of the limestone layers is 2 to 3% (in equations related to types of rocks is averagely based with ac2%). D_s, salinity degree, is the salt amount of formation water (ppm) and the $(H)_{Mg}$ is the Mg hardness of formation water (ppm). The sensitivity range of variable quantities depends on the quantity of variables in equations that are representing the reservoir nature.

7. B_k and Variables in Equations of B_k

In equations of (B_k) so that know how the physical parameters affect the B_k, how they obtain, how far the wellbore these calculations are applied to properly predict/treat the altered zone in the investigation radius, where they aren't applicable and how the B_k can be calculated, each physical parameter in these questions is separately explained to indicate its relationship with B_k. The parameters of structural characteristics of the rock mass in the definite sectional area according to structural classification of layers and the lithology in timescale are certainties estimating the overburden pressure of definite layer. Moreover, the certainty of acid expending in fluids could define how decide to treat the zone surrounding the wellbore that has been encircled by the other layers. The percent of solvent used, C_m, is other substantial variable that is applied according to the instructions of factory in the relationship of C_1.Therefore, the amount of B_k calculated depends on the quantity of variables in equations that are representing the reservoir nature. Very often, length or progress amount of the injection front which is being predicted, sensitivity to wettability, percent of the salinity and the ions displacement, required solvent amount, severity of particles migration in various porosities and percent of carbonate cement or clay in the layer are factors changing the B_k. However, as we determine variables existing in equations, the measurements on the large and small samples associated to models of mass fluxes and continuum can assess large and short length scales to attain to the better results of B_k. As a result, the equations obtained from a set of experimental data and purely empirical information could answer to very fundamental questions for types of anisotropic reservoir layers that rock framework is multi mineral with the various geometry of pores, especially while flowing fluid through which. The proposed equations impose a boundary on how much fluid will inject to a specified layer and how much damage will remove from. The table of the varying parameter of inter-fracture space (IFS) or fracture spacing is reliable in the reservoir layers without fault which are mostly in the depths of earth. Thus, equations aren't applicable in such layers having fault or any near earth surface layer. The table of fracture width, FW, is a reliable basis for the fracture situation for types of layers without fault. Three parameters inter-granular space (IGS), inter-fracture space (IFS) and fracture width (FW) as the critical and highly variable correlation indexes for types of formations are distinguished in the classification table relevant to these parameters at above.

7.1. Overburden Pressure (P_{ob})

This expression is an index for the layered structures in which from the distant past until now the beds may have been disrupted due to geological activity, resulting in fine and coarse fractures. In these layers where the P_{ob} decreases, the B_k also increases, as in the dense rocks the high P_{ob} caused to decline of the B_k. In sandstones the effect of P_{ob} decreases than other rocks and subsequently it can imply that the effects of porosity and permeability somewhat increases and decreases, respectively.

7.2. Production Pressure (P_p) and Production Flow Rate (q_p)

P_p is pressure exerted from the wellbore entrance fluid on the wellbore sectional area which its production rate is q_p and before the start of the acidizing operations is read from the well's history. These two quantities have obtained from the last oil production indexes before injecting the acid and non-acid fluids in which intend to treat the well, and both P_p and q_p have a direct relation with the variations of the B_k. Therefore, we should record the wellhead data of the pressure and flow rate in the radius of investigation in the altered zone near the wellbore when the well becomes closed. However, the gradual growth of the flow rate, q_p**,** can only be efficient in places where both the rocks of oil wet and water wet are loose that there accordingly the B_k would be more.

7.3. Pressure Loss ($\Delta P=P_1-P_2$) and Rate Changes ($\Delta q=q_2-q_1$)

When the acid 28% (or with less percent) and retarder acid (including of water, gasoil and acid) are injected, the initial date of rate and pressure, and as such after the injection of base fluid (in the oil reservoir is mainly gasoil) mixed with solvents, the secondary date of rate and pressure are obtained to calculate gradients.

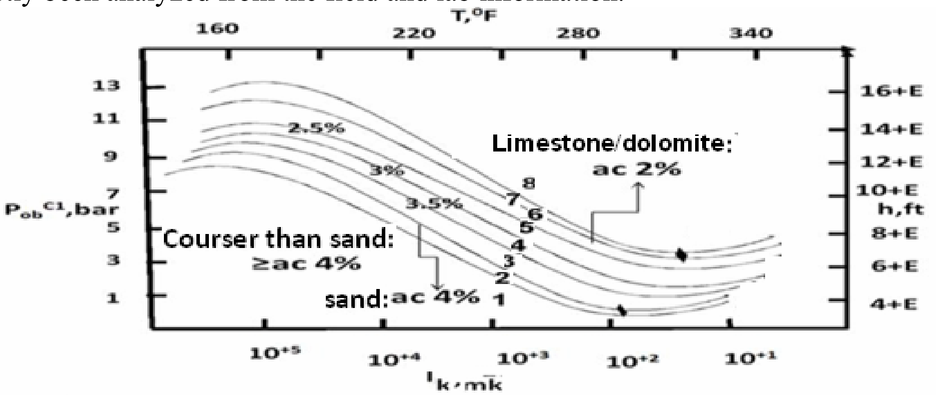
7.4. Injected Fluid Volume (V) and Base Fluid Density (ρ_f)

V is the volumetric difference the solution solvent in base fluid (here is gasoil) from the entire set of acid, retarder, gasoil and solvent injected (see example). This variable demonstrates that all the fluids (excluding solvent solution in gasoil) could be caused to block the water in radius of the wellbore of a well with sectional area of A_w in which the time elapsed for entire injection of acid and nonacid fluids is denoted with (t). For that reason, the gasoil as the base fluid mixed with solvent during the pre-or after-flash and/or throughout the acidizing operations has nothing role in forming the water block, and in equations the increase of the volume of any solvent solvated in gasoil has a direct ratio with the increase of the B_k. In injections, the higher the porosity, the more chemical is used, or equivalently the more water block is removed per unit time. Since the base fluid in the oil wells becomes gasoil, the density (ρ_f) of base fluid in the reservoir conditions has the relatively small effect in the increase of the B_k. Accordingly, B_k can then become a measure between the materials are employed and produced in the underground reactions.

7.5. Expending or I_k

I_k is the acid expending ability based on mK, which generally demonstrates the viscosity for acids expended to 2% and 4% under reservoir conditions for the two groups of the limestone/dolomite layers and the sandstone layers, as the other groups change between these percents. Because all layers are not homogenous with the containing of sand or limestone/dolomite and very often these layers partially or entirely contain the clay or shale, the layer structural variables (FW, IGS and IFS) in the equations of P_{ob} can include the role of layer characteristics, for instance, the percent and situation of minerals in which acids expended to 2% and 4%. Under these conditions, the hydrogen ion concentration of the chemical is not affected over the variations in the open-hole temperature and reservoir depth. An acid sample after expending in a sand-bed can be transformed to an acid about 4%. The chemical expending is usually directly proportional to the permeability and temperature, and inversely proportional to the porosity. It means as the chemical expending is high, the chemical has been converted to a substance with low percent of acid such a 2%. For example, a chemical in a limestone media with high temperature and permeability can better be expended than a sandy media usually with low porosity, instead, in the same sandy media the (B_k) volume is more.

In the I_k, under the same conditions of temperature, metamorphism and other changes that occur at the 1.5 ft from subsurface, are assumed and believed that there is not any difference with those that occur at the surface. This is due to the fact that this depth could never influence the calculations of significant parameters such a temperature of the reservoir and the surface, even as it gets less than 15ft. The I_k represents not only the property of the acid, but also it describes the various rocks that could alter in form and structure by natural agents. See Fig. 2 which is only to indicate the trend of alterations in the variables of the correlation of I_k for the different layers. Also, Fig. 2 illustrates the acid expending ability versus overburden pressure in the reservoir layers which have directly been analyzed from the field and lab information.



ID	Lithology	ID	Lithology
1	Coarse particles	5	Sand with limestone /dolomite
2	Coarse sands	6	Shale sands
3	Fine sands	7	Limestone/dolomite
4	Sand with limestone /dolomite/shale	8	Shale/clay

ac% in 2 as 3 and ac% in 7 as 8 (although in 8 a little less, including P_{ob}^{C1} in I_k is ignored); To estimate T° and h using P_{ob}^{C1} and I_k obtained of formulas, don't use of this curves.

Fig. 2 Acid expending ability versus overburden pressure in reservoir layers.

The exact I_k obtains from the correlation of I_k for types of the reservoir litholgies, thus we cannot extrapolate the curves to obtain a special variable so that read the intercept as an exact value. In the limestone layers with an increase in the reservoir temperature, the speed of acid expending is increased. If the variety of minerals and particles is high, the released CO_2 by acid injected in the reactions environment become more and the formation water appears very unclean, then for forming the weak acid of calcium hydrogen carbonate long after injection the chemicals injected have a much more probability to expend. Therefore, the P_{ob} in the relationship of I_k can effectively include the role of the types of minerals in various layers on the trend of the acid expending. If there is a coarse sand layer, then the percent of back-flow acid to the wellhead might be more than 4%. However, the viscosity of which can be measured with experimental tools to calculate the I_k.. Although equations avoid the cost and complexity of injecting, but should be noted that have their own hardness for other chemicals such as the types of alcohols, acids, surfactants or any other newly-introduced advanced chemical substance with various acidic properties. For this reason, the C_1 in the I_k for other solvents must be corrected to handling C_m in various fields, and as such the $\mu_{solvent+water}$ (the average of μ water mixed fluid) is also substituted in the I_k according to the desired changes of the reservoir temperature so that determine the result of the behavior of fluids and solvents in various rocks.

In general, as the φ increases, C_m or the same percentage solvent used also increases. Subsequently, $C_1 = 1 - C_m$ in the P_{ob}^{C1} declines and the I_k also declines. Under these conditions, q_B or the rate of blocking is high and B_k (or $q_B \sqrt{I_k}$) also increases. As was discussed, the B_k, power of removal the damage by chemical, is directly proportional to the product of the square root of expending in the rate of blocking , in other word, q_B is the expending square root of the removed water block.

The q_B obtains through the ratio of the B_k obtained of equation to the $\sqrt{I_k}$. Most often, as the h increases, then φ also decreases. Subsequently, the C_m or the same percentage solvent decreases, and the superscript C_1 in both P_{ob}^{C1} and I_k increases. Under this condition in which the acid expending (I_k) is more, up to 2%, q_B or rate of blocking in such a low porosity media with relatively-usual permeability is low and amount of (B_k) is less. If the I_k is estimated for a horizontal layer to length larger than 100 meters, then can estimate the I_k together with other layers as a multiple of 100m (for example, for the pure sandy layer in length of 152m, the entire of I_k is multiple of 1.52. If we assume that 52 m of this layer is limestone and 100m sand, then the entire of I_k is the sum of 0.52 I_k and 1 I_k in which the data are substituted in the related correlations to I_k). For additional detailed information on the index of I_k, the reader is referred to section of units.

7.6. μ_f, $\mu_{ac4\%}$, $\mu_{ac2\%}$, pH_f, $pH_{ac4\%}$ and $pH_{ac2\%}$

The fluids injected or flowing with the various viscosities in a porous media can change the pores status by the dynamic conditions made by the rock and fluid reactions. As a result, the underlying layer pressure alongside its length and thickness alters at depth of h. These mostly damaging changes are well observed more when the desired layer is influenced by the foreign forces such as stimulation, fracturing, acidizing, horizontal and directional drillings. On the other hand, the viscosity is a variable quantity in different temperatures, thus μ_O is calculated for different reservoir temperatures to share the role of salinity water and oil in resistance of fluids on the contrary movement. The higher amounts of the oil density at temperature 60^0F illustrate a higher viscosity, and their variations with pH are evaluated over the alterations of temperature. The pH has usually a nearly constant amount in each oil layer which with increasing it the viscosity decreases (discussed in eqs (3.2) and (3.3)). Note that the μ_w is also obtained substituting the similar information of water in equations of the μ_o [35].

The subject of acid and its products need to major theoretical discussion. We have tried to totalize what after the long run of a acidizing process results actually at wellhead from acids, solvents and underground fluids that return to wellhead in the expanded state, and have denoted them to the percent in discussions. In treatment of the reservoir layers some complexities between fluid and rock such as the acidity power, viscosity, interaction speed and solubility can precisely be evaluated by the knowledge of chemicals concepts. Here, we have two viscosities and two acidity strengths of the injected liquids to the well which evaluate them from a viewpoint of the fluid and rock interaction. Thus, a precise measurement of viscosity and pH of the base fluid (gasoil) mixed with solvent ($\mu_{solvent+water}$ and $pH_{solvent+water}$) are carried out at the reservoir temperature at laboratory so that assess it with the measured viscosity and pH values from the returned fluid to the wellhead after the well injection operation has been completed and tended to reproduce from. When the measured values in the laboratory is in doubt and/or with the high quantity difference, care should be taken to see if the measurements are conducted in a steady state situation of the temperature in the laboratory or fluid flow at the wellhead. The laboratory expert can measure the $\mu_{solvent+water}$ and $pH_{solvent+water}$ to the types of solvents in the various temperatures in the laboratory and always be substituted by μ_f and pH_f in the equations. But $\mu_{ac4\%}$ and $pH_{ac4\%}$ which have been measured from the expended acid that has been returned to the wellhead depending on the ability of the rock minerals against the injected fluids and the rock and fluid manner can vary over the depth and the variety of lithology in the various wells. The probable interactions between mineral composition and salt-laden water can ease the perception of the underground interactions related to the rock samples and the solvents behavior and consequently will be better researched the discussion of the water block and soluble salts in formation.

The more precise the knowledge of the salts in the surface and subsurface waters, the better will be the interpretation of the water damages in the reservoir conditions. Such damages in the well and around the wellbore are both the soluble acid mainly with the salts of carbonates and sulphids (for removing it a HCL is usually used), and the insoluble acid mainly with the salts of sulphates. These salts in various layers vary with the CO_2 beads as facing with the injected acids. Due to the decrease of pH by acidic environment, equilibrium will shift calcium carbonate into carbon dioxide (CO2) and calcium ions. [36]. Generally, because of underground probabilities an increase in water temperature causes an increase in the solubility of most salts. Composition of the formation water varies greatly with reservoirs, but the usual constituents are Na^{+}, Ca^{2+}, K^{+}, Mg^{2+}, Fe^{2+}, Cl^{-}, SO_2^{-4} and HCO^{-3}. Important and notable exceptions are $CaCO_3$, $CaSO_4$, $MgCO_3$, and Mg $(OH)_2$ that all of which become less soluble as the temperature increases. Therefore, these insoluble salts in water are main containing in the limestone/dolomite and/or in the composite of the clay/shale with limestone/dolomite. The same consequents are also seen in the sandstone reservoirs that usually contains an abundance of bivalent calcium cations [37], [38], [39}. As these precipitations made by fluids incompatibilities reduces pressure the pH is high and subsequently the acidizing and also increasing the injection well bottomhole pressure will increase the amount of the deposited calcium carbonate [40].

In general, the study of fluids for the equations of removed water block (B_k) investigates five sensitivities of water sensitivity, acid sensitivity, alkali sensitivity, salt sensitivity and rate sensitivity. Because the acid and the associated fluids to it in the long run under the reservoir temperature change gradually, their acidy percent is also decreased. Therefore, the percent is obtained at laboratory and or measured from the returned fluid to the wellhead, and is preferred to be evaluated a slightly smaller in the calculations. According to the descriptions in the units section, the injected acid percent in a layer with high carbonate percent (nearly less stable minerals) that contains the $CaCO_3$ minerals, during the interaction of acidic fluids, it layer has a tendency to form a strong alkalinity characteristic of Ca $(OH)_{2,}$ and the output product of rock and fluids is a weak acid of calcium hydrogen carbonate,$CaHCO_3$, up to 2 to 3% during the interaction of acidic fluids. Thus, the equations related to these rocks are averagely based with ac2%, and in containing of these carbonate layers there are commonly small clay minerals and or their similar that can disorder the flowing trend by the interchangeable ions of Ca^{+2} and Mg^{+2}. This percent with regard to solubility of minerals in the acid may range up and down, but has a relatively constant effect on the correlation of I_k according to the figure of I_k. However, the reactions either dolomites or limestones in acidic environments have the partial difference. These lithologies in the reservoir layers are rarely pure, and if the layer becomes a pure dolomite, then dolomite is entirely soluble. Reservoir layers contain an enormous variety of minerals which have always the compositions of other minerals such as clay, shale, sand and or any other combination of these sorts. Therefore, under these conditions the classification table of IGS, IFS and FW can include the effect of significant various minerals properties in the calculations. But if the layer has sand (with minerals of SiO_3), during the interaction of acidic fluids, it has a tendency forming the fluid with the nearly weak alkalinity characteristic and the output product of rock and fluids is a slightly weak acid by silicate salt approximately 4%. Because in containing of sandy grains may be the various percents of silt and the dolomite, it is preferred that the expended acid percent be measured through the acid flowing within the rock samples under reservoir conditions at laboratory and/or be used from the back flow acid in the wellhead. Secondary μ and pH ($\mu_{water+solvent}$ and $pH_{water+solvent}$) are measured based on the separately averaging of amounts of μ_{water} and pH_{water} (pH or μ of gasoil as base fluid) and as such $pH_{solvent}$ and $\mu_{solvent}$ (pH or μ of solvent) under reservoir conditions in the laboratory. These quantities can direct the equations to describe and model the behavior and the physics of many of the underground processes.

7.7. Salinity Degree (D_s) and Mg Hardness (H_{Mg})

Two parameters D_s and H_{Mg} are formation water salinity degree and Mg ion hardness, respectively. Because the salinity degree would develop the particles displacement and water density in the throats of porous media, therefore, the increase of D_s can develop the (B_k) in the reservoir and on the opposite side the (B_k) would be less (see under radical sign in eqs. 6.1 to 6.4). The hardness of calcium ion (Ca^{+2}) in making of the depositions of $CaCO_3$ has a significant role and can form damages to disorder the trend of repositions, and its calcium hardness enlargement has mostly a reverse relation to the magnesium hardness. Consequently, H_{Mg} in equations represents the effects of being unbalanced ions in environments confronted to fluids. Calcium hardness according to the common oil industry procedure is measured to dividing the Ca ion by 0.4.

The following paragraph relates to comments that more focus on the discussion of overburden pressure in the list of references. These equations have not been corrected for the gas reservoirs which mostly have the quite smaller pore space to spaces saturated to the water and oil. For facilitating this subject must be noted: Firstly, because the diversity of porous in gas-bearing layers is less than oil-bearing layers or as such in water-bearing type, therefore, in estimation of overburden pressure doesn't require these equations to be categorized in the three groups of porosity as did observe above for the oil layers or in other references for the water layers, instead, suffices an equation for porosities less or equal to 5. Secondly, because the gas compressibility has considerable variations as comparing to the density in the liquids, thus this property of gas is caused the gas occupies the less space under ambient conditions that consequently will increase the effects of adhesion and cohesion. For this reason, the high viscosity measure in the liquids will be modified for the gas viscosity when the compressibility of gas as a significant variable is included in its related equation for the viscosity. Finally, a combination of porosity and compressibility in the modified equation of gas viscosity proves the equation of overburden pressure for gas layers in a range of porosity (1 to 5%) that then can correct the equations of (B_k) to the gas reservoirs. As a result, in the equation of viscosity corrected through compressibility for the overburden pressure of a gas layer, the range of porosity in (3.1) in the set equations related to overburden pressure changes to 1 to 5 instead of 5 to 10, and term d or the same ($d_{1,2,3}$), distinguishes the type of lithology for each gas reservoir in which equation.

However, one who intends to show the similar equations to (B_k) in the gas well should note that only one equation needs according to the corrections carried out on compressibility. In which one equation, later on, the porosity should be modified and applied to calculate the overburden pressure in a defined layer, and lastly only two equations can predict the (B_k) in the gas wells to each one of layers the type of the water-wet and oil- wet (note that the gaseous layers are mostly water-wet). If assume there is no any water or oil in the gas reservoir, then the term viscosity in the equation of overburden pressure limits to 1.

8. Example

An oil well with oil-wet wettability characteristic under 191^0F temperature completed in the depth 3593m of a formation, with a cylindrical drainage area. As shown in Table 4, the salinity degree and Ca ion of formation are very high for the fluid of well. To treat the damage, the gasoil mixed with mutual solvent used in the acidizing process. For solution, in Table 5 the overburden pressure for a layer with length of 80m calculated with Eq.(3.3) using the rock information and the removed water block (B_k) calculated with (6.4) using the fluid and rock characteristics. It can be observed that high salinity and calcium ion concentration in the production wells located in a layer with the silt compositions can increase the formation of water block and the calcium deposits around the wellbore, as this amount is more in the salt water disposal wells. Therefore, we can as such measure the damage for the other wells with the various characteristics which have been producing with a constant flowing bottom hole pressure (BHP), and finally have confronted to the damaging or unloading conditions and or the decreasing production rate.

Table 4 Formation water ionic specifications.

Hardness, ppm		Salinity	Ions, ppm					
Total	Ca		Cl	Mg	Ca	Fe	Co_3	So_4
54000	45000	220000	150875	2187	18000	74	854	425

pH of Water	pH of Low vicous:LVS	pH of High viscous:HVS
5.4	4.99	9.52

*For the filtration of water used the filter 0.45µm.The pH of water is before boiling

Table 5 A example of (B_k) in acidizing of a oil oil-wet well located in a sandy layer with containing of dolomite.

Reservoir data to calculate $(B_k)_{O.W}$ in acidizing process		Geology data of a layer (L=80m) to calculate P_{ob}
Fluid and well data: {r_w=0.42ft=0.128m; A_{we}=0.05m^2; V_{we}= 1187 .25 bbl }, { V_{water} = 775 bbl; $V_{solvent}$ =5.5 bbl;$V_{water+solvent}$ =100bbl;V_p = 105090bbl;V= V_{inj}=V_{water}=775bbl = 123.22m^3} D_s=220000ppm H_{Mg}=9000ppm ρ_{water}@191^{0}F=8620 C_{mu}=5.5%; t_{inj}=204.83min Calculation $(B_k)_{O.W}$: C=0.10-C_{mu}=0.1-0.055=0.045 P_{ob}^C=2.52bar; (P_p/ P_{ob}^C)=16.27; $(1-\mu_f/\mu_{ac4\%})^2=1-(1.2/0.55)^2$ =1.44; $[(pH_f/pH_{ac4\%})-1]^{0.5}$ =3.02 Using ρ_{go}, V_{inj} in loose oil-wet rock and Δp=-65.6bar have: $[(A_w\Delta P)/((\rho_f V/t)\times(q_{max}-q_{mim}))]^{0.5}$= 0.03(1/m^2)$^{0.5}$=0.03(1/mmDarcy)$^{0.5}$ I_k@191^{0}F=3705 mK If substitute the data in Eq. 6.4 of loose oil-wet rocks, then have: $(B_k)_{O.W}$=52.53(m^3/min)×[(T^{0}m)$^{-0.5}$] =330.4(bbl/min)×[(T^{0}m)$^{-0.5}$]	Fluid and well data: ρ_{water} @ 191^{0}F=8620 kg/m^3 $\rho_{ac4\%}$@60^{0}F=1180 $\rho_{solvent}$ @191^{0}F=910 $\mu_{ac4\%}$@176^{0}F=0.57 $\mu_{ac4\%}$@191^{0}F =0.55 μ_{water}@60^{0}F =1.43 $\mu_{solvent}$@191^{0}F =0.99 $\mu_{water+solvent}$@191^{0}F =1.21 $pH_{ac4\%}$@191^{0}F=0.67 pH_{water}@191^{0}F=5.7 $pH_{solvent}$@60^{0}F=4.99 $pH_{solvent}$@191^{0}F=7.83 $pH_{water+solvent}$@191^{0}F =6.77 P_{water}=P_1=1700psi=115.6 bar $P_{water+solvent}$=P_2=950psi =64.5 bar P_p=600psi=41bar q_{mim}=$q_{water+solvent}$=4.5 bbl/min =(0.72m^3) q_{mam}=q_{water}=9.5bbl/min =(1.51m^3) q_p=q_i=1.4bbl/min	Layer data: {A, m^2=1.13×10^{+3};$W_{d,\ kgf}$=203,8984;L, m=80;h, m=3593 },{ρ_w@60^{0}F=1.145×10^{+3};ρ_w@191^{0}F=1.135×10^{+3};ρ_o@ 60^{0}F=0.8519;ρ_o@191^{0}F=0.8219;ρ_r, kg/m^3=2.82×10^{+3} } ,{φ,%=18.86;k, md=23;t, my=25; t_1,my=50},{μ_o @ 60^{0}F =11.3;μ_o@176^{0}F=3.3;μ_o@191^{0}F=2.43;μ_w@176^{0}F=0.72; μ_w@60^{0}F=1.73;μ_w@191^{0}F=0.65cp;pH_o@60^{0}F=6.8},{d_1 =7.7×10^{+4};d_2=5.5×10^{+4};d_3=?},{V_w, m^3=3.37; V_o, m^3 = 13.49;V_d, m^3=73.78;T, ^{0}F=191}. Because the patches of anhydrite in containing of rock, the d_1 equals to d_2. Calculation P_{ob} : In table 1 in ID of 4 have**:** d_3=50% (0.1M)=(d_{max}–d_{mim}) /d_{max}; d_3^2=[0.05(5.5×10^{-5} –10^{-5}) /(5.5×10^{-5})]^2=0.002m. μ_w at T=191^0 using Eq. 6.6 equal to 2.43cp. If substitute the data in Eq. 3.2, then P_{ob} in a layer with length of 80m in depth of 3593m equal to 834678036 +409 +455466392 =880,224,837 bar.

Notes of table 5: 1. Pi is the normal pressure before the start of operation. 2. The q_{max} obtains from last fluid injected (usually water) and q_{mim} is the rate of water mixed with solvent in situation of either pre- or after-flash. 3. The amount calculated of B_k in the oil-wet rocks of oil layers is more than the water-wet rocks of oil layers.4. μ and ρ are kg/m-s and kg/m^3, respectively. 5. 1bbl = 0.159m^3. Nomenclatures of table 5: A_{we}= sectional area of well; r_w=radius of well; V_p=volume of reservoir fluid; q_p=last production rate; C_{mu}= mutual solvent concentration; B_k = removed water block; ac=acid; O.W=oil wet; w.w=water-wet; inj= injection; o=oil; w=water; mu=mutual solvent

9. Conclusions

1. The previous findings on this subject is in the form of experimental investigations and so far have not been introduced any equations for this damage in the reservoirs of water, oil and gas, therefore, the limitations are an integrated methodology in order to interpret the underground interactions of fluid and rock after injecting acids and other fluids for estimating the removed water block. The approach is also introduced so as to provide computational methods so that determine how much and how the blocked fluid is removed from the definite strata around the wellbore after injecting acids and solvents.

2. The result of this research is the equations of removed water block (B_k) in the oil wells (Eqs. 6.1 to 6.4). While increasing depth (h) in the reservoirs the porosity (φ) decreases that this is a previously-known research. But the C_m or the same percentage solvent used according to the factors indicated in equations decreases over these variations. Under these conditions in which the acid expending (I_k) is more, the rate of blocking (q_B) as a quantity obtained from the outcome of equations in such a low porosity media with relatively usual permeability is low and the amount of the (B_k) is less. Therefore, the certainty of (I_k) as a quantity determining the amount of water block in equations of the (B_k) could conclude

how decide to treat water block the zone surrounding the wellbore that encircled by the other layers.

3. While using the solvents (e.g., mutual solvents) in the dense oil and water reservoirs, low flow rates should be used during injecting high viscosity mutual solvents (HVMSs) and low viscous mutual solvents (LVMSs). As discussed in section of findings, the increase of rate during the blocking of water and before the injection of solvents can mainly be efficient only in loose reservoirs. Under these interactions, the amounts of pH in (HVMSs) contrary to (LVMSs), at first, decrease and again in the higher temperatures commonly increase slightly.
4. The high viscous solvents (HVSs) have a gradually development in the water injection wells and this improvement rises in the high-temperature oil wells of the dense reservoirs, as comparing to the water injection wells.
5. HVSs have commonly a lower surface tension than LVSs, thus should show a better potential reducing the surface tension between the two fluids. Nevertheless, the HVSs with alkaline characteristic have a weaker performance in water wells than that of oil wells. Consequently, the starting point of the HVSs in affecting the permeability development occurs in the lower temperature. If the HVSs are used in acidizing processes as after-or pre-flash, then should be given a great time for the better performance of solvent, as this waiting time in the water wells is more than it in the oil wells.
6. Since the increase of flow rate has the significant influence in pushing water blocked in the permeable reservoirs, in the loose water-wet rocks the performance of the LVSs is more than the HVSs as well as in the dense water-wet reservoirs the treatment speed of damages by the solvent is lower. However, the effect of high viscosity mutual solvents and low viscous mutual solvents in loose reservoirs is averagely more than dense reservoirs.

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Nomenclature

Physical quantities K = absolute permeability, md ρ= density, kg/m^3 V=volume, m^3 W=weight, kg L=length, m T=temperature,^{0}F μ=viscosity, kg/m-s A_w=sectional area, m^2 P=pressure, bar or psi φ= porosity, % ΔP=pressure loss, psi q=rate, m^3/s q_{mam}=maximum rate, m^3/s q_{mim}=minimum rate, m^3/s q_B= rate of blocking the fluid, m^3/min C_{mu}=mutual solvent concentration D_s= salinity degree, ppm H_{Mg}= hardness of Mg, ppm pH=potential of hydrogen d_1=inter-granular space, m d_2=inter-fracture space, m d_3=width fracture, m I_k=Coefficient of Karimi, Expending (acid expending ability), mK or T^0 m mk= a unit of measure of acid expending ability B_k= removed water block or power of removal the damage by chemical, m^3/min × (T^{0}m)$^{-0.5}$ Subscripts r=rock b=bulk d=dry w=water w.w=water-wet o=oil o.w=oil-wet ac=acid mu=mutual p=pore B= blocking of water ob=overburden pressure HVMS=high viscosity mutual solvent LVMS=low viscosity mutual solvent HVSs=high viscosity solvents LVSs=low viscosity solvents Superscripts C_1=solvent percent Numbers A=convert Kgf to bar Functions, etc μ_O= equation of oil viscosity P_{ob}= equation of overburden pressure $(B_k)_{o.w}$= equation of removed water block in oil -wet oil wells $(B_k)_{w.w}$= equation of removed water block in water- wet oil well

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