Proceedings World Geothermal Congress 2020
Reykjavik, Iceland, April 26 – May 2, 2020

A Fully-Coupled Implicit Transient Two-Phase Wellbore Simulator

Fabian Nitschke*, Maziar Gholami Korzani, Sebastian Held and Thomas Kohl

Karlsruhe Institute of Technology (KIT), Institute for Applied Geosciences, Department of Geothermics, Adenauerring 20b, 76131 Karlsruhe, Germany

*fabian.nitschke@kit.edu

Keywords: Wellbore simulator, transient, fully-coupled, compressible fluid, two-phase fluid, drift-flux flow.

ABSTRACT

Boreholes under operation conditions typify a highly non-linear and complexly coupled thermo-hydraulic-chemical (THC) system. Multiple parameters, such as temperature, pressure, specific heat, enthalpy, viscosity, flow regime, heat transfer, degassing, steam quality, salinity and solubility are inter connected. Production and injection often entail several engineering challenges and operational problems within the boreholes but also up and down stream (reservoir-power plant-reservoir), which can be very diverse in their character. Finding solutions or working on process optimization prerequisite a profound understanding and a reliable tool to quantify these processes. Compared to reservoirs, the processes in boreholes are highly dynamic and fluctuating. Most existing simulators provide either only steady state solutions or are based on a just weakly coupled numerical scheme. We develop a new tool solving for the aforementioned parameters in a fully-coupled, implicit, and transient manner, which is a prerequisite to realistically model dynamic borehole conditions.

Herein, we present the current state of the development of the simulator for multicomponent non-isothermal two-phase flow. To demonstrate the capabilities of the code, validation results and synthetic test cases for compressible single-phase flow as well as two-phase drift-flux are shown. Applications of such a tool are manifold. It can be used for exploration in early stages of the reservoir development, to constrain the static formation temperature (SFT) from logging data measured under dynamic production/injection conditions. What-if-calculations support the design and dimensioning of future power plants. Optimization of production and injections scenarios are more reliable when they are based on solid quantifications of thermo-hydraulic borehole processes. Furthermore, borehole simulation can also be the basis for managing the complex handling of co-produced non-condensable gases or preventing scaling formation and steel corrosion.

1. INTRODUCTION

The access to a geothermal reservoir and the exploitation of its energy can only be accomplished via wellbores. This illustrates the enormous importance of wells for a geothermal site. The physical processes inside a well during production or injection, such as pressure drop, heat transfer, phase composition, densities, viscosities, etc., are characterized by large pressure and temperature differences between wellhead and bottomhole. For exploration, design, operations and optimization, a reliable quantification of these processes and governing parameters are highly crucial but contemporaneously hard to achieve. Due to inaccessibility, geothermal operations are purely wellhead controlled. Therefore, the assessment of the system parameters in depth has to be deduced from wellhead measurements. To tackle this task, numerous empirical and analytical approaches exist providing steady state solutions for the thermal system of a well (e.g. Kabir and Ameen, 1996; Ramey, 1962) and for the hydraulics (e.g. Beggs and Brill, 1973; Hagedorn and Brown, 1965; Orkiszewski, 1967). For three decades, since Aunzo (1990) released GWELL, numerous numerical tools have been developed to model coupled thermo-hydraulic well flow in order to overcome the typical limitations of analytical solutions (e.g. in complex scenarios, geometries, transients, etc.). Nowadays, several well-developed commercial oil-and-gas codes, such as OLGA (Bendiksen et al., 2007), LEDAFLOW (Goldszal et al., 2007), WELLFlo (Weatherford, 2008), exist. However, they are designed for the specific requirements of hydrocarbon production, e.g. solving immiscible two-liquids flow, slow mass transients, hydrate formation and wax deposition. On the other hand, also a number of codes were developed to provide solutions for typical challenges of geothermal operations. The majority of these codes are steady state simulators. HEX-B2 (Mégel et al., 2007) solves single-phase 1D-Navier-Stokes flow of pure water in boreholes. FloWell (Gudmundsdottir et al., 2013) additionally accounts for two-phase water (including supercritical conditions). To quantify the behavior of systems rich in non-condensable gases (NCG), Swelflo (Mcguinness, 2015) and GWELL (Aunzo, 1990) solve a two component system based on H_2O-CO_2-specific equations-of-state (EOS). Other codes, such as WellSim (Gunn and Freestone, 1991), GWNACL (Aunzo et al., 1991), SIMU2000 (Sánchez-Upton, 2000) and Profili (Battistelli, 2010) include additionally the effects of dissolved solids (usually as NaCl-equivalent) on fluid properties. The aforementioned codes mimic the reservoir only by setting productivity index-type boundaries at feed zones or by applying more specific inflow performance relationship models (IPR). The integrated system of reservoir and wellbore was simulated by Marcolini and Battistelli (2012) by coupling the wellbore simulator PROFILI with the reservoir simulator TOUGH2 (Pruess, 2003) allowing for modelling pure H_2O. For transient geothermal operation scenarios and the considered highly non-linear physics in the well, the steady state assumption is often a too strong simplification. With T2Well/ECO2N, an integration of a wellbore simulator into TOUGH2 as well, Pan et al. (2011) developed a transient tool for H_2O-CO_2 mixtures in wells and reservoir.

Applications of borehole simulators analyzing and solving problems during operation, to design, monitor and optimize new power plants or to explore new geothermal sites are numerous and equally diverse. Typical applications are the determination of the static formation temperature from dynamic log data, optimization of production- and injections scenarios, handling of NCGs (two-phase flows), design of geothermal reuse scenarios of abandoned oil wells, dimensioning of future power plants in an early project stage and handling of scaling and corrosion processes. Furthermore, the simulations are not limited to systems of vertical flow but can be used in horizontal pipe flow with countless applications. This diversity of involved processes shows the necessity for the development of an encompassing transient THC wellbore -simulator.

Herein, we present the current stage of the development of an in-house wellbore simulator for multicomponent non-isothermal two-phase flow, the underlying physics and the governing equations. In particular, developing the tool based on a fully-coupled, implicit and transient scheme is a major advance and eventually enables to realistically model the highly dynamic conditions of boreholes during operations. The simulator is able to handle a wide range of pressure-enthalpy conditions (up to supercritical water), multiple feed zones, transient production and injection histories, numerical and semi-analytical solutions for lateral heat exchange with the reservoir as well as complex well layouts and completions. Since the development of the tool is an ongoing process, here some of the most important ready-to-use features, such as fluid compressibility, well inclination, and two-phase flow are demonstrated by showing the results of application cases. Future work will mainly focus on the hydraulic and thermal coupling to a 3D-reservoir and on including aqueous chemistry and reactive multicomponent transport.

2. METHODS

The 1D-wellbore simulator is based on the drift-flux model (Hasan and Kabir, 2010; Shi et al., 2005). Non-isothermal fluid flow is calculated for a fully-coupled, implicit, transient, two-phase, single component system using generalized conservation equations:

Mass conservation equation:

$$\frac{\partial}{\partial t}(\rho_m) = -\frac{\partial}{\partial z}(\rho_m u_m) + Q \tag{1}$$

with ρ_m = mixture density, u_m = mixture velocity and Q are sink/source terms.

Momentum conservation:

$$\frac{\partial}{\partial t}(\rho_m u_m) = -\frac{\partial P}{\partial z} - \frac{f\,\rho_m u_m |u_m|}{2\,A} - \rho_m\,\mathrm{g}\cos\theta - \frac{1}{A}\frac{\partial}{\partial z}[A(\rho_m u_m^2 + \gamma)] \tag{2}$$

where A is the cross-sectional area of the well/pipe, P is the pressure, g the gravitational acceleration, θ the inclination of the well, f is the friction coefficient and λ is a term depending on the slip velocity between the liquid and vapor phase (Pan et al., 2011).

Energy conservation:

$$\frac{\partial}{\partial t}\left[\rho_m\left(u + \frac{1}{2}\,u_m^2\right)\right] = -\frac{\partial}{\partial z}\left[u_m\rho_m\left(h + \frac{1}{2}\,u_m^2\right)\right] + \rho_m u_m\,g\,\cos\theta - \frac{q}{A} + Q \tag{3}$$

where h is the enthalpy and q the lateral heat exchange through the casing or pipe wall.

The main variables, which are solved in the conservation equations are pressure, enthalpy and volumetric flow rate. Temperature, fluid and vapor density, quality of vapor fraction and saturation of vapor fraction are derived as auxiliary variables from the IAPWS-EOS (IAPWS, 2007). The formulation covers pure liquid, vapor, two-phase and supercritical conditions. The application of a drift-flux model, allows for solving two-phase flow as a mixture of a gas and a liquid phase.

3. VALIDATION AND APPLICATION

A wellbore simulator has to cover a wide range of physical processes. In the following, we demonstrate selected features and capabilities of the tool in the current state of development. Using validation data from Al-Safran and Brill (2017) the pressure drop of compressible single-phase borehole-flow is validated. In a second show case, two-phase flow patterns are validated as a function of phase velocities. Additionally, a production case for two-phase flow in an inclined well is modelled to demonstrate the drift flux flow of the liquid and the vapor phase of pure water and the effect of changing flow patterns on the pressure traverse.

3.1 Compressible Single-Phase Pipe Flow

In order to validate compressible single-phase borehole flow a test case is calculated and compared against analytical results (Al-Safran and Brill, 2017). The flowing pressure of a vertical gas well producing single-phase natural gas is modelled. The well has a depth L = 3048 m, a uniform diameter d = 0.06 m and a pipe wall roughness ε = 0.0213 mm. The temperature gradient is assumed to be linear, with T_{bh} = 118.3 °C at bottomhole depth and T_{wh} = 43.3 °C at wellhead. Depicting the wellhead-control of the modelled scenario, the hydraulic boundaries are set at the wellhead. The wellhead pressure (P_{wh}) is 138.3 bar and the flow rate (q) is 9.3 l/s.

The modelled flowing pressure values are matching the analytical results in very good agreement (Figure 1a). The coupled nature of the model is displayed in the non-linearity of the volumetric flow rate as a result of fluid compressibility. Reflecting thermal effects and fluid compressibility, the fluid density is a non-linear function, resulting in decreasing values with depth. Also the densities are predicted in good agreement with the results of the analytical reference (Figure 1b).

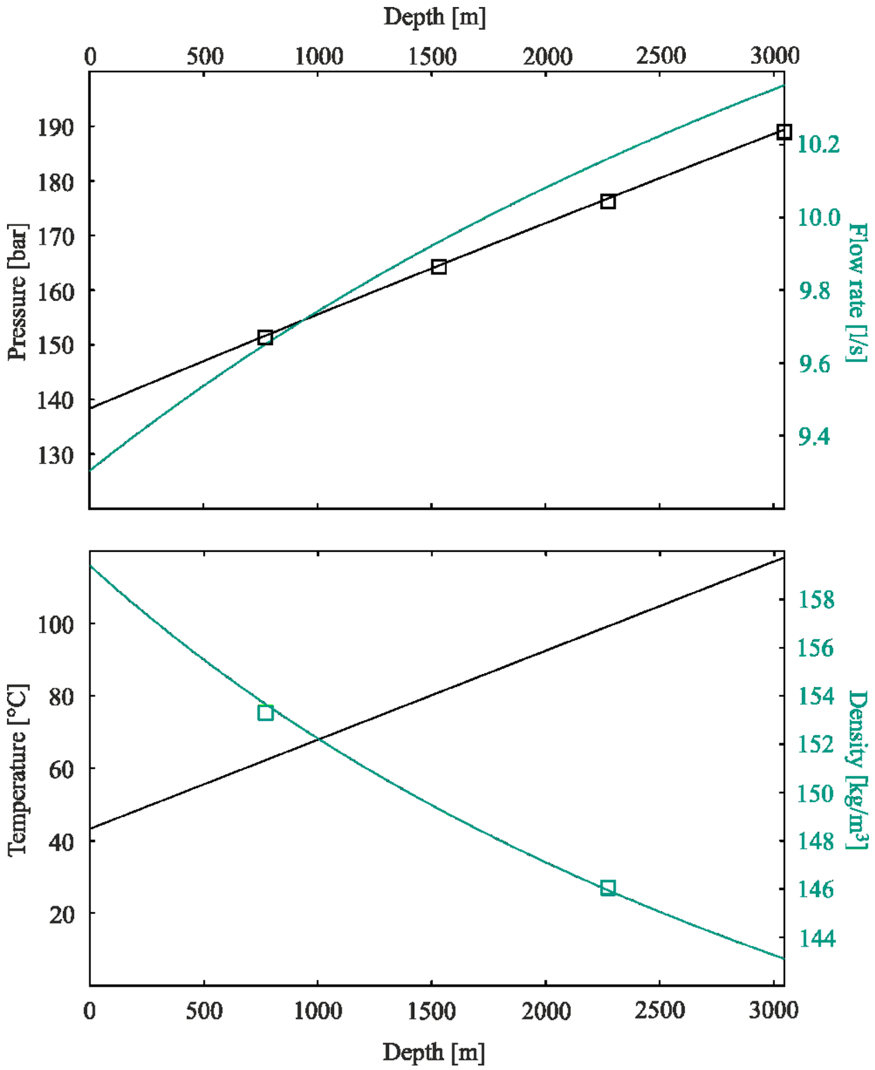

Figure 1: a) The modelled pressure (black line) is matching the analytical values (black squares) from Al-Safran and Brill (2017) in good agreement. Due to the compressibility of the fluid the volumetric flow rate (green line) is a non-linear function with depth. b) The linear temperature gradient (black line) from T_{wh} = 43.3 °C to T_{bh} = 118.3 °C together with fluid compressibility results in a non-linear fluid density function (green line), matching the decreasing analytical values (green squares) with depth.

3.2 Two-Phase Drift-Flux

For modeling the specific hydraulics of two-phase borehole flow, a commonly occurring scenario particularly in high enthalpy wells, the simulator entails a drift-flux model (Hasan et al., 2010 a, b). Treating the two-phase flow as a mixture, it allows to determine the velocities of the liquid and the gas phase by only solving one momentum conservation equation. As a function of the superficial gas (v_{sg}) and liquid (v_{sl}) velocities typical flow patterns (dispersed bubbly, bubbly, slug flow, churn flow and annular flow) are obtained. To demonstrate the validity of the implemented drift-flux model, a large number of realizations (n > 10’000) have been calculated varying v_{sg} and v_{sl}. In Figure 2, it is shown, that calculated flow pattern (grey shaded areas) are in very good agreement to experimentally determined pattern boundaries (Ishii and Hibiki, 2006).

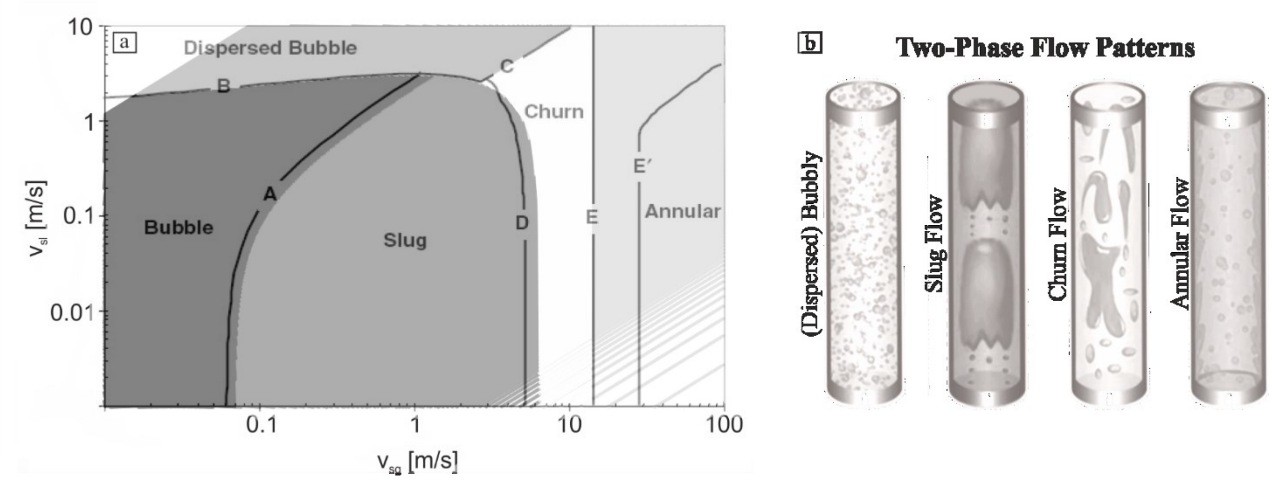

Figure 2: a) Validation of two-phase flow patterns. Simulated flow patterns (grey-shaded areas) as functions of superficial gas velocity v_{sg} and superficial liquid velocity v_{sl} match experimental data (field boundaries (black lines) according to Ishii and Hibiki, (2006)) in very good agreement. b) Scheme of different flow patterns ((disperse) bubbly, slug flow, churn flow and annular flow), which are evolving as a function of v_{sg} and v_{sl}.

Furthermore, a synthetic test case for a two-phase problem is simulated to demonstrate the capabilities of the featured drift-flux model. Two-phase H_2O is produced from a well with multiple inclination changes ($\alpha_1 = 6.96°$, $\alpha_2 = 18.47°$ and $\alpha_3 = 39.01°$) and step-wise reducing pipe diameter ($d_1 = 0.45$ m, $d_2 = 0.30$ m and $d_3 = 0.15$ m). The well trajectory is displayed in Figure 3. Bottomhole depth is at 4000 m TVD. Due to inclination the well length is 4239 m MD. Relevant hydraulic fluid properties are given by gas viscosity = 0.0001 Pa·s, liquid viscosity = 0.001 Pa·s and surface tension = 0.0288 N/m. The mixture viscosity is calculated based on Mean Maxwell Eucken (Awad and Muzychka, 2008). For simplification, heat loss during production is mimicked by applying a linear enthalpy gradient from 1.5e6 J at bottomhole to 1.4e6 J at wellhead. The hydraulic boundaries are set at the wellhead, assigning an ambient pressure of 1 bar and an extraction flow rate of 15 l/s.

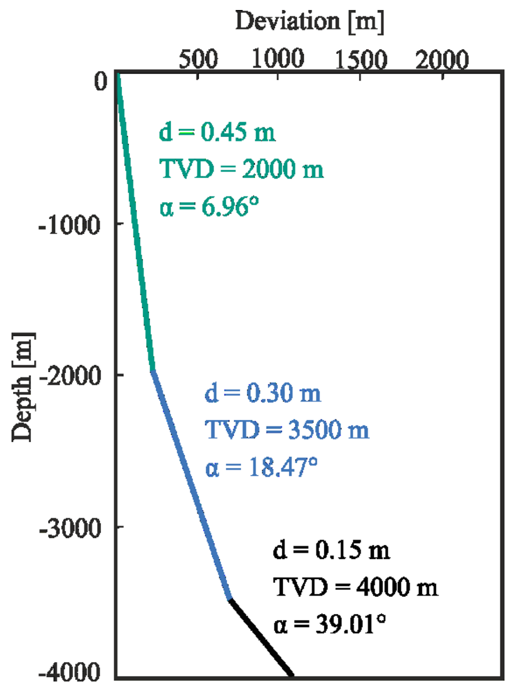

Figure 3: Layout of a 4000 m deep (TVD) production well with multiple inclination changes ($\alpha_1 = 6.96°$, $\alpha_2 = 18.47°$ and $\alpha_3 = 39.01°$) and decreasing diameters ($d_1 = 0.45$ m, $d_2 = 0.30$ m and $d_3 = 0.15$ m).

It is shown that the flow rate profile and the pressure traverse are highly non-linear functions (Figure 4a). The stepwise decreasing pipe diameters lead to an increase of flow velocities with depth, which provoke the changes of flow patterns. For the interplay of given pressure and enthalpy conditions as well as mixture velocities the observed flow pattern is alternating from bubbly to slug flow (Figure 4c). The changing pressure gradient results mainly from non-constant fluid density, due to fluid compressibility and non-constant volume ratio of liquid to vapor phase (with highly different compressibilities). The density functions (Figure 4b) reflect the different behavior of a liquid phase compared to a vapor phase. Increasing vapor density with depth indicates the dominant impact of the pressure (high compressibility of gas). The decreasing liquid density is resulting from the prevailing thermal expansion.

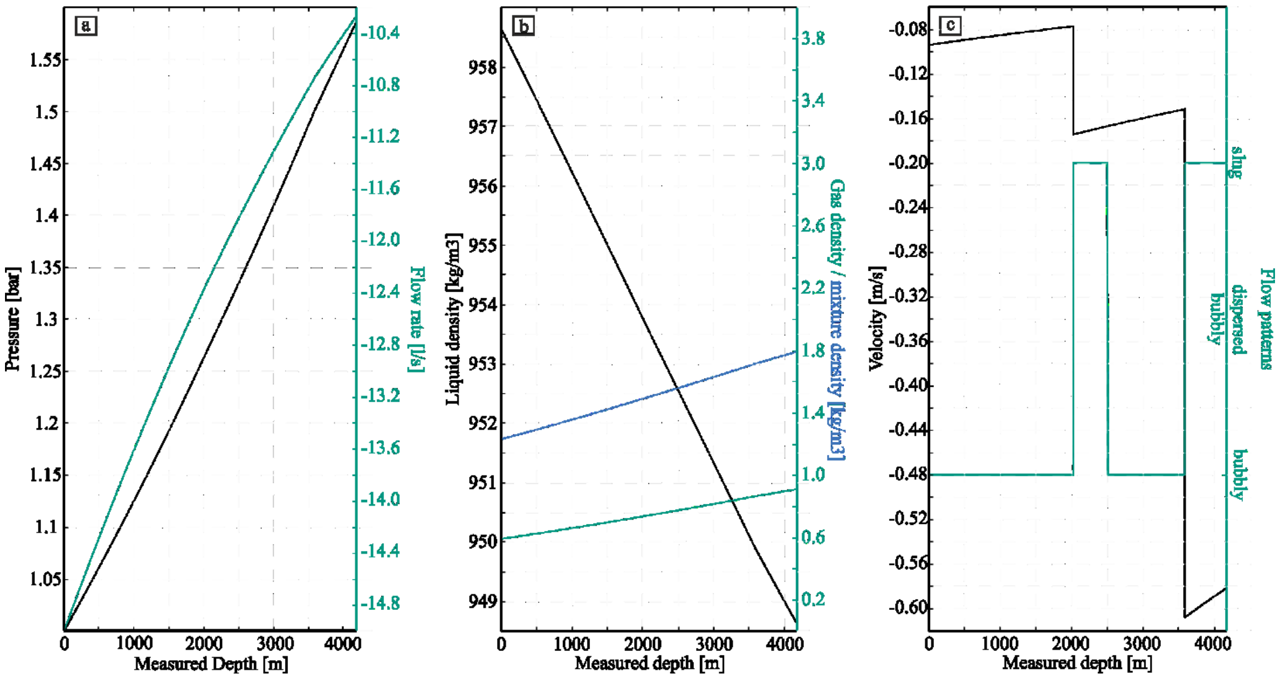

Figure 4: The pressure traverse and the flow rate are non-linear functions (Figure 4a), resulting from varying phase densities (Figure 4b) and changing volume ratios of the phases in the mixture. The decreasing pipe diameter causes increasing flow velocities which results in changing flow patterns alternating from bubbly to slug flow (Figure 4c).

4. DISCUSSION AND CONCLUSIONS

The quantification of borehole processes is a crucial task for many geothermal applications, varying from exploration, optimization, designing and monitoring purpose. Since a borehole under production or injection conditions is a highly dynamic system comprising many different physical, often complexly coupled processes, a fully-coupled and transient wellbore simulator is an absolute prerequisite.

In this work we present selected capabilities of the code. The current state of the in-house development features a fully-coupled implicit wellbore simulator for multicomponent non-isothermal two-phase flow. The code is able to handle water up to supercritical conditions, multiple feed zones, transient production and injection schemes, numerical and semi-analytical solutions for lateral heat exchange with the reservoir as well as complex well completions. We demonstrate the reliability of the code by validating the thermal system and the hydraulic behavior of compressible single-phase flow against analytical solutions. Furthermore, by calculating more than 10’000 realizations, it is shown that the resulting flow patterns for two-phase flow simulations are in very good agreement to experimentally acquired data.

We consider the current state of the tool as an intermediate step towards a fully-coupled THC-simulator. Since scaling formation and corrosion are severe problems for a sustainable exploitation of a geothermal resource, we consider the integration of the chemical system to be highly relevant. Therefore, future development will mainly focus on the proper quantification of the aqueous chemistry, the interaction with non-condensable gases and minerals as well as reactive multicomponent transport.

REFERENCES

Al-Safran, E.M., Brill, J.P.: Applied multiphase flow in pipes and flow assurance oil and gas production. Society of Petroleum Engineers, (2017).

Aunzo, Z.P.: GWELL: A multi-component multi-feedzone geothermal wellbore simulator. (1990), University of California, Berkeley.

Aunzo, Z.P., Bjornsson, G., Bodvarsson, G.S.: Wellbore Models GWELL, GWNACL, and HOLA User's Guide, Physical Review of Particle Physics. (1991), Berkeley, California, USA.

Awad, M.M., Muzychka, Y.S., 2008. Effective property models for homogeneous two-phase flows. Experimental Thermal and Fluid Science 33, (2008), 106–113.

Battistelli, A.: PROFILI wellbore flow simulator: From geothermal wells to GHG and acid gas injection wells. Proceeding: Risorse Geotermiche Di Media e Bassa Temperatura in Italia. Potenziale, Prospettive Di Mercato, Azioni. Ferrara, Italy, (2010).

Beggs, H.S., Brill, J.P.: A Study of Two-Phase Flow in Inclined Pipes. Journal of Canadian Petroleum Technology, 25, (1973).

Bendiksen, K.H., Maines, D., Moe, R., Nuland, S.: The Dynamic Two-Fluid Model OLGA: Theory and Application. SPE Production Engineering 6, (2007), 171–180.

Goldszal, A., Monsen, J.I., Danielson, T.J., Bansal, K.M., Yang, Z.L., Johansen, S.T., Depay, G.: Ledaflow 1D: Simulation Results With Multiphase Gas/Condensate and Oil/Gas Field Data. Proceedings: 13th International Conference on Multiphase Production Technology, BHR Group, Edinburgh, UK, (2007).

Gudmundsdottir, H., Jonsson, M.T., Palsson, H.: The Wellbore Simulator FloWell. Proceedings: 38th Workshop of Geothermal Reservoir Engineering, Stanford University, Stanford, California, (2013).

Gunn, C., Freestone, D., 1991. An integrated steady-state wellbore simulation and analysis package. Procceedings: 13th New Zealand Geothermal Workshop. Auckland, New Zealand, (1991).

Hagedorn, A.R., Brown, K.E.: Experimental Study of Pressure Gradients Occurring During Continuous Two-Phase Flow in Small-Diameter Vertical Conduits. Journal of Petroleum Technology 17, (1965), 475–484.

Hasan, A.R., Kabir, C.S.: Modeling two-phase fluid and heat flows in geothermal wells. Journal of Petroleum Science and Engineering 71, (2010), 77–86.

Hasan, A.R., Kabir, C.S., Sayarpour, M.: Simplified two-phase flow modeling in wellbores. Journal of Petroleum Science and Engineering. 72, (2010), 42–49.

IAPWS-2007. Revised Release on the IAPWS Industrial Formulation 1997 for the Thermodynamic Properties of Water and Steam. International Association for the Properties of Water and Steam. Lucerne, Switzerland, (2007).

Ishii,M., Hibiki, T.: Chapter 13. Drift-Flux Model, Thermo-Fluid Dynamics of Two-Phase Flow. (2006), Springer, Boston, USA.

Kabir, C., Ameen, M.: Determining Circulating Fluid Temperature in Drilling, Workover, and Well Control Operations. SPE Drilling and Completion, 11, (1996).

Marcolini, M., Battistelli, A.: Modeling of Wellbore Flow within Geothermal Reservoir Simulations at Field Scale. Proceedings, TOUGH Symposium, Berkeley, California, USA, (2012), 1–5.

Mcguinness, M.J.: SwelFlo User Manual. (2015).

Mégel, T., Kohl, T., Hopkirk, R.J., 2007. The potential of the use of dense fluids for initiating hydraulic stimulation. Geothermics, 35, (2007), 589-599.

Orkiszewski, J.: Predicting Two-Phase Pressure Drops in Vertical Pipe. Journal of Petroleum Technology, 19, (1967), 829–838.

Pan, L., Oldenburg, C.M., Wu, Y.-S., Pruess, K.: T2Well/ECO2N Version 1.0: Multiphase and Non-Isothermal Model for Coupled Wellbore-Reservoir Flow of Carbon Dioxide and Variable Salinity Water. Berkeley, California, USA, (2011).

Pruess, K.: The TOUGH codes - A family of simulation tools for multiphase flow and transport processes in permeable media. 746, (2003), 738–746.

Ramey, H.R.: Wellbore Heat Transmission. Journal of Petroleum Technology 14, (1962).

Sánchez-Upton, P.: The Wellbore Simulator SIMU2000. Proceedings World Geothermal Congress, Kyushu-Tohoku, Japan, (2000), 2851–2856.

Shi, H., Holmes, J.A., Durlofsky, L.J., Aziz, K., Diaz, L., Alkaya, B., Oddie, G.: Drift-Flux Modeling of Two-Phase Flow in Wellbores. SPE Journal, 10, (2005), 24–33.

Weatherford, WellFlo™ Petroleum Engineering Software. (2008).