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Mitigation of fines migration by using nano-fluid to alleviate formation damage in Abu Rawash G

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Abstract

Fines migration is a major obstacle confronting reservoir permeability and the most immediate cause of mechanical formation damage. Many oil wells are supposed to produce a high daily production rate at normal conditions but due to migration of formation fines, the reservoir permeability decreases, and subsequence well production declines. When the fluid flow rate increases and reach the critical flow rate, formation fines picked up into the reservoir fluid or gas stream causing plugging to thinner pore throats. This paper studies the effect of nanoparticles such as magnesium oxide, zinc oxide, and silicon dioxide with different concentrations 0.25, 0.5, 0.75 g/L and flow rates 0.5, 1, 1.5, 2 cc/min on fine migration and permeability of nine core samples extracted from Abu-Rawash north of Giza through using core flooding unit. The experimental results found that the magnesium oxide Nano-particles with concentration 0.5 g/L achieved the optimum permeability when compared with zinc oxide Nano-particles and silicon dioxide Nano-particles. Where magnesium oxide Np reduces the repulsion force between pore surface and formation fines, mitigates the migration of formation fines, and improves the permeability after displacement of NP by 68.5% when compared with the original permeability of the core sample.

Keywords: *Fine migration; Permeability; Flow rate; Plugging; Nanoparticles.*

1. Introduction

Fines migration consider one of the most common reasons for formation damage due to movement of fines such as (quartz particles, carbonates, amorphous silica, zeolite, micas, feldspar, salts) which happen in all sandstone formation reservoirs as a part of natural deposition over time and contribution of other factors that accelerate the movement of fines [1]. It is difficult to detect formation damage due to fines migration with direct evidence except for declining productivity over a period of time for weeks or months unlike other types of formation damages that has obvious evidence. Permeability reduction has been observed in oil and gas wells due to lifting, migration, and movement of fines that cause plugging in the pores. Formation fines are introduced as unconfined or loose solid particles existing in the pore spaces of the sandstone formation [2]. The average size of fines is usually less than 37 microns so it is small enough to cause plugging to pore throat and thus lead to permeability reduction [3].

Many factors are affecting fines migration such as flow rate, salinity, change in pH level, the velocity of the fluid, oil polarity, reservoir temperature, rock wettability, residual oil saturation, the fractional flow of oil and water, ion exchange, multiphase flow, matrix acidizing, lifting, and drag forces while production. All these factors increase and accelerate the motion of fines in a sandstone formation. The most significant factors that influence oil and gas wells are flow rate and salinity. The reservoir fluid moves directly to the wellbore with a certain velocity when the velocity of the fluid increases and reaches critical velocity, then these fines picked up into the fluid or gas stream and restrict the movement of fluid. Hence, these fines are deposited and concentrated in the wellbore region which causes a reduction in permeability, therefore, production decreases [3].

Changing in salinity of the water is one of the most significant factors that influence the mechanism of fines migration. Khilar *et al.* [4] showed that the value of critical salt concentration (CSC) equals 4125 ppm, as well as the concentration of injected fluid, must exceed the critical salt concentration value in order to prevent permeability reduction. There are different effective forces between fines particles and the surface of pores such as electric double layer (repulsion force), born (repulsion force), London van der Waals (attraction force) hydrodynamic potential (repulsion force). When the salinity of water decreased, the electrostatic repulsive force directly increased due to the negative charge that exists on the fines and surface of the pores no longer shielded. Moreover, when the electrostatic repulsive force exceeding the attractive force of van der Waals, the fines are mobilized and released induced size expulsion and concentrated near the well pore region causing permeability reduction.

Several studies have been done to find the optimum way to mitigate the migration of formation fines and remove the deposition of loose fines near the wellbore region that plugged the pore throats induced permeability impairment for example high-temperature acidization, developed acid systems, organic and inorganic clay agents in oil wells, sand exclusion in several completion techniques, and gravel packs [3].

Nanotechnology has become one of the best possible solutions in all sectors of oil and gas. In the last few years, the application of nanotechnology contributes to solving a lot of obstacles through several petroleum disciplines such as exploration, reservoir, production, completion, drilling, and refinery [5-10]. Nanofluid refers to a very small material called nanoparticles approximately ranged between 1 to 100 nanometers made of oxides, carbides, metals, and base fluids which are consisting of ethylene glycol water and oil. Nanofluid has special and novel characteristics such as chemical and thermal stability, large surface area, small size, environmental friendliness [11], catalytic properties, high conductivity through small-medium with high mechanical strength [12].

Habibi *et al.* [13] investigated the effect of coating the surface of pores media with various types and concentrations of nanoparticles on the migration of fines due to distinctive properties such as large surface area, small size, and highly conductive. Nanoparticles have a small size when compare with pores size and throats so it is easier to use them without any permeability reduction or formation damage. Nanoparticles selected as oxide magnesium silica and alumina (63 nm, 43 nm, 48 nm respectively) Advanced experimental work and zeta potential measurements showed that (MgO) Minimize the repulsion force between sandstone formation fines and grain's surface and increase the attachment of fines to the pores by 21.2% with compared to the initial state (uncoated) unlike alumina with high and low concentration did not minimize the fines migration process.

The (SiO_2) nanofluid core flooding tests were performed to alter the surface properties of pore spaces, enhance the attractive force between pore spaces, and formation fines against the repulsive forces to control fines migration and optimize the critical flow rate. (SiO_2) nanoparticles injection has significant potential to minimize fines migration which indicates that it is possible to design a higher fluid flow rate and higher injection rate. The results of core flooding tests showed that the optimum mass fraction of (SiO_2) nanofluid was 0.1% that decreased the fines migration by 80%. Raising the salinity level of the injected fluid has no impact on the efficiency of (SiO_2) nanofluid in reducing the migration of fines. (SiO_2) nanofluid has a negative charge on it is surface so did not influence the measurements of zeta potential. Analysis using (atomic forces microscope) demonstrated that the SiO_2 nanofluid enhanced the roughness of the pore spaces which is considered the main mechanism of controlling the migration of formation fines [14].

2. Experimental analysis

2.1. Materials

Magnesium oxide NPS (LOT: P28C011 Alfa Aesar) APS powder with a particle size of 5- 20 nm (porous, spherical), Zinc oxide NPS (LOT: W13C015 Alfa Aesar) APS powder with a particle size of 20-30 nm (porous, spherical), and silicon dioxide NPS (LOT: MKBR5721V Aldrich) nano-powder with particle size 5-15 nm (porous, spherical) 99.5% trace metals, were used during experiments with different concentration of NPS (0.25, 0.5, 0.75) g/l.

2.2. Nanofluids preparation

Magnesium oxide NPS, zinc oxide NPS, and silicon dioxide NPS were dispersed in double-distilled water (DDW) at different concentrations (0.25, 0.5, 0.75) g/L each Nanofluid solution was mixed by using a magnetic stirrer for 45 minutes to obviate the precipitation of nanoparticles then used ultrasonic probe (0.5 HZ, 400 W) for 30 minutes to avoid the agglomerates and ensure the stability and homogeneity of prepared solutions.

2.3. Experimental flooding setup

DCI test systems provide special core flooding tests were conducted to study the effect of fines movement on effective reservoir permeability through examine nine core plug samples extracted from Abu-Rawash sandstone formation with the possibility of injecting different types of nanoparticles to mitigate fines migration. DCL core flooding systems consist of a single-core holder that encloses the plug sample connected to confining pressure control system that controls the confining pressure through the core sample, the core holder subjected to three cylinders. As shown in Figure 1, the hydraulic piston pump allows the fluid to flow through the core sample with desired flow rate. after initiation of the reservoir, the fluids produced from the outlet valve are measured at a certain time. Finally, the Darcy equation is used to calculate the effective reservoir permeability before and after using Nanoparticles.

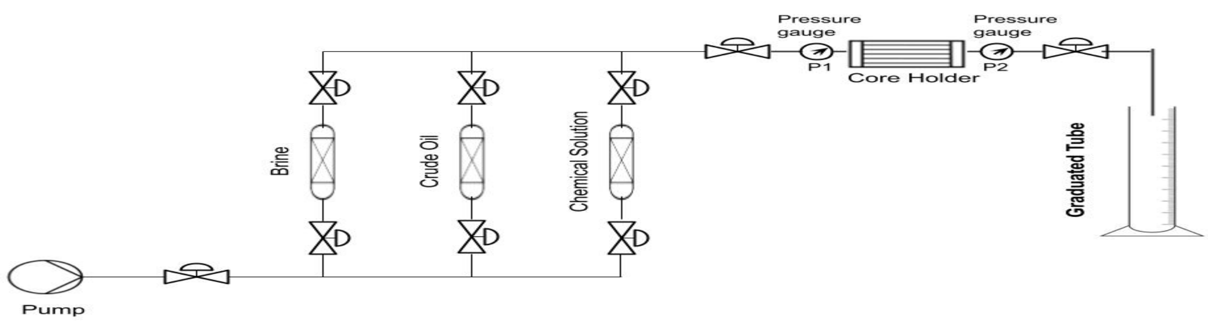


Fig. 1. The schematic diagram for the flooding system

2.4. Experimental work

Authors investigate the effect of three types of nanoparticles magnesium oxide, zinc oxide, and silicon dioxide on nine core samples extracted from Abu-Rawash G formation (1 inch in diameter) by using different concentrations of NPS (0.25, 0.5, 0.75) g/L and different flow rates (0.5, 1, 1.5, 2) cc/min in order to mitigate the fines migrations to alleviate formation damage. some laboratory works have been done to study the movement of formation fines at the critical flow rates and explain the reduction of reservoir permeability through the experiments. The total interaction energy between formation fines and pore's surface that are reasonable for attachment and detachment of fines was measured. We found throughout the experiments that magnesium oxide mitigates the fines migration and enhances the reservoir permeability by 68.60 %, zinc oxide NPS and silica oxide NPS showed less effectiveness through laboratory work. As shown in Table 1, the absolute permeability and porosity were measured using a liquid permeameter device and water saturation method, respectively.

Table 1. Physical Properties and dimensions of core samples

Core samples	Length (cm)	Diameter (cm)	Porosity (Φ, %)	Permeability (MD)
1	4.91	2.54	23.56	409.34
2	4.75	2.54	23.76	418.54
3	4.28	2.54	22.92	365.28
4	3.65	2.54	23.27	390.76
5	4.32	2.54	24.62	466.09
6	4.86	2.54	22.82	312.96
7	3.95	2.54	21.08	264.35
8	3.73	2.54	21.68	296.45
9	4.83	2.54	23.96	445.6

3. Results and discussion

3.1. Critical flow rate test

In order to determine the critical flow rate or critical fluid velocity that is reasonable for fines detachment and movement in narrow pore throats induced decline in reservoir productivity and injectivity. This test has been conducted in two different directions of the core plug sample (inlet and outlet). The sample was prepared by being evacuated the sample from the air, then saturate the core plug sample for 24 hours with brine water 200 ppm using sodium chloride (NaCl), after that the double-distilled water was injected with various flow rates to study the effect of high flow rate on detachment of formation fines.

Table 2. Reduction of permeability at different flow rates

No. sample	Flow rate (cc/min)	Permeability (MD) Normal direction	Permeability (MD) Reverse direction
1	0.5	212.96	217.67
1	1.0	222.51	229.19
1	1.5	234.37	236.72
1	2.0	265.39	242.16
1	2.5	254.36	259.86
1	3.0	249.39	268.82
1	3.5	246.69	271.26
1	4.0	239.71	277.98

As shown in Table 2, due to high flow rate and high fluid velocity the fines detachment at a critical flow rate (2.5 cc/min) induced permeability reduction. Permeability increased before reaching the critical flow rate due to increasing the flow rate until reaching the critical flow rate. Fines start to pick up with the fluid flow through narrow pore throats induced permeability reduction and subsequence productivity decline.

3.2. X ray -diffraction

X-ray diffraction (XRD) is a practical technique used in material science, geology, and industrial application in order to determine the crystallographic structure of the material, measure the shape and the size of atoms, identify the mineral composition and provide information about the physical properties and the chemical composition for organic and inorganic compounds.

The mechanism of X-ray diffraction (XRD) depends on the constructive interference of electromagnetic waves. By sending irradiation material provided by incident x rays, these waves are reflected from crystal atom with a pattern of spots these spots can be used to measure the scattering angel and intensities that reveal the atomic structure in the given compound.

As shown in Table 3, the types of formation fines contain in sandstone core samples are quartz 79%, kaolinite 13 %, Albite 4 %, and feldspar 4 %. XRD analysis test is an essential test by the way of study the interaction changes between various types of formation fines and different types of nanoparticles in order to mitigate fines migration to alleviate formation damage.

Table 3. Mineral composition and the percentage of each sandstone core sample used during the experiments.

Types of minerals	Chemical formula	Semi-quantitative, %
Quartz	SiO_2	79
Kaolinite	$Al_2Si_2O_5(OH)_4$	13
Albite	Na, Ca $AlSi_3O_8$	4
Feldspars	$KAlSi_3O_8$ –$NaAlSi_3O_8$ – $CaAl_2Si_2O_8$	4

3.3. Thin section analysis

Optical mineralogy is the scientific study of minerals and rock properties that provides a detailed image and description of grain contacts, sorting, grain size, and shape. The petrographic thin section is a microscopic slide of approximately 0.03 mm, very beneficial in the case of compositional analysis and identify the rock texture.

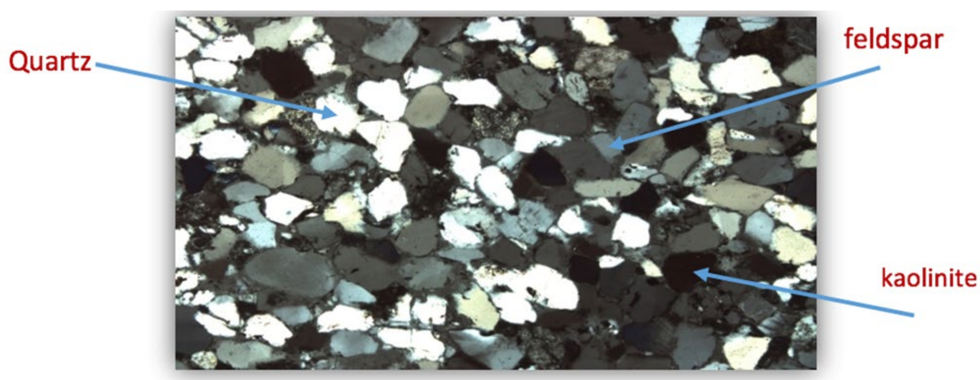
The petrographic thin section is extremely valuable during the production stage where it provides unparalleled information about reservoir homogeneity, reservoir quality, and potential formation damage.

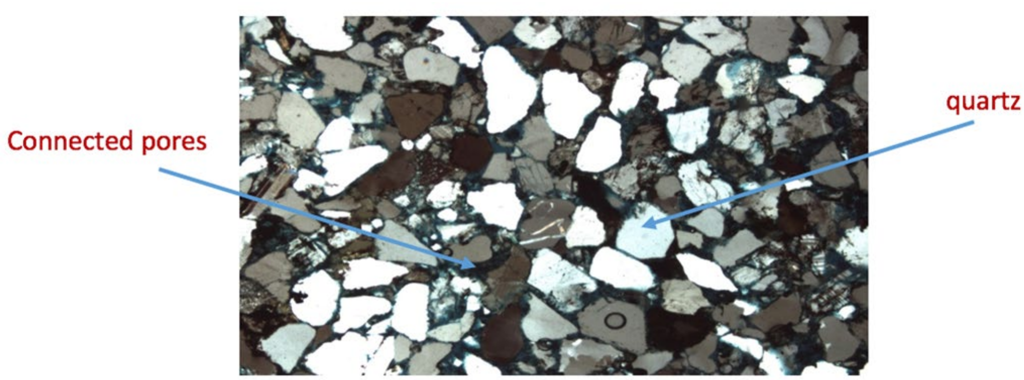
In order to prepare the thin section sample, it requires deliberate procedures such as:

- The samples must be thin enough in order to pass the light through it
- The size of the slice has to be 0.03 mm
- Using diamond saw to cut a thin section of rock
- It has to be mounted on a glass

As shown in Figure 2, the thin section slides and blue staining under the microscope showed that:

- Fine-grain sandstone with quartz grains and quarzitic cement.
- This sample shows high porosity and high permeability.
- The blue color between quartz grains represents the pore inside the sample.
- The blue staining sample shows interconnected pores which means high effective reservoir permeability.





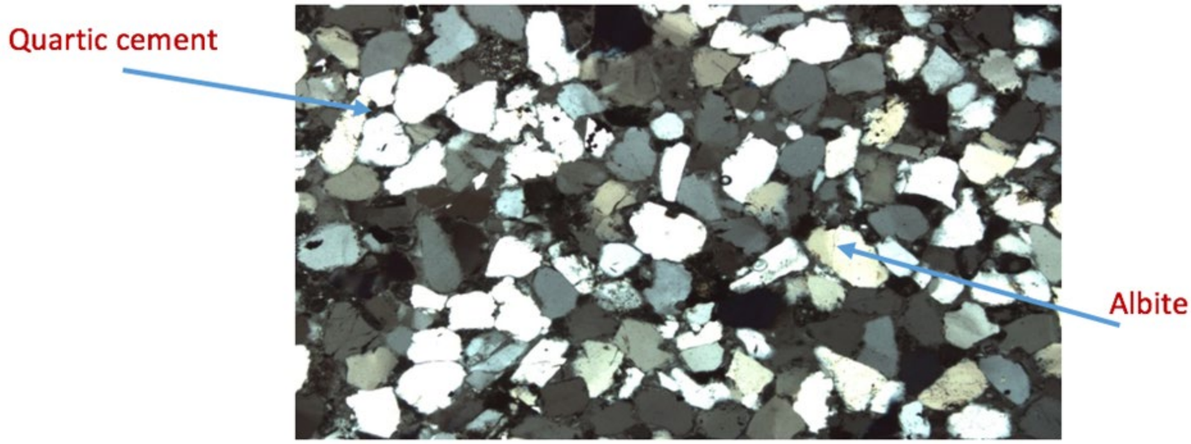


Fig. 2. Thin section slides and blue staining under the microscope

3.4. Core flooding tests

3.4.1. Effect of ZnO nano-fluid on permeability

Zinc oxide nanoparticles have been selected with different concentrations of 0.25, 0.5, and 0.75 g/L and flow rates 0.5, 1, 1.5, and 2 (cc/min) to study the effect of ZnO NP on fines detachment. As indicated in Table 4, the experimental results represent the effect of different concentrations of ZnO NP on effective permeability before and after displacement of Nanoparticles in order to determine the optimum type of nanoparticles and optimum flow rate to mitigate fines migration and enhance the reservoir productivity.

Table 4. Permeability Measurement at different flow rates and concentrations of ZnO Nano-fluid.

Sample No	Type of nano-fluid	Flow rate	Effective permeability K_O, (before)	Effective permeability K_O, (after)	Permeability improvement %
		cc/min	MD	MD	
1	ZnO at conc. 0.25 g/L	0.5	194.49	201.64	3.68%
		1	194.49	202.29	4.01%
		1.5	194.49	206.57	6.21%
		2	194.49	209.03	7.48%
2	ZnO at Conc. 0.5 g/L	0.5	190.66	196.56	3.09%
		1	190.66	198.24	3.98%
		1.5	190.66	203.69	6.83%
		2	190.66	207.52	8.84%
3	ZnO at Conc. 0.75 g/L	0.5	234.95	245.29	4.40%
		1	234.95	249.63	6.25%
		1.5	234.95	253.95	8.09%
		2	234.95	259.36	10.39%

As shown in Figure 3, the effect of ZnO NP on the permeability of sandstone core samples before and after displacement of ZnO NP. The results showed that the permeability has been increased from 234.95 MD to 259.36 MD. Also, when the flow rate increases, the permeability increases albeit to varying degrees. The permeability improvement ranges from 3.68 % to 10.39 % and maximum permeability improvement at concentration 0.75 g/L and flow rate 2 cc/min.

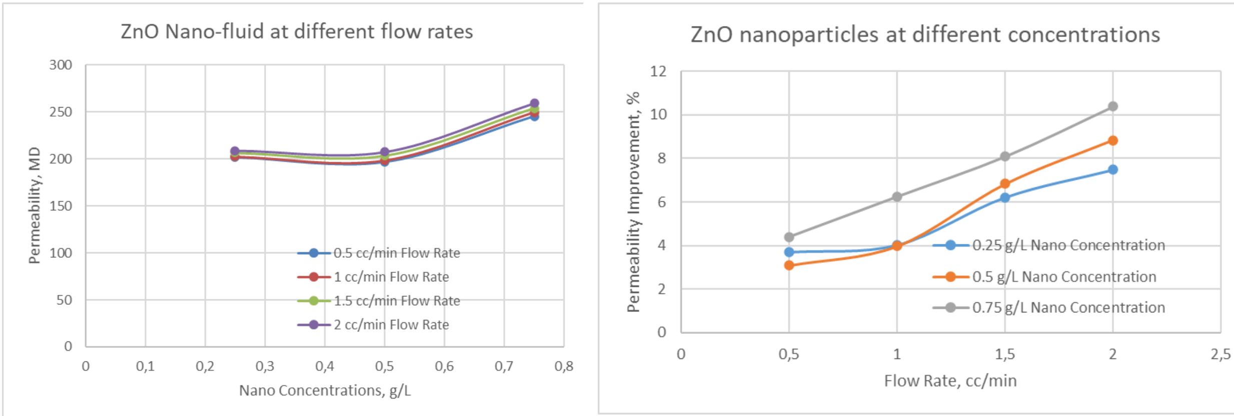


Fig. 3. (a) Permeability (MD) versus ZnO nano-fluid concentrations as a function of flow rates of 0.5, 1, 1.5, and 2 cc/min; (b) Permeability Improvement (%) versus flow rate as a function of ZnO Nano-fluid concentrations of 0.25, 0.5, and 0.75 g/L

3.4.2. Effect of SiO_2 nano-fluid on permeability

Practical work has been done using silicon dioxide with different concentrations of 0.25, 0.5, 0.75 g/L to determine the optimum type of Nano-particles to reduce and mitigate the movement of formation fines through sandstone core samples extracted from Abu-Rawash G formation. As shown in Table 5, the experimental results showed the effective permeability before and after using silicon oxide NP and the percentage of permeability improvement through the experiment.

Table 5. Permeability Measurement at different flow rates and concentrations of SiO_2 Nano-fluid.

Sample No	Type of nano-fluid	Flow rate	Effective permeability K_O, (before)	Effective permeability K_O, (after)	Permeability improvement %
		cc/min	MD	MD	
4	SiO_2 at conc. 0.25 g/L	0.5	270.62	281.75	4.11%
		1	270.62	289.58	7.01%
		1.5	270.62	293.62	8.50%
		2	270.62	296.36	9.51%
5	SiO_2 at conc. 0.5 g/L	0.5	384.65	395.69	2.87%
		1	384.65	401.74	4.44%
		1.5	384.65	411.56	7.00%
		2	384.65	422.39	9.81%
6	SiO_2 at conc. 0.75 g/L	0.5	208.63	220.36	5.62%
		1	208.63	231.58	11.00%
		1.5	208.63	236.97	13.58%
		2	208.63	240.54	15.30%

As shown in Figure 4, the effect of silicon dioxide nanoparticles on the permeability of sandstone core samples before and after displacement of SiO_2. The results indicated that the permeability has been improved from 208.63 MD to 240.54 MD. Maximum permeability has improved by 15.30%. Also, results indicated that when the fluid flow rate increases the permeability increases in a precarious way. finally, silicon dioxide shows more effective than zinc oxide in the way of permeability improvement and mitigation of fines migration.

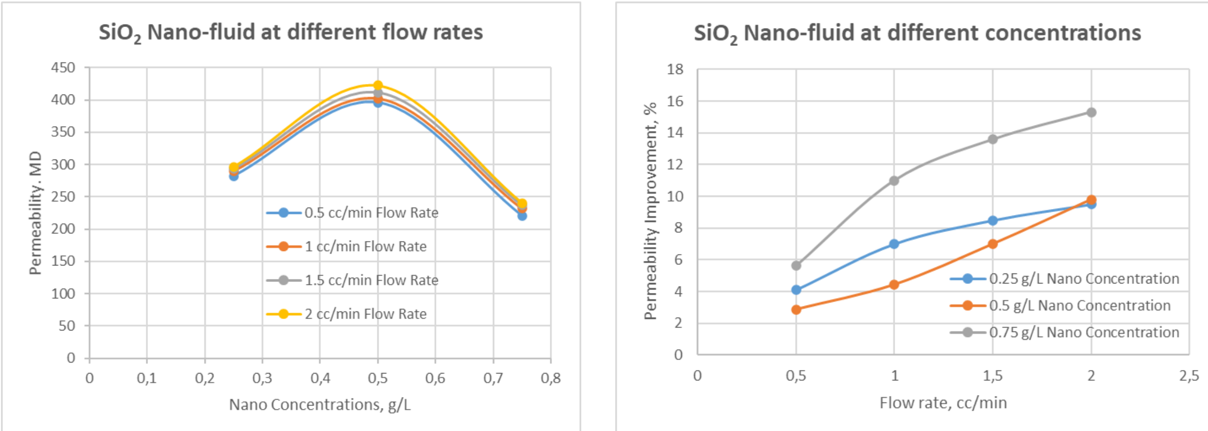


Fig. 4. (a) Permeability (MD) versus SiO_2 nano-fluid concentrations as a function of flow rates of 0.5, 1, 1.5, and 2 cc/min; (b) Permeability improvement (%) versus flow rate as a function of SiO_2 nano-fluid concentrations of 0.25, 0.5, and 0.75 g/L

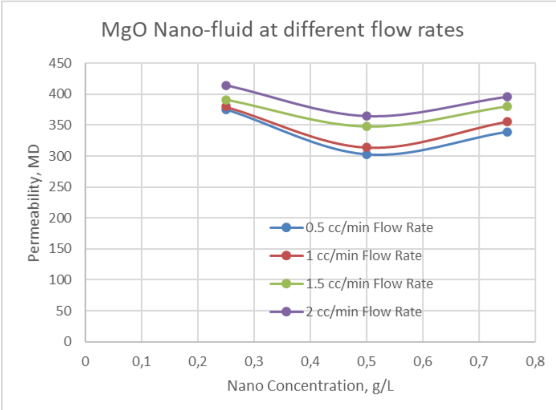
3.4.3. Effect of MgO nano-fluid on permeability

Different concentrations of magnesium oxide 0.25, 0.5, 0.75 g/L and different flow rates 0.5, 1, 1.5, 2 cc/min were conducted to select the optimum type of NPS and optimum flow rate in order to mitigate the fines migration and improve the permeability through flooding experiments. Magnesium oxide remains the suspended fines and retains a high percentage of migrated fines. Magnesium oxide NP minimize the repulsion force between sandstone formation fines and grain's surface and increase the attachment of fines to the pores as shown in Table 6.

Table 6. Permeability measurement at different flow rates and concentrations of MgO nano-fluid

Sample No	Type of nano-fluid	Flow rate	Effective permeability K_O, (before)	Effective permeability K_O, (after)	Permeability improvement %
		cc/min	MD	MD	
7	MgO at conc. 0.25 g/L	0.5	268.29	375.54	39.98%
		1	268.29	379.93	41.61%
		1.5	268.29	391.34	45.86%
		2	268.29	414.54	54.51%
8	MgO at Conc. 0.5 g/L	0.5	216.39	302.61	39.84%
		1	216.39	314.27	45.23%
		1.5	216.39	347.39	60.54%
		2	216.39	364.83	68.60%
9	MgO at Conc. 0.75 g/L	0.5	260.36	339.11	30.25%
		1	260.36	355.93	36.71%
		1.5	260.36	380.29	46.06%
		2	260.36	395.92	52.07%

As shown in Figure 5, magnesium oxide NP with a concentration of 0.5 g/L improves the permeability after displacement of nano-particles by 68.5% with concentration 0.5 g/L when compared with the initial state of permeability. The effective permeability has been improved from 216.39 MD to 364.83 MD. Magnesium oxide archiving optimal results than zinc oxide and silicon dioxide since the maximum results of zinc oxide was 10.39 % with concentration 0.75 g/L and the maximum results of silicon dioxide were 15.30% with concentration 0.75 g/L.



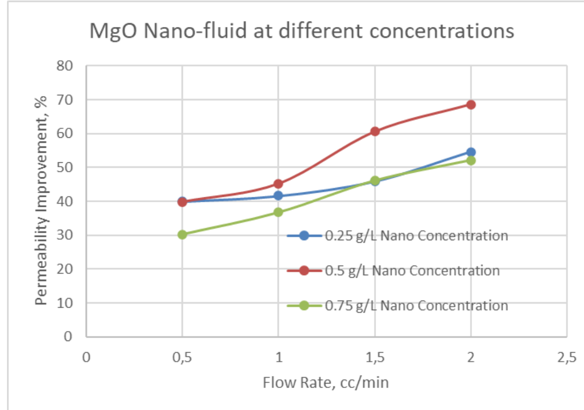


Fig. 5. (a) Permeability (MD) versus MgO nano-fluid concentrations as a function of flow rates of 0.5, 1, 1.5, and 2 cc/min; (b) Permeability improvement (%) versus flow rate as a function of MgO Nano-fluid concentrations of 0.25, 0.5, and 0.75 g/L

4. Conclusion

Magnesium oxide NP with a concentration of 0.5% improves the permeability by 68.5% when compared with the initial state. Magnesium oxide Np reduces the repulsion force between pore surface and formation fines and mitigates the migration of formation fines. Silicon dioxide NP and zinc oxide NP show less effectivity than magnesium oxide NP.

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