A simplified model for predicting temperature profiles in gas-lift oil wells

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Abstract.
This work presents a methodology for calculating temperature profiles in oil wells with artificial lift by gas injection. Artificial lift is employed when the reservoir pressure is insufficient to bring the oil to the surface or when increasing production efficiency is desired, with gas injection (gas-lift) being one of the most commonly used techniques. In this type of lift system, knowing the temperature profiles is important to ensure production efficiency and safety. However, calculating these profiles is challenging, as it involves obtaining data related to the underground structure and modeling the hydrodynamic behavior of fluids (single and multiphase flow). Due to this complexity, the development of simplified strategies for obtaining these profiles is justified. To develop the proposed strategy, the methodology of this work can be divided into three main steps: a) develop the mathematical model for the problem, explicating the simplifications adopted; b) present a strategy to solve the equations formulated in the previous step; and c) verify the strategy and discuss the results. The main contribution of this work is present a model for calculating temperature profiles in gas-lift oil wells. In the comparison of temperature profiles with an analytical model, the results obtained are satisfactory, which encourages further studies and comparisons with more realistic models.

Keywords: Heat transfer, Artificial lift, Multiphase flow.

1 Introduction

The oil and gas industry is highly dependent on artificial lift techniques, either to make production feasible or to maximize well yield. According to Okorochaa et al. [1], one of the most widely used techniques is gas-lift, a method in which gas is injected into the well to reduce static pressure and facilitate the ascent of oil to the surface. On the other hand, temperature profiles in oil wells are crucial for monitoring and ensuring the success of hydrocarbon production operations, including gas-lift artificial lift operations.

Obtaining these profiles in the field is impractical due to the remote locations of oil wells, combined with to need for many sensors throughout the well trajectory to adequately define the temperature profiles. These challenges encourage the development of mathematical and numerical models to obtain temperature profiles in oil wells, particularly those operating through gas-lift.

In this context, the objective of this work is to present a fast and reliable numerical procedure, based on the conservation equations of mass, momentum, and energy, capable of obtaining temperature profiles in oil well components during gas-lift operations.

2 Model Development

The primary difference between a naturally flowing production oil well and a production well operating with gas-lift is in the first annulus. In natural production, the annulus contains static fluid, whereas in gas-lift, it contains flowing fluid. Thus, the gas-lift process is more complex due to the occurrence of flow not only in the production tubing but also in the annulus around it. Figure 1 illustrates the mass flows and heat flows in an gas-lifted oil wells.

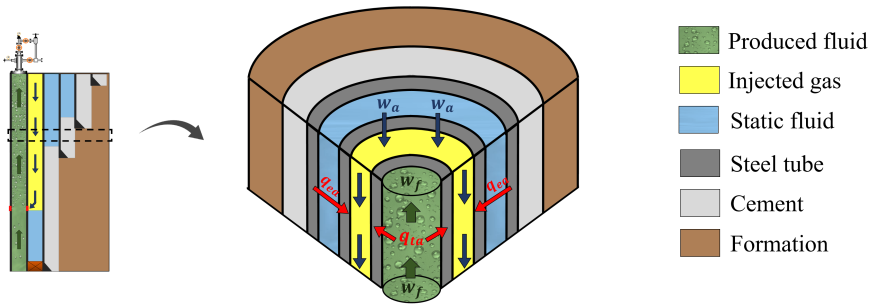

Figure 1. Section of the well with flow in the annulus.

In Fig. 1, q_{ta} is the heat transfer rate per unit length between the produced fluid and the fluid flowing in the annulus, q_{ea} is the heat transfer rate per unit length between the formation and the fluid flowing in the annulus, w_f is the production mass flow rate, and w_a is the gas injection mass flow rate in the annulus.

The section presented in Fig. 1 can be subdivided into three parts: a) the mass flows (in the tubing and in the annulus); b) the well components traversed by heat flows (tubing, casings, cement, and static annuli); and c) the surrounding formation. The mathematical formulation for each of these parts and the assumptions adopted in the development of the model are presented in the following sections.

2.1 Model Assumptions

In the conception of the model, some assumptions are made: a) the well geometry is axisymmetric; b) the thermophysical properties of the solids (steel, cement, and rocks) are constant; c) the effect of pressure increase in the annuli is negligible; d) the heat transfer regime is steady within the oil well; e) there is no fluid loss from the annuli to the formation, and f) the heat flows in the longitudinal direction of the well are negligible.

2.2 Governing Equations of Flows

The mathematical formulation for the flows is derived from the conservation of mass, momentum, and energy transported by the flows in the well. The combination of these equations gives rise to the energy equation and the pressure gradient equation, which are the governing equations of the mass flows.

Energy Equation

The energy equations originate from two energy balances in the section depicted in Fig. 1, one corresponding to the flow in the annulus and the other corresponding to the flow in the tubing, as presented by Hasan and Kabir [2]. For the fluid in the tubing, the following equation is obtained:

$$\frac{\mathrm{d}T_f}{\mathrm{d}z} = C_{JT_f} \cdot \frac{\mathrm{d}P_f}{\mathrm{d}z} - \frac{g \cdot \sin(\theta)}{C_{pf}} - \frac{v_f}{C_{pf}} \cdot \frac{\mathrm{d}v_f}{\mathrm{d}z} - \frac{q_{ta}}{C_{pf} \cdot w_f}, \tag{1}$$

where T_f is the fluid temperature, C_{JT_f} is the Joule-Thomson coefficient of the fluid, $\frac{\mathrm{d}P_f}{\mathrm{d}z}$ is the pressure gradient in the tubing, w_f is the production mass flow rate, g is the acceleration due to gravity, θ is the inclination with respect to the horizontal, C_{pf} is the specific heat at constant pressure, and v_f is the velocity of the produced fluid.

For the flow in the annulus, the following equation is obtained:

$$\frac{\mathrm{d}T_a}{\mathrm{d}z} = C_{JT_a} \cdot \frac{\mathrm{d}P_a}{\mathrm{d}z} + \frac{g \cdot \sin(\theta)}{C_{pa}} + \frac{v_a}{C_{pa}} \cdot \frac{\mathrm{d}v_a}{\mathrm{d}z} - \frac{q_{ta} + q_{ea}}{C_{pa} \cdot w_a}, \tag{2}$$

where C_{JT_a} is the Joule-Thomson coefficient of the gas, $\frac{\mathrm{d}P_a}{\mathrm{d}z}$ is the pressure gradient in the annulus, w_a is the gas mass flow rate, C_{pa} is the specific heat at constant pressure of the gas, and v_a is the gas velocity.

Pressure Drop Equation

Combining the momentum and mass balance equations yields the equations that describe the pressure variation with depth in the tubing $\frac{\mathrm{d}P_f}{\mathrm{d}z}$ and in the annulus $\frac{\mathrm{d}P_a}{\mathrm{d}z}$. In the case of the tubing, the flow is multiphase, composed of gas and oil. To predict the pressure gradient, the correlation of Beggs and Brill [3] was chosen:

$$\frac{\mathrm{d}P_f}{\mathrm{d}z} = -\frac{f_m \cdot \rho_n \cdot v_f^2}{2D_{int}} - \rho_s \cdot g \cdot sin(\theta) - \rho_s \cdot v_f \cdot \frac{\mathrm{d}v_f}{\mathrm{d}z}, \tag{3}$$

where D_{int} is the internal diameter of the pipe, f_m is the friction factor of the mixture, ρ_s and ρ_n are, respectively, the density with slip and no-slip conditions, and g is the acceleration due to gravity. The procedure for obtaining the parameters of this equation is beyond the scope of this work, but it is detailed in various studies, such as Barcelos [4] and Silva Filho [5].

In the case of the injected gas, the flow is considered single-phase (composed only of gas). Thus, the momentum balance equation can be written as:

$$\frac{\mathrm{d}P_a}{\mathrm{d}z} = -\frac{f \cdot v_a^2 \cdot \rho_a}{2D_{hd}} + \rho_a \cdot g \cdot sen(\theta) - \rho \cdot v_a \cdot \frac{\mathrm{d}v_a}{\mathrm{d}z}, \tag{4}$$

where ρ_a is the density of the injected gas, f is the Moody friction factor, and D_{hd} is the hydraulic diameter of the annulus, since flow in the annulus occurs in a non-circular area.

2.3 Well components

The components of the oil well are integrated into the model as thermal resistances. These resistances are used in the calculation of the heat transfer coefficients between the tubing fluid and the annulus, U_{ta}, and between the annulus and the formation, U_{ea}. For the coefficient U_{ta}, the thermal resistances of convection and conduction between the produced fluid and the gas in the first annulus are considered. For the coefficient U_{ea}, all resistances between the first annulus and the formation must be considered. To calculate forced convection, natural convection, and radiation resistances, it is necessary to define film coefficients, static convection coefficients, and radiation coefficients. This work utilizes expressions extracted from Colburn [6], Zhou [7], and Hasan and Kabir [8].

With the coefficients U_{ta} and U_{ea}, the heat fluxes q_{ta} and q_{ea} are determined following Eq. 5 and Eq. 6.

$$q_{ta} = -\pi \cdot D_{int} \cdot U_{ta} \cdot (T_a - T_f), \tag{5}$$

$$q_{ea} = -\pi \cdot D_{int} \cdot U_{ea} \cdot (T_a - T_{wb}), \tag{6}$$

where T_a is the temperature of the annulus and T_{wb} is the temperature at the wellbore formation interface.

2.4 Energy transfer in formation

The temperature at the wellbore formation interface, T_{wb}, is the link connecting the steady heat transfer within the oil well to the transient regime of the formation. Obtaining T_{wb} can be achieved numerically by solving the thermal diffusivity equation in the formation domain. However, this process is costly, so an alternative is to use approximate expressions. In the literature, there are several equations that aim to describe the approximate longitudinal transient temperature distribution at the wellbore/formation interface, such as Ramey [9], Chiu and Thakur [10], Cheng et al. [11], and Hasan et al. [12].

The equation used in this work is presented by Hasan and Kabir [13]. The solution to the problem is presented in the form of a dimensionless temperature T_D, given by Eq. 7 as:

$$T_D = \begin{cases} 1.1281\sqrt{\frac{4\cdot\alpha\cdot t}{D_{int}^2}} \cdot \left(1 - 0.3\sqrt{\frac{4\cdot\alpha\cdot t}{D_{int}^2}}\right), & \frac{4\cdot\alpha\cdot t}{D_{int}^2} \leq 1.5 \\ \left[0.4063 + 0.5\ln\left(\frac{4\cdot\alpha\cdot t}{D_{int}^2}\right)\right] \cdot \left(1 + \frac{0.6\cdot D_{int}^2}{4\cdot\alpha\cdot t}\right), & \frac{4\cdot\alpha\cdot t}{D_{int}^2} > 1.5 \end{cases} \tag{7}$$

where t is the operation time and α is the thermal diffusivity of the formation.

The temperature at the interface with the formation is obtained using T_D, following Eq. 8.

$$T_{wb} = \frac{0.5 \cdot D_{int} \cdot U_{to} \cdot T_D \cdot T_f + k_{earth} \cdot T_{geot}}{0.5 \cdot D_{int} \cdot U_{to} \cdot T_D + k_{earth}}, \tag{8}$$

where k_{earth} is the thermal conductivity of the formation and T_{geot} is the geothermal temperature.

3 Numerical procedures

To solve the mathematical model, the mass flows in the well are discretized longitudinally into finite control volumes (CVs) of length Δz. Control volumes are inserted where there is flow, namely throughout the production tubing and in the annular section from the wellhead to the gas-lift valve. The definition of the lengths Δz is done to optimize computational resources. Therefore, smaller elements (after a convergence analysis, it was adopted $\approx$ 1 m) are used at locations where there is a change in cross-sectional area, while longer elements (up to 100 m) are used in regions with similar conditions (geometry and materials). Figure 2 illustrates the distribution of control volumes in a well and the definition of lengths.

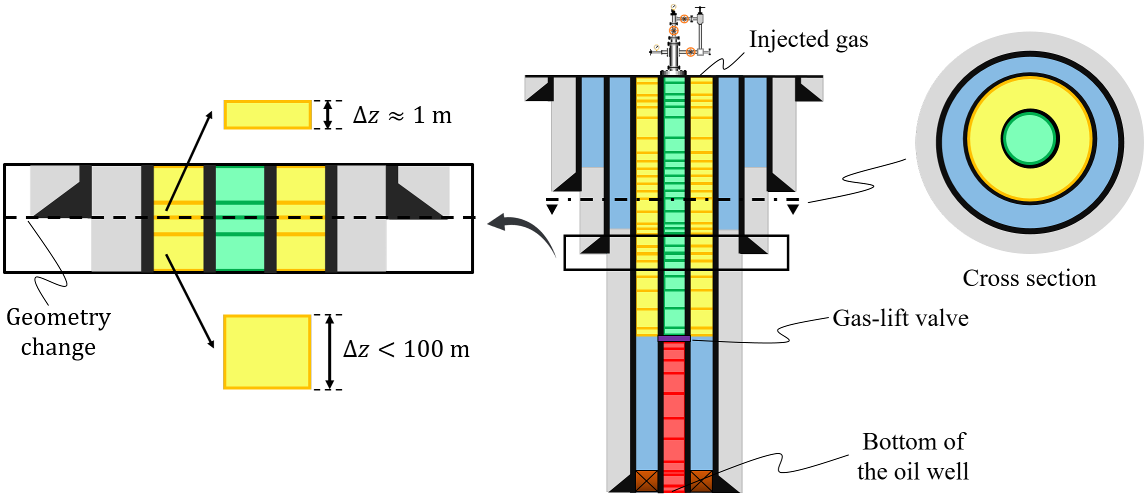

Figure 2. Distribution of control volumes.

The control volumes are present only in the areas where there is flow and can be categorized into three classes, differentiated by colors in Fig. 2. The yellow elements belong to the annulus, and only the injected gas flows through them. The red elements are part of the tubing section below the gas-lift valve, and only reservoir fluid flows through them. The green elements are part of the tubing section above the gas-lift valve, and they carry a mixture of injected gas and reservoir fluid. The sought solution consists of determining the pressure and temperature in each of the control volumes shown in Fig. 2.

The temperature of the elements below the gas-lift valve (red) can be determined using methods found in the literature, such as those presented by Moradi et al. [14] and Silva Filho [5], so the challenge is in calculating the temperatures in the green and yellow elements. Thus, the system shown in Fig. 2 can be reduced to the model presented in Fig. 3, where the well components (tubing, casings, annuli, and cement) that are not covered with control volumes are replaced by heat transfer coefficients. Additionally, Fig. 3 also presents the numbering scheme for the mesh elements.

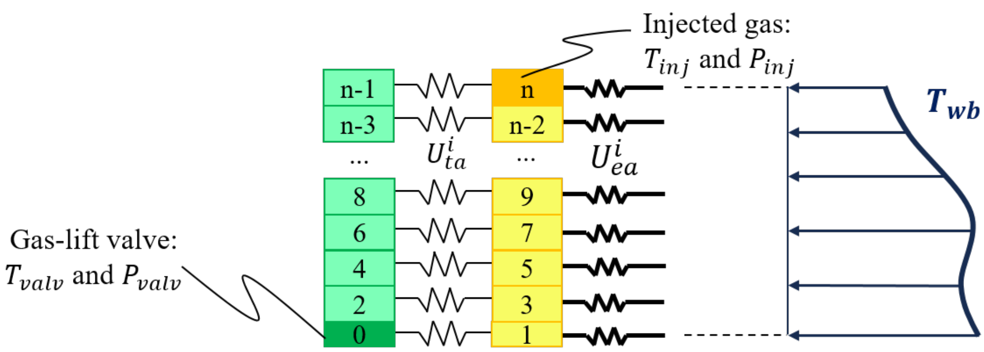

Figure 3. Equivalent system.

In the developed mathematical model, the temperature in the green elements (even-numbered elements) is described by Eq. 1, and the temperature in the yellow elements (odd-numbered elements) is described by Eq. 2. Discretizing these equations yields:

- For the even-numbered elements:

$$-T_{i-2} + \left(1 + \frac{\pi \cdot D_{int} \cdot U_{ta}^{(i)}}{C_{pf} \cdot w_t} \cdot \Delta z\right) \cdot T_i - \frac{\pi \cdot D_{int} \cdot \Delta z \cdot U_{ta}^{(i)}}{C_{pf} \cdot w_t} \cdot T_{i+1} = \left(C_{JT_f} \cdot \frac{\mathrm{d}P_f^{(i)}}{\mathrm{d}z} + \frac{g \cdot \sin(\theta)}{C_{pf}}\right) \cdot \Delta z. \quad (9)$$

- For the odd-numbered elements:

$$\left(\frac{2 \cdot \pi \cdot r_{t,int} \cdot \Delta z \cdot U_{ta}^{(i)}}{C_{pa} \cdot w_a}\right) \cdot T_{i-1} - \left(1 + \frac{\pi \cdot D_{int} \cdot \Delta z}{C_{pa} \cdot w_a} \cdot \left(U_{ta}^{(i)} + \frac{U_{ea}^{(i)} \cdot k_{earth}}{k_{earth} + 0.5 \cdot D_{int} \cdot U_{ea}^{(i)} \cdot T_D}\right)\right) \cdot T_i + T_{i+2} = \left(C_{JT_a} \cdot \frac{\mathrm{d}P_a^{(i)}}{\mathrm{d}z} + \frac{g \cdot \sin(\theta)}{C_{pa}}\right) \cdot \Delta z - \frac{\pi \cdot D_{int}}{C_{pa} \cdot w_a} \cdot \frac{U_{ea}^{(i)} \cdot k_{earth} \cdot T_{geot}}{k_{earth} + 0.5 \cdot D_{int} \cdot U_{ea}^{(i)} \cdot T_D} \cdot \Delta z. \quad (10)$$

Additionally, the following boundary conditions are considered: a) temperature and pressure at the first element (values in the tubing at the depth of the gas-lift valve); and b) temperature and pressure at the last element (values at the gas injection point at the wellhead).

With these equations, a system of equations can be assembled whose dimension is the number of control volumes (number of yellow and green elements). It is noteworthy that fluid properties and radial resistances vary with temperature. Hence, an iterative process is necessary to determine the temperatures T_i.

The procedure used to obtain temperatures and pressures in the elements of the system shown in Fig. 3 can be summarized by the flowchart in Fig. 4, which is easily programmable.

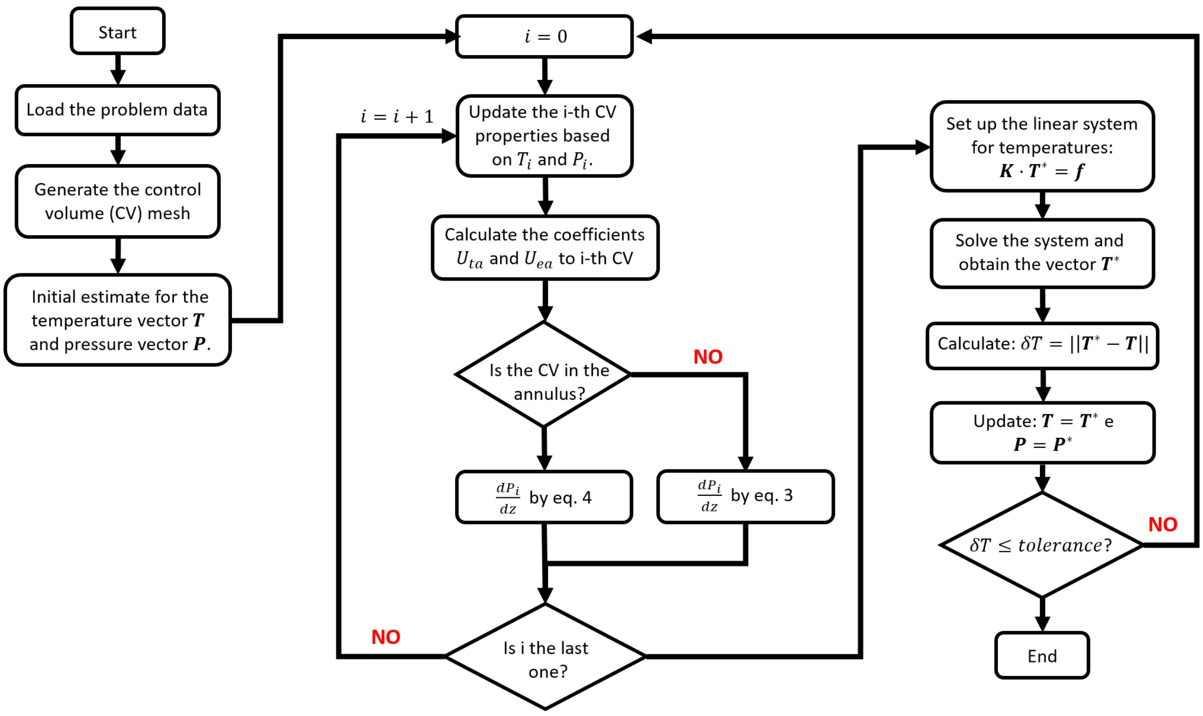

Figure 4. Flowchart for obtaining temperature profiles.

4 Model verification

In this section, the proposed strategy is compared with the work of Hasan and Kabir [2]. This comparison serves as verification of the procedure. Verification is necessary to ensure the validity of the mathematical model, solution technique, and computational implementation. The model presented by Hasan and Kabir [2] is quite simplified; it assumes that the terms related to pressure gradient ($C_{JT} \cdot \frac{\mathrm{d}P}{\mathrm{d}z}$) and hydrostatic head ($\frac{g \cdot \sin(\theta)}{C_p}$) are approximately equivalent and of opposite signs, which eliminates two equations (related to pressure gradients) and simplifies the equations related to temperature significantly.

The well presented by Hasan and Kabir [2] is a synthetic scenario of a well with one casing, one annulus, and one tubing. It operates by gas-lift, with a produced mass flow rate of 15.87 kg/s and gas injection at 10% of the mass flow rate. The produced fluid has a specific heat capacity at a constant pressure of 1674.72 J/(kg·K), and the injected gas has a specific heat capacity at a constant pressure of 1046.7 J/(kg·K). The well operates continuously for 44 hours. A schematic of the well with its geometric description is shown in Fig. 5.

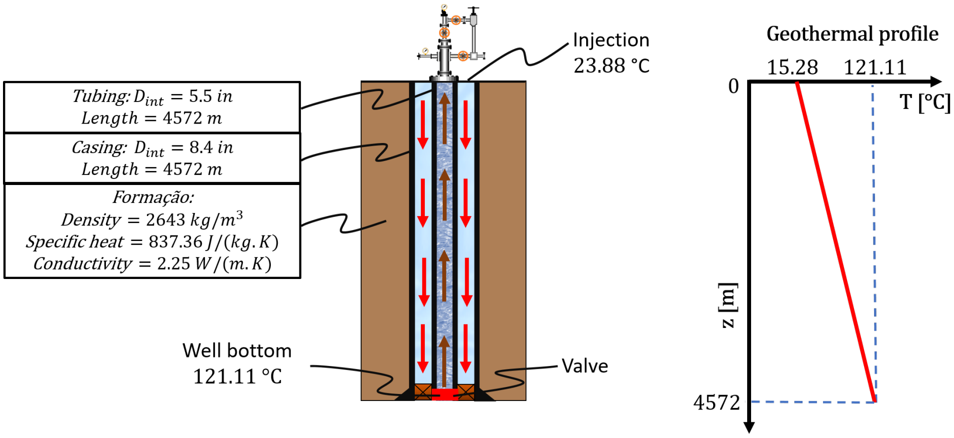

Figure 5. Hasan and Kabir [2] well schematic.

Using the presented procedure (and incorporating the simplifications introduced by Hasan and Kabir [2]), this well is simulated for two cases: a) with a global heat transfer coefficient between the fluid and the annulus of 56.78 $\mathrm{W.m^{-2}.K^{-1}}$ and a global heat transfer coefficient between the annulus and the formation of 22.71 $\mathrm{W.m^{-2}.K^{-1}}$ (left); and b) with a global heat transfer coefficient between the fluid and the annulus of 113.56 $\mathrm{W.m^{-2}.K^{-1}}$ and a global heat transfer coefficient between the annulus and the formation of 22.71 $\mathrm{W.m^{-2}.K^{-1}}$ (right). The results are compared with the work of Hasan and Kabir, and this comparison can be seen in Fig. 6.

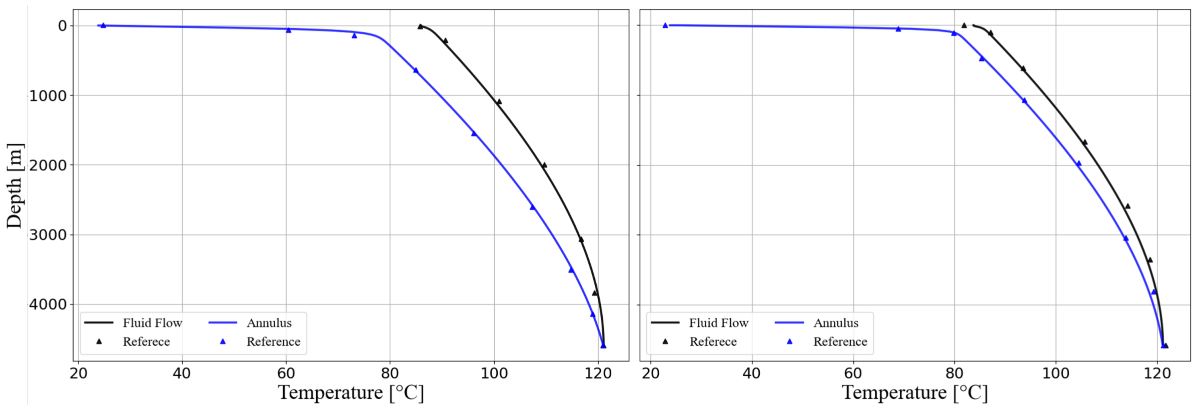

Figure 6. Results obtained.

The results obtained are consistent, which contribute to validating the methodology proposed in this work. The computed deviations can be attributed to differences in the modeling of this work and the model of Hasan and Kabir [2], numerical errors, the choice of the dimensionless temperature function, or even inaccuracies in the extraction of results.

Furthermore, it is important to note that the oil well used in the verification is quite simple and has constant properties, serving as a starting point for the verifications, but it encourages more detailed studies using the described methodology in more realistic wells.

5 Conclusions

This study presented a model for predicting temperature and pressure profiles in gas-lifted oil wells. The model was verified by comparing it with another method described in the literature, and the results were satisfactory. Other comparisons should be conducted to ensure the method is suitable for more realistic cases. Furthermore, the presented procedure can be used in parametric analyses or optimization studies.

The presented model can be improved by investigating more suitable correlations for calculating friction factors and heat transfer coefficients. Additionally, it can be coupled with modules for oil well integrity calculations, such as Annular Pressure Buildup (APB), enabling an integrated tool for obtaining temperature profiles and calculating APB. There is still room to enhance the model for evaluating temperature profiles over short periods by reformulating the energy equations to accommodate such scenarios.

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