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Dimensionless Heat Transfer Models for the Prediction of Flowing Temperature in Waxy Crude Oil Systems

Joseph, A* and Ajienka, J.A
Department of Petroleum and Gas Engineering, University of Port Harcourt, Port Harcourt, Rivers State
*Corresponding author's email: amieibibama.joseph@uniport.edu.ng

Abstract
Waxy crudes are generally light crudes except that they precipitate wax at temperatures below their pour-point. Wax precipitation pose serious flow assurance problems that not only increase production downtime but also interrupt flow and can lead to loss of flowlines of unimaginable lengths downstream of operations. Managing heat loss through insulation and heating are some of the veritable options to guarantee flow and ensure continuous production. Whereas insulation is preventive, heating can be both curative and preventive. Preventive measures are proactive and sometimes can be very expensive to undertake. One way of preventing wax precipitation is the development of well specific flowing temperature profiles to predict flowing temperatures downstream of flow lines and wellbores. In this work, a generalized non iterative dimensionless pipeline and wellbore flowing temperature models are developed to predict the flowing temperatures in wellbores and flowlines. From the models, it was observed that at a constant heat conductance, the flowing temperature decreases downstream of the wellhead for pipelines and from the wellbore to the wellhead, and the rate of heat conductance and thus, heat loss is higher for pipelines with higher conductivity than those with lower conductivity. These dimensionless models could be used as quick estimates for predicting flowing temperatures for wells producing oil.

Keywords: *Waxy crude, Dimensionless flowing temperature, Pipeline, Wellbore, Heat conductance*

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1. Introduction

The behaviour of fluids in the reservoir and wellbore is a strong function of temperature and pressure thus, an accurate prediction of flowing fluid temperature is important in the evaluation of fluid properties and their behaviour. For effective production of waxy crudes, it is necessary to know when the temperature might drop below the pour-point to prevent sudden interruption of fluid flow. Ramey (1962), Squier et al. (1962) and Hunt (1962) variously published heat transfer models for approximate solutions to wellbore and flowline heat transmissions for fluids susceptible to wax deposition as a function of depth and time. Also, Willhite (1967) developed models for calculating the overall heat transfer coefficient to enable accurate estimation of the heat transmission in wellbores during the injection of hot or cold fluids. The works of Ramey (1962) and Willhite (1967) are steady-state heat transfer models in the wellbore and unsteady radial heat conduction to the earth.

Accurate prediction of the flowing temperature profiles is key to effective production of waxy crude oil wells to forestall and mitigate early flow assurance problems that might occur from wax deposition. Flowing temperature prediction has many applications. More importantly, applications in enhanced oil recovery projects, underground wastewater disposal systems and carbon capture and sequestration are some major projects that can only be successful if an accurate temperature profile model is developed (Hasan et al., 2002; Moradi, 2013; Hamdi et al., 2014; Moradi et al., 2020).

Moradi et al. (2020) developed models for predicting temperature profiles for injection wells in enhanced oil recovery using surface injection parameters instead of download gauges that are susceptible to failure over time. With such well specific flowing temperature profiles, potential problems can be abated before their occurrence even if such problems are inevitable. Although, several software packages such as computational fluid dynamics (CFD) solutions (Fluent 2011) offer great relief and benefits, it would be more beneficial and proactive to have flowing temperature profiles predicted from surface injection parameters (Peterson et al., 2008). Moreover, these software packages are slow and require a great deal of expertise to run them.

The heat transfer from a fluid in a pipe of constant cross-sectional area is a function of the mass flowrate; thus, varies with changes in flowrate. Besides, the overall heat transfer coefficient, change in enthalpy also depends on pressure. However, because of the many dependant variables to effectively calculate and predict flowing temperature profiles in wellbores, the solutions to developed algorithms are usually iterative and require intensive calculations that involve the coupling of pressure and heat loss calculations together. Thus, developing dimensionless heat transfer models would help develop generic models for quick estimates of flowing temperatures and overcome these time-consuming iterative solutions. In this paper, from first principle, dimensionless heat transfer models are developed to aid quick prediction of flowing temperature profiles in pipes and wellbores that are susceptible to wax deposition.

2. Materials and methods

2.1 Model development

Although, Ramey's (1962) model was developed with some assumptions and that makes it not suitable for predicting fluid flow for injection wells at near critical point in deep injection wells (Messer et al. 1974; Alves et al. 1992; Yasunami et al. 2010), it has become widely acceptable because of its simplicity and accuracy for predicting heat transmission in wellbores and flowlines. It is an approximate solution to the wellbore heat transfer problem; thus it was adopted to develop the dimensionless heat transfer models in this paper.

Assuming that fluid and surrounding temperatures are equal at the inlet temperature, T_1, which is the reservoir temperature, the temperature at any depth in the well and time is given by Ramey (1962) as:

$$T(L,t) = T_1 - g_t\left[L - A\left(1 - exp\left(\frac{-L}{A}\right)\right)\right] \quad (1)$$

where T_1 is the inlet temperature, g_t is the geothermal gradient, °F/ft, L is pipe length, ft and A is the relaxation distance which is dependent on the heat transfer and fluid conditions as follows:

$$A = \frac{q\rho C_p\,[k + r_1\, U\, f(t)]}{d_1 \pi\ \ Uk} \quad (2)$$

where q is the flow rate, bbl/day, ρ is the fluid density, lbm/ft^3, C_p is the specific heat capacity at constant pressure in Btu/lbm-°F, k is the thermal conductivity, Btu/hr.-sq.ft-°F/ft, r_1 is the inside radius of tubing, ft, U is the overall heat transfer coefficient, Btu/ft-sqft, and d_1 is the inside diameter of the tubing, ft.

Assuming that heat loss is independent of time, then from equation (2),

$$A' = \frac{q\rho C_p}{\pi d_1 U} \quad (3)$$

Therefore,

$$A = A'\frac{[k + r_1 U f(t)]}{\mathrm{k}} \quad (4)$$

With equation (3), we can easily modify equation (1) for multiphase flow and also include the time function, f(t), for times less than 7 days. The function f(t), is obtained from tables (Willhite, 1967), but for times greater than 7 days, Ramey (1962) gave a line source solution to the time function as:

$$\mathrm{f}(t) = ln\left(\frac{\sqrt[2]{\propto t}}{r_2{}'}\right) - 0.290 + \varphi\left(\frac{r_2'}{4 \propto t}\right)^2 \quad (5)$$

where $r_2{}'$ is the outer radius of casing, ft, t is the total flowing time, yrs, $\varphi\left(\frac{r_2'}{4\alpha t}\right)$ is the degree of error introduced and $\propto = \frac{k}{\rho C_f}$ is the thermal diffusivity of the earth, sq.ft/day. Typical values of f(t) ranges between 0.5 and 3.0.

For multiphase flow in a well, the variables involved in evaluating the relaxation distance A, and the overall heat transfer coefficient U, are difficult to measure. Thus, Shiu and Beggs (1980) developed an empirical correlation for A' for a flowing oil well as shown:

$$A' = a_1\,(\rho_L q)^{a_2}(\rho_L)^{a_3} d^{a_4} p_{tf}(\gamma_o)^{a_5}\gamma_g{}^{a_6} \quad (6)$$

where the a_i, for i = 1 to 6 are constants, ρ_L is the liquid density, q is the liquid flow rate, d is the inside diameter of the tubing, p_{tf} is the flowing surface pressure, γ_o is the API gravity of oil, and γ_g is the gas specific gravity, To include the effect of time then, equations (4), (5) and (6) should be combined together. Assuming that the surrounding temperature, T_s , is constant, we can modify equation (1) to calculate flowing temperature profile in an unheated pipeline as:

$$T(L,t) = T_s + (T_1 - T_s)exp\left(\frac{-L}{A}\right) \quad (7)$$

For compressible multiphase flow, we can include the Joule-Thompson effect which is pressure dependent and thus, requires an iterative solution.

Hence, for flow in the well, Equation (1) can be modified to (Beggs, 1983):

$$T(L,t) = T_1 + \varphi A\left(\frac{dP}{dL}\right) - g_t\left[L - \Psi A\left(1 - \Psi\frac{dP}{dL} - exp\left(\frac{-L}{A}\right)\right)\right] \quad (8)$$

while for flow in pipe, equation (7) becomes:

$$T(L_1,t) = T_s + \varphi A\left(\frac{dP}{dL}\right) + \left[T_1 - T_s - \Psi A\left(\frac{dP}{dL}\right)\right] exp\left(\frac{-L}{A}\right) \quad (9)$$

where Ψ = Joule-Thompson coefficient and $\frac{dp}{dL}$ = pressure gradient at L.

2.2 Dimensionless form of model

By defining the following dimensionless parameters, equations (1) and (7) can be recast into dimensionless form. The dimensionless parameters are:

Dimensionless temperature in pipe

$$T_{DP} = \frac{T(L,t) - T_s}{T_1 - T_s} = exp\left(\frac{-L}{A}\right) \quad (10)$$

Dimensionless temperature in wellbore

$$T_{DW} = \frac{T_1 - T(L,t)}{g_t A} \quad (11)$$

Dimensionless distance for flowing systems

$$X_{DF} = \frac{L}{A'} = \frac{L d_1 \pi U}{q\rho\ C_\rho} \quad (12)$$

Dimensionless conductance to heat flow in flowing systems

$$K_{DF} = \frac{k}{k + r_1 U f(t)} \quad (13)$$

With these dimensionless parameters equation (1) becomes

$$T_{Dw} = X_{DF}K_{DF} + exp(-X_{DF}K_{DF}) - 1 \quad (14)$$

and Equation (7) becomes:

$$T_{DP} = exp(-X_{DF}K_{DF}) \quad (15)$$

For surface pipeline, single phase flow can be assumed. To include the effect of pressure on the temperature profile, then the dimensionless parameter in Equation (10), can be modified as (Ikoku, 1988):

$$T_{DP} = \frac{T_{(L,t)} - (T_s + \theta)}{T_1 - (T_s + \theta)} \quad (16)$$

where the pressure-effect factor, θ, is defined as:

$$\theta = \frac{q\rho}{UAJ}[1 - \alpha_T(T_{av} + 460)]\left(\frac{\Delta p}{L}\right) \quad (17)$$

where q = oil flowrate, ft^3/hr, ρ = density lbm/ft^3, J = conversion factor = 778.16/144, T_{av} =average line temperature, °F, Δp = line pressure drops, psi and α_T = thermal expansion coefficient. For quick estimate and short lines, θ can be neglected.

3. Results and discussion

Figures 1 and 2 show the behaviour of flowing temperatures in wellbores and pipelines at varying heat conductance. As can be seen in Figure 1, the flowing temperature decreases at a given pipe conductance as the pipeline distance increases. More so, the rate of heat loss is higher in pipelines with high heat conductance. For example, when the heat conductance is 1, the temperature drop in the pipeline is rapid compared to when it is 0.1.

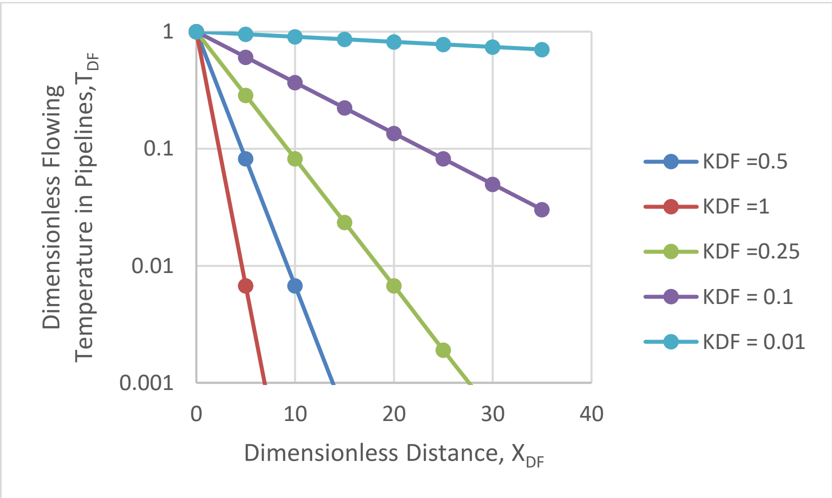

Fig. 1: Dimensionless temperature for flowing pipelines versus dimensionless distance for various values of dimensionless conductance to heat in flowing pipelines**.**

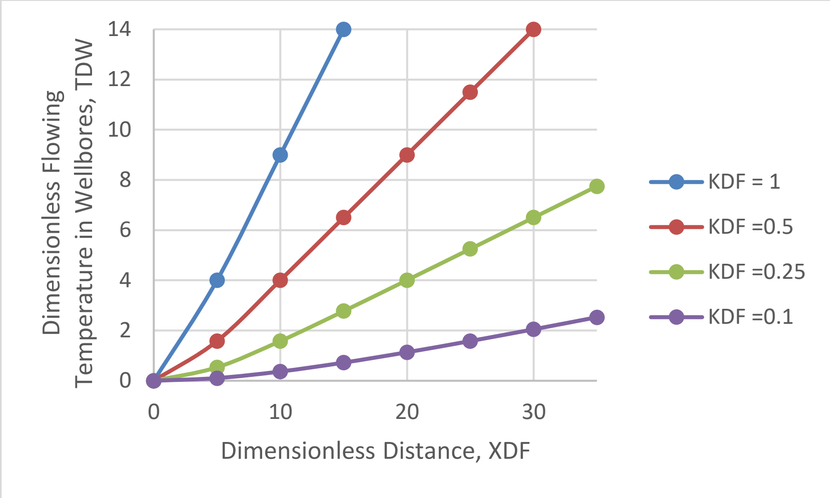

Fig. 2: Graph of dimensionless temperature versus dimensionless distance for various values dimensionless conductance in flowing wells.

This highlights the importance of insulation in heat control in pipelines conveying waxy crudes. A similar observation was seen in wellbores. Here point zero is the wellhead and the direction of fluid flow is from the wellbore to the wellhead. As the crude flows from the wellbore to the wellhead, there is a cooling effect that causes temperature reduction at a constant heat conductance as shown in Figure 2. Also, the rate of heat loss is dependent on the conductance of heat transfer in a given tubing. Hence, tubings with high conductance have much higher heat transfer loss compared to tubing with low heat conductance.

4. Conclusion

Prediction and estimation of flowing temperatures in wellbores and flowlines is key to ensuring the continuous flow of hydrocarbons from the wellbore to surface facilities. Dimensionless models have been developed in this work to enhance the estimation of flowing temperatures in wellbores and flowlines at a given heat conductance. The higher the heat conductance of flowlines and tubings, the higher the rate of heat loss and verse versa. Because these models are developed as dimensionless parameters, they are generalized models that will enhance the prediction and estimation of flowing temperatures of wellbores and flowlines at various depths and distances to guarantee flow assurance.

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