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Carbonate rock wettability changes by Nonionic surfactant in water-based drilling fluid

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K E Y W O R D S: wettability, drilling fluids, contact angle, formation damage

ABSTRACT: Formation damage is defined as permeability reduction of Reservoir rock to the fluid production. This phenomenon may be done by several mechanisms and lead to reduce production of hydrocarbon fluid from the wellbore. One of the most important cases of formation damage may be caused by drilling fluid. The influx of solid or liquid particles of drilling mud into the pores of rock or mud loss phenomenon and clay swelling can sometimes lead to severe productive formation damage and cause to wettability alterations of reservoir rock from hydrophilic to oelophilic. Therefore designing an appropriate fluid that is compatible with formation fluids and have the least damage to the reservoir is very necessary that can cause to increase the productivity of wells.The two main mechanisms of surfactants are reduction of the surface tension and wettability alteration of rock reservoir that are effective in taking the oil. Regarding the importance of the wettability in reservoir productivity, this article is aimed to study the effect of non-ionic surfactants polyethylene glycol (PEG) in the presence of acrylamide hydrolysis (PHPA) in water-based drilling fluids. For the measurement of wettability alterations, measurements of contact angle as a quantitative method and tests of buoyancy and separation of the two phases as qualitative methods were used. The mineral calcite was used as a representative of the reservoir rock. The experiment was designed so that the parameters of drilling fluid (fluid loss control, rheology, chloride, potassium chloride, PH, temperature, PEG and PHPA volume percent) is close to the reservoir. In order to simulate reservoir conditions after contact of calcite stone with drilling fluid, we put the sample in cylinder containing of drilling fluids and for more simulation of reservoir conditions the test were repeated at 110 ° C without the presence of surfactants and in the presence of surfactant. The salty water in the reservoir (Dec field) was used to obtain the contact angle. The results of this study showed that Since the reservoir is carbonate and hydrophilic, drilling fluid (without surfactant) makes the reservoir to go into oelophilic state but drilling fluid in the presence of surfactant causes the reservoir to go into hydrophilic state which will follow by reducing formation damage and increasing oil production.

Introduction

Using of the drilling fluid to remove cuttings from the well hole was suggested for the first time in 1845 by Mr Faeoule, a French engineer. Drilling fluid includes a wide range of fluids, gases and liquids that are used in drilling operations to achieve specific goals. Fluids are including air, natural gas, water, oil or a mixture of liquids with additives and special chemicals. Drilling fluids are designed for compensate or reduce many drilling problems and understanding of these goals help to successful designing of program, proper use of additives and dealing with the problematic sectors.

Drilling fluid tasks
Cooling and lubricating the drill and drill string
Clean the bottom of well and carry off the cuttings up to ground
Hold the cuttings suspended while the mud pumping is stopped
Create a filter cake to prevent of destroying the wellbore and filter penetration into the formation
Prevent the entry of fluid into the well by control of formation pressure
Clearance of formation cuttings and sand on shaky bolter
Bearing a part of drill pipe and casing pipe weight
Transferring the pump hydraulic power to drill
Control of well blowout through the mud weight
Minimizing the formation damage

Assessment of different drilling mud

There are different kind of drilling mud that the most important and widely used of them include:

Water-based drilling mud: it is a class of drilling fluids that its liquid component is water.

Oil-based drilling mud: it is a class of drilling fluid that its liquid components are oil and grease.

In the other words each of the above drilling fluid in the particular circumstances based on type of formation and fluid used are used.

When water -sensitive shales are exposed to common water-based drilling fluids, they like to absorb water quickly in drilling fluids that as a result and because of the shale chemical properties swelling or scattering phenomenon can cause to the lack of cohesion in cuttings, wellbore relaxation, twisting and high stress and tensile and pipe sticking. (Bleier, R, 1990)

Reservoir rock damages

Some particles are created during operational activities such as drilling, completion, repair and stimulation of wells or during secondary recovery methods or tertiary recovery. These particles by building bridges between holes and blocking them that lead to reducing the permeability and porosity, and also by filling the gaps that have an essential role in production cause to damage the reservoir. (Sanchez E 2003)(Thomas B 2000). Different kind of reservoir rock damages due to drilling operations on well are including:

Clay swelling

Deposits of mineral water (scales) and cuttings of drilling

Mud weight and other additives

The reaction of the acid and its by-products

Bacteria

Blocking the holes by water drops (water Blocks)

Oil-based fluid (Oil Base Mud)

Inorganic and organic mixed deposits

Drilling mud properties

The type of drilling fluid

Fluid mud selection is one of the most important factors in the formation damage. A well may be drilled by spending a lot of time and money, but due to poor design, the reservoir clay is damaged and during its application the operation is reduced. One of the most important factors in formation damage that caused by Penetration of drilling mud into reservoir is the wettability alterations of reservoir rock. The best type of fluid during the drilling operation and well completion is the fluid that makes the least amount of influx of fluid and solid particles into the formation and is along with the least destructive reactions to the rocks and reservoir fluid, to not changing the amount or type of reservoir rock wettability. The best type of fluid is selected according to the reservoir rock and fluid characteristics.

Mud Weight

Drilling mud weight in the reservoir section should be low to an acceptable level. The research results indicate that the proper mud weight in a higher state of equilibrium pressure (Overbalance) should be approximately 200 psi higher than the formation fluids pressure. One of the important points that should be stated is that there are sometime high pressure organic shales in depleted reservoirs that their pore fluid pressure is about initial pressure of reservoir and if the weight of drilling fluid column is designed based on the current reservoir pressure, it is possible to erupt the well while drilling. During drilling because the hydrostatic pressure (the pressure of the fluid column) is higher than formation pressure, a few drilling fluid losses into the formation (0 to 4 barrels in an hour). In order to increase the mud weight in the reservoirs we use of the solutes. Because the reservoirs are carbonate in Iran, we use the limestone that is similar to reservoir material in order to increase the weight and reduce the formation damages. We use the salt (NaCl) for increasing the water weight (62.4 pcf) to 75 pcf and from 75 to 90 pcf (pounds per cubic foot) we use of limestone (limestone).

Rheology

Drilling fluid rheology is including viscosity and fluid gel strength:

Measuring viscosity is caused by friction between the molecules of the fluid. So when the amount of contact between the molecules is greater, the viscosity is higher. In other words, the local shear stress to elemental shear strain is of the fluid which moves. Most drilling fluids have non-Newtonian behavior. And do not have a constant viscosity and their viscosity varies with shear rate. It means there is no linear relationship between shear stress and velocity gradient.

Gel strength is an amount to express the thixotropy properties of drilling mud. This property depends on the system tensile forces (adsorption) in static mode. Thixotropy properties is an amount to express the drilling mud ability that can make a gel by a liquid phase and vice versa. In fact, it is the fluid ability to suspend the crumbs at a standstill.

Mud jelly properties should change into liquid by stirring. Suspending the drilling cuttings and mud solid particles while shutting down the mud pump will cause to not dropping of cuttings into the well and not sticking the drill. If the drill sticks, it requires to fishing operation. In soft rock where the drilling speed is high, there are a lot of accumulations in the annular space, so in this case jelly-like properties has a great importance. In hard rock by low drilling speed, this property is of less importance. The amount of viscosity and drilling mud jelly strength must be enough that if there is a large solid particles it should be able to hold them suspended to reduce the formation damages (Dolz M 2007).

In other words the exceeding of the viscosity reduces the cleaning operation of the well bottom, increases hydraulic pressure drop in pipes , reduces the hydraulic power of drill and finally increases the well bottom pressure and induces formation damage that is caused by the loss. Also exceeding the viscosity causes to increase the wave pressure (Surge) and suction (Swab), and the formation destruction that is caused by this phenomenon. So the amount of viscosity must be achieved according to their manufacturer characteristics, drilling and optimization of drilling parameters such as weight, round and hydraulic system. In water-based mud, the multiplier viscosity polymers (viscosifire) such as xanthan gum and a pack with high viscosity is high. (Hamed S.B. & Belhadri M 2009).

Filtration

If the fluid filtration rate is lower, the formation has lesser damages. In water-based drilling fluid, free water cause its filtration that react in shales classes with active clay and cause to swelling clay. This increased volume leads to lower permeability in reservoir rock. Clay by the effect of the electrical charge alterations, swell and replace in formation pores cause to sedimentation, damage to the reservoir rock and flat cake in wells. The sensitivity of clay to the water and the clay including in the reservoir rock and clay position, are three main factors in clay swelling. So the free water in formation in the clay should be the lowest amount possible (Horton, D & Jones, A., 1998). Penetration of mud material into the formation cause to emulsion. Iron ions (sulfide), asphaltenes and resins, various kinds of organic acids and aromatic hydrocarbons and circled help to the emulsion balance (water in oil). The biggest problem that is caused by emulsion is at least 4 times viscosity in the flowing fluid that certainly prevented from more production. In order to prevent loss of drilling fluid (Fluid Loss Control) polymers such as green and red starch is used to form thin, smooth and impenetrable filter cake. (Jiao D. & Sharma M. 1994).

Drilling fluid solid percent

If the fluid is free of solid materials or its solid material is as the lowest possible, it will cause to reduce formation damage. By the mud penetration into formation, different deposits are produced These materials are water-soluble chemicals that are deposited by dealing with heterogeneous or incompatible water (water formation or smoothness of mud) with a change in solution equilibrium conditions such as temperature, pressure and flow viscosity. In simple terms their deposits around the wellhead is due to lower temperature and lower pressure while production. These deposits can make problem in tubing or perforation or reservoir rock. The problematic deposits are including calcium carbonate, gypsum, iron deposits, deposits of chloride, barium sulfate, and silica deposits (Han S 2010). In order to control and disable cuttings and drilling deposits (Shale Inhibitor) the materials such as PHPA and KCl are used.

PH

Water-based drilling fluid in an acid environment and PH less than 7, lead to corrosion drilling pipes and arrival of iron deposits into the reservoir environment that is an important factor in asphaltene deposits. Asphaltene deposits in addition to reducing the relative permeabilityand produces sludge with acid or cause emulsion or high viscosity and lead to trap the water particles and blocking the reservoir rock pores. And help to be oelophilic. Also the formation of carbonate have the alkalinity characteristics, reacts in an acidic environment and create water droplets that block the path. (Water Block)

In alkaline environment and PH greater than 10, soluble salt of drilling fluid increase decomposition of formation clay particles such as Kaolinite and Elite and increase dispersion of clay particles that cause formation damage .Also the deposition of calcium carbonate and bacterial growth in high PH, will be led to formation damage.
The results indicate that PH about 9/5 -8/5 will not cause corrosion.

An important point is that sodium carbonate is added to non-ionic surfactants polyethylene glycol (PEG) to a better wettability of reservoir rocks from hydrophilic to oelophilic which makes drilling fluid to be alkaline. While anionic and cationic surfactants in acidic environment have a better wettability on reservoir rock.

Chloride

Chloride ion protects the polymers and cause its better performance in the fluid. Chloride cause to dissolve polymer in water and prevents from polymer flocculation. Moreover prevents from breaking the polymer chains and expantion and solubility in water. If the amount of fluid chloride is high and reach to the maximum (194000 mg / L) it means amount of fluid salinity is reached to maximum (320000ppm) . Due to reducing temperature in surface or partial evaporation of the water in the pipes, chloride deposits are formed that damages the Formation.

If the amount of fluid chloride is low and salt fluid is low, electrostatic bonds between the clay molecules with the fluid molecules are weaken and cause to clay deflocculation. Exposure of clay particles in pipes and large holes increases the possibility of blocking. As a result, the amount of drilling fluid chloride should be between 180000 to 190000 (mg / L).

Total hardness

When the calcium and magnesium that are bivalent ions are present in drilling mud, react with anionic groups on the polymer. If this happens, the polymer accumulates and change to coarse grains and when mud are circulated they drive out of the shaking sieve. The polymers that are a little anionic such as xanthan gum and non-ionic polymers such as starch are influenced by strong features of water absorption of calcium and their efficiency is reduced in the presence of calcium. Because of this when creating the pre-polymer drilling fluid, sodium carbonate (soda ash) is added to remove calcium and magnesium ions from the system.

Potassium

Potassium ions have inhibitory effect (Shale Inhibitor). The effect of clay activities reduction is through ion exchange and lack of formation damage. As the potassium ions put in the space between the sheets of clay, cause to change the clay to cation minerals and reduced their activity and prevents from clay swelling. Ability of a cation for substitution to other cations depends on the nature of cations and their relative concentrations. The use of potassium salts in drilling fluid causes more stability of shale rock and increase the hardness of drill cuttings (Carcio C., Bagshaw R.D1978)

Poly Hydrolyzed polyacrylamide (PHPA)

This polymer has the responsibility to encapsulate the drill cuttings, wellbore stabilizers and formation, viscosity subsidiary, improver of fluid cake operation in wall building, spreading anionic particles to dissolve organic particles in water-based fluid

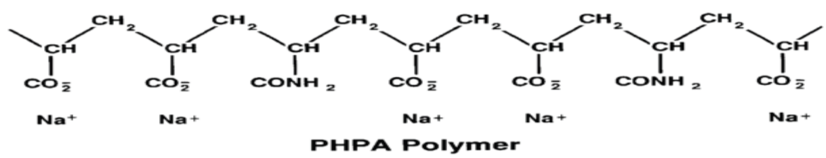

Figure 1. PHP Molecular structure

In drilling mud, nonionic natural polymers (such as, cellulose and starch) are not dissolved in water. In this case they should be converted into polyelectrolyte to dissolve in water. Carboxyl group are in the amide group. Acrylamide should be converted into Sodium acrylate copolymer to be soluble in water (1). Copolymerizing with sodium acrylate, create a polyacrylamide that is anionic due to carbon connection is soluble in water. It has high thermal stability and is resistant against bacteria.

Polyelectrolyte efficiency changes due to the polymer concentration, distribution of self-carboxylate ion group, the amount of salt (salinity), hardness (calcium and magnesium) and the pH value. Most of starch solubility and anionic PHPA occurs at pH 8/5- 9/5. If the PH is greater than 10, a large amount of sodium hydroxide should be added to reduce the adhesion properties. If the PH is less than 7, the carboxyl group is converted into its previous carboxylic acid form and the polymer loses its solubility.

According to the used KCl and NaCl, polymer by encapsulating mechanism bind to clay particles and prevent from Clay swelling and its deflocculation. Anionic Carboxyl group binds to positive charges that exist at the edges of clay particles (2). This leads to increased stability of the well inner wall to prevent flooding and reduce the fluid penetration into the formation.

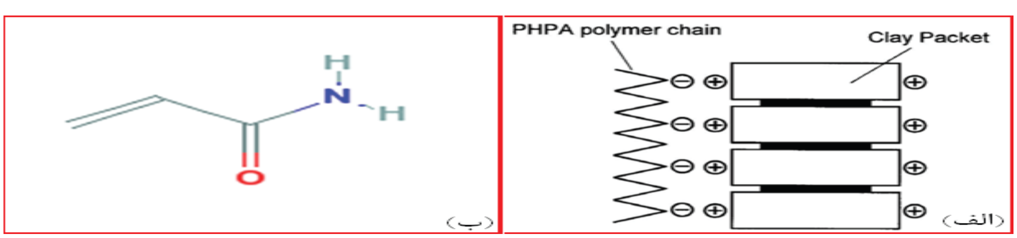

Figure 2. anionic carboxyl group anionic carboxyl group binding to clay particle

Because of the encapsulation and increasing the fluid viscosity, drill cuttings and solid particles are thrown from the shaking sieve and thus the amount of polymer should be controlled and added to the drilling fluid.

The high sensitivity of this polymer to the calcium ion is one of its disadvantages. The polyacrylamide of anionic carboxyl groups react with calcium, and cause to sediment the polymer. In some cases, the polymer in the presence of calcium acts as a coagulant and thus cause to create a very high viscosity of drilling mud (Majid Naeemavi 2014).

Polyethylene glycol (PEG)

Glycols are two hydroxyl groups that are formed on two different carbon atoms. PEG is a reducing agent on surface tension (Surfactant). Surfactants are divided into three categories, nonionic, anionic and cationic that polyethylene glycol is nonionic. Polyethylene glycols that is used in drilling industry depends on the percentage of chloride of drilling fluid in colorless, light brown or yellowish form.

The advantages of nonionic surfactant polyethylene glycol in water-based drilling fluid are as follows:
The lubricating properties of drill at high temperatures and pressures
Preventing from shale swelling or dispersion in large amount
Well wall stability and control of smooth water in drilling mud at high pressure and temperature conditions

One of the most important advantages of glycol drilling mud compared to oil -based mud is the compatibility of these muds with the environment and natural ecosystems because glycol drilling fluids has a very small amount of waste and thus create the limited problems about waste disposal.

The mechanism of inhibition

Active thermal emulsion fluids usually influence on wellbore stability by three very different methods:
By providing thin cakes with smaller pores on the wellbore
By chemical absorption method
By creating a micro emulsion and putting them on the well pores and blocking them

Although the polymer through chemical adsorption make a desirable inhibition, but the phenomenon of cloudy point has a main mechanism for stabilizing shale inhibitory. Cloudy point is a temperature in which PEG completely transformed from soluble state to an insoluble state.

When polyethylene glycol reach to temperature of 80 ̊C at formation when are being drilled, cause to create a cloudy point and in this case, polyethylene glycol is adsorbed on the inner wall of well and formation .it Should be noted that the absorption of insoluble polyglycols on clay formations creates a protective barrier against water and prevent it from swelling.

At a higher temperature than the cloudy point, polyethylene glycol are converted into little colloidal droplets that leads to micro emulsion. In the other hands insoluble PEG, tends to combine to surfaces and can cover solids and reservoir rock surfaces. This phenomenon in the drilling mud is often referred to as active thermal mud emulsion (3). Also, the insoluble PEG absorption into the cake tissue on pore formation reduces cake thickness and smooth water. At the time of drilling fluid circulation, when insoluble polyethylene reaches from the well annular space to well surface, its temperature is reduced and again turns into solution mode.

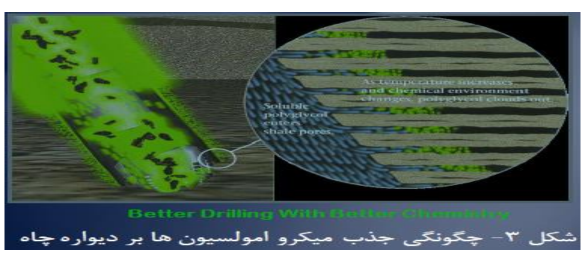

Figure 3. how to attract the micro-emulsions on wells

The main issues regarding the maintenance of glycolic mud system are control of clay solids, using the concentration and proper polyglycol type in the system to achieve the active thermal emulsion mud. Cloudy point of glycol is reduced by clay salinity with sodium chloride and calcium chloride (Aston, M.S., Elliott, G.P., 1994)

Wettability Alteration

There are three important properties in porous media in the presence of two or more fluids: wettability - capillary pressure - relative permeability. The wettability is the relative tendency of a solid surface for wetting in the presence of two immiscible fluids. In the system that has two or more fluids there are two modes of miscible and immiscible that if two or more fluids in certain circumstances constitute a phase, thus are miscible to each other and if they do not constitute a phase under no circumstances, they are immiscible with each other. Wet phase is developed on the solid surface and fills the small pores of the porous space that can moves by difficulty. But no wetted phase discharges more easily from the porous space and fills the larger pores and can easily move.

When a drop of water is spread on a solid surface, if water contact angle with Solid surface is less than 90 degrees, the drops will moisturized the surface. It means the solid surface is hydrophilic to water. The partial permeability of a fluid depends on its wettability with reservoir rock. Therefore, a hydrophilic reservoir (water wet), shows more relative permeability to water (Krw); in other words it cause to reduce the relative permeability of oil (Kro). In the oil reservoir that water and oil are together, there is surface tension not only between oil and water but also between the fluid and solid in a reservoir rock. Adhesion tension of a fluid with solid surface is a function of the surface tension and can be expressed with the following statement:

$$\boxed{A_T = \sigma_{WS} - \sigma_{OS} = \sigma_{OW} \cos\theta}$$

σos: surface tension between oil and solid surface
σws: surface tension between the solids and water
σow: surface tension between oil and water
COS θ: contact surface angle
If adhesion tension is positive (0<At), wetting phase can moisturize the solid surface better (hydrophilic)
If AT = 0, both phases have similar wetting properties (neutral system)
If adhesion tension is negative (0>At), un wetting phase can moisturize solid surface better. (Oelophilic)

When the solid surface is in water and oil phases If we consider friction forces between the phases and the solid surface we have the following equation according to Yang (figure 5) (Mehdi. Aghebati 2005):

$$\cos\theta_{wo} = \frac{\sigma_{so} - \sigma_{sw}}{\sigma_{wo}}$$

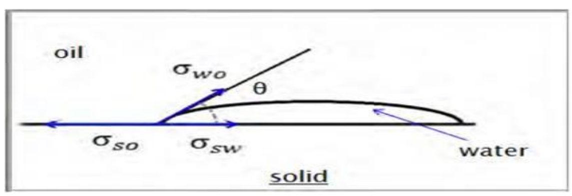

Figure 5. the solid surface in the presence of water and oil

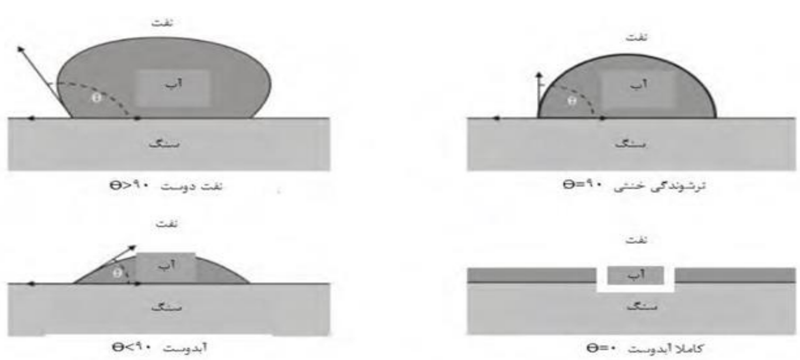

Figure 6. the contact angle in different wettability situations

The effect of wettability alterations on relative permeability

When two immiscible fluids (water and oil) flow simultaneously in a porous medium, fluid flow paths are controlled by their wettability. Regarding that most levels of carbonate reservoir rocks is high water (it means that water in the vicinity of oil tends more to moisturize the surface) water flows on the surface of rocks and narrow channels, while oil will flow at the center of large pores and channels. Relative permeability of each depends on the rock wettability and saturation percent of each fluid.

Oil relative permeability at a certain saturation over water permeability is the same as water saturation. This saturation can be anywhere up to 60% of water saturation. As a result water is spread above rock level and fill small pores in porous space and it can move difficultly (figure 7). Water relative permeability is reduced, oil can be easily discharged from the porous space and fills the larger pores and are easily moveable that makes the reservoir rock as hydrophilic (Figure 8).

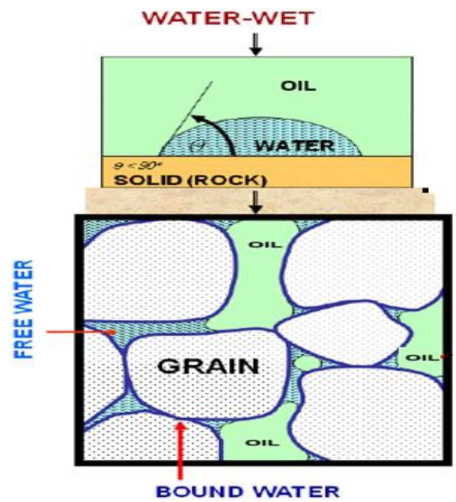

Figure 7. hydrophilic properties of reservoir rock by filling the small pores

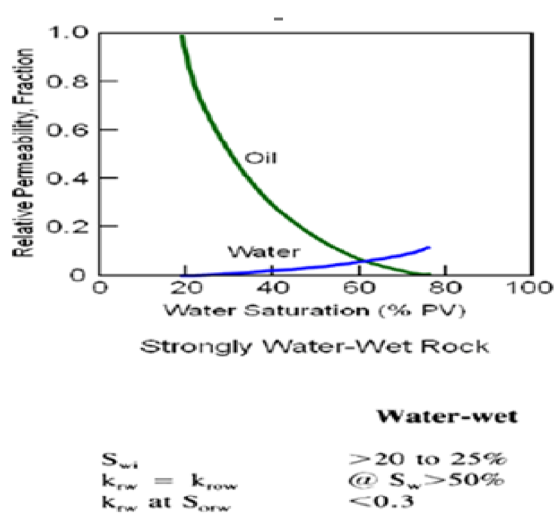

Figure 8. reducing water relative permeability (Krw)

Wettability alterations in carbonate rock by permeability effect of drilling fluid

From hydrophilic to Oelophilic

When the oil flows in a certain pressure, the minimum of water saturation is the remaining water saturation. Intact carbonate reservoirs are hydrophilic and are in the residual water saturation. In other words, small pores on rock surface covered by water and the larger pores are filled by oil that is easily moveable.

In oil zone, drilling fluid penetrated into the formation by the capillary pressure (due to the porosity of the rock, the fluid column differential pressure and fluid loss (barrels per hour) inside the formation and the volume and depth of drilling fluid is different). It leads the oil to residual oil saturation in porous media that it could be anywhere up to water saturation less than 50%. Oil is spread above the rock surface and fills all the small pores of the porous space and it is difficultly movable (figure 9). Relative permeability of water increases, water can be easily discharged from the porous space and fills the larger pores and are easily moveable. This will make the reservoir rock as Oelophilic .and finally leads to increase formation damage and reduce the oil production (figure10) (Shehadeh K. M2003).

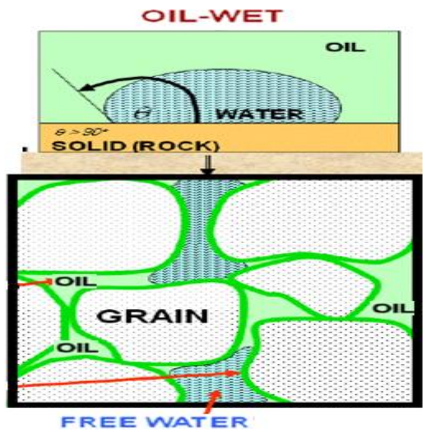

Figure 9. Oelophilic properties of reservoir rock by filling small pores

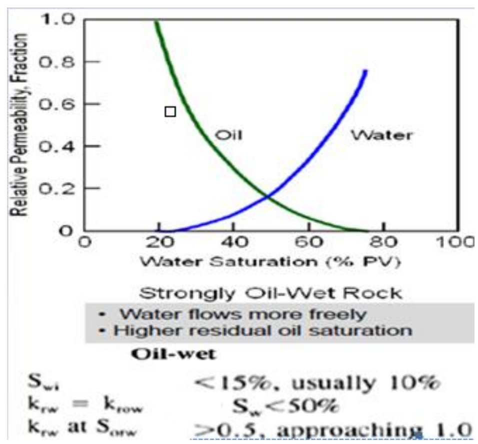

Figure 10. increasing the relative permeability of water (Krw)

The effect of polyethylene glycol non-ionic surfactants on the wettability

Surfactants are able to reduce the Oelophilic surface tension of carbonate rocks. But none of them is not able to make the water completely hydrophilic. By the influence of drilling fluid into the reservoir, after the carbonate rock wettability changes from hydrophilic to Oelophilic, at a higher temperature than the cloudy, polyethylene glycol micro emulsion in drilling fluid converted to colloidal droplets that tends to combine with surface. When Micro-emulsion covers the carbonate rock surface, it is absorbed by hydrogen bonds on the rock surface with a negative charge and a hydrophobic group absorb the Oelophilic organic material.

Nonionic surfactant through polarized electrons is capable of forming two layers on carbonate rock in which the polarized electron heads are in hydrophilic environment and their non-polarized heads are in Oelophilic environment. (Figure 11).and this causes to reduce the surface tension and approaching the two phases together. Carbonate rock converts from Oelophilic to hydrophilic and then hydrophilic phase is spread over the rock surface and fills the small pores of the porous space that is difficultly movable. But Oelophilic phase is discharged from the porous space and fills the larger pores that can be easily moved and ultimately increase the oil production.

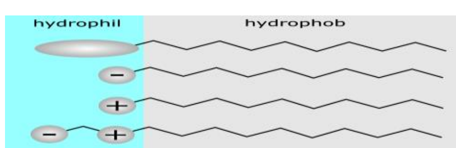

Figure 11. the surfactant performance. Polar head in polar environment and nonpolar head in Oelophilic environment

Jarahian and colleagues (2012) proposed a model for wettability alteration by polyethylene glycol non-ionic surfactants (TritonX -100). They claimed that the surfactant in the surface is absorbed by TT-polarized electron and ion-exchange. Through hydrophobic interaction, stearic acid is released and anionic compound is absorbed on a new layer of the surface. As a result the wettability of rock surface is changed from Oelophilic to hydrophilic conditions. (Yan J1993) and (Mohammad Ali Ahmadi. Seyed Reza Shadizadeh 2014)

Laboratory design stages of glycol water-based drilling fluid

In this test the properties of drilling mud is similar to fluid properties that is used in the drilling mud rig. Regarding that adding polymer cause to increase the drilling fluid rheology, it creates some problems during drilling. It has been tried that on design of this glycol drilling fluid by considering the apparent viscosity and opposite point in the drilling mud program, the lowest loss and highest efficiency of the micro-emulsion polyethylene glycol is done by controlling the amount of chloride, potassium and sodium carbonate (England, AA and Davis, N., 1988). Laboratory design of a barrel of glycol water-based drilling fluid consists the following steps:

350 cc of regional water (Chloride: 5000 Calcium: 200)
86 g of sodium chloride
24 g of potassium chloride
1 g of sodium carbonate
8 grams of green starch (that were mixed for 5 minutes in the Mixer at high speed)
1 g poly hydrolysis acrylic amide (that were mixed for 2 minutes in the mixer at high speed)
22 cc of polyethylene glycol (5% of fluid volume)

Measurement of drilling fluid properties

Properties of prepared drilling mud at 25 and 110 ̊C

Measuring of the rheological properties of plastic viscosity, opposite point and gel resistance by VG meter
Measuring the smoothness drop by Filter Press (in 30 minutes)
Measuring the concentration of chloride ions by chloride test
Measuring the percentage of glycol volume by Retort Kit
Measuring the percentage of PHPA volume by centrifuges
Measuring the percentage of potassium volume by centrifuges
Measuring the drilling fluid weight by Mud Blance

Results and discussion presentation

We repeated the tests two times in order to enhance their accuracy. Table 1 presents experimental results of designed drilling fluid properties.

Table 1. Laboratory results of designed drilling fluid properties

MW	PHPA	glycol	K	Cl	API Fluid loss	pH	Gel (10sec/10min)	Yp	PV	θ300	θ600	Mud properties temperature
Pcf	%wt	%wt	%wt	mg/l	cc/30min		lb/100ft2	lb/100ft2	Cp			unit
73	1	5	5	181000	2	8/8	5/6	14	20	34	54	Temperature: ̊C25
73	0/8	4	5	181000	1/6	8/8	5/6	22	38	60	98	Temperature: ̊C110

Table 12.Cloudy point of glycol drilling fluid in 90 ̊C

Table 13.

Thin cake on filter paper and fluid loss reduction

Thus, it is observed at 110 ° C that glycol polyethylene after cloudy point affects on fluid rheology and cause to increase the apparent viscosity and opposite point.

Also after the cloudy point, the created micro-emulsion fills the small pores of filter paper and cause to reduce fluid loss that is observable by API Fluid loss.

Wettability measurement method

In this study, contact angle measurements were used as a quantitative method and Flotation tests and separating the two phases were used as qualitative methods to show the effects of glycol water-based drilling fluid on carbonate rock samples in the absence and in the presence of polyethylene glycol nonionic surfactant.

Contact angle measurement

Figure 12 shows the instrument used in the contact angle measurement. The experiments were conducted in two temperature at 25 and 110 ° C. Since the reservoir material is carbonate, mineral calcite was used as a representative of reservoir rock. Samples of the mineral calcite in 2 × 2 × 0/5 cm was prepared according to the mineral surface roughness effects on measuring contact angles, it was polished well.

Figure 14: the way of installing the components of used device in the study

As mentioned before, the aim of this study was to determine the effects of nonionic surfactant polyethylene glycol in water-based drilling fluid on the carbonate reservoir rocks. Salt water of reservoir was used to obtain the contact angle (chloride 85,000 and calcium 1200).

The test procedure

To study the effects of drilling fluid it is necessary to obtain contact angle of the samples in 4 modes in the absence and presence of surfactants in water-based drilling fluid at 25 and 110 ° C. For this purpose, we measure the contact angle of the samples in 4 modes. Table 2 shows the different sample modes (Mohammad Mostafa Maghferati 2014).

Table 2 .different modes of samples for experiments

mode	Rock type	test temperature (° C)	water-based fluid
1	Mineral calcite	25	Without surfactant
2	Mineral calcite	110	Without surfactant
3	Mineral calcite	25	With surfactant
4	Mineral calcite	110	With surfactant

The first stage of the experiment: durability of sample

In this stage, at first we put samples in water-based drilling fluid without surfactant. To obtain the effect of rock samples durability in the drilling fluid, we performed the experiments on samples at different times that the result is shown in Figure 12. The vertical axis shows the results of contact angle and the horizontal axis shows the sample duration time in drilling fluid in terms of hours. So the results of the (figure 12) states that the duration of samples in drilling mud should be 48 hours.

Figure 15. contact angle results in terms of samples duration in drilling mud

The second stage of experiments: samples of rock and drilling fluid without surfactant

In this case, the samples were suspended for 48 hours in the cylinder containing drilling fluids without surfactant (room temperature) and also one of them placed at 110 ° C. by using the device that is shown in Fig. 3 we use the salt water of reservoir to measure the contact angle. Figure (13) shows the photo that is taken by camera as a sample.

Figure 16. a water drop in reservoir in the vicinity of the mineral calcite

We measured the contact angle of the drop by using the software AutoCAD. We repeated the tests for the sample that was reached to 110 ° C.

Third stage of experiment: Samples of rock and drilling fluid with surfactant

In this stage, the samples were suspended in a cylinder containing drilling fluids with surfactants for 48 hours and one of them also placed at 110 ° C. by using of the device that is shown in Figure 12, we use the salt water of reservoir to measure the contact angle.

Presentation Of Results And Discussion

To enhance the accuracy of experimental tests were repeated 2 times. Table 2 presents the results of drilling fluid without surfactant in the second stage.

Table 3. Results of drilling fluid without surfactant

mode	Rock type	Drop kind	Test temperature	Contact angle
1	Mineral calcite	Salt water of reservoir	25	115
2	Mineral calcite	Salt water of reservoir	110	116

Table 4. Results of drilling mud with the surfactant

mode	Rock type	Drop kind	Test temperature	Contact angle
1	Mineral calcite	Salt water of reservoir	25	88
2	Mineral calcite	Salt water of reservoir	110	83

Thus, it is observed that water-based drilling fluids without surfactant with calcite rock cause the contact angle to be greater. As a result it changes the wettability from the hydrophilic state to Oelophilic state and this can reduce the relative permeability of oil and gradually cause to reduce our oil production in the reservoir.

But water-based drilling fluid samples cause the contact angle becomes smaller in the presence of polyethylene glycol nonionic surfactants with calcite rock. As a result, wettability changes from Oelophilic state to a hydrophilic state .This can increase the oil relative permeability and cause to increase oil production in our reservoir.

Flotation test

In this way, 0.2 grams of Contact rock with drilling fluid without surfactant and 0.2 grams of Contact rock with drilling fluid in the presence of surfactant were weighted, then two clean test tubes were filled with distilled water and gently the rock samples were cast above the water. If the rock sample sink in the water, it means that they are hydrophilic, otherwise the rock samples are Oelophilic. (Fig. 17)

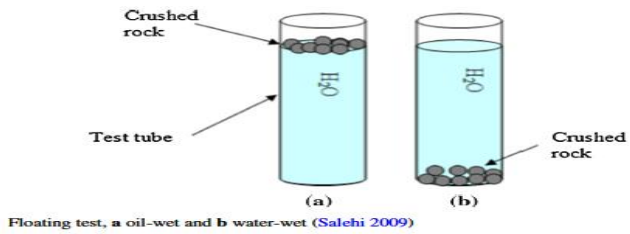

Figure 17. Flotation test Salehi model a) Oelophilic b) hydrophilic

The results indicate that presence of surfactant in the drilling fluid makes rock samples to be hydrophilic and they immediately sinks in the water and a very low percentage of sample floats above the water (figure a). Rock samples without surfactant in the drilling fluid after a few hours floated at the top of the water that show the rock sample is Oelophilic (figure b) (18)

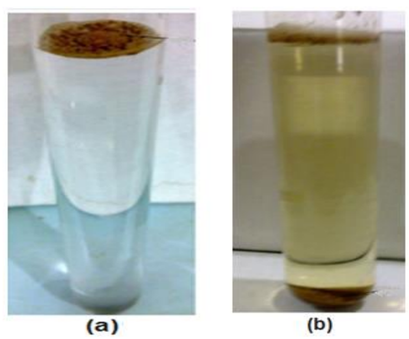

Figure 18. Flotation test a) Oelophilic b) hydrophilic (with surfactant)

Separation test

Such as flotation tests 0.2 grams of Contact rock samples with drilling fluid without surfactant and 0.2 grams of Contact rock samples with drilling fluid in the presence of surfactants were weighted. Then two clean test tube, each of them were filled with 20 ml of distilled water and 20 ml of kerosene and rock samples gently were poured above the water. If the rock sample stone sinks in the water, it means that the rock sample is hydrophilic (figure b). Otherwise the rock sample is Oelophilic (figure a).

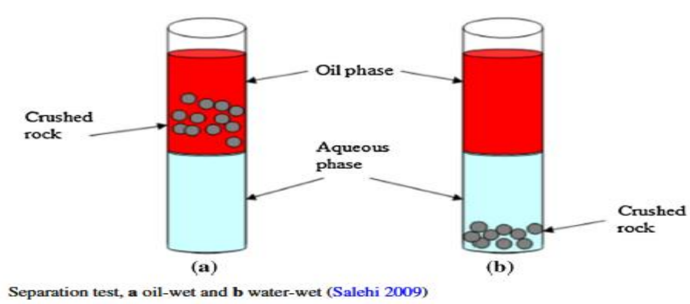

Figure 19. Salehi separation test a) Oelophilic b) hydrophilic

The results indicate that the presence of surfactant in the drilling fluid makes rock samples to be hydrophilic and they are immediately immersed in water and a low percentage of sample floats above water (figure b). Rock samples without the presence of surfactants in drilling fluid remains at the top of water after several hours floating that it shows the sample is Oelophilic (figure a)(20)

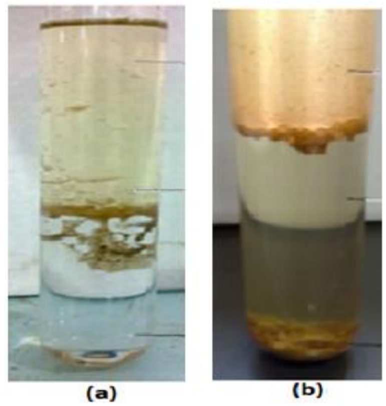

Figure 20. Separation test a) Oelophilic b) hydrophilic (with surfactant)

Conclusion

Rheology testing of drilling fluid polyethylene glycol at 110 ° C showed that the cloudy point causes to increase the apparent viscosity and opposite point of (lb / 100ft²) 14 to (lb / 100ft²) 22. If the opposite point (Yeild point)is more than (lb / 100ft²) 25 cause to reduce the well bottom cleaning action, increases the hydraulic pressure drop in the pipeline , reduce the drill hydraulic power and increase the pressure at well bottom and formation damage due to the loss.

Filtration test showed that after cloudy point, created micro-emulsion fills the fine pores of filter paper and leads to reduce fluid loss and reduce the formation damage.

Wettability is an important and determining factor in the formation damage.

For the drilling fluid affects on the wettability of reservoir rock, it should be placed in the vicinity of sample for 48 hours to reach the durability period.

Wettability test proved the rock samples that used of water-based drilling fluids without surfactant, alters the wettability from hydrophilic to the Oelophilic and this in turn reduces formation damage and oil production. Drilling fluid losses (without surfactant) in porous media Circulation losses (without surfactant) in porous media, lead the oil to residual oil saturation. Oil is spread above the rock surface and fills all the small pores of the porous space and is difficultly movable. Water relative permeability increases, drilling fluids can be easily discharged from the porous space and fills the larger pores and are easily moveable. This will cause the reservoir rock as Oelophilic which eventually increase the oil production and reduce formation damage.

Wettability test proved that a rock sample that is used of water-based drilling fluids in the presence of surfactants cause to alter its wettability from Oelophilic to be hydrophilic. This in turn reduces formation damage and increases oil production, which is followed by mobility improvement.

Raising the temperature in sample rock with water-based drilling fluids was used in the presence of surfactant up to 110 ̊C that is the same as rock temperature and drilling fluid in the reservoir. At a higher temperature than cloudy point , polyethylene glycol micro emulsion as non-ionic surfactants through polarized electrons are capable of forming two layers on carbonate rock in which the electron polarized head is placed in the hydrophilic environment and its non-polarized head is placed in Oelophilic environment. And it reduces the surface tension and approaching the two phases together and carbonate rock changes from Oelophilic to hydrophilic mode. .

Qualitative test results about wettability of float and separation in drilling fluid of polyethylene glycol showed that Oelophilic intensity can be reduced in carbonate sample.

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