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INVESTIGATION OF SALT PRECIPITATION IN GEOTHERMAL RESERVOIR NEAR SEALING CONDITIONS

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ABSTRACT

The main goal of the work is to investigate the behavior of a geothermal reservoir containing salty water when its physical parameters exceed the critical values, i.e. when the vaporization process cannot be described by the asymptotic self-similarity solution. We consider a low-permeability rock, where salty water vaporizes at a sharp front, because of fluid extraction at constant pressure. If the parameters are below the critical values the analytical results are in good agreement with results of 1D numerical simulations carried out by the TOUGH2-EWASG code. In these cases the numerical solution reaches a quasi-stationary regime, describing by the similarity solution. For a higher mass flux towards the well bore, when the critical parameters exceed the critical values, the numerical solution maintains a non-stationary regime until the porous space at the vaporization front is fully clogged (sealed) with solid salt.

INTRODUCTION

The processes in porous rock in which solid material is deposited from solution or is removed due to dissolution are very important for different applications. Battistelli, Calore & Pruess (1995, 1997) used the TOUGH2-EWASG code to study the reduction of rock porosity and permeability due to salt precipitation in porous and fractured geothermal reservoir. A mathematical model of salt precipitation at a sharp vaporization front, which develops in geothermal reservoir, was presented in Tsypkin & Woods (2005). They found that two branches of self-similar solution might exist in a wide range of parameters. For a large mass flux from a far-field towards the front these two branches coincide and above a critical value of the flux the self-similarity solution ceases to exist. The authors guess that this critical value corresponds to the sealing of rock with solid salt at the vaporization front.

Analytical solutions are usually used to have insight into the main features of basic physical processes and to verify the accuracy of numerical simulators. When analytical solution demonstrates untypical behavior, then numerical calculations may help in clarifying the reasons of their non-existence.

In this work we use the TOUGH2-EWASG code to investigate salt precipitation near the critical point, where asymptotic solution ceases to exit.

PROBLEM FORMULATION

We consider decompression and boiling of salty water in hot rock, because of fluid extraction at constant pressure, with development of a sharp vaporization front. As a result the vapor region behind the vaporization front contents salt in a solid form. For the simplicity we consider a one-dimensional depletion problem, which can be described by the similarity solution given by Tsypkin & Woods (2005). We assume that the initial reservoir temperature, T_0, pressure, P_0, and salt concentration, c_0, are uniform throughout the semi-infinite system. The fluid extraction point, located at x=0, represents a well operated at constant bottom-hole pressure, P_w (flow in the well is not considered).

ANALYTICAL SOLUTION

Tsypkin & Woods (2005) derived the boundary condition at the vaporization front, which describes conservation of mass for the salt component. Ignoring the salt diffusion in the simplest case the relation can be written as

$$SS = \frac{\rho_b c_0}{\rho_{ss}} \left[1 + \frac{k}{V\phi\mu_b} \left(\frac{\partial P}{\partial x} \right)_+ \right] \quad (1)$$

where SS is the fraction of volume of the porous space occupied with solid salt (solid saturation), ρ_b and ρ_{ss} are the densities of the solution (brine) and solid salt, respectively, k is the permeability, V the boiling front velocity, ϕ the porosity, μ_b the viscosity of the brine and subscript + denotes the region ahead of the front. This relation shows that *SS* increases with the initial salt concentrations and brine flux from the far-field, as well as for smaller front velocities. It should be mentioned that mass of precipitate depends on reservoir permeability weakly, because the front velocity $V \sim k^{1/2}$ and $dP/dx \sim k^{-1/2}$, as it follows from the conservation of mass of H_2O. Though *SS* does not depends on permeability "directly", permeability affects vaporization temperature, T_*, therefore vaporization pressure, P_*. As $dP/dx \sim P_0 - P_*$, then for a large reservoir pressure we have $P_* << P_0$ and $dP/dx \sim P_0$. They found that there are two branches for the similarity solution (figure 1). For the upper presumably unstable branch the mass of solid salt decreases with the reservoir pressure, whereas it increases for the lower presumably stable branch.

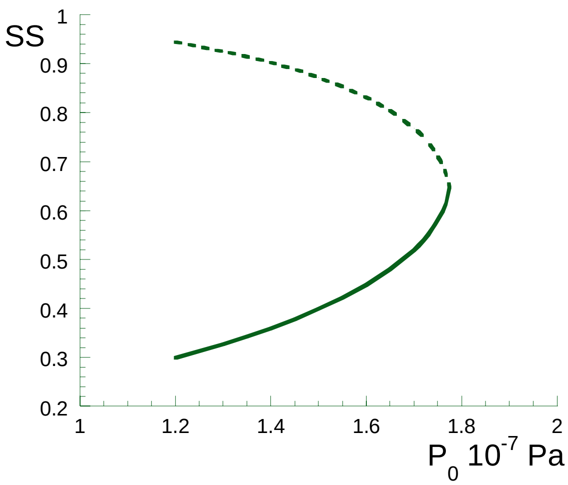

Figure 1. Bifurcation diagram of the similarity solution: solid saturation versus reservoir pressure. Dashed line corresponds to the unstable branch of the solution. $\phi = 0.1$, $k=0.5{\cdot}10^{-17}$ m^2, $T_0=513.15$ *K*, $P_w = 2{\cdot}10^6$ *Pa.*

The two branches coincide at a bifurcation point and for higher reservoir pressures the similarity solution ceases to exist. It was hypothesized that this value of the reservoir pressure is the critical pressure above which rock is sealed with solid salt.

NUMERICAL RESULTS

Numerical experiments were then performed to verify the above hypothesis and predictions from the analytical model, using the multi-phase, multi-component fluid and heat flow simulator TOUGH2-EWASG. For comparison we modeled the idealized one-dimensional analytical problem, thus neglecting gravity, salt diffusion and vapor pressure lowering effects. The 1–D homogeneous porous medium horizontal column is discretized with a relatively fine grid (spacing of 0.1 m) near the extraction point to resolve the sharp thermal and phase fronts there. Grid spacing is then increased out to a total length of 100 km (system infinite acting for the periods of time simulated). Cross sectional area is 1 m^2. In all cases presented here, the system is initially saturated with salty water at uniform temperature of 513.15 K and salt concentration of 0.30. Other parameters of the system are: k=$0.5{\cdot}10^{-17}$ m^2, ϕ=0.10, rock density, thermal conductivity and specific heat of 2600 kg/m^3, 2.51 W/m·K and 920 J/kg·K, respectively. Relative permeability and permeability reduction functions have a linear form. Vapor extraction at one edge of the column (x=0) is represented by a "boundary" element with a well on deliverability at constant bottom-hole pressure P_w= 2 MPa (flow in the well is not considered). Initial reservoir conditions are constant at the other edge of the system. Several numerical simulations were carried out varying initial reservoir pressure in the range 13-19 MPa.

Precipitate formation at low reservoir pressure

Simulations at low reservoir pressures show that precipitation occurs near the production well. During the initial stage, when vaporization front develops, the mass of the solid salt per unit volume in the vapor region increases (figure 2). Then precipitation process reaches quasi-stationary regime and *SS* becomes constant. This regime corresponds to the similarity solution.

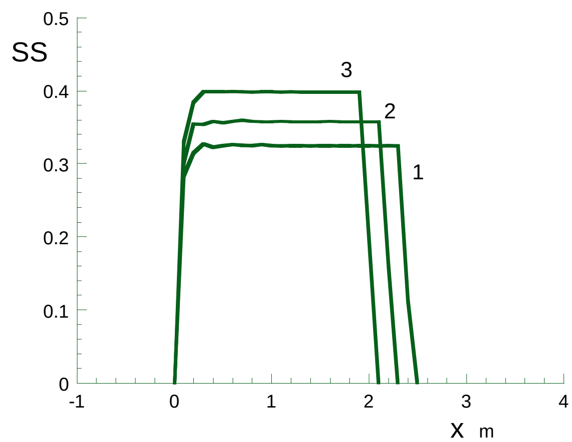

Figure 2. Solid salt distribution after 10 years of production for different initial reservoir pressure. 1 – $P_0 = 1.4{\cdot}10^7$ *Pa. 2 –* $P_0 = 1.5{\cdot}10^7$ *Pa. 3 –* $P_0 = 1.6{\cdot}10^7$ *Pa.*

Duration of the initial stage increases with reservoir pressure. With reservoir pressure $P_0 = 1.4{\cdot}10^7$ Pa, solid salt function reaches limit value SS = 0.325 after 1.75 months and for $P_0 = 1.6{\cdot}10^7$ Pa we obtain quasi-stationary regime after 2.5 months with SS = 0.398.

Figure 2 shows that *SS* increases with the reservoir pressure, whereas velocity of the vaporization front decreases, as well as the extension of the region with quasi-stationary regime.

Precipitate formation at high reservoir pressure

Increasing of the reservoir initial pressure leads to the case in which quasi-stationary regime cannot be reached in a reasonable period of time (figure 3, line 1). If the reservoir pressure is enough large, then the high mass flux of salt in dissolved form to the vaporization front causes the formation of a plug, which consist of solid salt and this plug separates water and vapor-saturated regions (line 2). For a higher reservoir pressure the dimension of the vapor region becomes smaller (line 3).

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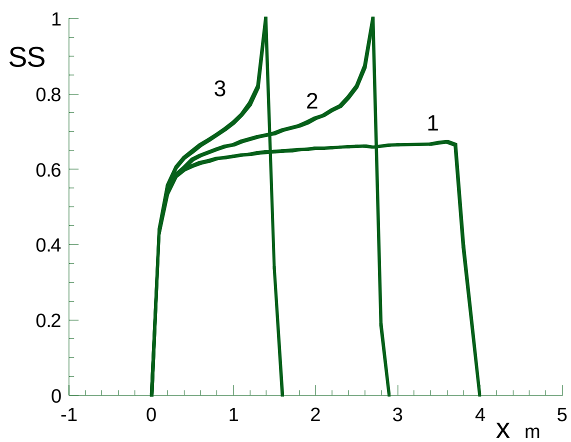

Figure 3. Non-stationary regime of salt precipitation after 100 years for $P_0 = 1.87{\cdot}10^7$ Pa (line 1). Reservoir sealing after 66 years for $P_0 = 1.885{\cdot}10^7$ Pa (line 2). after 20 years for $P_0 = 1.89{\cdot}10^7$ Pa (line 3).

Figure 4 shows comparison between similarity solution (line 1) and results of numerical simulations (line 2). The agreement between the two methods is good. We suppose that some differences arise because the similarity solution ignores the decrease in temperature ahead of vaporization front due to the water decompression. As a result, the brine viscosity is lower in the numerical model, and consequently brine moves more slowly, but vaporization front develops quickly, passing the large distance, whereas the brine flux from the far field supplies the same amount of salt. Therefore, as formula (1) shows, the mass of precipitate (solid saturation) behind the front is smaller.

Similarity solution shows that the porous space sealing occurs at 17.75 MPa, whereas the numerical solution gives the critical pressure value P_{crit} between 18.6 and 18.8 MPa. The numerical experiment at the reservoir pressure P_0 = 18.7 MPa has shown that after 500 years the *SS* function is still increasing (figure 5) and does not give information about reservoir sealing. We suppose that the even slow monotonic increase of *SS* characterizes the sealing of the reservoir.

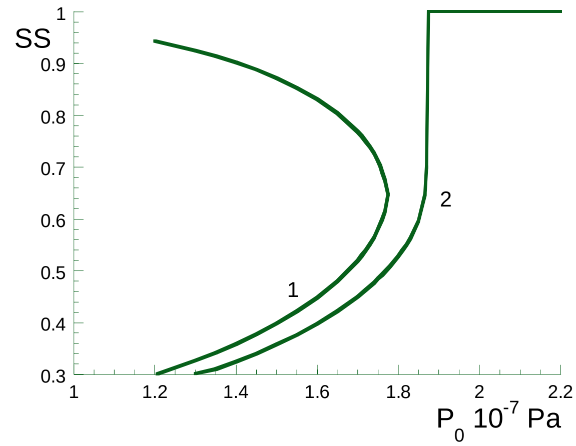

Figure 4. Comparison between the analytical (line 1) and numerical (line 2) results.

Thus, as the reservoir pressure tends to the critical value, the duration of the monotonic behavior of *SS* tends to infinite. This means that the vaporization front passes a large distance and porous space sealing occurs far from the extraction well-bore.

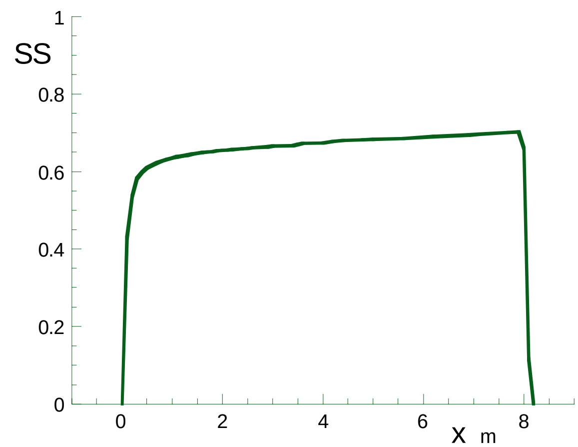

Figure 5. Non-stationary regime of salt precipitation

SUMMARY

We considered sealing processes in low-permeability infinite reservoir, containing salty water, where vaporization of the solution occurs at a sharp front because of vapor extraction at constant pressure.

The analytical solution to this problem is characterized by a bifurcation point, in which the solution ceases to exist. It was hypothesized that this critical point, given the other physical parameters, corresponds to the value of the reservoir pressure above which rock is sealed at the vaporization front with precipitate.

The TOUGH2-EWASG code has been used to verify this hypothesis and predictions from the analytical model, and investigate the precipitate formation near the critical point.

For assumptions and parameters used here, the above hypothesis has been verified and regimes of precipitate formation can be divided into three groups. First group includes precipitation regimes when quasi-stationary state can be reached quickly (reservoir pressure less than critical pressure). Second group describes transient regimes when mass of precipitate at the vaporization front slowly increases for a long time. In this case non-stationary regime can go on for hundred years or even more to reach quasi-stationary regime or reservoir sealing (reservoir pressure very close to the critical pressure). Third group consists of sealing regimes, which are characterized by comparatively fast filling of porous space with solid salt (from reservoir pressures slightly above the critical pressure). Sealing point approaches the production well with increasing reservoir pressure.

The simple analytical model used here describes the main features of the clogging process in a satisfactory way. Comparison with numerical results shows that this analytical model supplies conservative estimates of reservoir clogging, as it neglects brine decompression effects ahead of the vaporization front.

ACKNOWLEDGEMENTS

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