



Modeling and Simulation of Carbonate Scaling in Oil Production Scenarios: A Coupled Geochemical and Fickian Transport Approach Implemented as an ALFAsim Plug-in.

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Abstract

Inorganic scaling on the surface of oil production equipment such as tube pipes and completion valves is a flow assurance challenge, particularly in carbonate production scenarios. It obstructs flow and leads to increased head loss and, in extreme cases, complete production blockage. The formation of carbonate deposits is influenced by local pressure, temperature, and the presence of various ionic species at different concentrations. Changes in the aqueous composition of CO₂, coupled with pressure drops, can alter the saturation index and precipitation rate, initiating scaling. Furthermore, scaling is affected by turbulence intensity, which influences the transport of crystals or chemical species towards the wall. This paper presents a coupling approach of a geochemical simulator and a Fickian transport in the 1D multiphase flow simulator ALFAsim. Using this approach, the scaling rate on a simulated production model (well, pipelines, and risers) was simulated, demonstrating good agreement with field and literature observations. Specifically, the results indicate that scaling increases with flow rate, pressure head, CO₂ flash, and temperature.

Keywords

Inorganic scaling; Carbonatic scaling; Flow assurance; Geochemical simulator; Multiphase flow.

Introduction

Inorganic scaling within production equipment poses a significant challenge in the oil and gas industry, impacting flow dynamics and potentially leading to production blockages. Carbonate scaling, particularly sensitive to environmental factors, is of particular concern due to its intricate nature and the complex interplay of factors influencing its formation and deposition. As such, understanding the mechanisms and factors contributing to inorganic scaling is critical for developing effective flow assurance strategies.

Numerous studies have been dedicated to investigating the precipitation of calcium carbonate (CaCO₃) on metal surfaces exposed to environments containing carbon dioxide (CO₂). Numerical models and simulations have been widely employed to deepen our understanding of the CaCO₃ precipitation process, with a focus on factors such as the oily phase, CO₂ degassing, turbulent flow environments, CO₂-WAG injection in carbonate reservoirs, water evaporation, and CO₂ dissolution ([1], [2], [3], [6]).

In this paper, we present a modeling approach to simulate the inorganic scaling rate within a one-dimensional framework using the 1D multiphase well simulator ALFAsim. This approach allows us to simulate the effect of local flow rate (oil, gas, and brine) with a complex composition of formation

water, accounting for the effects of temperature, pressure, and CO₂ solubilization, including its flash due to pressure head. By integrating a geochemical simulator with a Fickian transport model, the approach accommodates multiphase flow scenarios and the complex effects of CO₂ on the precipitation reaction.

The study simulates scaling rates on a near-realistic well-pipeline-riser model, considering the effects of local pressure, temperature, flow rate (oil, gas, and water), and CO₂ concentration on scaling. The simulation output includes local pH and saturation index, which aid in the analysis of scaling trends. This comprehensive framework allows for a better understanding of the mechanisms and factors contributing to inorganic scaling in oil and gas production equipment, informing the development of effective flow assurance strategies.

Methodology

To achieve our goal of modeling and simulating the scaling rate, we developed a methodology based on references [7] and [5]. Unlike [7], which only considers a simplified H₂O-CO₂-Ca system, our current approach allows us to work with a real formation water solution.

Figure 1 illustrates our complete methodology, showing inputs such as local oil, gas, and water

volumetric flow rates, temperature, pressure, hydraulic diameter, and water composition. We utilized a geochemical computational package (Reaktoro®) to model and simulate the equilibrium state of ionically saturated formation water, including ions such as Ca^{+2} , K^+ , Sr^{+2} , Ba^{+2} , Mg^{+2} , Na^+ , Cl^- , SO_4^{-2} , Fe^{+2} , and HCO_3^{-2} .

The geochemical model takes the ionic concentration and the CO_2 molar fraction to account for gas solubility in the solution and outputs the precipitate molarity of CaCO_3 , its saturation index (SI), and the equilibrium pH.

Simultaneously, we applied the procedure from [5] to calculate mixture properties such as velocity, specific mass, viscosity, and mixture Reynolds number. According to [8], based on the Reynolds and Froude mixture numbers, if the flow fits a segregated flow configuration, further calculations are based on water velocity and wet diameter; otherwise, the flow is modeled as a mixture flow. Finally, CaCO_3 diffusivity was determined as a function of the Reynolds, Sherwood, and Smith numbers according to [9].

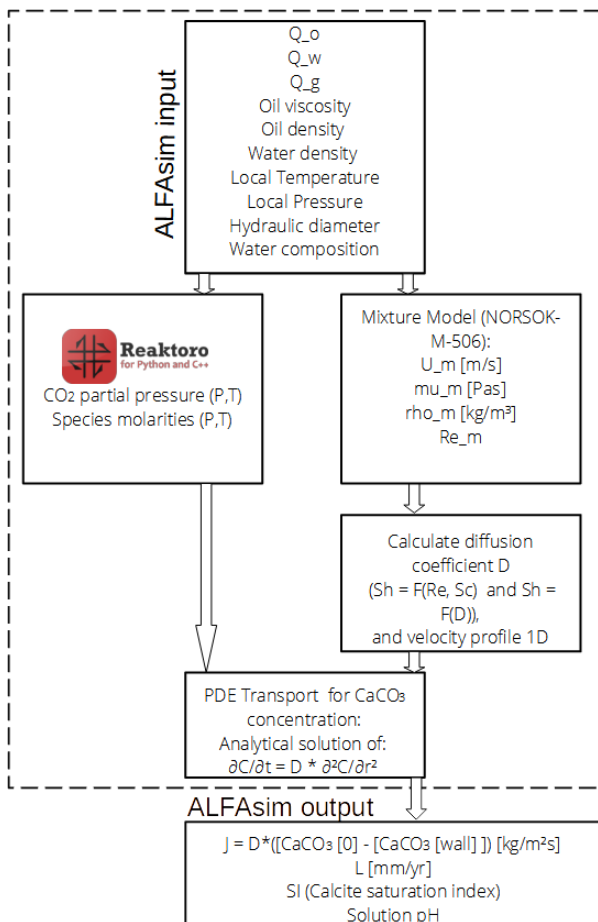


Figure 1. Inorganic scaling model.

Finally, the concentration profile was obtained by the analytical solution of a diffusion equation, as presented by [7], and the wall mass flow rate $[\text{kg}/\text{m}^2\text{s}]$ as well as the scaling rate in $[\text{mm}/\text{yr}]$ were estimated. Also, the calcite saturation index and solution pH are estimated for each simulated cell.

The saturation index $\text{SI} = \log(\text{SR})$, being the SR the saturation ratio, where $\text{SR} = \{a(\text{Ca}^{2+})\} \{a(\text{CO}_3^{2-})\} / K_{\text{ps}}$, with K_{ps} representing the solubility product constant ([7]). These terms within braces correspond to the chemical activity and change with the presence of other ions adverse to the reaction, in a more realistic brine.

Simulated Conditions

To analyze the output, a generic formation water assumption was made, similar in magnitude to that typically observed in a Brazilian pre-salt reservoir. Table 1 lists the main chemical species along with their concentrations. Additionally, two molar fractions of CO_2 were considered.

Table 1. Insert the Table title.

Ionic specie	Concentration
H_2O	1[kg]
Ca^{+2}	800 [mg/kg]
K^+	2000 [mg/kg]
Sr^{+2}	200[mg/kg]
Ba^{+2}	1[mg/kg]
Mg^{+2}	200[mg/kg]
Na^+	30000[mg/kg]
Cl^-	50000[mg/kg]
SO_4^{-2}	1000[mg/kg]
Fe^{+2}	50 [mg/kg]
HCO_3^-	2000 [mg/kg]

To evaluate the scaling plug-in, a representative model of a production system was assembled based on field data, as shown in the physical model presented in Figure 2.

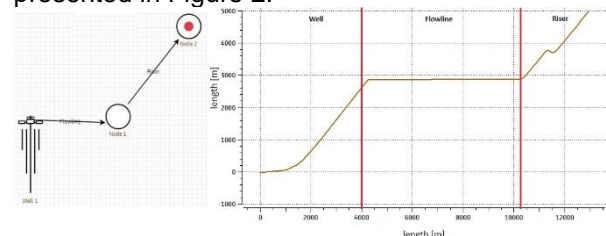


Figure 2. Simulated model.

In addition to geometric data, which enabled the modeling of the well, a set of hypothetical production data with volumetric flow rates of the phases, PDG P, PDG T, WH P, WH T, and pressures and temperatures at the platform, or topside, were used considering a generic well A ($Q_g = 600000 \text{ m}^3/\text{s}$ std, $Q_o = 3000 \text{ m}^3/\text{d}$ std, $\text{BWS} = 1\%$, and CO_2 molar percentage of 10%).

Results and Discussion

The PVT model shows good agreement with experimental data, as it can be calibrated with both laboratory and field data, reproducing the trend of increasing pH with decreasing pressure and increasing temperature. This phenomenon is indirectly related to the precipitation of CaCO_3 , as a decrease in pressure tends to increase pH due to the release of CO_2 . Furthermore, an increase in temperature tends to elevate the fugacity of CO_2 , accelerating its release and further increasing pH.

Figure 3 illustrates the simulated data for a reference chemical solution (well A) considering a 10% CO₂ fraction. It also shows the experimental pH data for the CO₂-H₂O system for comparison ([6]). In this case, simulations indicate that when considering an aqueous solution with a real composition, the pH curves are higher than those for the case with 100% CO₂ and only water. This occurs due to the reduced chemical activity of the solution and the consequent increase in pH.

In addition to the previous analysis, the Reaktor[®] model was used to simulate the effects of pressure and temperature on the calcite saturation index. Figure 4 (top) illustrates the effect of pressure and temperature for an ideal 100% CO₂ and H₂O solution. It is observed that for all simulated conditions, the IS was less than zero, meaning the solution is undersaturated, thus the tendency for calcium carbonate dissolution is dominant over precipitation.

However, when considering the aqueous solution specified in Tab. 1, Figure 4 (bottom), the behavior of the IS curves changes substantially. Figure 4 illustrates this behavior, showing that for various conditions, the IS becomes greater than zero, making precipitation and scaling likely from a thermodynamic perspective.

The results presented suggest that the thermodynamic model estimates the solution's pH with reasonable accuracy and correctly predicts the physical trend for the saturation index and pH. In other words, the reduction of pressure in the CO₂-containing system induces the release of the aqueous solution, leading to an increase in pH and IS. Furthermore, the model captures the effect of temperature increase on IS and pH, indicating that the increase in temperature raises these variables. Figure 5 shows the ALFAsim simulated profile in steady state, highlighting the mass flow rate profiles of oil, gas, and water, as well as the pressure and temperature profiles along the well geometry (well, flowline, and riser).

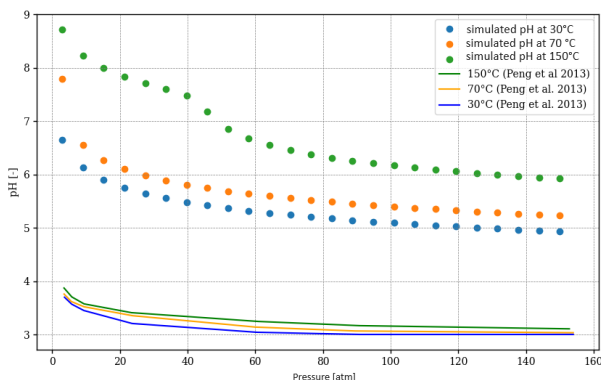


Figure 3. pH simulated for 10% of CO₂ molar fraction and Tab 1 water and [6] pH data.

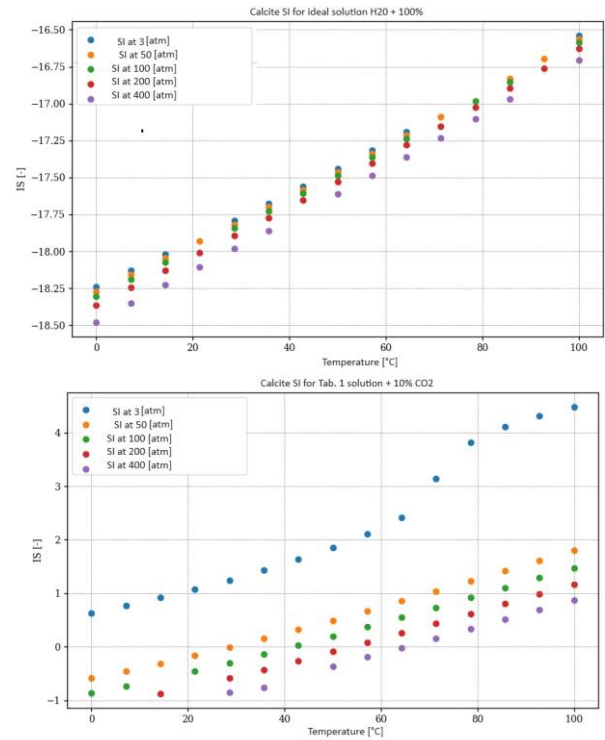


Figure 4. Top: Saturation index (IS) for the solution from well A considering 100% CO₂ in the gas phase. Bottom: Saturation index (IS) for the solution from Tab.1 considering 10% CO₂ in the gas phase.

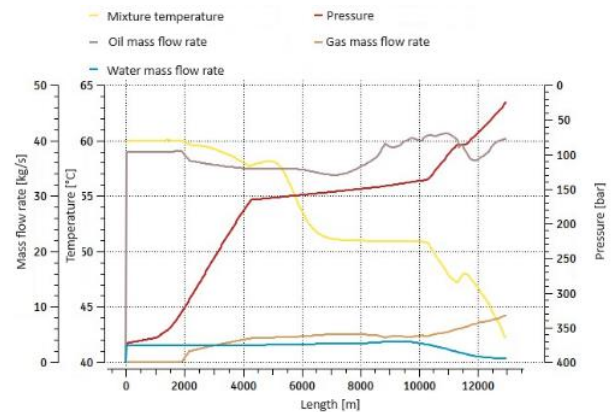


Figure 5. Simulated profile of mixing temperature, absolute pressure, and oil, gas mass flow rate.

In Figure 6, the profiles along the control volume of the well (well at top) and flow line + riser (at bottom) for scaling rate, pH, temperature, and pressure are presented. It is observed that the depressurization of fluids, from the bottom to the wellhead, results in an increase in the scaling rate, simultaneously with an increase in pH. This phenomenon occurs due to the solubilization of CO₂, which is influenced by pressure and temperature. With depressurization, the solubility of CO₂ decreases, promoting the flash release of this component, which results in the deacidification of the aqueous solution and an increase in pH. These factors contribute to the increase in the saturation index (SI) and the precipitation rate. Additionally, it is relevant to note that with depressurization, the release of other

gases from the liquid phase occurs, increasing the mixing velocity and, consequently, the diffusivity of CaCO_3 , leading to an increase in the scaling rate. Similarly Figure 8 presents the scaling rate profiles. However, in these cases, instead of pH, the SI profiles are highlighted. This allows mapping the SI along the simulated domain, emphasizing the conditions of pressure and temperature on the solubility of CO_2 and, consequently, on the saturation index.

The results show good agreement with the scaling mechanisms due to CO_2 flash, incorporating the effects of the thermo-hydraulic profile along the domain, the effect of pH, and the calcite saturation index as a function of local pressure and temperature. Additionally, the effect of flow intensity is accounted for, assuming a diffusivity transport for bulk precipitates of CaCO_3 . Coupling this system in ALFAsim allows engineers to analyze the scaling trend along the domain and simulate case scenarios, aiding in the design of the completion system.

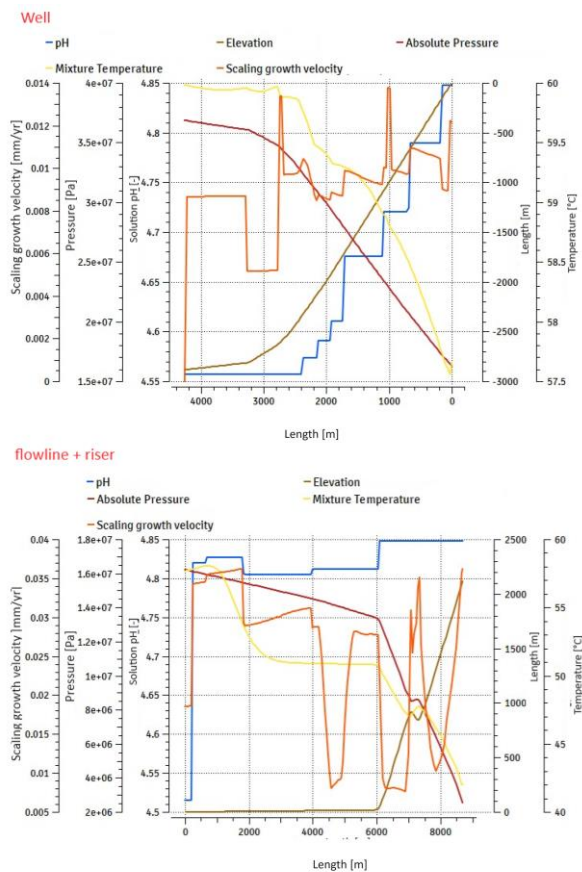


Figure 7. Profiles of scaling rate, pH, temperature, and pressure along the well (top) and flow line + riser (bottom).

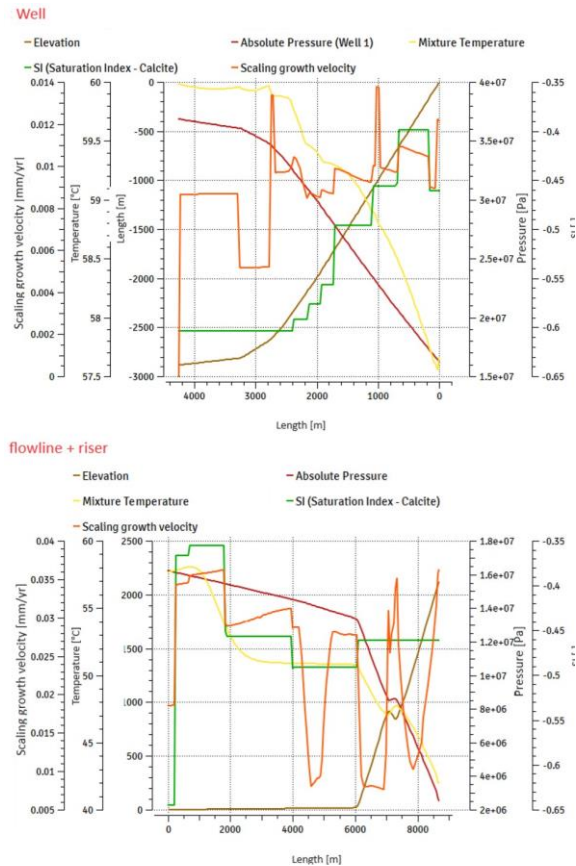


Figure 8. Profiles of scaling rate, SI, temperature, and pressure along the well (left) and flow line + riser (right).

The integration of the inorganic scaling model into ALFAsim enables 1D multiphase flow simulations that analyze critical variables like pressure, temperature, pH, and saturation indices along well and flowline profiles. By modeling interactions between thermo-hydraulic profiles and scaling mechanisms, including CO_2 solubility and diffusive transport of CaCO_3 , the tool helps engineers predict and mitigate scaling issues. This approach supports the design and optimization of production and completion systems, providing a detailed understanding of scaling tendencies in oil wells.

Conclusions

In conclusion, this study highlights the intricate dynamics of inorganic scaling in oil and gas production systems, particularly focusing on calcium carbonate (CaCO_3) precipitation influenced by environmental conditions such as temperature, pressure, and CO_2 solubility. Using the 1D multiphase well simulator ALFAsim, we have effectively modeled the scaling rates, incorporating the complex effects of multiphase flow rate and the chemical interactions within formation water. The integration of a geochemical simulator with a Fickian transport model allowed for a nuanced simulation of scaling trends in a near-realistic production system. The results demonstrated that depressurization significantly impacts the scaling rate by altering the solubility of CO_2 , thus affecting the pH and the calcite

saturation index. This comprehensive approach not only validated the geochemical model against experimental data but also provided critical insights into the conditions that promote scaling. These findings are pivotal for developing robust flow assurance strategies, ensuring the operational efficiency and longevity of production equipment in the oil and gas industry.

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