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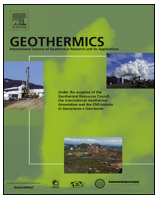

Modeling the geochemical evolution of fluids in geothermal wells and its implication for sustainable energy production

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A B S T R A C T

In practice, geothermal fluids are sampled under surface conditions for geochemical interpretations. However, the physical and chemical properties of geothermal waters change as the waters flow from a reservoir to the surface along the well due to processes such as mineral scaling, degassing, cooling and boiling. The objective of this study is to estimate the geochemical characteristics of water-dominated geothermal reservoirs and to model the geochemical evolution of fluids in geothermal wellbores to provide information on the parameters that contribute to sustainable energy production. A workflow was developed for commonly used non-commercial software PHREEQC and geochemical modeling approach was demonstrated for fluid samples of four geothermal wells located in the Kizildere geothermal field (SW Turkey). According to the modeled reservoir chemistry, the reservoir type in the field is water-dominated, and the sum of partial pressures of dissolved CO_2 and steam in the reservoir varies from 135–160 atm. First gas bubble depths, where an inhibitor should be injected below, were calculated for relevant flow rates of the wells as 1597, 1751, 1884 and 1579 meters. The calculated initial total calcium concentrations in the reservoir are 3.67, 5.93, 5.04 and 6.01 mg/kg. Besides calcite, 16 minerals including silica polymorphs, amphibole, serpentine, pyroxene, carbonate and phyllosilicate groups, are gained precipitation tendency under the separator conditions. To provide sustainable energy production by preventing mineral scaling in reservoirs and wells, the required parameters such as; appropriate depth for inhibitor injection in wellbore, type and initial concentration of scaling minerals, total dissolved gas and steam pressures in reservoir to limit maximum flowrate can be determined for any water-dominated geothermal field by using the proposed workflow in the PHREEQC software.

1. Introduction

Geochemistry is extensively applied in all stages of geothermal exploration and development (Arnórsson, 2000). In each individual stage, geothermal fluids are sampled at the surface rather than the reservoir. However, the physical and chemical properties of geothermal water that is at or close to equilibrium with host rocks in water-dominated reservoirs change from their initial state to the surface sampling condition during the up flow of the fluid along the wellbore. The main processes that change the reservoir water chemistry in the wellbore are the boiling of water, degassing of dissolved gases and the consequences of adiabatic cooling and mineral scaling. The combined effects of the increase in dissolved species concentration (boiling), decrease in temperature, rise in pH (degassing) and redistribution of bulk compositions among species (speciation) cause mineral scaling in the wellbore.

Continuous mineral scaling gives rise to a reduction in the geothermal well flow rate by clogging the wellbore and surface equipment (Satman et al., 1999). Falling off energy production due to mineral scaling is widely encountered at geothermal fields around the world (Kristmannsdóttir, 1989; Mercado et al., 1989; Tarcan, 2005; Yanagisawa et al., 2008; Sugiaman et al., 2004). The most effective way to prevent mineral scaling and achieve sustainable energy production is by using various chemicals as inhibitors (Akın et al., 2015). To prevent mineral scaling efficiently, the inhibitor should be injected into the liquid phase at a depth where it can be mixed homogeneously with the geothermal water before the transition of the flow regime to the two phases in the wellbore (Fig. 1a). The inhibitor is injected through preset permanent capillary tubing, and it is exposed to high temperatures until it is ejected from a diffuser at the end of the tubing. If the injection is carried out at a deeper depth than required, the inhibitor may undergo thermal degradation in the tubing and lose its efficiency. For these reasons, the gas breakout depth where the liquid phase starts to form gas bubbles and transforms into both liquid and gas phases should be determined to set the capillary tubing sensitively for wellbore.

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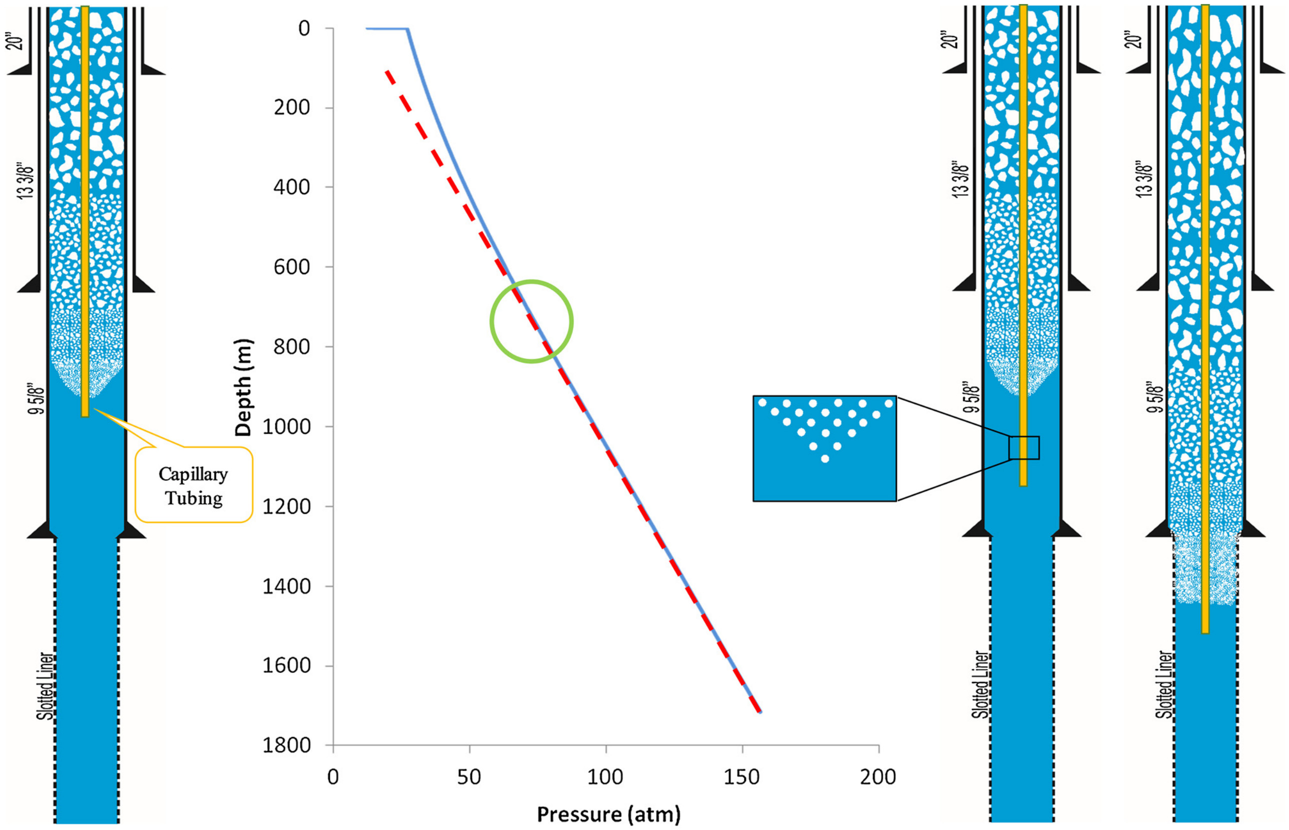

a) b) c) d)

Fig. 1. a) Inhibitor injection via capillary tubing at the depth evaluated from the dynamic pressure plot. Inhibitor is injected into the water slightly below the two-phase formation. b) Determination of gas breakout depth in practice. In this method, a deviation from linearity on the dynamic pressure profile is used, but the results may vary in the green circle according to the evaluator. c) First gas bubble formation. It is deeper than the depth determined from the dynamic pressure plot. The fluid chemistry changes as soon as first gas bubbles form, so the inhibitor should be injected below this evaluated depth. d) Two-phase formation in the reservoir level of the well due to overproduction (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article).

On a plot of the wellbore dynamic pressure profile, the point that begins to deviate from linearity is practically used to determine the gas breakout depth (Fig. 1b). However, the depth of the point is shallower than the depth of first gas bubbles because a significant amount of boiling is needed to change the slope of the line on the plot. When the first gas bubbles form, the pH simultaneously changes and triggers consecutive reactions that affect the mineral saturations. Therefore, both the detection of the gas breakout depth and the evaluation of the initiation of mineral scaling should be determined based on the first gas bubble formation rather than the curve on the dynamic pressure profile (Fig. 1c). Even if the depth where inhibitor should be injected is determined precisely, another requirement for the effective operation of the inhibitor is to ensure that the gas phase is formed within the well (Fig. 1d). In water-dominated geothermal reservoirs, the utilizable maximum flow rate of the wells should be determined by taking into consideration the total gas pressure (TGP) in the reservoir. TGP is the sum of the partial pressures of all dissolved gases and the saturation pressure of water at relevant temperature and chemistry. Since the dynamic pressure in the reservoir level of the wellbore decreases with an increasing flow rate, production should be constrained to keep the gas formation in the casing rather than the reservoir. Otherwise, fractures and porous media in the reservoir could be clogged by mineral precipitation (Fig. 1d). Therefore, the limitation of the flow rate required for sustainable production should be determined by considering the TGP and should be used when designing geothermal projects instead of the maximum flow rate measured in short-term production tests. To do this, TGP can be measured via special in situ sampling equipment in the reservoir, or it can be calculated by geochemical modeling.

The technological implementation of well testing in the petroleum industry has led to the development of advanced wellbore sampling equipment (Aghar et al., 2007). There are basically two ways of sampling fluids from a deep developed well: either directly at the depth of interest, which is denominated ‘downhole’ sampling (positive displacement, vacuum, flow-through), or by conveying the fluid to the surface, which is termed ‘uphole’ sampling (pump, U-tube). Downhole sampling involves the periodic and temporary introduction of a sampling device into the well and is suitable for short-term research and monitoring projects, whereas uphole sampling relies on the (semi-) permanent installation of components (e.g., line shaft, submersible pump, U-tube) in the well (Wolff-Boenisch and Evans, 2014). Although the exact values of critical parameters, such as pH, alkalinity, P_{CO2} and the initial amount of precipitated constituents, can be measured and analyzed sensitively with the aid of these tools, these applications are quite expensive and time-consuming as well as risking the loss of a tool. In addition, the installation of permanent wellbore capillary tubing under the scope of inhibitor application precludes continuous downhole fluid sampling.

Estimating the reservoir fluid characteristics by geochemical modeling in cases where samples cannot be obtained directly from the reservoir is a widely used method (Torres-Alvarado et al., 2012; Wolff-Boenisch and Evans, 2013; Pátzay et al., 2003; Reed, 1989). Various computer programs that can perform the calculations in terms of geochemical modeling have been developed (Parkhurst and Appelo, 2013; Bjarnason, 2010; Verma, 2012; Bethke, 2006; Xu et al., 2014). Each modeling program had been developed for specific purposes and thus