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Sulphate scale occurrences in Campos Basin production wells due to post and pre-salt water crossflow

Carlos E. A. N. Gomes[1], Christiane R. Abreu[2], Giselle H. Canuto[2*], Marcelo R. Galvão[2], Felipe M. R. Cardoso[3]
[1] AGP/RES-EE/OPR, PETROBRAS, Brazil,
[2] AGP/RES-EE/CTGI, PETROBRAS, Brazil, *giselle.canuto@petrobras.com.br

Abstract

Recent scale deposition events were observed in some Campos Basin unexpected wells, all of them from the same field. From the connate water composition itself and thermodynamic conditions reached during production, simulations showed that medium risk of scale deposition was expected. On the other hand, produced water ionic routine characterization evidenced some enrichment in metallic species content during wells production. The referred behavior is related to water production from crossflow between post- and pre-salt aquifers. When the latter feeds the former, metallic species enrichment occurs in the post-salt produced water composition, which is a rich-sulphate fluid. The incompatibility between both waters, leads to barium and strontium sulphate deposition into production tubing and even on reservoir, causing relevant oil production losses. This paper discusses how this risk analysis process should be carried out, with a strong emphasis on the need to integrate all available data. The process has combined monitoring of the unexpected chemical composition of the produced water, thermodynamic simulation of scale risks, historical production, and skin evolution. For solving this problem, routine scale inhibitor squeeze is planned for all producers of this field.

Keywords

Sulphate scales; crossflow; Campos Basin

Introduction

Scale deposition in whole production system (reservoir, well, flowline and topside facilities) is one of the major challenges in the oil industry, which focuses research and development efforts worldwide to mitigate these problems. Inorganic scale solids adhered to metallic surfaces of production tubing progressively reduce its free flow diameter, and in some cases, can stop fluid flow. Scale deposition can also damage valves and accumulate at topside facilities, causing economic losses and compromising the safety of many operations in the oil industry.

In oil and gas fields, water is one of the fluids present in the reservoir, and the problem of salt precipitation occurs due to its production. The formation of inorganic solids occurs because formation water contains Ba^{2+}, Sr^{2+} and Ca^{2+} cations, sulphate anions as well as carbon dioxide dissolved under pressure that gives bicarbonate /carbonate equilibrium with water. Depending on the pressure and temperature production profile, solids can auto precipitate from the connate water. On the other hand, precipitation can be worse by adding sulphate from another source, for example, seawater usually injected into wells to increase the oil recovery factor from the reservoir. The incompatibility between the injection water, seawater which is a sulphate-rich fluid, and the formation water promotes the precipitation of $BaSO_4$ and $SrSO_4$ [1].

Another source of incompatibility, less common, is metallic ions enrichment in the produced water due to crossflow from a deeper aquifer. For this mechanism, a hydraulic communication between two reservoirs must be in place, in which the more pressurized one feeds the depleted reservoir.

A better-known way to assess incompatibility between two different waters is applying a thermodynamic simulation in which two parameters are calculated: SR and MMppt. SR is a parameter that shows the degree of saturation of an aqueous system in relation to each of its chemical components. Therefore, when the SR value is greater than 1, there is a thermodynamic possibility of precipitation occurring until a sufficient amount of the dissolved salt passes into solid form and the SR value drops to 1, reaching the equilibrium. This amount of salt, which is in excess in the solution, is the maximum precipitable mass (MMppt) and indicates the total amount of solids that could came out from solution in a long-term basis. While SR measures the tendency for scaling to occur, MMppt measures the possible extent of the problem.

Methodology

Thermodynamic simulations were conducted using Multiscale software [2]. Pressure and temperature at notable points were obtained from a PETROBRAS proprietary multiphase flow simulator, adjusted with flow rate, pressure and temperature measured by downhole, Xmas tree and/or surface gauge sensors.

For production management reasons, routine anion and cation water characterization are carried out sampling produced fluid from each well every 3-4 months.

The deposition risk was classified using a map from the most recent update of the SWELL V Joint Industry Project [3], that relates risk with saturation ratio (SR) for each salt and flow temperature at a given notable point. Besides, maximum precipitable mass (MMppt) was also evaluated to explain the deposition expected behavior.

Dilution curves for each species could be plotted using connate water and a given second water (e.g., injected water, reinjected water or another aquifer water) compositions and ratio. Comparing diluted curves with actual produced water compositions allows evaluation of scale risk in an expected condition (case of injected water reaching the producers) or may be useful for detecting unexpected cases (enrichment of some species due to crossflow between two aquifers).

Results and Discussion

Wells in the Campos basin referred in this article as well 1 (W1), well 2 (W2) and well 3 (W3), produce from the post-salt zone. From the ionic composition of produced brines, it was inferred that there was mixture with pre-salt water. The composition of pre- and post-salt waters are quite different, especially the concentration of strontium, calcium and sulphate (Table 1). The enormous difference in the concentration of Sr^{2+}, Ca^{2+}, SO_4^{2-} ions makes this mixture of connate waters favorable to scale deposition.

Table 1. Composition of pre- and post-salt connate water*

Component (mg/L)	Pre-Salt	Post-Salt
Na	82419	37891
K	3499	997
Mg	1091	485
Ca	9972	4405
Ba	16	2
Sr	1223	210
Cl	151640	67671
Br	354	131
SO_4	201	1040
pH	4,87	5
Alkalinity	232,4	366,2

*Balanced water for reservoir condition of pressure and temperature

Figures 1, 2 and 3 show the evolution of the ratio of Sr/Cl, Ca/Cl e SO_4/Cl concentrations in the wells, and the comparison with the values of the ratios in the pre- and post-salt water. Chloride ion was used to normalize the values of the curves presented. This approach enables the use of Sr/Cl, Ca/Cl, and SO_4/Cl ratios to identify any deviations in the expected behavior of the produced water from the evaluated wells. To enhance visualization, these ratios were multiplied by 10^3. It is important to highlight that the observed metallic ions enrichment in the produced water is not possible to occur due to seawater injection.

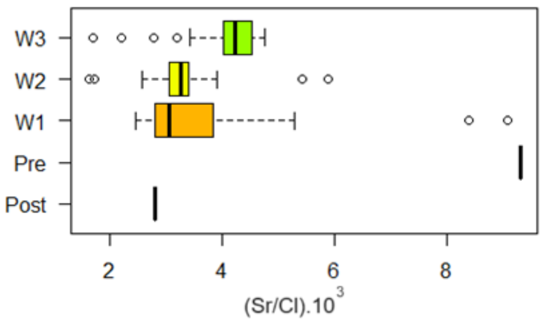

Figure 1. Distribution of Sr/Cl concentration in wells compared to pre- and post-salt waters.

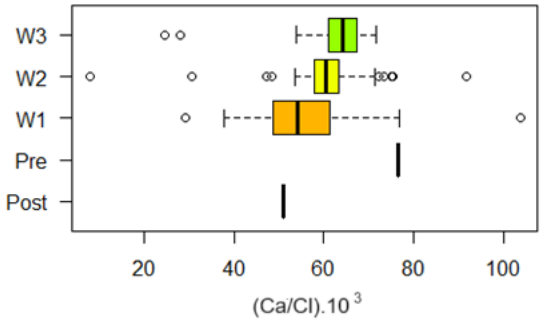

Figure 2. Distribution of Ca/Cl concentration in wells compared to pre- and post-salt waters.

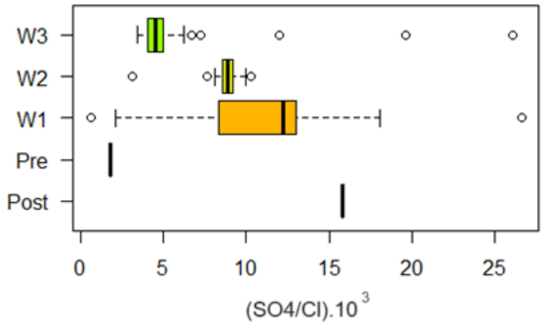

Figure 3. Distribution of SO_4/Cl concentration in wells compared to pre- and post-salt waters.

Produced water ionic characterization over time evidenced enrichment in strontium (Figure 1) e calcium (Figure 2), presenting a Sr/Cl, Ca/Cl ratio greater than the ratio in the post-salt water over time, indicating that the pre- and post-salt connate water has been mixed.

Regarding Fig. 1 and Fig. 2. for the wells W1 and W2 the medians of strontium and calcium concentration in the produced water are closer to the post-salt formation water. However it is possible to note that there is a shift towards pre-salt composition, indicating the possibility of water mixing from different zones. W3 shows a similar behavior of the previous wells, with the central distribution of data shifted to the Sr/Cl value found in the pre-salt formation.

W1, W2 and W3 SO_4/Cl ratio moves towards the pre-salt water composition (Figure 3). Over time, there is a progressive decrease in sulphate concentration, with W3 being the well with produced water having the greatest pre-salt influence, following the trend seen in the Sr/Cl and Ca/Cl ratios.

For example, Fig. 4, 5 and 6 show the W3 dilution curves for the ions strontium, barium, and calcium, respectively. In Fig. 4 and Fig.5 it is possible to observe the deviation of measured values from the expected ones, indicating possible precipitation of strontium and barium sulphates. Fig. 6 depicts calcium consumption, suggesting the possible precipitation of anhydrite or calcite.

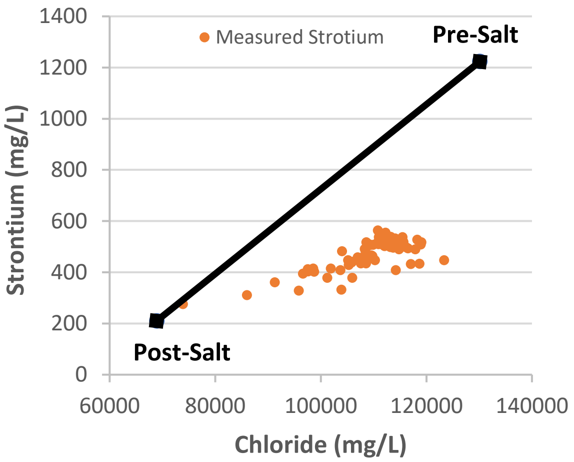

Figure 4. Measured strontium and dilution curve for W3

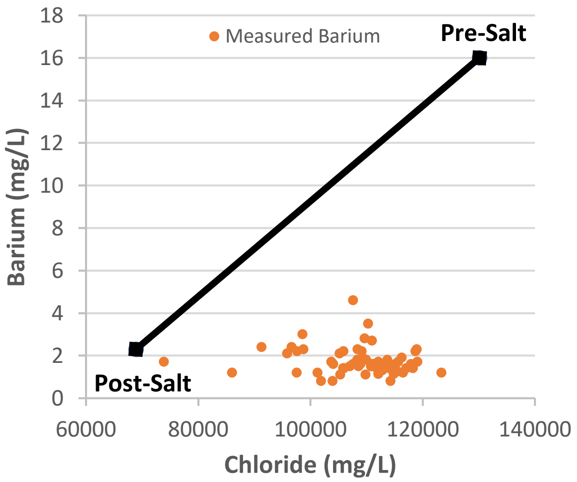

Figure 5. Measured barium and dilution curve for W3

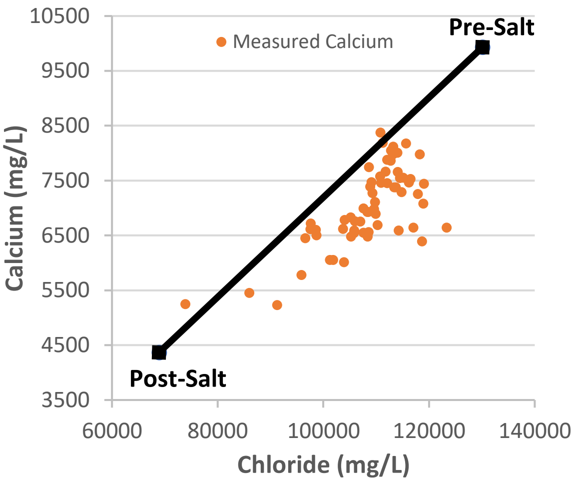

Figure 6. Measured calcium and dilution curve for W3

For the pressure and temperature flow profiles for all three post-salt wells evaluated, even for connate water, the thermodynamic simulation predicts precipitation of $CaCO_3$, $BaSO_4$ and $SrSO_4$ at all notable points since SR > 1 for each salt. The scenario becomes worse as crossflow feeds metallic cations. These ones are the limiting species that conducts to more salt precipitation, giving higher SR and MMppt compared with that from connate water alone.

Precipitation of $CaCO_3$ increases with the growth in pre-salt water content in the mixture, reaching maximum values on well W3 of $SR_{max} = 5$ and $MMppt_{max} = 125$ g/m^3 of produced water at topside conditions.

Thermodynamic simulation for sulphates showed the same behavior, adding more deposition risk as more pre-salt water feeds the three evaluated post-salt wells. For $BaSO_4$, its solubility increases with temperature up to 100 ºC [4]. Thus, it was observed that SR has higher values on topside, which achieves a lower temperature in the flow profiles. The SR calculated for $BaSO_4$ was bigger than that for $SrSO_4$, which is expected due to the lower solubility of the former. However, in terms of precipitable mass, strontium sulphate plays a significant role in deposition, as strontium-rich pre-salt water (1223 mg/L) is mixed with the sulphate-rich post-salt water (1040 mg/L), as can be seen in the thermodynamic simulation for Well 3 (Fig. 7). It can be noticed that a maximum $SrSO_4$ precipitated mass is reached downstream GLV (gas lift valve) when crossflow between post- and pre-salt aquifers gives a 50:50 mixture, reaching values of 593 g of salt per cubic meter on produced water.

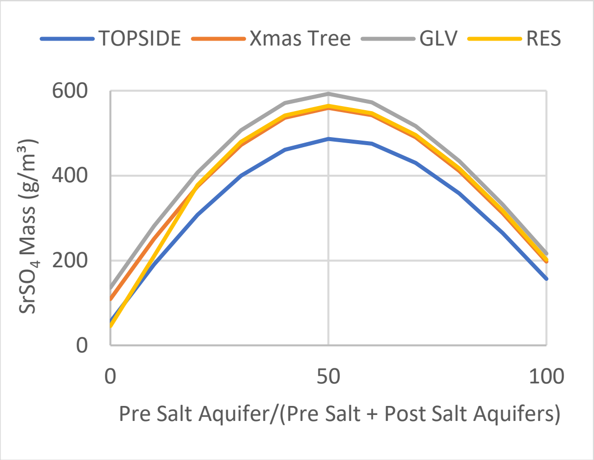

Figure 7. $SrSO_4$ precipitable mass from several mixtures between pre- and post-salt waters for W3. Temperature was not informed to protect SWELL copyrights.

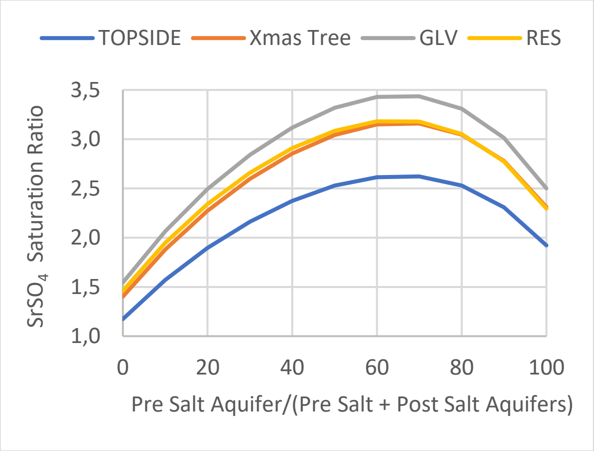

Figure 8. $SrSO_4$ saturation ratio from several mixtures between pre- and post-salt waters for W3. Temperature was not informed to protect SWELL copyrights.

For example, applying SWELL scaling risk for $SrSO_4$ deposition, the risk was classified as low on topside even for 40:60 mixture between post- and pre-salt water, considering SRs values from Figure 8. From the other evaluated points (XMas Tree, GLV and reservoir) it was noticed an increased risk of $SrSO_4$ deposition, crossing the high-risk line at XMas tree and entering more in the highly risky area at GLV and reservoir. Despite higher SR leading to fast precipitation kinetics, it is well known that SR alone does not govern the deposition rate. Variables not considered in thermodynamic studies of scaling, such as geometric characteristics of the wells, type of completion, typical flow conditions and chemical inhibition strategy can significantly change the risks of scaling.

Unluckily, the studied wells do not have bottomhole pressure data wide available during their lifetime to characterize well damage or column pressure drop evolution. But production data show that the well production lowered greater than the decline expected from reservoir depletion or saturation changes. This fact associated with the evidence of scale potential justified some acid treatments performed in these wells which accomplished significant productivity gains.

W1, W2 and W3 are equipped with chemical injection mandrels, but all of them are placed in a production tubing quota that does not protect the risky area for this case, namely the reservoir. From this way, a routine of chemical squeeze at reservoir could be an efficient strategy for inhibiting scale deposition for all wells of the referred field.

Conclusions

From the routine water analysis, it was observed that three wells from the same post-salt reservoir were fed with water from a communicated pre-salt aquifer. There is a possibility that this connection occurred through natural fractures systems. Thermodynamic simulations showed that unexpected mixtures between both incompatible waters carried out to scale risky fluids, which compromised oil flow due to strong $CaCO_3$, $SrSO_4$ and $BaSO_4$ deposition inside production tubing. An inhibitor chemical squeeze routine strategy will be planned for avoiding production losses due to scale deposition in all wells from the related oilfield.

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