Petroleum and Coal

Article Open Access

Mitigate Formation Damage due to Fines Migration through Experimental Work on Abu Rawash Sandstone using Different Nanofluids

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Received January 16, 2020; Accepted April 20, 2020

Abstract

The term formation damage is known as any decline in well productivity. Formation damage due to fines migration is a major reason for well productivity decline for oil and gas wells. Formation Fines are defined as any loose or unconsolidated particles in the pore space of the porous media. These fines are small enough to pass through 400 U.S. mesh screen or pore throats causing pore plugging and permeability decline. The formation damage mechanism related to fines migration includes that surface attachment, pore-throat bridging or straining and infiltration sedimentation. Different factors affected on fines migration such as flow rate, salinity, pH value, Reservoir temperature, oil polarity and as well as the changes of chemical environment induced by Enhanced Oil Recovery (EOR) agents. This paper discussed the effect of flow rates on fines detachment. As the fluid inside the reservoir moves towards the wellbore, the fluid velocity increases and at a critical velocity these fines can be picked up into the fluid and move with it. Different concentrations of nanoparticles were used to fix fine on its sources and prevent its mobilization at different flow rates. Different concentrations of nanoparticles were used to fix fines on its sources and prevent their mobilization at different flow rates. Different concentrations of SiO_2 and MgO nanoparticles were used in treating the Abu-Rawash sandstone reservoir using Formation Damage System Cell FDS-350 (VINIC Technologies). The experimental studies investigated that using MgO NPs would prevent fines detachment from the pore surfaces and decrease the reduction of permeability at high flow rates more than SiO_2 NPs. The optimum concentration of MgO NPs was at 0.5 g/L as the permeability remediation at this concentration reaches to 64.83%.

Keywords: *Formation damage; Fines migration; Nanoparticles; Zeta potential; Permeability reduction; Fluid flow rate; Electrostatic energy forces.*

1. Introduction

Formation damage due to fines migration is a major reason for well productivity decline for oil and gas wells. Fines are defined as any loose or unconsolidated particles in the pore space of the porous media. The formation damage mechanism related to fines migration includes that surface attachment, pore-throat bridging or straining and infiltration sedimentation [1]. These fines are small enough to pass through 400 U.S mesh screen or pore throats [2-3]. They are usually smaller than 37 microns, which can easily migrate with the fluid flow in sandstone reservoirs causing pore plugging and permeability decline [4]. These particles can classify as clay and non-clay particles, charged and non-charged particles and either deposited naturally with rock sediments over geologic times or introduced through complex drilling and completion processes.

Formation fines migration affected by different factors such as flow rates, salinity, pH value, temperature, oil polarity, and the changes of chemical environment induced by EOR agents. Lemon *et al.* [5] reported that the change of salinity of the pore fluid is the main chemical mobilization of fines in oil reservoirs. The contact between fresh water and clay-containing formation can make clays expand, migrate and plug so fines might be released easily [6]. In sometimes decreasing salinity of in-situ fluids increases the pH value and once the pH increases it can dissolve the silica cement causing more fines and the result can be fines migration [1].

The other main factor affected on fines migration is the flow rate (fluid velocity). As the fluid inside the reservoir moves towards the wellbore, the fluid velocity increases and at a critical velocity these fines can be picked up into the fluid and move with it. These fines are captured by porous media and block the pore throat area causing plug of the flow path which leads to productivity decline as shown in Figure 1.

Moreover, low salinity water is a main factor on the fine's detachment from the rock surface. Faergestad [7] mentioned that Clay particles found in the reservoir rocks such as smectites, kaolinites and illites become unstable as a result of swelling or expansion of lattice space of a clay particle, at low-saline water or fresh water. Clay minerals can expand and increase in volume up to 20 times of their original volume through adsorption of layers of water between their unit cells.

The negative charge nature of clay minerals will attract positive ions to align them around the clay plate. Clay lattice cations will exchange places with water solution cations. Clay lattice cations are initially equilibrium with those in surrounding water. As a result of salinity change, the cations exchange process occurs and cause clay particles to swell or break apart and dispersed within the fluid and plug the pore throats.

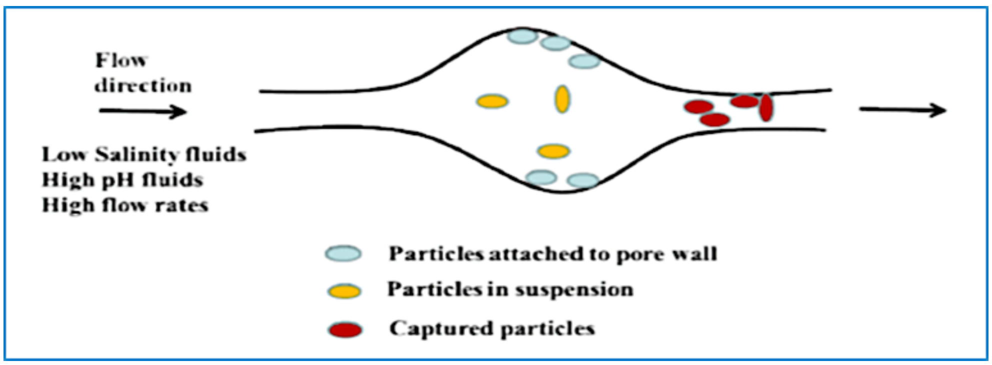

Fig. 1. Blockage of the pore throat area by fines migration [8]

There are different surface forces affected on the detachment of fines and their release from the pore surface, for example, London Van der Walls attraction, double layer and born repulsion and hydrodynamic forces. When the total interaction energy between fines and pore surface becomes positive, that demonstrates repulsive force are bigger than attractive forces and detachment of fines would take place [9-11].

The best technique to prevent fines movement at high flow rates is to fix these fines at their sources. Using nanoparticles with extremely high surface areas is suitable choice for fixate formation fines mobilization by changing the potential surface of fines and grain surfaces. The nanoparticles used in this study to mitigate fines migration are on the order of ten nanometers (SiO_2 ranges from 5 to 15 nm and MgO ranges from 30 to 40 nm) because of their small size compared with the pore throats sizes, nanoflow doesn't have any effect on blockage of pore throats or reservoir permeability.

Many studies and techniques have been conducted to mitigate the fines migration or fixation of fines near the wellbore region. Organic and Inorganic control agents had been widely used to reduce fines migration in high water-cut wells. Acidizing or the acidic fracture is one of these agents [12-13]. The acidizing is used to dissolve fines located in the pore throat area in the porous media and enlarge the pore throats geometry to increase the permeability and maximize the wells productivity. The production performance in the wells treated with acidic fracture or acidizing show only high production rates at short time, flowed by a drop-in production because the damage increased by these fines.

Nanotechnology has been widely used in recent years in oil and gas industry. The nanoparticles have a high surface area and small size (1-100 nm) gives it the ability to exist in the small pore throats without changing in the porosity and permeability of the formation. Nanoparticles are used in many applications in petroleum industry such as wettability change, Enhanced Oil Recovery (EOR) and formation damage [14].

Huang *et al.* [13] mentioned that using nano silica in the propping packs strength the attractive forces and fix the suspended fines in the porous media. The nanoparticles used to control fines have high surface forces, electrostatic forces and Vander Walls force, so when the reservoir fines move through the nanoparticles-treated reservoir, the surface force of nanoparticles attract and retain fines, and by this way preventing fines from moving to the wellbore region. The best technique to mitigate fines migration is fixing these fines at their sources. This thesis using unique nanoparticles to fixate formation fines and prevent their movement near the wellbore region.

Belcher and Seth [15] investigated the use of nanoparticles application in the Gulf of Mexico to increase the production life of the well. The nanoparticles were applied along with hydraulic fracturing in order to eliminate the fines migration problem in the well. A lab study was performed to confirm the outcome of this treatment in which two proppant packs were prepared so that one is treated and the other was left as it is, then a solution containing fines was injected in each pack, the effluent solution from each pack was collected. The treated pack resulted in a clear effluent, while the original un-treated pack resulted in a turbid effluent similar to the influent. From the results it was concluded that: the nanoparticles are successful in removing migrating fines including clay and non-clay particles. The case study from Gulf of Mexico also confirmed the effectiveness of nanofluid in eliminating fines migration and increasing significantly the production life of the reservoir.

Gabrysch *et al.* [16] presented a technique to remove formation fines through high temperature acidization by a mixture of organic and HF acid. Conventional acidization jobs include acid washing the screens that are plugged due to fines migration, however this solution is temporarily and requires repetition which consume more time and money. The new technique consists of acidization of the formation to permanently remove the formation fines. There are some considerations that must be taken into account while acidizing a high temperature reservoir, such that the acid must be chosen wisely to avoid further formation damage. Core flow tests were performed at high temperatures in which NMR method was used to compare the pore size distribution before and after the acidizing job. Also screen damage tests were performed in which a screen was placed in from of the core and introduced to fines until it plugs, it is then dried and weighted then placed again in front of the core where acidization is performed, after which it is dried and reweighted. From the results it was concluded that: The acid mixture proved its effectiveness in both tests; in core flow tests the number of large pores in the core increased significantly, while in the screen damage tests the acid was able to dissolve the fines to unplug the screen and at the same time no damage has occurred to the screen itself.

Nguyen *et al.* [1] suggested a new technique to control fines migration by utilizing a polymer; ultra-thin tackfying agent (UTTA). The mechanism consists of injecting the UTTA into the proppant pack or the formation to form a layer around the fines which will allow the fines to be retained at the formation without plugging the pore throats. The tests included the use of a stainless-steel sand pack fitted with pressure gauges at the inlet and outlet in which different sizes of sand smaller than 200-mesh were packed. The experiment consisted of performing two runs, the first run consisted of injecting brine at different flow rates and recording the pressure difference, while the second run consisted of injecting 2 pore volume of UTTA solution after brine injection and also recording the pressure difference. The first run resulted at sharp increase in the pressure difference at high flow rate indicating formation damage due to fines migration, while the second run showed no sharp increase in the pressure difference throughout the experiment. From the results it was concluded that: the UTTA polymer is effective in treating the formation to prevent the migration of formation fines at almost all types of formations; sandstone, carbonate and coals. Also, the treated formations were found to maintain its effectiveness at elevated flow rates.

Rozo *et al.* [17] suggested a new technique of utilizing a non-acid based fluid namely fines migration control agent to mitigate the formation damage resulting from fines migration to address the conventional acidization job limitations. The mechanism consists of mixing a chelating agent with the salt of acid to obtain similar dissolving power as the conventional mud acid. Core flow tests were performed to determine the effectiveness of this treatment, the experimentation was done by using a scanning electron microscope to take photos of the core used. The photos taken show that in case of the fines migration control agent more fines were dissolved, and the pore throats were larger in size. From the results it is concluded that: the fines migration control agent was proven to be effective in dissolving fines reducing the formation damage, also it has the same dissolving power as conventional mud acid. The advantages of the fine migration control agent include lower cost due to its compatibility with the formation and oil and not needing any additional additives, it also takes less treatment time than acidization; 50% less time.

Valdya [18] demonstrated the ion exchange and pH effect on the formation damage as a reason of the fine migration by some experiments which were based on the water flooding, alkaline flooding and drilling fluid design properties. Also, the in-situ release of the clay fines can be the reason of colloidal of permeating fluid change which may be the main reason for huge formation damage in sand quartz which will affect the oil productivity. Valdya and Fogler latest studies on an operation based on the mixture between the high pH and low salinity fluid experiments, as a result of these experiments, our scientists reached to that indeed the change of the pH and the ion exchange can change the water sensitivity and make it incompatible to be injected to the formation during the water flooding technique as it may cause serious formation damage.

2. Experimental work

This study is aimed at studying the surface modification of Abu Rawash sandstone by the adsorption/adhesion of Magnesium oxide and silica dioxide NPs to reduce fines migration and colloid facilitated transport in porous medium. Two types of nano-fluids with different concentrations were investigated. The dynamic adsorption/desorption of the NP was addressed by continuous monitoring of the permeability reduction. It was found that using Magnesium oxide NPs reducing fines migration more than using Silica NPs. Zeta potential measurements indicated surface modification of Abu Rawash sandstone by magnesium oxide NPs.

For the determination of rock properties using the smaller samples (core plugs) and the core plug sample refers to a smaller portion of the whole core sample. A core plug sample is obtained by cutting cylindrical plugs of typically 1.0 or 1.5 inches in diameter and of lengths up to 2.5 inches from a whole core.

The rock properties measurements on core plugs are the most common practice in the petroleum industry, are tended to achieve several goals and the data derived from core analysis are typically utilized by several targets such as the formation damage or/and completion design, petrography and routine core analysis (porosity, permeability, fluid saturation, wettability and so on). The results of helium porosity and absolute permeability values are shown below Table 1. The porosity for six core plug samples used in this work ranges from 21.40 to 23.34%, as well as the absolute permeability were measured ranges from 335.12 to 645.74 mD.

Table 1. Parameters of used cores

Sample ID	Length	Diameter	Porosity	Air Permeability
	L	D	□	K_{air}
	Cm	cm	%	mD
1	5.2	2.4	21.90	473.97
2	5.4	2.4	22.01	484.62
3	5.0	2.4	22.59	548.95
4	4.8	2.4	21.84	335.12
5	4.7	2.4	21.44	402.88
6	3.7	2.4	23.34	645.74

2.1. Materials and methods

Two types of nanoparticles were used in this study. First type was the silicon dioxide NPs (637246 Aldrich) were acquired from Sigma Aldrich, the silica NP_s had particle size of 5–15 nm (spherical, porous). The other type of NPs used was the magnesium oxide Nano powder (549649 Aldrich) and it was acquired from Sigma Aldrich; the magnesium oxide powder had particle size of 30–40 nm. Abu Rawash sandstone cores used in this work were acquired from North Western Desert of Egypt.

The (XRD) X-ray diffraction and mineral composition of the used cores listed in Table 2 were performed at Central Laboratories Sector of the Egyptian Mineral Resources Authority. The nanofluid preparation was done using ultrasonic processor UP400S (400 watts, 24 kHz) at Corex Company labs. Scanning Electron Microscope (SEM) imaging of the studied cores saturated with the nanofluids was performed in Nanotechnology Research Centre (NTRC) at the British University in Egypt.

Table 2. X-Ray diffraction (XRD) of sandstone cores

Mineral	Chemical formula	Semi-Quantitative, [%]
Quartz	SiO_2	89
Kaolinite	$Al_2Si_2O_5(OH)_4$	9
Albite	Na, Ca $AlSi_3O_8$	2

2.2. Practical work

Silica and magnesium NPs were dispersed in distillated water at different concentration using a magnetic stirrer at 400 RPM for 30 min, and then probe sonication was applied using an ultrasonic processor to prevent the agglomerates of the nano-powder and disperse it. Sonication was performed for 120 min (50% amplitude and 0.5 pulse) with breaks every 15 min to avoid overheating. Three different concentrations of nanofluids were prepared for each type of NPs. Two types of NPs with different concentrations were used in this study. Firstly, silica NPs followed by the magnesium NPs.

Core flood tests throw FDS-350 system were performed to study the problem of fines migration damage in Abu Rawash sandstone. The core flood system consists of a core holder connected to a piston cylinder filled with injection nano-fluids. The prepared core samples were inserted in a cylindrical rubber sleeve and loaded into the core holder as shown in the schematic of the setup core flood system shown in Figure 2. As well as another pump and cylinder filled with confining oil was used for applying confining pressure on the core. The overburden pressure applied on these cores was 2000 psi and temperature 100°F (37.8°C). The brine concentration of the reservoir was 200,000 ppm. The experimental methods used in this study were explained in details in the following sections.

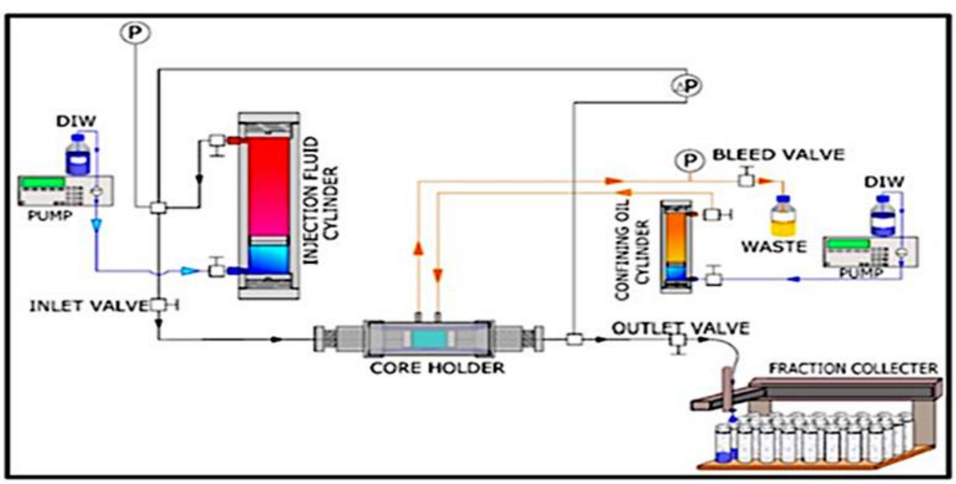

Fig. 2. Setup of experimental flooding

To investigate fines movement while production processes the core was vacuum before saturated. Saturation of core samples with formation water and nanoparticles solutions was done by using auto saturator. The samples were vacuum saturated for 12 hours. Firstly, the cores were saturated with 1.0 pore volume of formation water with 200,000 ppm. Followed by injection of ultra-filtrated water with different flow rates to address the effect of flow rate on fines movement. The same process was applied on reverse inlet-outlet orientation of the previous process and the produced effluents and permeability reduction was recorded in each process. It noticed that the permeability reduced by increasing the rate of injection on the normal inlet-outlet orientation of the process and began to increase again on reverse inlet-outlet orientation as shown in Table 3. It shown that permeability increases with increasing the flow rate and at a critical flow rate (2.0 cc/min) the permeability begins to decrease as a result of fines movement.

Table 3. Permeability reduction through different flow rates

Sample ID	Type of fluid injected	Flow rate, Q	Flow rate, Q	Permeability at reverse direction (outlet-inlet direction)
		cc/min	cc/min	mD
1	Ultra filtrated water	0.5	0.5	219.08
		1.0	1.0	222.42
		1.5	1.5	229.19
		2.0	2.0	231.02
		2.5	2.5	236.82

3. Results and discussion

Nanotechnology has been widely used in many aspects in oil and gas industry. Nano solutions that contain nanoparticles have a unique chemical, electrical and magnetic properties which give it the opportunities to improve oil and gas production by making it easier to separate oil and gas in the rock reservoirs. These nano-solutions were designed by adding a certain nanoparticle to a fluid in order to enhance or improve its properties or performance. Essentially, nano-sized particles were suspended in the fluid phase in low volumetric fractions. Accordingly, the fluid or liquid phase can be any liquid such as oil, water or conventional fluid mixtures. To study the effects of different fluid flow rate and concentrations of nano-solutions on the permeability history with used the nano-fluids.

The best technique to prevent fines movement at high flow rates is to fix these fines at their sources. Using nanoparticles with extremely high surface areas is suitable choice for fixate formation fines mobilization by changing the potential surface of fines and grain surfaces. The nanoparticles used in this study to mitigate fines migration are on the order of ten nanometers (SiO2 ranges from 5 to15 nm and MgO ranges from 30 to 40 nm) because of their small size compared with the pore throats sizes, nanoflow doesn't have any effect on blockage of pore throats or reservoir permeability. It has investigated that nanoparticles can change the Zeta potential values, which as a result can reduce the double layer repulsion force between fines and grain surfaces of the rock, so prevent fines detachment from the grain surfaces.

The main function of nanoparticles in this study is to reduce the repulsion forces between fines and grain surfaces. The potential surfaces of fines are usually less than the potential surfaces of rock grains, so the nanoparticles injected would have a stronger attractive force with fines than that with rock grains. Therefore, the nanoparticles are coating the fines surfaces rather than the pore surfaces as shown in Figure 3. Adsorption of nanoparticles on the fines surfaces could change the surfaces potential of fines, which consequently reduce the repulsion force between fines and grain surfaces.

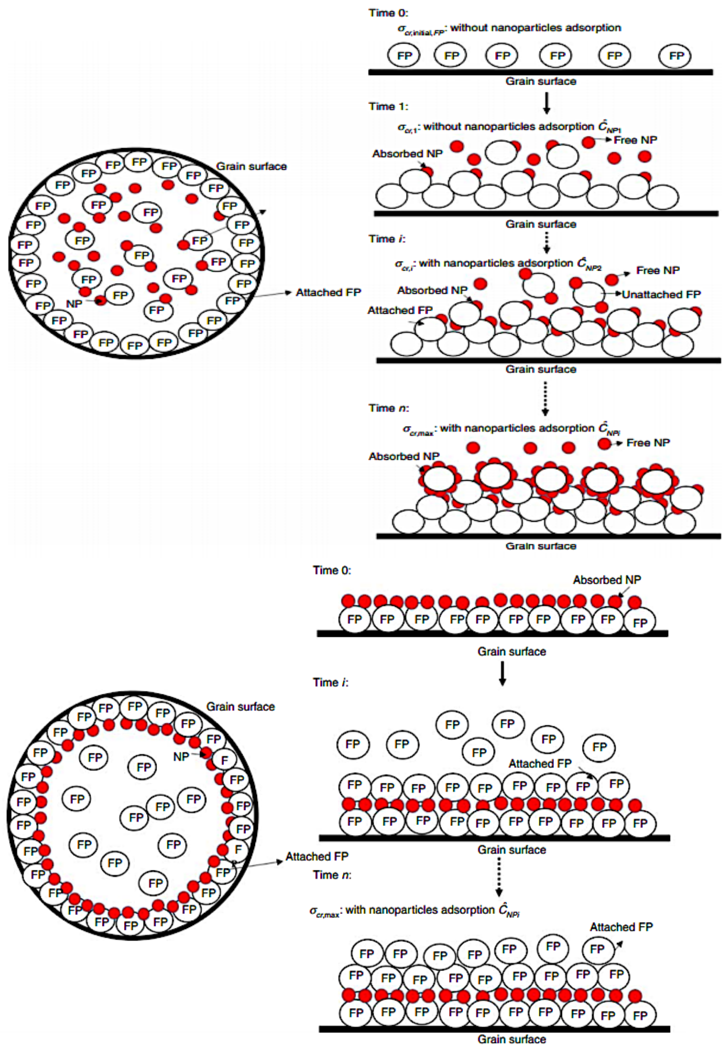

Fig. 3. Adsorption of nanoparticles on the fines surfaces mechanism [19]

The results from experimental design indicate the effect of different nano-particle concentrations and fluid flow rates in the porous medium on the fines detachment from the grain surfaces. The results include the addition of different coated concentrations of 0.25, 0.50, and 0.75 wt. % or g/l from SiO_2 and MgO NPs that is reduce the fine migration by range of percentage compared to the reference case (without coated).

3.1. Effect of nano-particles concentration

First of all, three different experimental tests have been designed to investigate the effect of different concentration of nanoparticles with different two types of NPs that used to mitigate or reduce fines migration and surface modification of Abu Rawash formation. In addition to, the following Table illustrate the changing of permeability for selected core plug samples with different nano-fluids concentration 0.25, 0.50 and 0.75 g/l for SiO_2 and MgO nano-particles types. Table 4 illustrate the design of experimental tests for parameters selecting and their levels.

Table 4. Parameters selecting and their levels for experimental tests

Parameter	Level 1			Level 2			Level 3		
SiO_2 or MgO nanoparticles concentration,	0.25 g/L			0.50 g/L			0.75 g/L		
Injection fluid flow rate, Q, cc/min	1.0	2.0	3.0	1.0	2.0	3.0	1.0	2.0	3.0

The results found in this section has been illustrated in the following values that represent the air permeability, liquid permeability at the initial water saturation through the flood of oil displaced in the core plug sample. Therefore, the liquid permeability after injected the nano-fluid with different fluid flow rate 1.0, 2.0 and 3.0 cc/min has been determined and calculate of the changing of permeability after completing the displacement of nano-fluid.

3.1.1. Effect of SiO_2 nanoparticles

Different experimental tests have been designed to investigate the effect of different concentration of SiO_2 nanoparticles with different nano-fluids concentration 0.25, .0.50 and 0.75 g/L at different injection fluids flow rates ranging from 1.0, 2.0 and 3.0 cc/min to mitigate or reduce fines migration and surface modification of Abu Rawash formation. In addition to, the list of injections and the experimental results are shown in Table 5.

The experimental results show that the permeability has been increased at the same injection flow rate (3.00cc/min) from 197.06 mD at concentration 0.25 g/L of SiO_2 nanoparticles to 542.12 mD at concentration 0.75 g/L of SiO_2 nanoparticles. The permeability remediation has the maximum value in case of using SiO_2 nanoparticles at concentration 0.5 g/L and 3.0 cc/min by percentage of permeability remediation reaches to 12.65 % (from 281.06 mD of untreated samples to 316.35 mD of sample treated with SiO_2 nanoparticles).

Table 5. Different parameters for core permeability measurement and calculate of permeability reduction and percentage for SiO_2 at different concentration and fluid flow rate

Sample No.	Type of Nano-fluid flood	Flow Rate, Q	Air Permeability	Ko @Swi (Before)	Ko @Sor (After)	Decline permeability, Ko @Swi (Before)	Decline permeability, Ko @Sor (After)	Percentage Decline permeability	$K_{final}/K_{initial}$
	at certain conc.	cc/min	mD	mD	mD	%	%	%	fraction
1	SiO_2 at conc. 0.25 g/L	1.0	473.92	181.55	192.24	61.69	59.44	5.89	0.406
		2.0	473.92	181.55	195.04	61.69	58.85	7.43	0.412
		3.0	473.92	181.55	197.06	61.69	58.42	8.54	0.416
2	SiO_2 at conc. 0.50 g/L	1.0	484.62	281.06	302.42	42.00	37.60	7.60	0.624
		2.0	484.62	281.06	309.14	42.00	36.21	9.99	0.638
		3.0	484.62	281.06	316.35	42.00	34.72	12.56	0.653
3	SiO_2 at Conc. 0.75 g/L	1.0	548.95	490.21	505.25	10.70	7.96	3.07	0.920
		2.0	548.95	490.21	520.06	10.70	5.26	6.09	0.947
		3.0	548.95	490.21	542.12	10.70	1.24	10.59	0.988

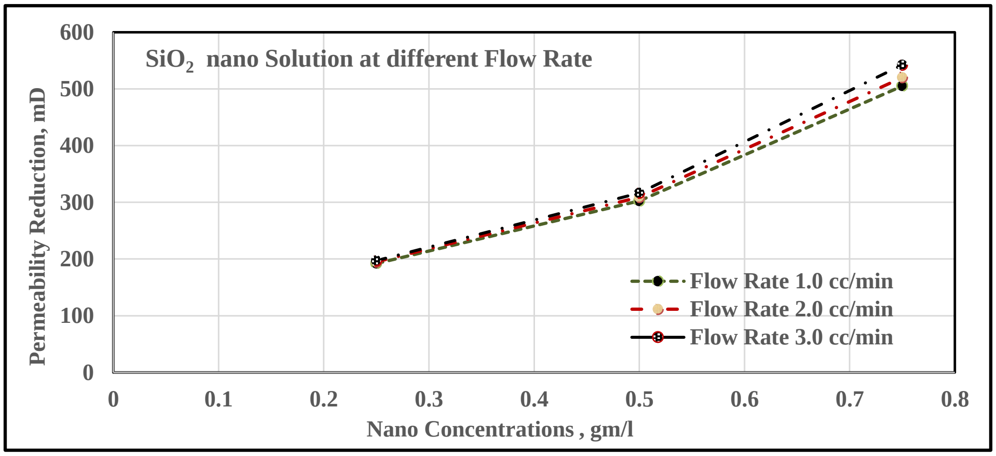

Fig. 4. Compare of permeability reduction through different nano-solutions at nano-concentration of SiO_2 nano particle 0.25. 0.50, and 0.75 gm/L for different fluid flow rate 1.0, 2.0 and 3.0 cc/min

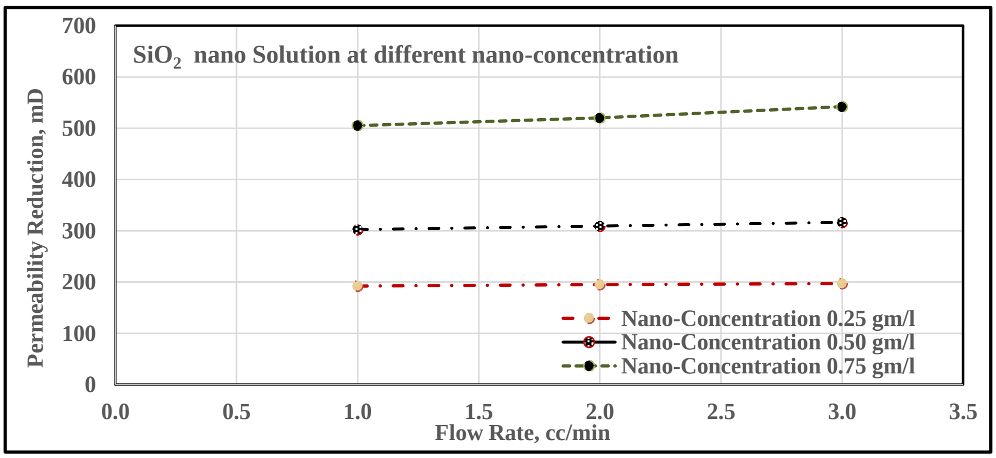

Fig. 5. Compare of permeability reduction through different fluid flow rate 1.0, 2.0 and 3.0 cc/min for different nano-solutions at nano-concentration of SiO_2 nano particle 0.25. 0.50, and 0.75 gm/L

Figure 4 and 5 show a compare of permeability remediation with different nano-solutions at nano-concentration of SiO_2 0.25. 0.50, and 0.75 g/L and different fluid flow rate 1.0, 2.0 and 3.0 cc/min. it shows that the maximum value of permeability was at concentration 0.75 g/L and with 3.0 cc/min flow rate compared with other concentrations and flow rates (from 192.24 mD to 542.12 mD). However, the best remediation value of the permeability was at concentration 0.5 g/l of SiO_2 at flow rate 3.0 cc/min which reaches to 12.65 % (from 281.06 mD of untreated samples to 316.35 mD of sample treated with SiO_2 NPs).

3.1.2. Effect of MgO nano-particles

Different experimental tests has been designed to investigate the effect of different concentration of MgO nano-particles with different nano-fluids concentration 0.25, .0.50 and 0.75 g/L at different injection fluids flow rates ranging from 1.0, 2.0 and 3.0 cc/min to mitigate or reduce fines migration and surface modification of Abu Rawash formation. In addition to, the list of injections and the experimental results are shown in Table 6.

The results found in this table has been illustrated the following values that represent the air permeability, liquid permeability at the initial water saturation through the flood of oil displaced in the core plug sample. Therefore, the liquid permeability after injected MgO nanofluid with different fluid flow rate 1.0, 2.0 and 3.0 cc/min has been determined and calculate of the changing of permeability after completing the displacement of nanofluid.

Table 6. Different parameters for core permeability measurement and calculate of permeability decline and percentage for MgO at different concentration and fluid flow rate

Sample No.	Type of Nano-fluid flood	Flow Rate, Q,	Air Permeability	Ko @Swi (Before)	Ko @Sor (After)	Decline permeability, Ko @Swi (Before)	Decline permeability, Ko @Sor (After)	Percentage Decline permeability	$K_{final}/K_{initial}$
	At certain conc.	cc/min	mD	mD	mD	%	%	%	fraction
4	MgO at conc. 0.25 g/L	1.0	335.11	222.77	285.14	33.52	14.91	28.00	0.851
		2.0	335.11	222.77	310.60	33.52	7.31	39.43	0.927
		3.0	335.11	222.77	322.01	33.52	3.91	44.55	0.961
5	MgO at conc. 0.50 g/L	1.0	402.74	236.62	336.52	41.25	16.44	42.22	0.836
		2.0	402.74	236.62	346.16	41.25	14.05	46.29	0.860
		3.0	402.74	236.62	390.02	41.25	3.16	64.83	0.968
6	MgO at conc. 0.75 g/L	1.0	645.74	398.28	525.04	38.32	18.69	31.83	0.813
		2.0	645.74	398.28	562.14	38.32	12.95	41.14	0.871
		3.0	645.74	398.28	591.08	38.32	8.46	48.41	0.915

Figures 6 and 7 show the changing in permeability through different fluid flow rate 1.0, 2.0 and 3.0 cc/min and the permeability changing through different nano-concentration of MgO nano particle 0.25. 0.50, and 0.75 gm/L. It shows that the maximum remediation of permeability was at concentration 0.75 g/L and with 3.0 cc/min flow rate compared with other concentrations and flow rates.

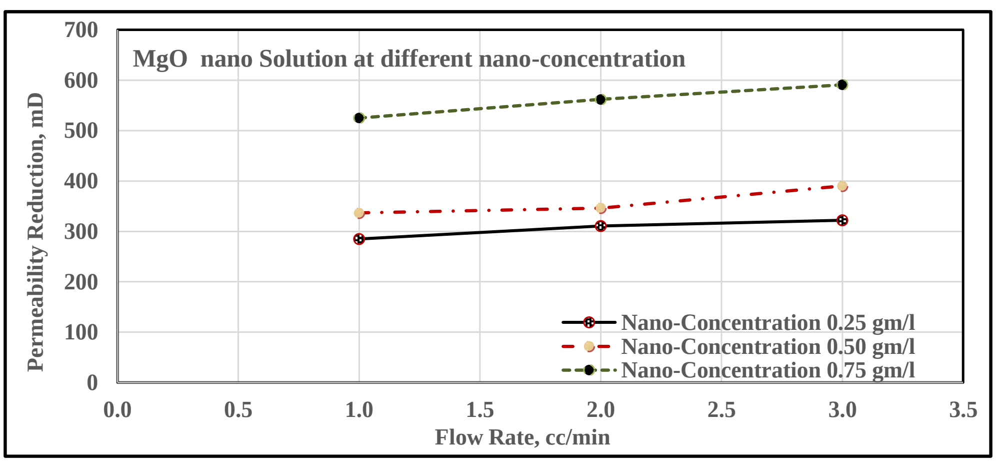

Fig. 6. Compare of permeability reduction through different fluid flow rate 1.0, 2.0 and 3.0 cc/min for different nano-solutions at nano-concentration of MgO nano particle 0.25. 0.50, and 0.75 gm/L

Figure 8 illustrated the relationship between nano-fluid flow rate versus ratio of final permeability to initial permeability (air permeability) for SiO2 and MgO nano-particles at different concentration 0.25, 0.5 and 0.75 g/L. Therefore, the ratio final permeability result after displacement of nano-fluids and permeability result before flooding their fluids for SiO_2 and MgO nano-particles types used at different concentration 0.25, 0.5 and 0.75 g/L for both.

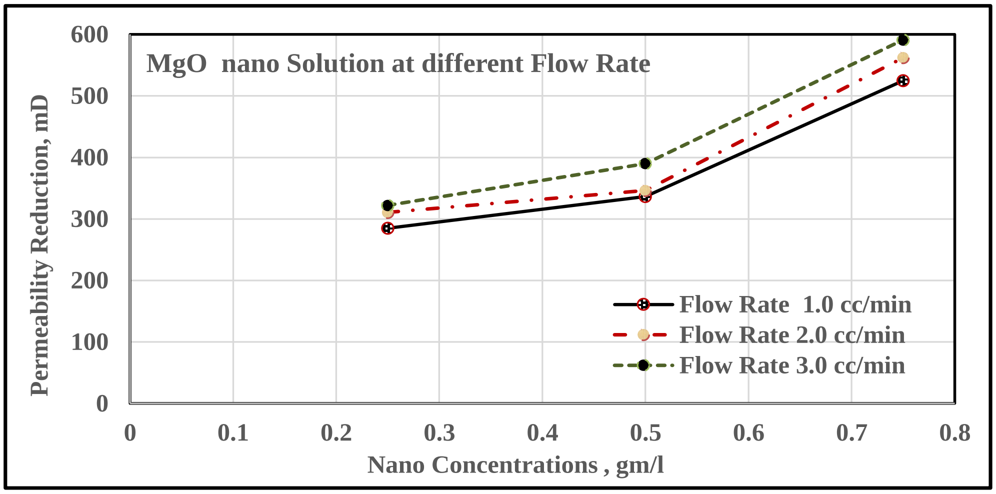

Fig. 7. Compare of permeability reduction through different nano-solutions at nano-concentration of MgO nano particle 0.25. 0.50, and 0.75 gm/L for different fluid flow rate 1.0, 2.0 and 3.0 cc/min

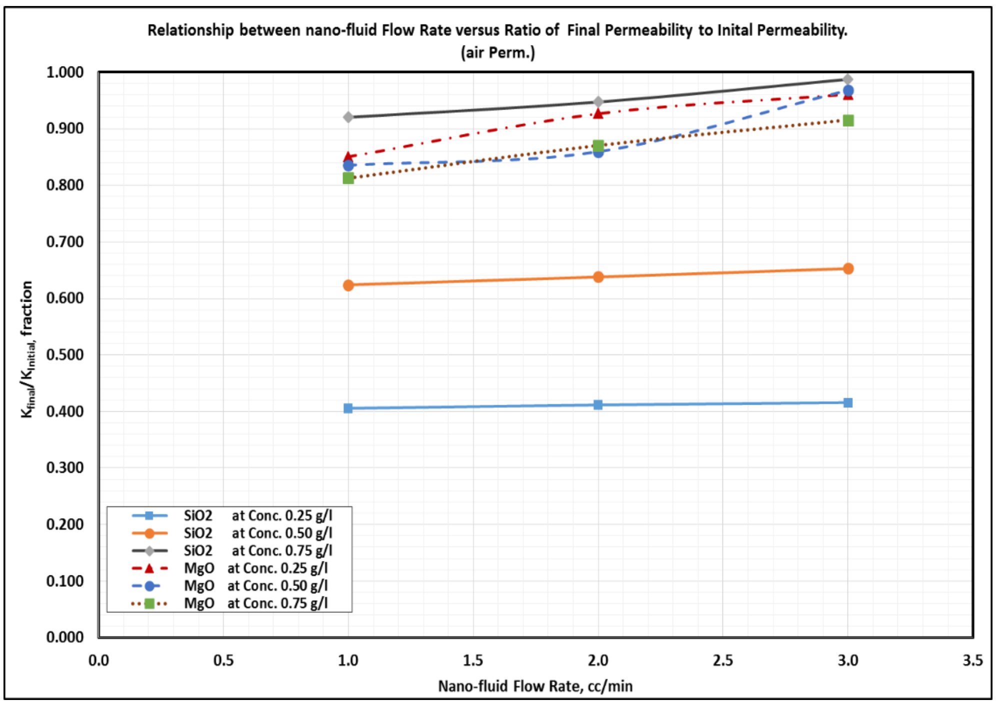

Fig. 8. Relationship between nano-fluid flow rate versus ratio of final permeability to initial permeability (air permeability) for SiO_2 and MgO nano-particles at different concentration 0.25, 0.5 and 0.75 g/L

Based on the experimental tests design used for this study, it's found that the reduction of effective permeability decreases with increasing the nano-fluids concentration were investigated in three levels of experiment procedure techniques. It found that the best ratio present in the use of MgO nanoparticles at certain concentration of 0.5 g/L that other cases of the experiment tests.

While Figure 9 clearly indicates the calculation of percentage of reduction permeability at different fluid flow rate at 1.0, 2.0 and 3.0 cc/min. Then, MgO nano-particles types by mean pressure differentials between inlet and outlet the fluid reverse. The best result of percentage of changing permeability and reduction of fine migration than another level, which found with MgO nanoparticles at concentration 0.5 g/Lof nano-fluid injected through the porous medium of rock.

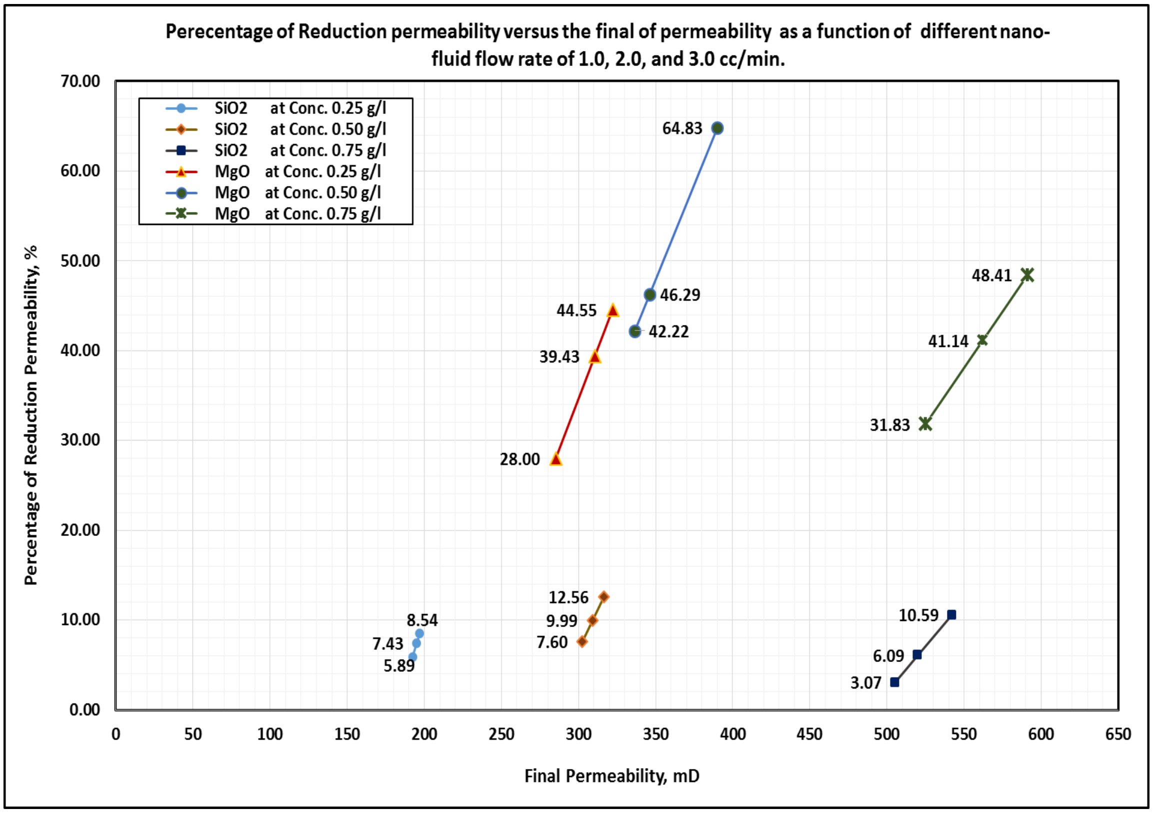

Fig. 9. Percentage of permeability remediation versus the final of permeability as a function of different nano-fluid flow rate of 1.0, 2.0, and 3.0 cc/min for SiO_2 and MgO nano-particles at different concentration 0.25, 0.5 and 0.75 g/L

This figure shows the best concentration, which will be used to mitigate fines migration and improve the permeability, is MgO nanoparticles with concentration 0.5 g/L at flow rate 3.00 cc/min. Using MgO nanoparticles with concentration 0.5 g/L can increase the permeability from 236.62 mD of untreated samples to 390.62 mD of sample treated with MgO nanoparticles with permeability remediation reaches to 64.83%. The figure shows the other percentage of permeability remediation with different nanofluids concentrations at different flow rates.

3.2. Effect of NPs on grain surfaces through (SEM) images

Images of Scanning Electron Microscope (SEM) of Abu Rawsh studied core samples was performed by Field Emission Scanning Electron Microscope (FESEM, Quattro S, Thermo Scientific) with an integrated energy-dispersive X-ray spectroscopy (EDX) to analyze the core minerals at the British University in Egypt Nano Technology Research Center (NTRC). SEM imaging was performed on a slice of core samples before and after application of nano-fluids. Field emission Scanning Electron Microscope was used to measure the elemental analysis with Energy Dispersive X-ray (EDX) and Mapping. Figure 10 shows the elemental of the minerals of the core samples used on these experiments.

A cylindrical slice of Abu Rawash Sandstone was examined using SEM. The images showed that the core was mainly composed of quartz grains and some few iron mineral and the sample has many voids, as shown on images in Figure 11. Another slice of Abu Rawash Sandstone, saturated with different concentrations of NP_s was examined. The coating of NP_s on the mineral's surface was clearly observed as shown on images in Figure 12. This coating of NP_s on the mineral's surfaces cause surface modification, which make this surfaces more effective on capturing and fixing these fines in their sources.

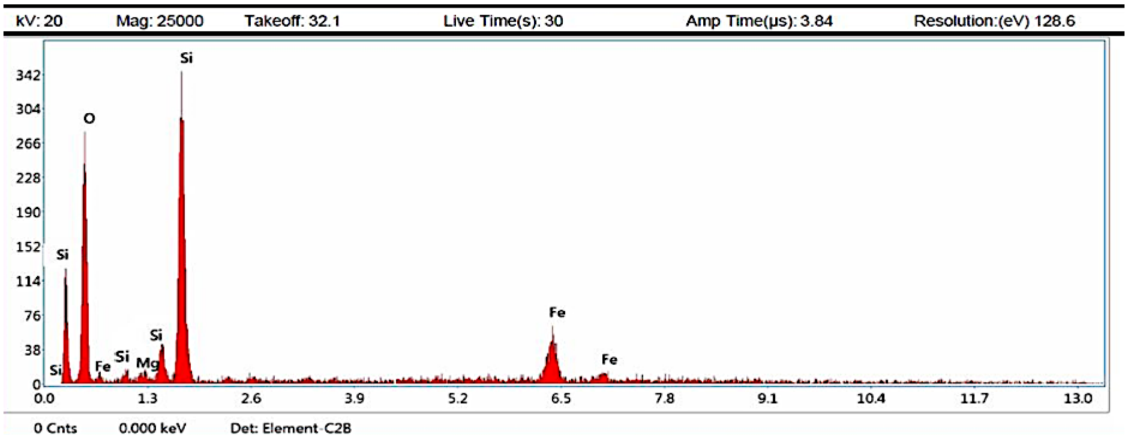

Fig. 10. EDX analysis of sandstone core samples

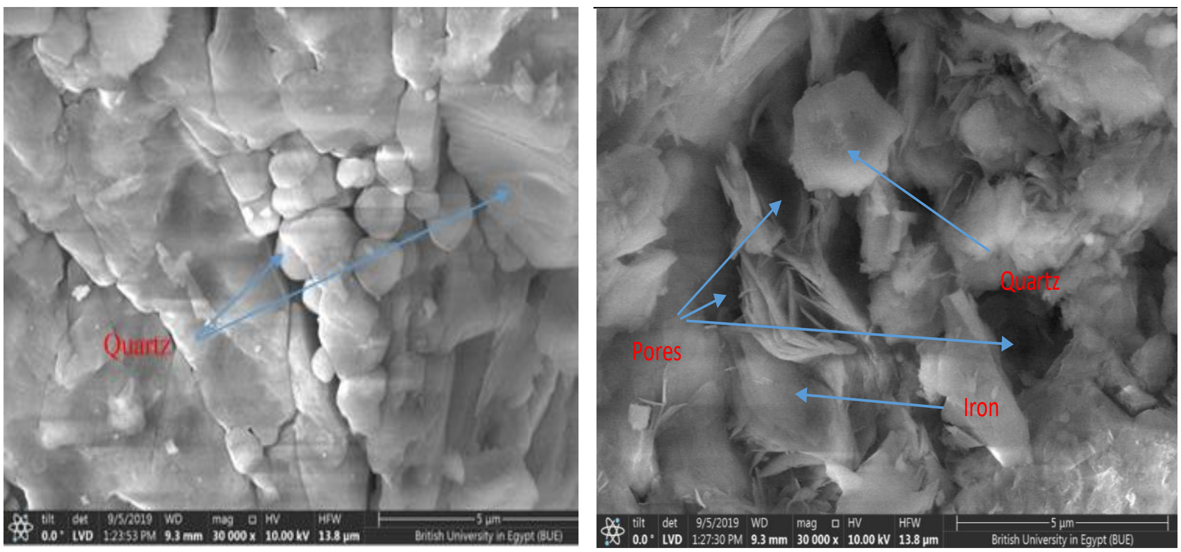

Fig. 11. SEM images of untreated sandstone core samples showing quartz mineral with some iron mineral

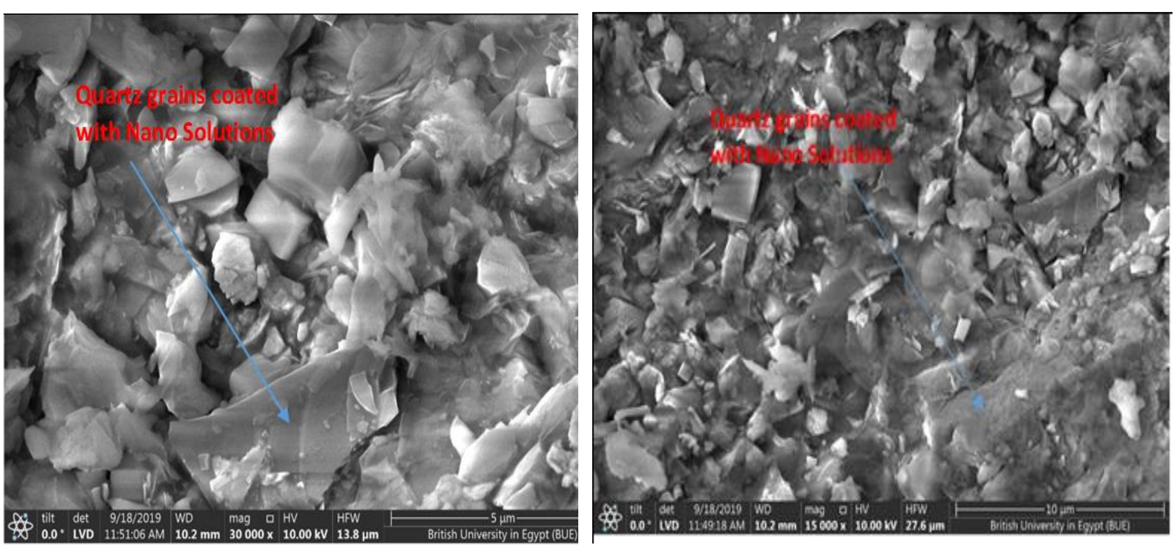

Fig. 12. SEM images of sandstone core samples treated with nanaofluid

4. Conclusions

Two types of nanoparticles were used in this study. Silica dioxide and magnesium oxide nanofluids were used to treat porous media to decrease fines migration and permeability reduction. Different concentrations of nanofluids were used to obtain the optimum concentration, which have more effective on prevent fines migration. Our results in this study shown that the moderate concentration of MgO nanofluid used, could fix fines more effectively than SiO_2 nanofluid. The optimum nanosolution concentration with MgO nanoparticles were found to be 0.50 g/L of nanofluid and would considerably prevent the fine migration.

The experimental studies investigated that using MgO NPs would prevent fines detachment from the pore surfaces and decrease the reduction of permeability at high flow rates more than SiO_2 NPs. The optimum concentration of MgO NPs was at 0.5 g/L and flow rate 3.o cc/min as the permeability remediation at this concentration reaches to 64.83% (from 236.62 mD of untreated samples to 390.62 mD of sample treated with 0.5 g/L MgO NPs).

While the maximum percentage of permeability remediation in case of SiO_2 NPs was at concentration 0.5 g/L and flow rate 3.0 as the remediation percentage reaches to 12.65 % (from 281.06 mD of untreated samples to 316.35 mD of sample treated with SiO_2 NPs).

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