

Prediction of Salt Deposition in Oil Wells of Hassi Messaoud Field

Brahmia Nabil, Bengana Atik, Tati Saif Eddine, Zeddouri Aziez*

Laboratory of hydrocarbon gaz and aquifer underground reservoirs, Kasdi Merbah University, Ouargla, Algeria

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Abstract

This paper proposes a method for engineers and water treatment chemists to predict mineral scale deposition and its inhibition in saline oil wells during water injection during different phases of well life. The predictive study was explained by the DownHOLE SAT program based on the analytical results of the formation water samples taken from the Hassi Messaoud oil field and the Albian water used in the injection operation which provide physical and chemical conditions for formation of salt deposits of all types due to the incompatibility between these waters at the molecular level, which requires treatment of injection water in the well by the deposit inhibitor AD32 to avoid this dilemma. The analysis of samples from selected wells (HGA8, MD411, MD525, MD226, MD625, and MDZ556) for the period of 2010 to 2018 showed that treatment effectiveness is influenced by several factors and operational conditions such as water mixing proportions and Temperature variations. The research provides for various types, Forms and cases of mineral deposits but the main emphasis is on the more dangerous deposition. (Barium Sulphate BaSO_4), plus a few other deposits to showcase the results with, 2D and 3D graphs of Saturation Level and Momentary Excess in terms of mixing Injection water with Formation water and Temperature manipulation.

Keywords: Salt deposits; DownHOLE SAT; Saturation level; Momentary excess.

1. Introduction

Extremely large quantities of water are used daily by the oil industry, since the production of a ton of oil because the production of one ton of oil requires only a few tons of water. This use of water is justified by its low cost, as well as its availability in sufficient volumes. A large percentage of the oil reservoirs are in carbonate, sulfate and silicate carbonate, sulfate and silicate-rich regions, which provide considerable concentrations of anions. concentrations of anions. The abundance of cationic species present in the geologic surrounding the geological formation is responsible for the shape of the mineral layers. Thus, the high percentages of silica, calcium and iron provide the cationic species to combine with the available anions. Also, during the long geological periods, the processes of biodegradation and aqueous filtration through the different mineral layers have produced salty waters, these salty waters are responsible for much of the formation of crystals in the pores of the rock [1].

The production of the Hassi Messaoud field is stimulated by injecting water into the reservoir structures can occur as a result of the mixing of the Cambrian reservoir water (hot and very highly mineralized) and the injection water from the Albian aquifer [2]. The risks of deposits arise from the temperature variations resulting from the mixing and from the double decomposition reaction between the ions brought by the two (02) types of mixed water. The risks of precipitation of CaCO_3 and CaSO_4 are added the risks of appearance of BaCO_3 and BaSO_4 . There may even be a risk of chloride deposition (especially NaCl) at the level of the production wells if the deposit water is supersaturated in relation to the surface conditions [3]. Deposits can lead to clogging problems in the production formation, Downhole equipment, and/or piping/surface equipment [4]. Scaling of inorganic compounds in pipes are one of the

major flow assurance concerns in oil and gas production, and lead to significant reductions in productivity and increasing operating cost if the scale is allowed to form uncontrolled [5-6]. Today, operators have access to a portfolio of chemical and mechanical products designed to remove deposits and prevent their accumulation. Improvements in placement technology, tank chemistry, and smart fluids provide more cost-effective options for chemical deposit inhibition and removal in the formation [7-8]. Our approach is described below using DownHole SAT software to calculate the indicators of scale potential, simple indices for reference over the range of conditions specified include: The most common (Stiff-Davis, Langelier, and Ryznar).

2. Methods and materials

2.1. Study area

Hassi Messaoud oil field is considered to be one of the most prospected of the Saharan platform and one of the largest oil deposits in the world. Located 800 km southeast of Algiers, 350 km from the Algero-Tunisian frontier, and 80 km east of Ouargla (Fig. 1).

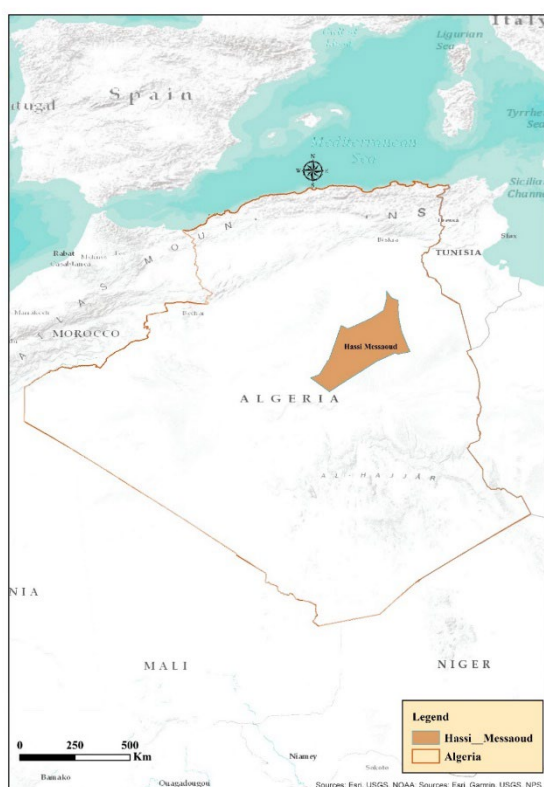


Fig. 1. Location map of the study area.

2.2. Used data

This study was adopted on the comparison between the formation of deposits in the different wells in the Hassi Messaoud field before us (HGA8, MD411, MD525, MD226, MD628, and MDZ556). Its saline wells are in a state of continuous injection of Albian water treated with the inhibitor AD32 for desalting. AD32 is a deposition inhibitor used in the treatment of water systems to prevent the precipitation of calcium, strontium, barium, iron, and other cations in combination cations in combination with sulfates, carbonates, and oxides. The inhibitor AD32 is particularly recommended for crude oil lines and water injection systems to water injection circuits to control the scaling of tubing, pumps, and pipes.

Water samples were taken from:

- Albian water sample (MDHA11 well).
- Deposit water sample (Cambrian).

Hassi Messaoud field is constituted by formations dating from the Cambrian to the Cenozoic. The Cambrian formations, deposited on the infra-Cambrian crystalline basement, are formed by sandstones, quartzites, and conglomerates. Conglomerates, constitute the reservoir designated by R3, R2, Ra, and Ri units [9]. According to the deposit, the production unit of petroleum gas is accompanied by a more or less important quantity of water. The presence of water is due to various natural causes, either from the rock store itself which can retain considerable quantities of water. This last one is generally very charged in salts until over-saturation. The predominant salt is sodium chloride, but it is always accompanied by variable quantities of calcium, potassium, magnesium, barium, and strontium salts, in the form of carbonate sulfates, bicarbonates, and chlorides. The Albian formation characterized by sandstone sedimentation more important than the Barremian, reservoir of fresh water used for the secondary recovery of hydrocarbons by maintaining reservoir pressure [10].

The parameters analyzed for the different samples are Chemical parameters which consist of cations (K^+ , Na^+ , Ca^{+2} , Mg^{+2} , Ba^{+2} , Sr^{+2} , Fe^{+2}); anions (HCO_3^{-2} , CO_3^{-2} , SO_4^{-2} , Cl^-), and physical parameters which consist of pH, density, and temperature.

Table 1 The chemical and physical composition of the waters.

Water composition		Deposit water sample (Cambrian)	Albian water sample (MDHA11 well)
Cations (mg/L)	Na^+	80000	391.7
	K^+	9760	47.11
	Ca^{2+}	33066	332
	Mg^{2+}	9521.3	97
	Ba^{2+}	1150	0
	Sr^{2+}	970	0
	Fe^{2+}	1217.5	1.44
Anions (mg/L)	HCO_3^-	0	170
	CO_3^{2-}	0	0
	SO_4^{2-}	0	1097
	Cl^-	221606.3	652
Physical parameters	pH	7.1	2.93
	Density at 25°C	1.13	1.23

2.3. DownHole SAT software

DownHole SAT was selected in this study to evaluate the scale potential for common scalants over the range of water chemistry, temperature, pressure, pH, and pCO_2 anticipated in a surface water, brine, or mixture. The scale potential for common scalants was evaluated at mixtures in lowest and highest temperature.

DownHole SAT calculates indicators of scale potential for barium sulfate (barite), barium carbonate, (witherite) calcium carbonate, calcium sulfate (anhydrite and gypsum), strontium sulfate (celestite), calcium phosphate (hydroxyapatite and tricalcium phosphate), amorphous iron hydroxide, iron phosphate (strengite), iron carbonate (siderite), amorphous silica, calcium fluoride (fluorite), and magnesium hydroxide (brucite) [11]. It also calculates common, simple indices for reference. Simple indices calculated over the range of conditions specified include:

- The most common (Stiff-Davis, Langelier, and Ryznar);
- An evolving index (Oddo-Tomson);
- Those that have been used by the major water treatment companies but have generally been unavailable to most water treaters (Saturation levels based upon an ion association model);
- And some that the program author has found useful (the Larson-Skold corrosivity index) [12].

2.4. Saturation level

A saturation level is defined as the ratio of the ion activity product to the solubility product:

$$\text{Saturation level} = \frac{\alpha Ca[Ca]\alpha CO_3[CO_3]}{K_{sp}} \quad (1)$$

$$\text{Saturation level} = \frac{IAP}{K_{sp}} \quad (2)$$

where: αCa is the activity coefficient for calcium; αCO_3 is the activity coefficient for carbonate; $[Ca]$ is the molar concentration of calcium; $[CO_3]$ is the molar carbonate concentration.

Ion association model saturation levels are often used in oil fields for the prediction of barium and strontium based scales [13]. The degree of saturation of a water is described by the relationship of the ion activity product (IAP) to the solubility product (K_{sp}) for the compound as follows:

- If a water is undersaturated with a compound: $IAP < K_{sp}$ (It will tend to dissolve the compound).
- If a water is at equilibrium with a compound: $IAP = K_{sp}$ (It will not tend to dissolve or precipitate the compound).

- If a water is supersaturated with a compound: $IAP > K_{sp}$ (It will tend to precipitate the compound)

2.5. Momentary excess (Precipitation to Equilibrium)

To estimate precipitation (or dissolution) for many different scales, the free ion momentary excess was used in this study [14]. Equation 3 represents the quantity X. Momentary excess is reasonably accurate when used to estimate precipitation of scales that are not pH sensitive. It overestimates precipitation for pH sensitive scales like carbonate (CaCO_3), barium carbonate (BaCO_3), and calcium sulfate $\text{Ca}_3(\text{PO}_4)_2$:

$$[\text{Ca}][\text{CO}_3] = K_{\text{spc}} \text{ at equilibrium...} \quad (3)$$

The same relationships are used to predict the amount of precipitation. Equation (3) is modified to calculate the amount of a mineral scale, X, that must dissolve, or precipitate to bring a water to equilibrium

$$[\text{Ca} - X][\text{CO}_3 - X] = K_{\text{spc}} \dots \quad (4)$$

The quantity X is negative when a water is undersaturated, and will indicate the quantity that will dissolve to bring a water to equilibrium. X is positive when supersaturated and represents the quantity that will precipitate to bring a solution to equilibrium. X will be 0 for a saturated solution where the mineral will not dissolve or precipitate.

Graphs produced by DownHole SAT are color coded (red, magenta, blue, yellow) as an aid in interpreting them. If the treatment will not work regardless of dosage level the color code is red. The system is out of range (e.g. too high a saturation level) for the treatment selected.

In the case of calcium carbonate inhibitors, Magenta signifies that the system is within ten (10%) percent of the limit for the inhibitor (e.g. 135 calcite saturation level to 149 calcite saturation level for an inhibitor that fails at 150 or above). In the case of blended orthophosphate/copolymer products, MAGENTA signifies that insufficient polymer is present for calcium phosphate scale control when the product is dosed at the level required for adequate corrosion protection. The corrective action is to increase the ratio of copolymer to phosphate. A safe operating range where the treatment will prevent deposition of the scale evaluated in blue color. Blue is also used to signify a successful treatment in treated system profiles [12].

3. Results and discussion

The mixture of Albian water with Cambrian water gives rise to the formation of deposits, the most harmful of which is undoubtedly barium sulfate, which is insoluble even in the presence of strong mineral acids. The reading of the results presented in Table 2, shows that it is possible to obtain BaSO_4 deposits with mixtures formed, with Albian water, and Cambrian water. Several mixtures were prepared (Table 2). The interaction between these two waters was made at room temperature. The masses of BaSO_4 deposits formed were calculated with the DownHOLE SAT program and the results obtained are presented in Table 2 [15]. The evolution of the mass of the deposit formed as a function of the Albian water/Cambrian water mixing ratio is given in Figure 2. The shape of the curves presented in Figure 2 shows that the maximum deposition was obtained with the critical mixing rate of 66.7/33.3% (Albian/Cambrian). This mixing rate allowed for collecting 450 mg/l of deposit at room temperature.

Table 2. Masses of BaSO_4 in terms of water mixing rates (Albian/Cambrian).

Mixing rate (%) at T°C (ambient) Albian/ Cambrian	Mass of BaSO_4 (mg/L)
0/100	0
16.7/83.3	30
33.3/66.7	90
50/50	205
67.7/33.3	450
83.3/16.7	330
100/0	0

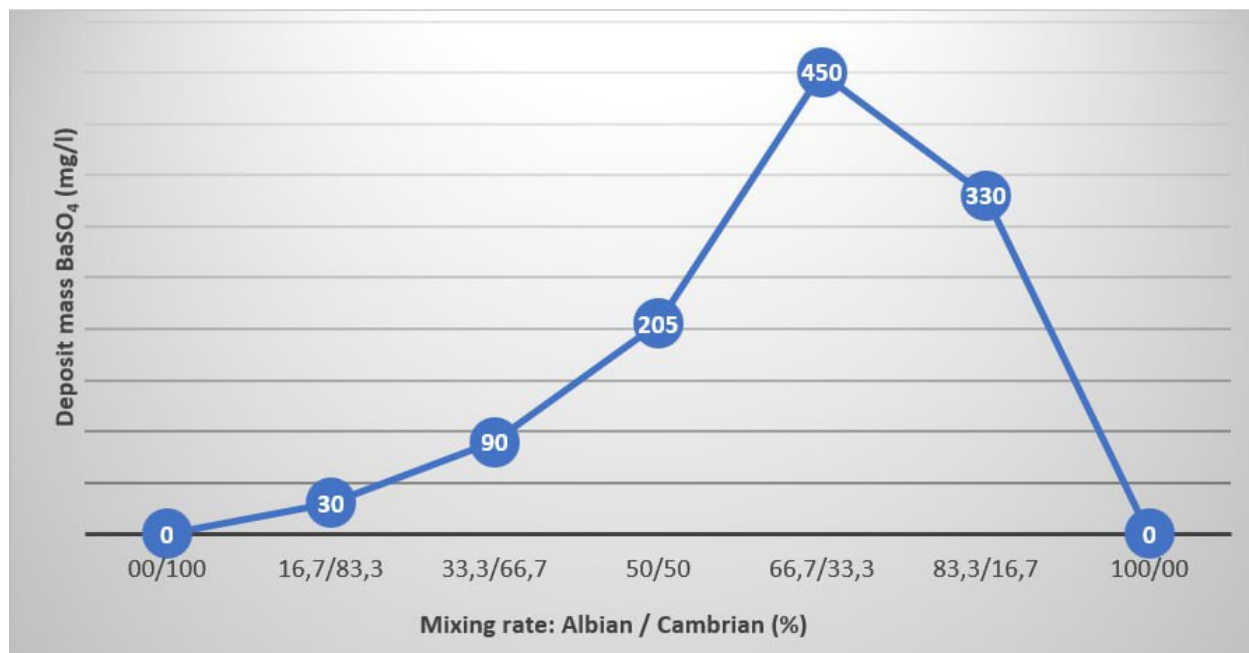


Fig. 2. Masses of BaSO₄ in terms of water mixing rates (Albien/Cambrian).

3.1. Barium sulfate

3.1.1. Momentary excess

Shows a strong increase in the concentration of barite particles in the mixture (16.7 – 83.3%) which corresponds to a progressive increase in the mixing ratio (Albian/Cambrian), reaching a peak of 450mg/L at 66.7% at 20°C, but a decrease in BaSO₄ values with increasing predicted temperature, which explains the effect of temperature on the formation.

3.1.2. Saturation level

Barite deposition is predicted for supersaturation with a maximum value rate of 1200 which appears in red, indicating the severity of the situation, and the urgency of treatment, or adjustments in pH, and concentration due to loss of control. If the solubility of barite (Ks) increases with temperature, therefore, is a decrease in the saturation rate when the temperature increases, this means that the saturation ratio can be said to increase as Ba²⁺ and SO₄²⁻ mix until its peak, then decreases with temperature (Fig. 3).

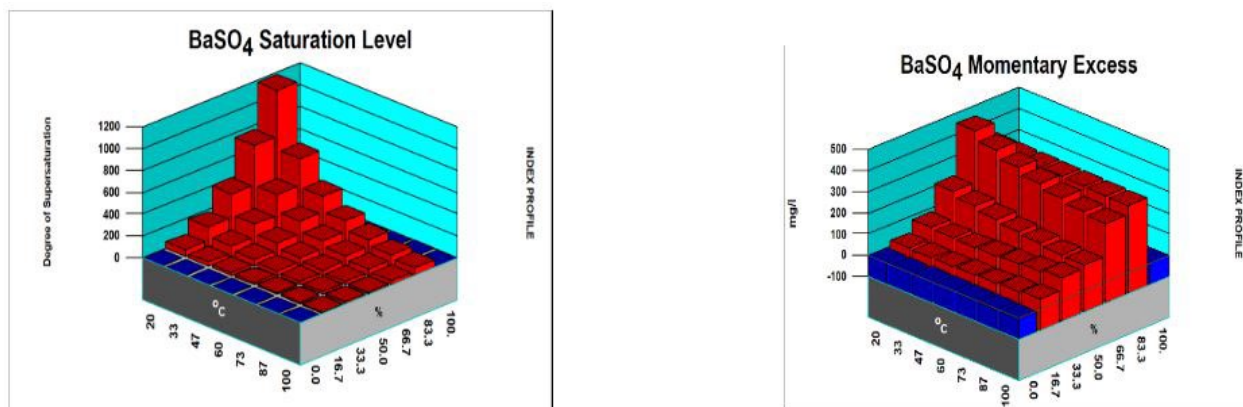


Fig. 3. Saturation level and momentary excess of BaSO₄.

3.2. Sodium chloride

The percentage of salt in the mixture is significantly reduced in both 3D graphs (ME/SL). If by increasing the rate of Albion water in the mixture at different temperatures (20-100°C) until the precipitation forecast is completely absent, as shown on the SL plot (Fig.4). Salt appears blue, indicating a safe working environment and treatment to prevent permanent deposits.

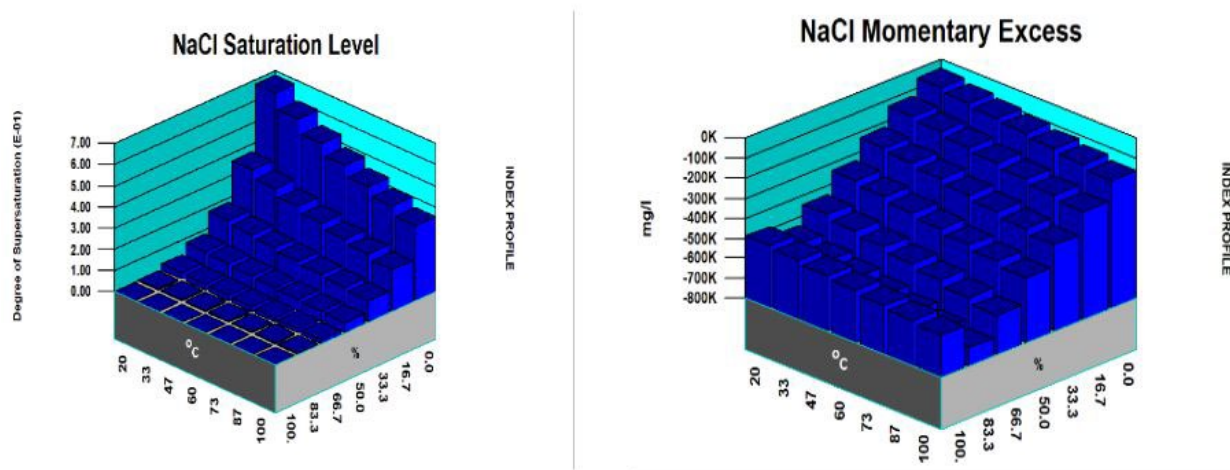


Fig. 4. Saturation level and momentary excess of NaCl.

3.3. Strontium sulfate

This case is the reverse of the previous case considering the SrSO_4 deposition precipitation prediction but, the graph remains in blue, indicating a safe working environment (Fig. 5).

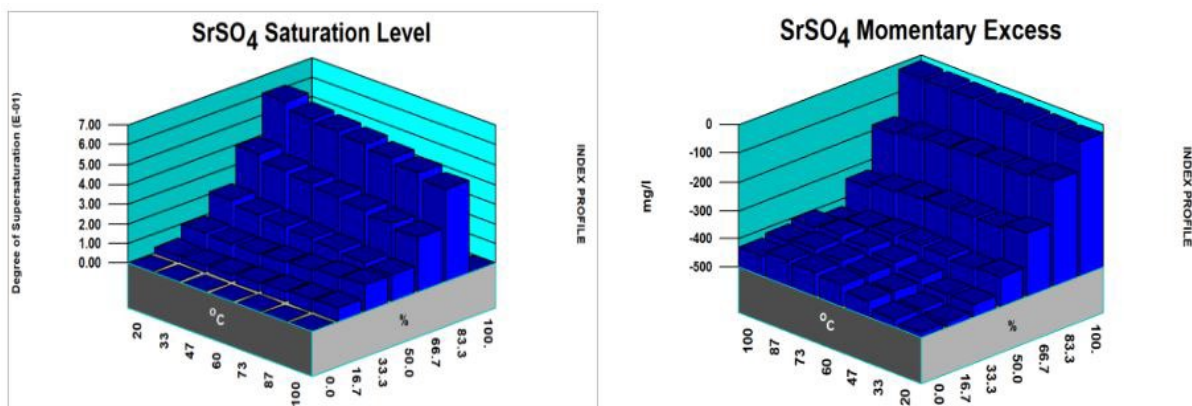


Fig. 5. Saturation level and momentary excess of SrSO_4 .

3.4. Calcium sulfate

CaSO_4 is a mineral deposit that doesn't cause high-risk issues but it raises some red flags in high temperatures as it appears in its momentary excess graph at 100°C in red color which requires taking measures for the problem in progress, saturation levels are relatively high at 100°C in different mixing ratios appearing in yellow and green in the saturation level graph signifies that a problem will occur with a minimum of change. Recheck your measurements. A slight error in pH could mean that you are operating in a RED zone (Fig.6). The system should be controlled.

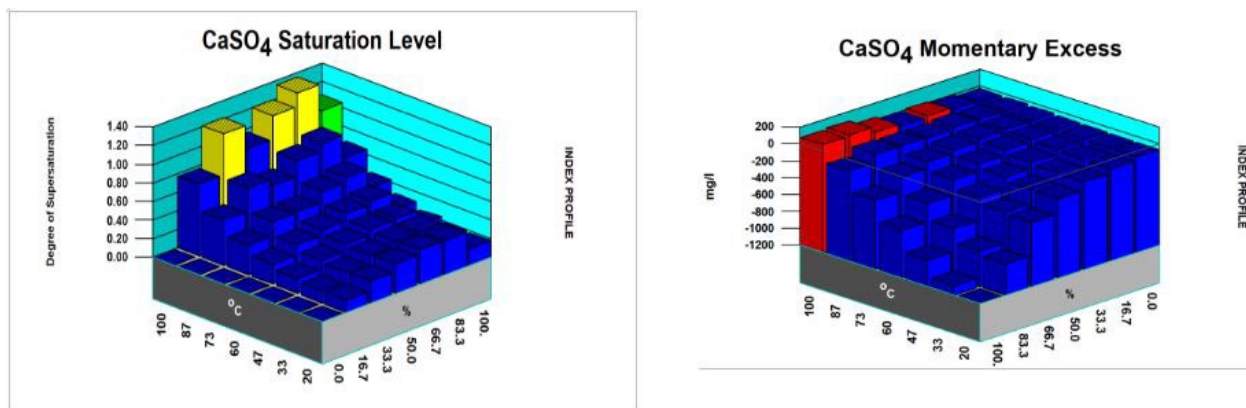


Fig.6. Saturation level and momentary excess of CaSO_4 .

Other types of depositions may occur; However, many are the by-products of bacterial activity, the corrosion of metal components by acid gases, or the result of mixing incompatible waters. A review of water analysis, field failure history, and monitoring of biological activity can help determine the source of deposits. Iron carbonate and iron sulfide are two deposits that can arise from corrosion or biological activity. They should not be classified as deposits, but as "deposits" and are most effectively controlled with corrosion inhibitors, biocides, or by controlling the quality of make-up water for injection systems (i.e. the mixture of incompatible waters).

4. Conclusions

Following the study and research on the analysis and treatment of water before reinjection into the salt oil well, we have come to the following conclusions:

- A strong increase in the concentration of barite particles in the mixture (16.7–83.3%) which corresponds to a progressive increase in the mixing ratio (Albian/Cambrian), reaching a peak of 450mg/l at 66.7% at 20°C, which matches a deposition predicted for supersaturation with a maximum value rate of 1200.
- Injecting wastewater presents several equivalent advantages to damage, the well is cleaned of salt formation during production to prevent the formation of salt deposits such as NaCl , CaCO_3 , SrSO_4 , CaSO_4 , and BaSO_4 , but in this procedure, the formation of barite is due to incompatibility between injected water and reservoir water, as indicated in wells (HGA8, MD411, MD525). It must be treated with inhibitors to avoid it, as indicated in wells (MD226, MD628, and MDZ556), although not sufficiently.
- The study of salt deposit formation prediction between the Albian well water (MDHA11) and the Cambrian water has clearly shown the cause of the incompatibility currently present between these waters, with Albian containing SO_4^{2-} and Cambrian containing Ba^{2+} , which produces the most serious salt deposit BaSO_4 .
- Each new technology improves a specific aspect of deposit control in the well. When combined, these new technologies become a part of the balance management process in which monitoring methods can be applied to identify all deposit conditions and develop an optimal strategy to reduce production losses and repair costs related to deposits.
- The strategy may include elements of deposit prevention and periodic removal. Engineers working in deposit-sensitive reservoirs appreciate any improvement in the technology used to address their deposit problems.
- Regular tests of produced water (every year, unless conditions justify otherwise) can indicate if corrective actions are needed and will also help confirm the success or failure of past actions. In water supply systems, quarterly monitoring of injection water is recommended. However, any sampling frequency should be modified if changes are made to a system or if conditions within a system deteriorate.
- Saline sediments formed by the water source need better solutions and unprecedented developments for their final elimination.

Authors' contributions

Conceptualization was developed by Brahmia Nabil- bengana Atik; methodology was proposed by Brahmia Nabil-; software was developed by _Bengana Atik; validation was performed by Bengana Atik and Brahmia Nabil; formal analysis was done by Brahmia Nabil and Bengana Atik; investigation was done by Tati Saif Eddine and Bengana Atik ; resources were given by Brahmia Nabil and Atik Bengana; data curation was performed by Brahmia Nabil Zaeddouri Aziez and Atik Bengana.

Declarations Statements and declarations: The authors declare that they have no conflict of interest.

Data Availability

The dataset was collected from the SONATRACH company's Engineering Production Division & Tests were conducted in a Laboratory company based in Irara Hassi Messaoud Algeria. Data is available upon request.

Competing Interests:

The authors declare that they have no financial or non-financial interests directly or indirectly associated with the work submitted for publication.

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To whom correspondence should be addressed: Brahmia Nabil, Laboratory of Hydrocarbon Gaz and Aquifer Underground Reservoirs, Kasdi Merbah University, Ouargla, Algeria, E-mail: nabilbra@yahoo.fr
ORCID: <https://orcid.org/0000-0002-9263-8399>