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Developing a Novel Temperature Model in Gas Lifted Wells to Enhance the Gas Lift Design

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Abstract: In the continuous gas lift operation, compressed gas is injected into the lower section of tubing through annulus. The produced liquid flow rate is a function of gas injection rate and injection depth. All the equations to determine depth of injection assumes constant density for gas based on an average temperature of surface and bottomhole that decreases the accuracy of gas lift design. Also gas-lift valve design requires exact temperature at each valve depth. Hence, enhanced gas lift design can be achieved by more accurate prediction of temperature profile in annulus and tubing. Existing temperature models for gas lifted wells have been roughly and inaccurately estimated for they ignore temperature variation due to phase changes as well as cooling the effect of injected gas inflow to the wellbore. Also, they find temperature profile from a known injection depth obtained from unreal previous assumptions.

In this paper a novel model is developed to obtain the temperature profile in annulus and tubing of gas lifted well and injection depth simultaneously. This new model considers all the real conditions such as heat transfer between triple systems of liquid slug, injected gas and formation, cooling effect of gas inflow, joule-Thomson effect, potential energy, and phase changes in both conduits.

The model was applied on Iran's Aghajary oil field wells. Results showed how ignoring temperature variations caused substantial errors in gas lift design. From our experience and according to results of this simulator, it can be concluded that the calculated injection depth from classic method and developed model had a difference between 200 and 400m for Aghajary field wells, as the total depth varied from 3000 to 4200m. The comparison made between temperature profile resulted from developed simulator and previous temperature models using temperature survey data of Aghajary wells showed much better matching for developed simulator.

Keywords: Gas Lift Design, Temperature Profile, Pressure Profile, Joule-Thomson Effect, Modeling

Introduction

The analysis and design of gas lift strings in oil wells has been done ignoring the heat transfer between the injected gas in the annulus, liquid flow in the tubing and formation which shifts away the results such as optimum injection depth, optimum gas surface pressure as well as appropriate valve spacing depth of gas

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injection. The reason of this fact relies on the complexities of these systems.(Ramey, 1962)

In gas lift process, cool gas is injected in the annulus and enters tubing through an orifice installed in the tubing string. There is a heat exchange between the injected gas, fluid in the tubing and surrounding formation, due to temperature difference, which causes warming of the gas while flowing in the annulus.

There are a few works that consider different aspects of temperature modeling in gas lift process. Current methods rely on a linear temperature profile for the injected gas in the annulus and use an empirical correlation for the tubing fluid temperature. Kirkpatrick's method results in a linear temperature profile, while the Shiu-Beggs correlation predicts a nonlinear profile. Originally intended for flowing wells, the Shiu-Beggs correlation does not appear to have a physical basis. For example, the relaxation distance, A, in Ramey's formulation was correlated with eight parameters, including tubing head pressure, for many field cases. Moreover, as known, Ramey's long-time approximation of a line-source well may not be applicable to certain heat-transfer problems, such as wells involving large mass flow rates, newly completed wells, and deep wells encountering high temperatures.

The most complete work in this area was done by Hasan and Kabir (1996). However, even in thier model, changes of physical and thermo-dynamical properties, in spite of variation in multiphase fluid flow regimes in the tubing, are ignored. Also they neglected Joule-Thomson effect and potential energy changes for calculating temperature profile of injected gas. Moreover, cooling and heating of the fluid caused by phase changes was ignored in their proposed model. Another problem with this work was neglecting cooling effect of gas inflow to the tubing at injection depth. In this work, we present a novel temperature model that takes into account all of the real conditions and avoids the abovementioned limitations. In addition to modeling temperature profile, which is necessary to multiphase flow modeling and valve design, the important achievement of this work is obtaining injection depth that is assumed to be known in previous works. Furthermore, unlike previous works which calculated the temperature profile from a known injection depth, another main novelty of the developed model was simultaneous calculation of temperature and injection depth.abir(A.M.Ansari, 1994; A.R.Hasan, 1996)

This model was applied in the Aghajary oil field in order to find the effect of considering a non-isothermal flow in the gas lift design. Aghajary oil field is located in the south of Iran. Additionally, 165 wells in this huge mature field are completed where 60 of them are equipped with artificial gas lift system. Due to the critical role of gas lift process in this field, it seem necessary to develop an accurate mathematical model to simulate and predict performance of the wells under artificial lift process and obtaining its main parameters (e.g., depth, rate and pressure of gas injection) to achieve desired oil rate.

Prediction model

To predict the temperature inside the tubing, an inflow temperature model can be coupled with a non-isothermal wellbore flow model developed by Mohseni et al. [2010]. The model is based on simultaneous solution of liquid and gas mass conservation laws, momentum conservation law of the mixture and energy balance equation. It accounts for all the real conditions such as non-homogeneous multiphase flow with mass transfer between the phases. The final form of the energy equation is:

$$\frac{dT}{dZ} = \frac{(W)_I}{W\Delta z}(T_I - T) + \eta_m\left(\frac{dP}{dZ}\right) - \frac{g sin\theta}{C_{pm}} - \frac{2\pi R_{ti}\,(1-\gamma)U(T-T_e)}{WC_{pm}} \qquad (1)$$

where W is the mass flow rate, U is overall heat transfer coefficient and subscript I and m express inflow and mixture properties, respectively. The first term in right hand side of this equation shows the effect of energy inflow from the reservoir to the wellbore. The second term is the temperature change in the wellbore caused by Joule-Thomson effect. The third term accounts for temperature variation due to potential energy changes and the last term is the heat exchange between the wellbore and the surrounding area.

In the gas lift process, gas and liquid flow in the tubing while a single gas phase flows in the annulus, so we can rewrite Eq.1 for the tubing under gas lift as

$$\frac{dT_t}{dZ} = \frac{(W)_{a,I}}{W_t \Delta z}(T_{a,I} - T_t) + \eta_m \left(\frac{dP_t}{dZ}\right) - \frac{g sin\theta}{(C_{pm})_t} - \frac{2\pi R_{ti}(1-\gamma)U_{ta}(T_t - T_a)}{(WC_{pm})_t} \quad (2)$$

where U_{ta} is the overall heat transfer coefficient between tubing and annulus fluid and subscript t stands for tubing. It is necessary to note that the first term of Eq.2 is temperature reduction resulted from inflow of injected gas. This inflow can make an abrupt deviation in the fluid flow temperature profile in the tubing.(Mohseni, 2010; Mostofinia, 2009; Pourafshary, 2007)

Subsequently, temperature change in the annulus can be expressed as:

$$\frac{dT_a}{dZ} = \eta_m \left(\frac{dP_a}{dZ}\right) - \frac{g sin\theta}{(C_{pm})_a} - \frac{2\pi R_{ci}(1-\gamma)U_{af}(T_a - T_f)}{(WC_{pm})_a} - \frac{2\pi R_{ti}(1-\gamma)U_{ta}(T_a - T_t)}{(WC_{pm})_a} \quad (3)$$

where U_{af} is the overall heat transfer coefficient between formation and annulus fluid. Subscript a also stands for annulus.

Calculation algorithm

The borehole interval is divided into a set of subintervals of constant properties the calculation should be done continuously starting from the boundary subintervals and then using the calculation results of the previous subinterval as the initial value for the next one. The proposed algorithm for numerical solution of temperature model is as follows:

1. Guess temperature profile in the annulus and calculate gas injection pressure (at first step formation temperature can be used).
2. Calculate tubing temperature by Eq.2 and pressure profile based on a non-homogeneous multiphase flow model (A.M.Ansari, 1994; Pourafshary, 2007)
3. Obtain the temperature and pressure profiles in the tubing to allow for updating gas temperature (Eq.3) and pressure as well as properties in the annulus.

Results and Discussion

The simulator was applied to one of the wells in Aghajary oil field to obtain the effect of heat transfer in gas lift design. The results are depicted on Figure 1 and Figure 2. The first figure shows the temperature profile calculated by developed simulator inside the tubing and annulus. As it is clear, with increasing the depth, gas temperature also increases and becomes closer to the tubing temperature. At depth around 4000 ft where the injected gas enters into the tubing, a considerable change in tubing temperature profile occurs that is due to cooling effect of gas. Hence, according to these temperature profiles the density and pressure inside the annulus and tubing can be calculated to obtain exact injection point (Figure 2and Figure 3). These figures also emphasize how ignoring the heat transfer between formation, annulus and tubing fluid, and Joule-Thomson effect results in a significant error in design of gas injection point and gas injection pressure. Gas injection point by the simulator in this case that assume the changes in pressure and temperature of fluid in tubing and annulus and subsequently changes of gas density in annulus and fluid density in tubing, is obtained as 4400 ft while from previous assumptions that use the average of pressure and temperature between the surface and bottomhole it is predicted as 4800 ft. These errors become more considerable when the oil production or water cut increases.

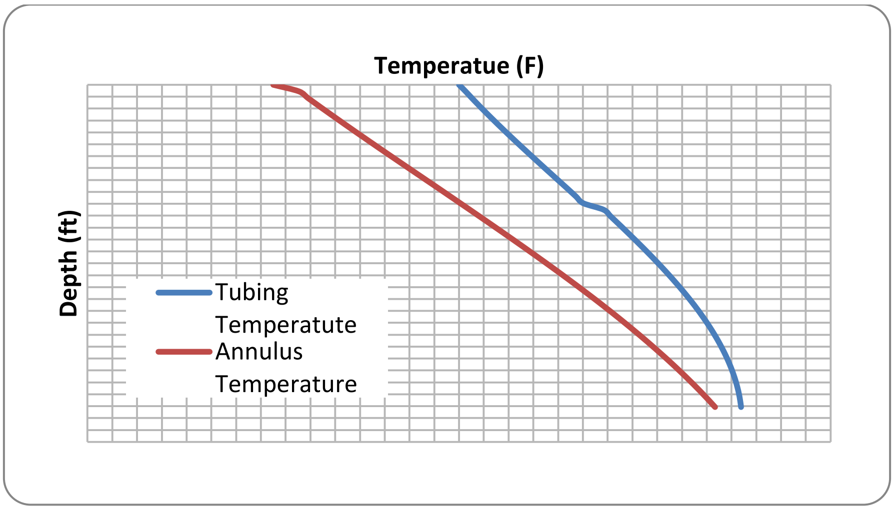

Figure 1. Temperature profile in tubing and annulus

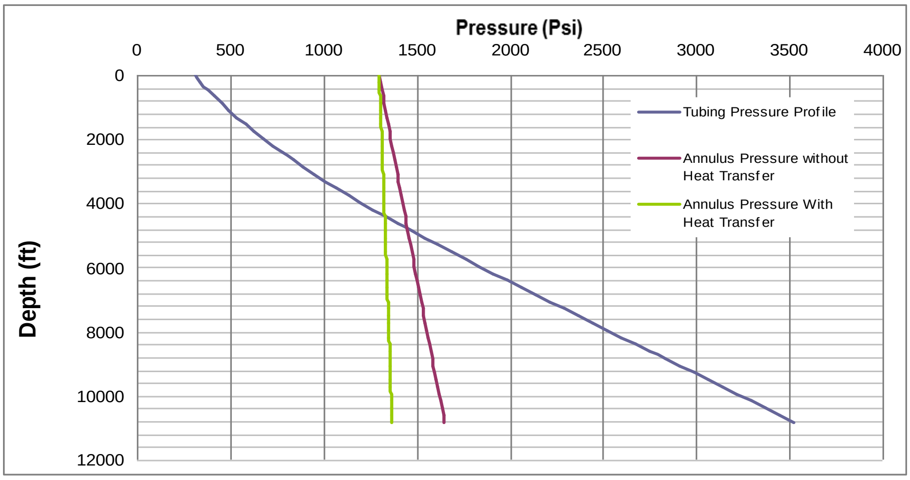

Figure 2. Comparison of Pressure profile in the annulus with and without heat transfer

Conclusion

This article proposed a novel model to optimize main gas lift parameters that included gas injection point and gas injection pressure by developing a mathematical model with less assumptions and more real conditions. The model predicted temperature, density, and pressure profile in the annulus and tubing. Simulation results illustrated that the assumption of an isothermal flow in the annulus could introduce sensitive and considerable errors in density profile of the injected gas and consequently led to incorrect design of gas injection point and gas injection pressure.

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