



Compatibility study of injection water for barium sulfate scale prediction in one of Iranian oil fields

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Abstract

One of the most important challenges during water injection into oil reservoirs is the formation of inorganic scale due to incompatibility of injection water and formation brine. In this study, injection water compatibility study for evaluation of barium sulfate scale formation were carried out for one of the Iranian oil fields located in Persian Gulf. The laboratory experiments were performed with synthetic formation and injection waters at reservoir temperature. Sensitivity analysis was carried out on mixing ratio of formation water to injection water and injection water salinity to determine the condition of minimum barium sulfate scale formation. Results showed that barium sulfate scale is formed at any ratio of injection water and maximum precipitation was observed at 90% formation water. By increasing the temperature, barium sulfate solubility increases and therefore, turbidity of waters mixture was decreased. As injection water salinity is decreased, solution turbidity and the amount of sulfate scale decreased. Overall, damage potential of barium sulfate scale should be considered for water injection operation in the studied oil field.

Keywords: Formation damage, Water incompatibility, Barium sulfate scale, Water injection

Introduction

Water injection is one of the common techniques to keep the reservoir pressure constant and to improve the recovery factor, in which the incompatibility of injection and formation waters can lead to the risk of inorganic scale formation [1,2]. Ionic composition incompatibility of injection fluid and formation water causes the formation of mineral scales in the reservoir, which results in formation damage and permeability impairment [3]. The formation water in carbonate reservoirs has a significant amount of positive charges cations such as Ca^{2+} , Sr^{2+} , and Ba^{2+} while injection water which is often sea water, contains high concentrations of sulfate ions (SO_4^{2-}) [4-6]. Mixing of injection water with formation water may lead to the precipitation and deposition of BaSO_4 , SrSO_4 and/or CaSO_4 scales which are extremely difficult to dissolve or remove [7,8]. The deposition of inorganic scales can lead to pore plugging in the formation near the wellbore, partial or total blocking of production tubing, pressure rise in injection wells, etc. resulting in overall reduced field productivity [9,10]. The most common types of mineral scales in oil fields are summarized in Table 1 [11].



Table1: Common types of mineral scales in oil fields

Inorganic scale	Chemical formula	Determining parameters
Calcium carbonate	CaCO ₃	Partial pressure of CO ₂ , TDS, temperature, pH
Calcium sulfate	CaSO ₄	Temperature, pressure, TDS
Barium sulfate	BaSO ₄	Temperature, pressure
Strontium sulfate	SrSO ₄	Temperature, pressure, TDS
Ferrous sulfide	FeS	Corrosion, dissolved gases, pH
Ferrous carbonate	FeCO ₃	Corrosion, dissolved gases, pH
Ferrous hydroxide	Fe(OH) ₂ , Fe(OH) ₃	Corrosion, dissolved gases, pH

The main cause of mineral scales formation is supersaturation phenomenon which is affected by factors including temperature, pressure, ionic composition of solution, and salinity [12]. In fact, the extent of formation damage caused by inorganic scale deposition depends on the mentioned parameters. Since sulfate scales are hard, stable and almost insoluble in mineral acids and difficult to remove mechanically, their deposition leads to operational problems and high costs [13].

Various methods including experimental methods and thermodynamic modelling are used to predict the amount and type of mineral scales. In this study, the formation potential of barium sulfate scale in one of the Iranian oil fields located in Persian Gulf were investigated through static compatibility study. The effect of mixing ratio of formation water to injection water and injection water salinity on barium sulfate precipitation were evaluated. The scale formation was determined by measuring the electrical conductivity and turbidity of waters mixture at different conditions. The amount of formed solid scale was measured and compared for the studied oil field..

Experimental

Synthetic formation and injection water were made based on the compositional data of real samples. In order to prepare the solutions, specified amounts of high purity salts including BaCl₂.2H₂O, NaSO₄, KCl, NaCl, MgCl₂.6H₂O, and NaHCO₃, all prepared from Merck Chemicals were dissolved in distilled water. The water samples were kept at constant temperature for 24 hours to ensure the solutions stability. Ionic composition and the total dissolved solids (TDS) of injection and formation waters are presented in Table 2.

Table 2: Ionic composition of injection and formation waters.

Ions	Formation water (ppm)	Injection water (ppm)
Na ⁺	89982	13131
K ⁺	3640	460
Mg ²⁺	2737	1642
Ba ²⁺	50	-
Cl ⁻	150000	23042
SO ₄ ²⁻	-	3200
HCO ₃ ⁻	126	92
TDS	249320	41569

Jar test was used to perform static water compatibility experiments to determine the potential of barium sulfate scale formation. Before performing each test, the water samples were filtered by 0.45µm filter paper in order to remove all of the undissolved particles. Then



electrical conductivity and turbidity of injection and formation water samples were measured using EC-Meter GLP 31+ and Turb 355 IR turbidimeter, respectively.

Injection water was added to the glass tubes containing formation water at different ratios and stirred thoroughly to complete the precipitation reaction. The glass tubes were kept at constant temperature and pressure for at least four hours and then the electrical conductivity and turbidity of the solutions were recorded. To measure the amount of barium sulfate scale, the solutions were filtered through the filter paper and the solid crystals were separated and dried. Finally, the weight of the crystal samples were measured by a high precision digital balance. The same procedure was applied for investigating the effect of salinity of injection water on barium sulfate scale formation. For this purpose 2, 3 and 5 times diluted injection water were mixed with formation water at various mixing ratios. The tests were repeated three times for each mixing ratio and the average results were reported. The measurement uncertainty in the experiments was assessed as 5.2%.

Results and discussion

The mixing of formation water containing barium ions with injection water having high concentration of sulfate ions results in solution supersaturation with respect to barium sulfate. The solubility of barium sulfate is affected by various parameters including temperature, pressure, salinity, water ionic composition. The precipitation reaction for barium sulfate occurs according to the following equation.



The first series of experimental tests were carried out to explore the impact of mixing ratio of formation water to injection water on barium sulfate scaling. Fig. 1(a) and (b) illustrates the variations of solution electrical conductivity and turbidity due to barium sulfate precipitation as a result of mixing of injecting and formation waters, respectively. As can be seen increasing the mixing ratio (i.e., ratio of formation water to injection water) increases both conductivity and turbidity of waters mixture. The increase of solutions turbidity indicates the formation of barium sulfate precipitation. Maximum turbidity of 86 NTU was observed at 90% formation water at ambient temperature.

Because of low concentration of barium ions in formation water, this divalent cation is the limiting agent in barium sulfate precipitation reaction. Thus, by increasing the mixing ratio, the amount of existing barium ions in the vicinity of sulfate ions increases and precipitation reaction proceeds towards solid scale formation. The solution electrical conductivity increases by increasing the mixing ratio due to increasing the dissolved ions available in formation water. As TDS content of formation water is much more than injection water, the waters mixture conductivity is increased by adding more formation water. Measurement of mass deposition of barium sulfate showed that maximum precipitation of 76.14 mg/L at ambient temperature and 67.34 mg/L at reservoir temperature was formed at 90% formation water.

Another point that can be understood from Fig. 1 is the effect of temperature on barium sulfate scale formation. It can be observed that increasing the temperature results in reduction of barium sulfate precipitation. The obtained results can be justified by the endothermic reaction of barium sulfate formation. In fact, an increase in temperature results in lower reaction rate of ions in waters mixture and consequently reduction of scale formation. The reduction of the rate of precipitation reaction by increasing temperature causes a decrease in formation damage due to barium sulfate scale. However, barium sulfate precipitation is more likely to form on the surface and wellhead facilities that have lower temperatures.

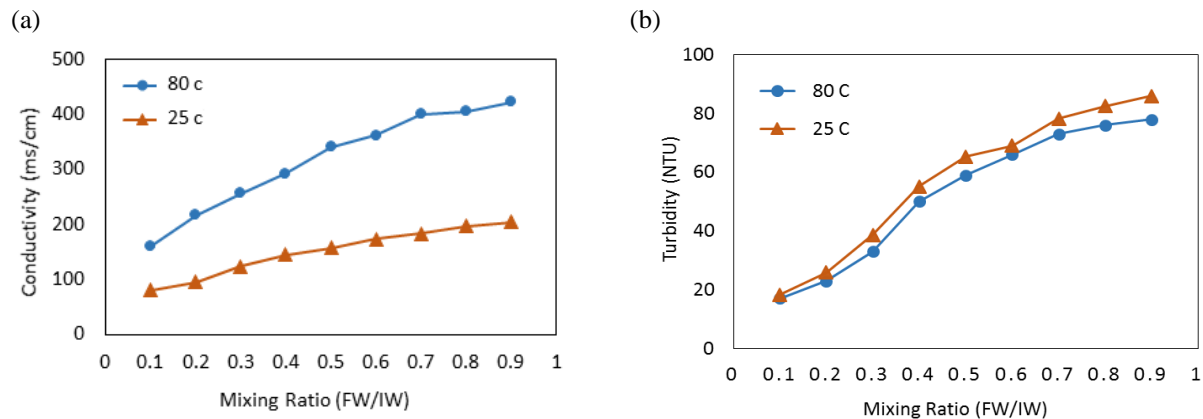


Fig. 1: Effect of formation water to injection water ratio on solution (a) conductivity, and (b) turbidity

The impact of salinity of injection water on barium sulfate precipitation was investigated by diluting injection water 2, 3 and 5 times. The variations of electrical conductivity and turbidity of waters mixture for different injection water salinities are shown in Fig. 2. As can be seen in Fig. 2(a), decreasing the salinity of injection water causes the concentration of dissolved ions to decrease and therefore electrical conductivity of the solution reduces. Fig. 2(b) indicates that at constant mixing ratio turbidity of waters mixture reduces by decreasing the salinity of injection water. In fact, by diluting the injected water the concentration of sulfate ions decreases and as a result, less barium sulfate scale is formed from the mixing of formation and injection waters. As the amount of solid precipitate crystals decreases, turbidity of the solution decreases. It is also observed that turbidity of solutions are increased by increasing the mixing ratio for all diluted injection waters.

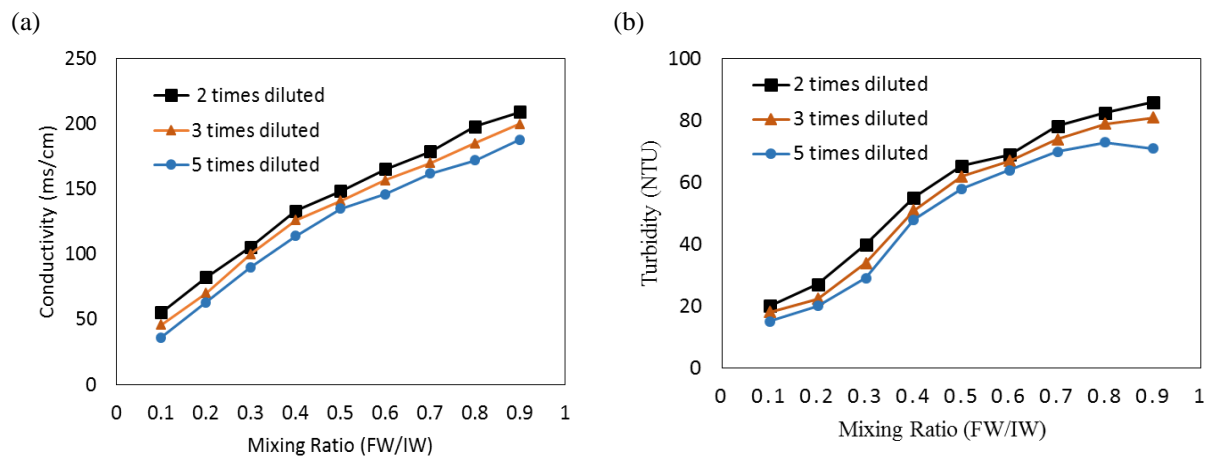


Fig. 2: Effect of injection water salinity on solution (a) conductivity, and (b) turbidity.

Fig. 3 shows the amount of barium sulfate precipitation as a result of mixing of formation and injection waters for different salinities of injection water. Maximum precipitation of 74.21 mg/L at ambient temperature and 60.32 mg/L at reservoir temperature was observed at 90% formation water for 2 times diluted injection water.

As stated previously, by increasing the temperature, barium sulfate solubility increases and therefore the amount of solid scale is reduced at reservoir temperature. Reducing the excessive salinity to 5 times dilution, causes the amount of precipitation to reduce especially



at high formation water ratios. The reason is that by diluting injection water 5 times, the concentration of sulfate ions in solution is greatly reduced. Therefore, barium sulfate precipitation reaction proceeds towards scale dissolution and thus the amount of solid crystals reduces. The results of water salinity study reveals that low salinity water injection to the studied reservoir can reduce formation damage potential due to barium sulfate scale.

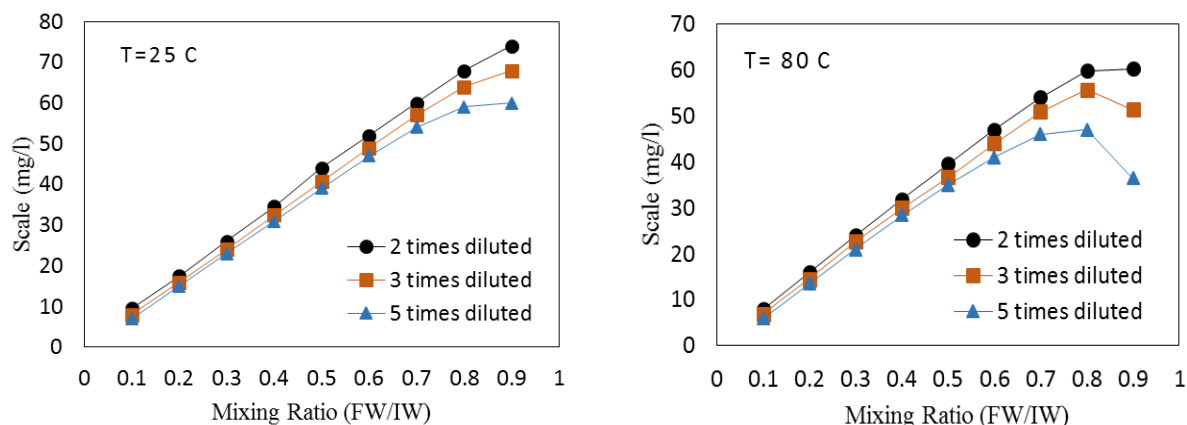


Fig. 3: Barium sulfate scale predictions as mixing ratios at for different injection water salinities.

Conclusions

In the current investigation, it was intended to perform compatibility study on injection water for one of the Iranian oil fields located in Persian Gulf. The damage potential as a result of barium sulfate scale was experimentally evaluated through static Jar test. The influence of mixing ratio of formation water to injection water and salinity of injection water on electrical conductivity and turbidity of waters mixtures were investigated. Results indicated that by increasing mixing ratio, barium sulfate precipitation increases and the maximum solution turbidity was observed at 90% formation water. Increasing temperature enhances the solubility of barium sulfate, and therefore solution turbidity decreases by raising the temperature. At constant mixing ratio, reducing the salinity of injection water results in reduction of solution turbidity which is an indication of precipitation reduction. Maximum barium sulfate precipitation of 76.14 mg/L at ambient temperature and 67.34 mg/L at reservoir temperature was observed at 90% formation water.

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