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Development of a Thermal Wellbore Simulator With Focus on Improving Heat Loss Calculations for SAGD Steam Injection

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Abstract

Typical thermal processes involve sophisticated wellbore configurations, complex fluid flow and heat transfer in tubing, annulus, wellbore completion, and surrounding formation. Despite notable advancements made in wellbore modeling, accurate heat loss modeling is still a challenge using the existing wellbore simulators. This challenge becomes even greater when complex but common wellbore configurations such as multi-parallel or multi-concentric tubings are used in thermal processes such as Steam Assisted Gravity Drainage (SAGD).

To improve heat loss estimation, a standalone fully-implicit thermal wellbore simulator is developed that can handle several different wellbore configurations and completions. This simulator uses a fully implicit method to model heat loss from tubing walls to the surrounding formation. Instead of implementing the common Ramey method (1962) for heat loss calculations that has been shown to be a source of large errors, a series of computational fluid dynamical (CFD) models are run for the buoyancy driven flow for different annulus sizes and lengths and numbers of tubings. Based on these CFD models, correlations are derived that can conveniently be used for the more accurate heat loss estimation from the wellbore to the surrounding formation for SAGD injection wells with single or multiple tubing strings. These correlations are embedded in the developed wellbore simulator and results are compared with other heat loss modeling methods to demonstrate its improvements. A series of validations against commercial simulators and field data are presented in this paper.

Introduction

With continuous developments of different sophisticated wells (e.g., horizontal and multilateral wells), wellbore modeling and simulation have increasingly received more attention. Especially in the heavy oil industry that needs to use some wellbore sensitive technologies such as SAGD and Cyclic Steam Stimulation (CSS), there is a growing demand for wellbore studies. Compared with traditional correlations for calculating pressure and fluid properties along wellbore, wellbore simulation can offer more accurate results and handle more complex wellbore configurations. In thermal injection wellbore and lines, the wellbore simulation can accurately predict heat loss and temperature profiles along a well trajectory and, therefore, provides parameters crucial for evaluation and optimization of thermal operation.

The wellbore modeling and simulation work can be dated back to the early 1930s when people began to perform theoretical analyses on two-phase gas-liquid flow in a vertical pipe. Ramey (1962) proposed the first mathematical model and its analytical solution for calculating liquid and gas temperature profiles varying with the vertical wellbore depth and time. Although Ramey made several assumptions for simplifying his model, his work founded the basis of wellbore modeling and simulation. In the next few years, several researchers published their work on improvements of Ramey's model. Based on Ramey's model, Willhite (1967) proposed a workflow to estimate the overall heat transfer coefficient and model a well that has been widely used until today. Farouq Ali (1981) developed a mathematical model for simulating steam-water flow in steam injection wells and geothermal wells. Farouq Ali's model is the first model that considered a complete wellbore simulation system: the steam flow in tubing or annulus, the heat loss to the surrounding formation through tubing, annulus, casing and cement and heat dispersion in formation. Fontanilla and Aziz (1982) proposed an analytical model for calculating pressure and steam quality in a steam injection well. Later on, Stone et al. (1989) developed the first wellbore simulator that was fully coupled with a reservoir simulator. This wellbore simulator is a thermal simulator and considered three-phase flow. It simultaneously solved the wellbore variables and reservoir variables together. Hasan and Kabir (2002) introduced analytical fluid temperature equations for single-tubing and double-tubing wellbores. They developed analytical solutions for calculating temperature of transient fluid flow. In the same year, Cao (2002) developed an isothermal compositional wellbore simulator which is also fully coupled with their reservoir simulator, General Purpose Reservoir Simulator (GPRS). Pouraf-shary et al. (2008) developed a thermal compositional wellbore simulator which was coupled with a reservoir simulator. Livescu et al. (2008; 2010) developed a series of fully-coupled thermal multiphase (black oil and compositional) wellbore flow models. Bahonar et al. (2011) further developed a non-isothermal wellbore simulator for steam injection wells. Most recently, Dong (2012) developed a fully-coupled thermal wellbore and reservoir simulator.

Wellbore modeling and simulation, especially in those wells with complex configurations, are not an easy task. It relates to analyzing and modeling the multiphase nature of fluid flow inside the wellbore and the heat transfer mechanisms between the wellbore and its surrounding formations and handling complex wellbore configurations. In particular, for the heat exchange between the fluids in wellbore and surround-ing formations, one needs to consider complicated mechanisms such as radiation and natural convective heat transfer through the annulus full of air or other fluids and heat dispersion in the surrounding formations that consist of different rocks and minerals. Despite notable advancements made in wellbore modeling, accurate heat loss modeling is still a challenge using the existing wellbore simulators. This challenge becomes more evident when complex but common wellbore configurations such as multi-parallel or multi-concentric tubings are used in thermal processes such as SAGD.

In this paper, we present wellbore modeling equations, a numerical scheme, a methodology for development of a standalone thermal wellbore simulator, a technique for improving the heat loss calculations, and validation results. The wellbore model is comprised of a series of mathematical equations including the main governing equations for fluid flow in tubing or annulus, wellbore heat loss equations, heat transfer in formation, and a drift-flux model. The development of the wellbore simulator involves discretization, a grid system design, a solution method, linear equation solvers, and a computer language. In pursuance of improved accuracy of heat loss calculation to the surrounding formation, a semi-numerical method has been proposed and a series of FLUENT simulations have been conducted for single and double-tubing SAGD processes in this study. The semi-numerical method involves extending the 2D formation heat transfer simulation to include the casing wall and cement and adopting new correlations regressed in this study. Validations against CMG SAM and CMG FlexWell have been performed for hot water injection, steam injection, and a double-tubing well.

Model Description

The mass conservation equation describes the fluid flow velocity and density change along wellbore. Considering that there are *Nc* hydrocarbon components and one water component, the mass conversation equations for a hydrocarbon component and water component are (Livescu et al., 2009):

$$\frac{\partial}{\partial t}\left(\rho_g\alpha_g x_{cg}+\rho_o\alpha_o x_{co}+\rho_w\alpha_w x_{cw}\right)+\frac{\partial}{\partial z}\left(\rho_g V_{sg}x_{cg}+\rho_o V_{so}x_{co}+\rho_w V_{sw}x_{cw}\right)=m_{cg}+m_{co}+m_{cw}\quad(for\ hydrocarbon\ component\ c=1,2,\ldots,N_c) \tag{1}$$

$$\frac{\partial}{\partial t}\left(\rho_g\alpha_g x_{wg}+\rho_o\alpha_o x_{wo}+\rho_w\alpha_w x_{ww}\right)+\frac{\partial}{\partial z}\left(\rho_g V_{sg}x_{wg}+\rho_o V_{so}x_{wo}+\rho_w V_{sw}x_{ww}\right)=m_{ww}+m_{wo}+m_{wo}\quad(for\ water\ component) \tag{2}$$

where ρ is the density, α is the in-situ phase volume fraction, x_c is the molar fraction of a hydrocarbon component in a phase and *o, w*, and *g* represents the oil, water, and gas phases, respectively.

The momentum equation expresses the pressure loss along tubing or annulus accounting for gravity, friction and kinetic energy. The momentum equation for both a producer and an injector can be expressed as (Hasan and Kabir, 2002; Livescu et al. 2008; Bahonar et al. 2009):

$$\frac{\partial p^w}{\partial z}=\rho_m g\cos\theta\pm\frac{f_{tp}\rho_m V_m^2}{2d_{in}}\pm\left[\frac{d(\rho_m V_m)}{dt}+\frac{\rho_m V_m dV_m}{dz}\right] \tag{3}$$

where p^w is the pressure in tubing or annulus, ρ_m is the fluid mixture density calculated by $\rho_m=\rho_g\alpha_g+\rho_o\alpha_o+\rho_w\alpha_w$ and V_m is the mixture velocity that is computed from the drift-flux model which will be described later. f_{tp} is the Moody friction factor which can be computed from a Reynolds number, pipe roughness and a pipe diameter by empirical correlations one of which is proposed by Colebrook (1939).

The energy conservation equation has different varieties among the publications (Ramey 1962; Ali 1981; Fontanilla and Aziz 1982; Stone 1989; Hasan and Kabir 2002; Livescu et al. 2008; Bahonar et al. 2009). It can be expressed as follows:

$$\frac{\partial}{\partial t}\sum_p\rho_p\alpha_p\left(u_p+\frac{1}{2}V_p^2\right)=-\frac{\partial}{\partial z}\sum_p\rho_p V_{sp}\left(h_p+\frac{1}{2}V_p^2\right)+\sum_p\rho_p V_{sp}g\cos\theta-\frac{Q_{loss}}{A}+m_h \tag{4}$$

where p is the phase index and represents the oil, water and gas phases, u_p is the internal energy of phase oil, water or gas, and h_p is the corresponding phase enthalpy. As Livescu et al (2008) pointed out, the relationship between the internal energy u_p and the enthalpy h_p is: $h_p=u_p+\frac{p^w}{\rho_p}$. As it can be seen, the Joule-Thompson effect is also incorporated in this equation by the phase density ρ_p. V_p is the phase real velocity and V_{sp} is the phase superficial velocity, which is defined as $V_{sp}\alpha_p V_p$. The left-hand side of this equation represents the sum of the energy accumulation within unit time in the unit control volume. On the right-hand side, the first term is called spatial derivative and it depicts the convection heat flux and kinetic energy change in the unit control volume. The second term on the right-hand side represents the energy change due to the gravitational force. $\frac{Q_{loss}}{A}$ is the fluid heat loss to the surrounding formation in unit tubing or annulus length. The last term on the right-hand side is the heat flux sink/source term akin to a production sink/source term in the reservoir simulation grid with a well.

There are some auxiliary equations for making these governing equations a closed system:

$$\alpha_g+\alpha_w+\alpha_o=1 \tag{5}$$

$$V_{sg}+V_{sw}+V_{so}=V_m \tag{6}$$

$$\sum_{i=1}^{N_c}x_{cp}+x_{wp}=1\quad(p=o,w,g) \tag{7}$$

Another important part for modeling a wellbore system is related to heat loss to the surrounding formations. As shown in Fig. 1, a typical wellbore is comprised of tubings, annulus between tubings and casing, casing, cement and surrounding formation.

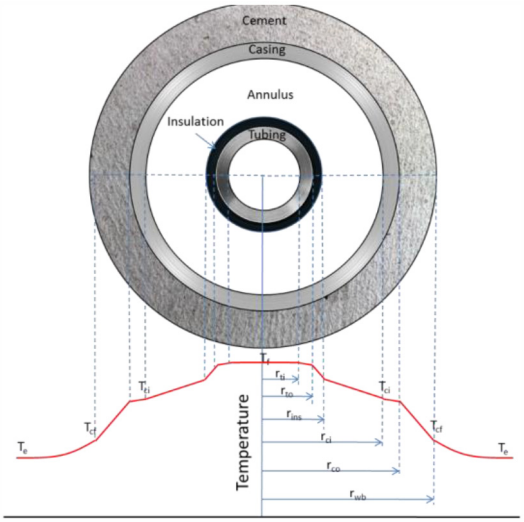

Figure 1—Heat loss and temperature gradient in a typical wellbore

Ramey (1962) first proposed a formula to calculate the transient heat loss rate between the outside of a casing wall and formation:

$$Q_{loss} = \frac{2\pi k_e (T_{co} - T_e)}{f(t)} \tag{8}$$

where k_e is the formation thermal conductivity, T_{co} is the temperature of outside of the casing wall, T_e is the formation temperature and $f(t)$ is called the transient time function. When time is greater than one week, Ramey gave the following analytical expression for computing the time function:

$$f(t) = ln\frac{2\sqrt{\alpha t}}{r_{cf}} - 0.29 \tag{9}$$

where α is the formation thermal diffusivity and r_{cf} is the cement/formation interface radius.

Willhite (1967) introduced an overall heat transfer coefficient for calculating heat loss that integrates all the heat resistances of the flowing fluid, tubing wall, annulus, casing wall and cement as a single factor. Thus the formula for calculating heat loss is given by:

$$Q_{loss} = 2\pi r_{to} U_{to} \left(T_f - T_{cf}\right) \tag{10}$$

where U_{to} is the overall heat transfer coefficient, r_{to} is the outside radius of tubing, T_f is the fluid temperature and T_{cf} is the temperature at the cement/formation interface. The overall heat transfer coefficient developed by Willhite (1967) can be written as:

$$\frac{1}{U_{to}} = \frac{r_{to}}{r_{ti} h_f} + \frac{r_{to} ln(r_{to}/r_{ti})}{k_t} + \frac{r_{to} ln(r_{ins}/r_{to})}{k_{ins}} + \frac{r_{to}}{r_{ins}(h_c + h_r)} + \frac{r_{to} ln(r_{co}/r_{ci})}{k_{cas}} + \frac{r_{to} ln(r_{cf}/r_{co})}{k_{cem}} \tag{11}$$

where r_{ti}, r_{to}, r_{ins}, r_{ci}, r_{co}, and r_{cf} represent the radii of inside tubing, outside tubing, tubing insulation, inside casing, outside casing and cement/formation interface, respectively. k_t, k_{ins}, k_{cas}, and k_{cem} are the thermal conductivities of the tubing wall, tubing insulation, casing wall and cement. h_f, h_c, and h_r are the convective heat transfer coefficient between the fluid film in tubing and the tubing wall, and the convective and radial heat transfer coefficients of fluid inside annulus.

In order to appropriately calculate the overall heat transfer coefficient, Willhite (1967) proposed an iteration procedure that is widely used until today. In particular, for the calculation of the convective heat transfer in annulus, Willhite used the Dropkin and Sommerscales (1965) method which was based on experimental data on two vertical parallel plates which certainly are not the best representative of a typical wellbore geometry. Since then, a lot of research on heat transfer in vertical, inclined and horizontal annulus including experimental work and theoretical studies have been conducted. Particularly after 2000, the research on annulus heat transfer has more relied on numerical simulation. Complete models for describing heat transfer phenomenon in annulus were built and software (e.g., FLUENT) that can simulate heat transfer in annulus was used (Hamad et al. 1998; Inaba et al. 2005). There are some widely-used correlations for calculating convective heat transfer in annulus such as Raithby and Hollands (1974) and Churchill (1983). Papers like Weng et al. (1996) provided a complete mathematical model for developing numerical simulation for heat transfer in annulus.

One of important steps for heat loss calculation is to evaluate the temperature at the cement/formation interface T_{cf}. Ramey (1962) solved this problem by proposing an empirical time function $f(t)$. However, a more accurate answer by solving the partial differential equation for heat transfer in the formation can be acquired. Researchers such as Farouq Ali (1981) and Bahonar (2009) presented detailed information on this kind of modeling in their publications. The 2D heat transfer equation (Faroug Ali, 1981; Bahonar 2009) can be expressed as follows:

$$\frac{1}{r}\frac{\partial}{\partial r}\left(k_r r\frac{\partial T_e}{\partial r}\right)+\frac{\partial}{\partial z}\left(k_z\frac{\partial T_e}{\partial z}\right)=\rho_e C_{pe}\frac{\partial T_e}{\partial t} \tag{12}$$

where r is the radius to the wellbore center, z is the vertical depth, k_r is the formation thermal conductivity along the radial direction, k_z is the formation thermal conductivity in the z direction, T_e is the formation temperature, ρe is the formation density and C_{pe} is the formation heat capacity.

Modeling two-phase or multiple phase flow in pipes involves how to represent flow regimes and appropriately calculating some important fluid parameters including the fluid mixture density and in-situ volume fractions. There have been a lot of correlations and mechanistic models that can undertake this task. However, these kinds of methods cannot be easily incorporated into wellbore simulation because they are not continuous and differentiable and may cause convergence problems. The drift-flux models have been proved to be good candidates for developing a wellbore simulator. Two drift-flux models which were, respectively, proposed by Shi et al. (2005) and Hasan et al. (2007), can be used for the wellbore simulator.

Development of Wellbore Simulator

The finite difference method is used here to numerically solve the partial differential equations because of its easy implementation and fast computation speed. A staggered grid system which is automatically built through directional wellbore survey data is applied (Fig. 2). Primary variables such as velocity (V_m), pressure (p^w) and enthalpy (h) are assigned to the boundary of a grid and the in-situ phase volume fractions (e.g., αg) are assigned to the center of the grid for convenience of discretization. This is the so-called "staggered" grid system. For wellbore modeling equations, the momentum equation is highly nonlinear and the whole governing equations are highly coupled. A fully implicit scheme will be the most accurate choice for solutions. The discretized equations are linearized by Newton iterations.

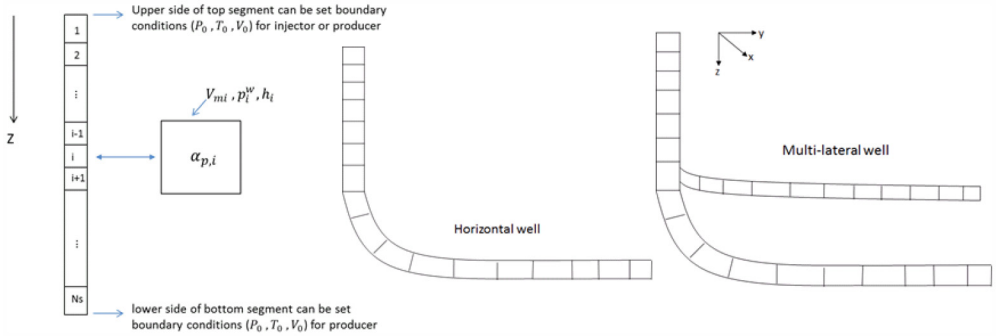

Figure 2—Staggered grid systems for a wellbore simulator

Currently, nearly all wellbore simulators are still using a correlation-based method proposed by Ramey (1962) and Willhite (1967) for calculating wellbore heat loss to the surrounding formations (Fig. 3). However, these correlations have been shown to be a source of large errors. In this study, methods that adopt new heat transfer estimation have been applied for improving the accuracy of wellbore heat loss calculation. Because the most uncertain part in the Ramey method is about the heat transfer calculation in annulus, improving the accuracy of heat transfer calculation in annulus is the focus of this study. In order to find better correlations for predicting natural convective heat transfer in annulus between tubing and casing, a series of FLUENT simulations have been conducted with typical combinations of tubing and casing sizes (Table 1) in thermal injection wells. For each combination of a tubing and casing size, a set of tubing and casing temperatures are used as shown in Table 2 to have a range of the Rayleigh number in the annulus. The heat flux rate q has the following relationship with the Nusselt number N_u:

$$q = \pi k_a N_u (T_{ci} - T_{to}) \tag{13}$$

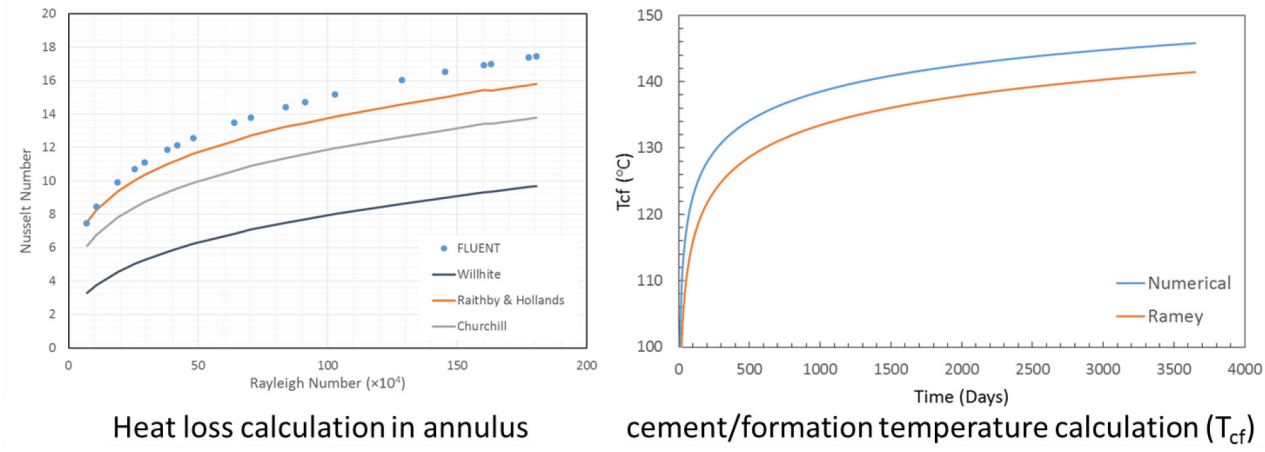

Figure 3—Comparison between Ramey & Willhite correlation with numerical simulation

Table 1—Combination of tubing and casing sizes used in FLUENT simulation

No.	Tubing OD	Casing ID
1	3½”	7”
2	3½”	11¾”
3	4½”	9⅝”
4	4½”	11¾”
5	5½”	9⅝”

Table 2—Set of tubing and casing temperatures used in FLUENT simulation

Outer tubing temperature (K)	Inner casing temperature (K)
310	290
360	290
410	290
460	290
510	290
560	290
610	290
410	340
510	340
610	340
460	390
560	390
510	440
560	440
610	440
510	490
560	490
610	490
610	550

where k_a is the air thermal conductivity in the annulus, T_{ci} is the inner casing temperature and T_{to} is the outside tubing temperature. Because the heat flux rate can be read from FLUENT simulation results, the Nusselt number N_u is calculated from equation (13) for each Rayleigh number.

Each FLUENT simulation is distinguished by tubing temperature, casing temperature, tubing radius and casing radius. Each run usually reaches a steady state condition in several seconds to tens of seconds with a typical flow pattern shown in Fig. 4. Correlations can be regressed based on these simulation results for predicting heat transfer in annulus. Comparison between FLUENT simulation results and some well-known correlations has been made in this study. Results show that the prediction results by the correlations used by Willhite (1967), Raithby and Hollands (1974) and Churchill (1983) have errors compared to results from the FLUENT simulation (Fig. 5). A new correlation based on these FLUENT simulation results is regressed. This new correlation is expressed as follows:

$$N_u = C\delta^a {R_a}^b \tag{14}$$

C=0.951182 a=1.098661 b=0.246907

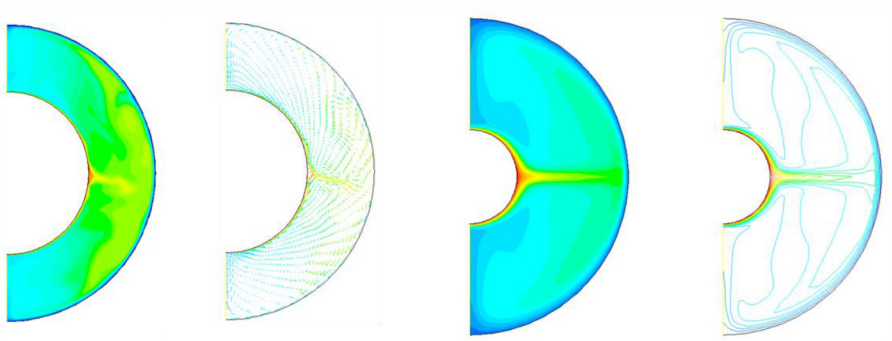

Figure 4—Sample flow patterns from FLUENT simulation

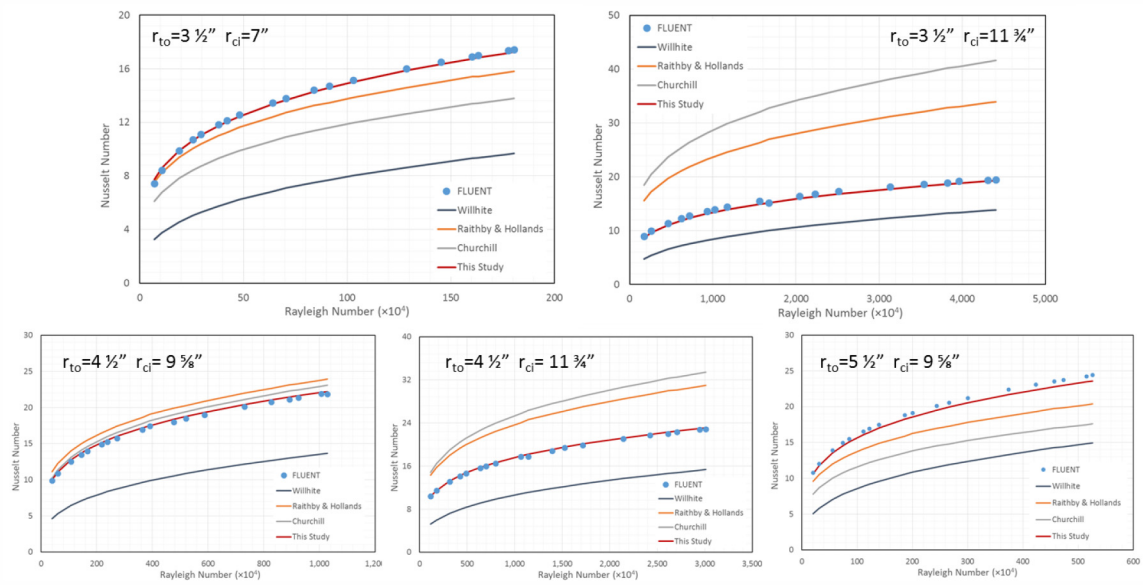

Figure 5—Performance of the proposed correlation in this study

where N_u is the Nusselt number, δ is the annulus aspect ratio ($\delta = r_{to}/r_{ci}$) and R_a is the Raleigh number.

In order to validate the correlation (14), two combinations of tubing and casing sizes are selected and FLUENT simulations based on the temperature values in Table 2 are conducted. The comparison between the prediction by correlation (14) and the FLUENT simulation results is shown in Fig. 6. From Fig. 6, it can be seen that the prediction by correlation (14) can match well with the FLUENT simulations results. The maximum mismatch error in Fig. 6 is 6.7%.

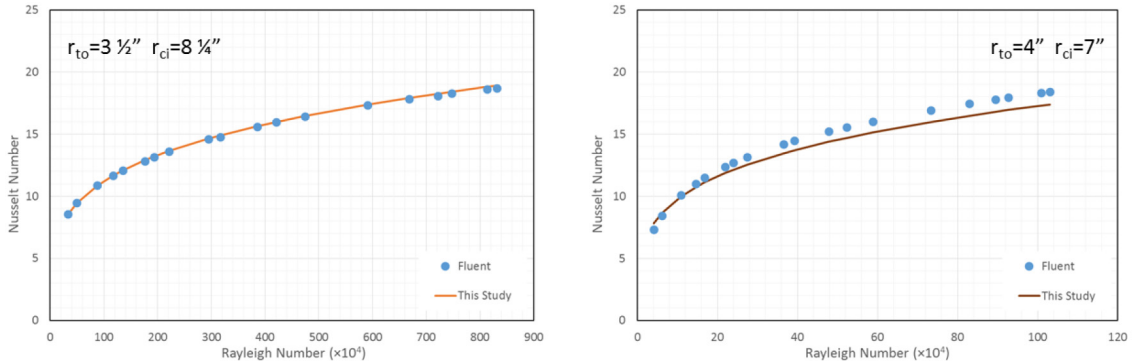

Figure 6—Comparison between the prediction by correlation (14) and the FLUENT simulation results

Traditionally, the wellbore modeling only considered fluid flow and heat transfer in the single tubing case and currently majority of wellbore modeling methods are built on such a configuration. However, contemporary production technologies such as SAGD are based on sophisticated wellbore configurations with commonly multiple tubings. In this study, the heat transfer mechanism in a double-tubing wellbore space has been preliminarily investigated. A model that includes two tubings (3½" and 4½") and 11¾" casing is built (Fig. 7). Typically a heat flow pattern in the double-tubing case looks like the one shown in Fig. 8.

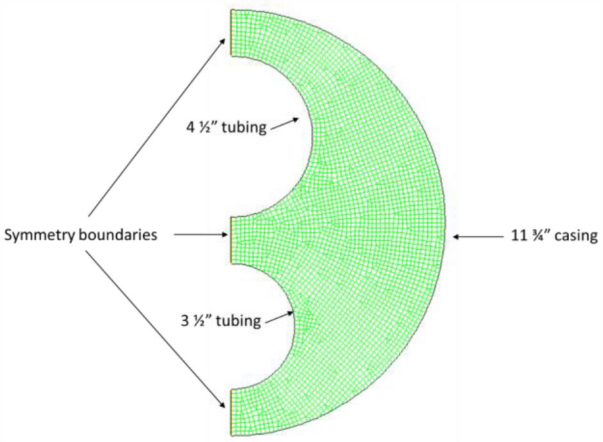

Figure 7—A FLUENT model for double-tubing wellbore

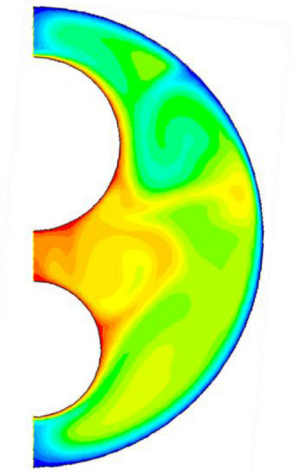

Figure 8—A sample of heat flow pattern in double-tubing space

The simulation results for the double-tubing model have been compared with those of the single-tubing model which has the same-sized tubing and casing. Comparison results show that each tubing has a less heat transfer rate in the double-tubing model than that in the single-tubing model (Fig. 9). The Nusselt numbers for each tubing in the double-tubing model are lower than those for each tubing in the single-tubing model in all tested Rayleigh numbers. As it can be seen from equation (13), the Nusselt number represents the intensity of natural heat transfer. This means that with a higher Nusselt number, we will have a greater heat transfer rate at the same temperature difference between tubing and casing. Fig. 9 shows that each tubing in the double-tubing model has a lower heat transfer rate than that in the single-tubing model. Therefore, correlations for predicting single-tubing heat transfer are not suitable for double-tubing heat transfer. From Fig. 9, we can also observe that the two curves of each tubing for the single-tubing model and double-tubing model are almost parallel and have the same trend. Thus a coefficient can be used to convert the single-tubing correlations to the double-tubing case. Through the observation and comparison with the single-tubing model, it is not difficult to find out that such a coefficient is related to the ratio of the tubing size to the casing size, and the Rayleigh number. Thus we introduce a new modified Nusselt number N_u' expressed as follows:

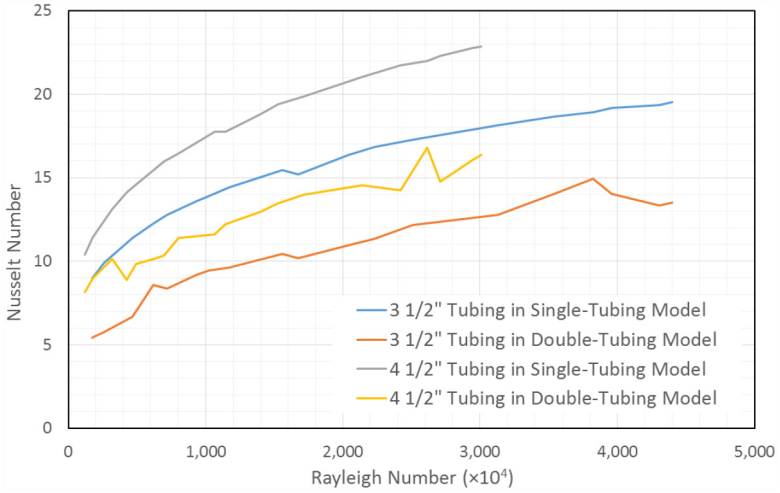

Figure 9—Nusselt number by single-tubing model and double-tubing model

$$N_u' = \alpha N_u \tag{15}$$

$$\alpha = C\beta^a {R_a}^b \tag{16}$$

$$\beta = \frac{\pi r_{ci}^2 - \pi r_{to1}^2 - \pi r_{to2}^2}{\pi r_{ci}^2 - \pi r_{to1}^2} = \frac{r_{ci}^2 - r_{to1}^2 - r_{to2}^2}{r_{ci}^2 - r_{to1}^2}$$

$$C = 0.527105 \quad a = 0.560901 \quad b = 0.021058$$

where α is the multiplier for converting the single-tubing Nusselt number to the modified Nusselt number N_u' and β is a coefficient that represents the reduced space ratio for a tubing in the double-tubing case. Comparison between the real coefficient α and the one predicted by equation (15) for the two tubings are shown in Fig. 10. The combination of equations (14)-(16) can be used to predict natural convective heat transfer in double tubing annulus.

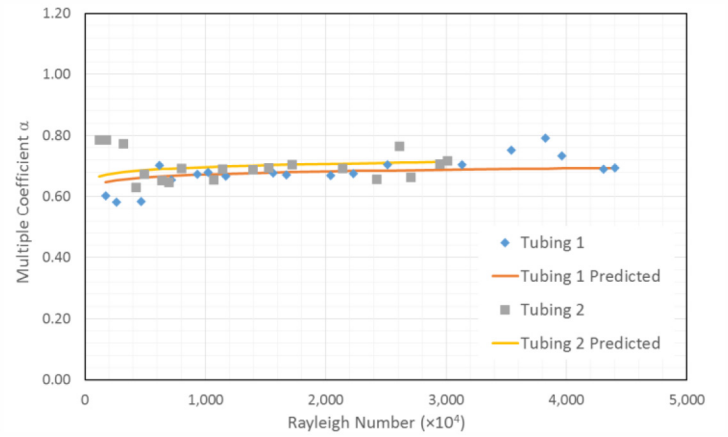

Figure 10—Comparison between real coefficient α and the predicted one

With the regressed correlations for natural convective heat transfer in single-tubing or double-tubing annulus and a simulation scheme for heat transfer in formation, two methodologies that can improve the calculation accuracy of wellbore heat loss are proposed and implemented into the simulator. The first methodology relates to replacing the older correlations with ones in this study. The second methodology

is a semi-numerical technique that further expands the numerical calculation range in heat loss calculation. As shown in Fig. 11, the second methodology involves extending the 2D formation heat transfer simulation to include the casing wall and cement.

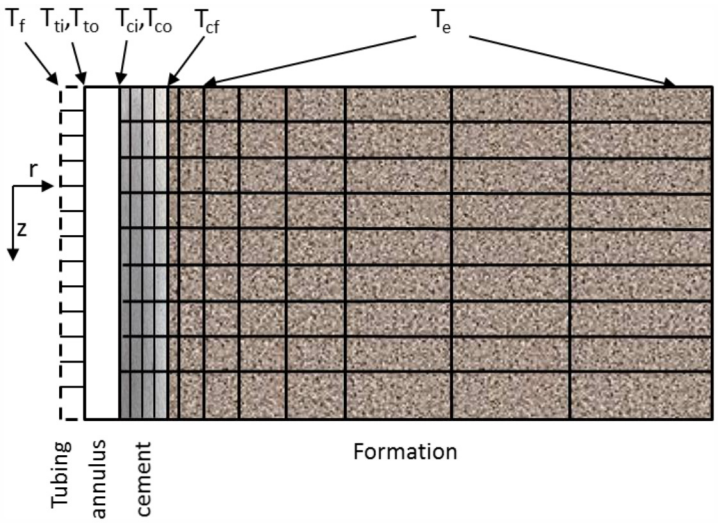

Figure 11—Schematic description of semi-numerical method for wellbore heat loss calculation

Results and Validation

Hot Water Injection

In this case, hot water is injected into a vertical well at a depth of 1,500m. It is assumed that the well has only one tubing (OD=3½") and one casing (OD=7"). The hot water is kept at a constant rate of 350 m^3/d (Cold Water Equivalent). The hot water temperature is 250.3 °C and pressure is 4,100 kPa at the wellhead. The model is run for two-year injection. The wellbore parameters (Table 3) are taken from Bahonar's paper (2009) and the default values of the CMG FlexWell model.

Table 3—Typical wellbore parameters

Item	Name	Value	Unit	Item	Name	Value	Unit
r_{ti}	inside tubing radius	0.038	m	k_{ez}	vertical thermal conductivity of formation	1.73	W/(m °C)
r_{to}	outside tubing radius	0.04445	m	α	formation thermal diffusivity	0.738063E-6	m^2/s
r_{ci}	inside casing radius	0.081	m	ε_{to}	emissivity of outside tubing surface	0.8	
r_{co}	outside casing radius	0.089	m	ε_{ci}	emissivity of inside casing surface	0.8	
r_{wb}	cement/formation radius	0.124	m	g_t	geothermal gradient	0.03513	°C/m
k_t	tubing thermal conductivity	43.2639	W/(m °C)	T_{surf}	surface geothermal temperature	12	°C
k_{cas}	casing thermal conductivity	43.2693	W/(m °C)	ρ_0	water density at standard condition	998.2	kg/m^3
K_{cem}	cement thermal conductivity	0.35	W/(m °C)	ε/d	relative roughness of tubing	0.0001	
k_e	radial thermal conductivity of formation	1.73	W/(m °C)				

A CMG model with a SAM option was built by using the same wellbore and injection parameters. The results calculated by this study (indicated by WM) and CMG SAM are plotted in Fig. 12 for comparison. The results by this study and CMG SAM can match very well at different times from one hour to two

years. Although the hot water injection is a simple single-phase case, it provides a relatively strong validation for some key computations such as heat loss calculation and friction loss calculation. Notice that the Ramey (1962) and Willhite (1967) methods have been used for simulation runs because the CMG uses the same method for calculating heat loss as well. If the new methods for improving heat loss calculation are used, the results by program WM will have obvious deviation from the CMG SAM results (Fig. 13). It shows that the improvement of the new methods for calculating heat loss can be significant.

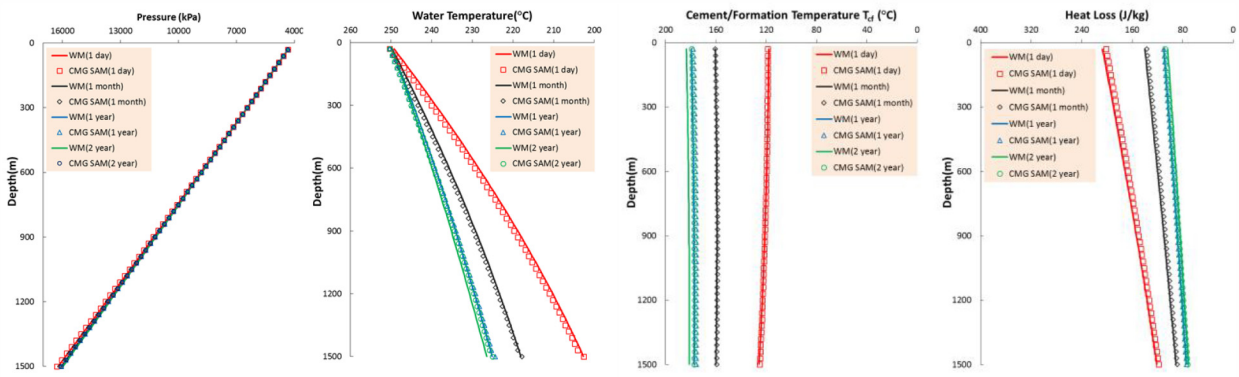

Figure 12—Results comparison between this study and CMG SAM for hot water injection

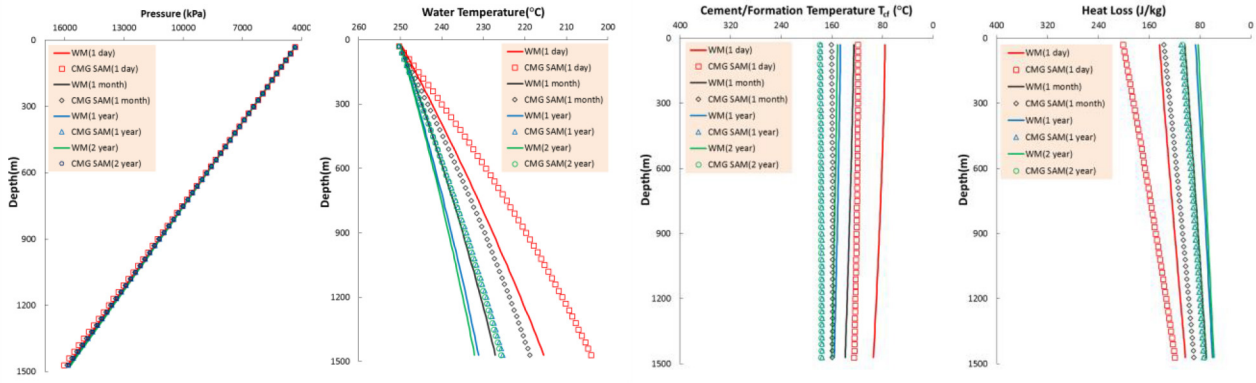

Figure 13—Results comparison between this study and CMG SAM for hot water injection (Non-Ramey method in this study)

Steam Injection

In this case, saturated steam is injected into a vertical well at a depth of 500m. It is also assumed that the well has only one tubing (OD=3½") and one casing (ID=7"). The saturation steam injection rate is set to be 260 m^3/d (Cold Water Equivalent) for which the steam velocity can be very high in the tubing. The steam saturation temperature at wellhead is assumed to be 250.3 °C which is common in in-situ thermal injection cases. The corresponding saturation pressure for that temperature is 4,027 kPa. The steam quality is 0.95. The total simulation time of this model is two years. The same wellbore parameters in Table 3 are used in this model.

The steam injection is considered as two-phase flow (steam and water condensate) in the tubing. Thus the drift-flux model is implemented to represent the effects of different flow regimes. Fig. 14 shows that the WM and CMG SAM can predict close results for key parameters such as steam pressure, temperature, cement/formation temperature and steam quality at different times from one hour to two years.

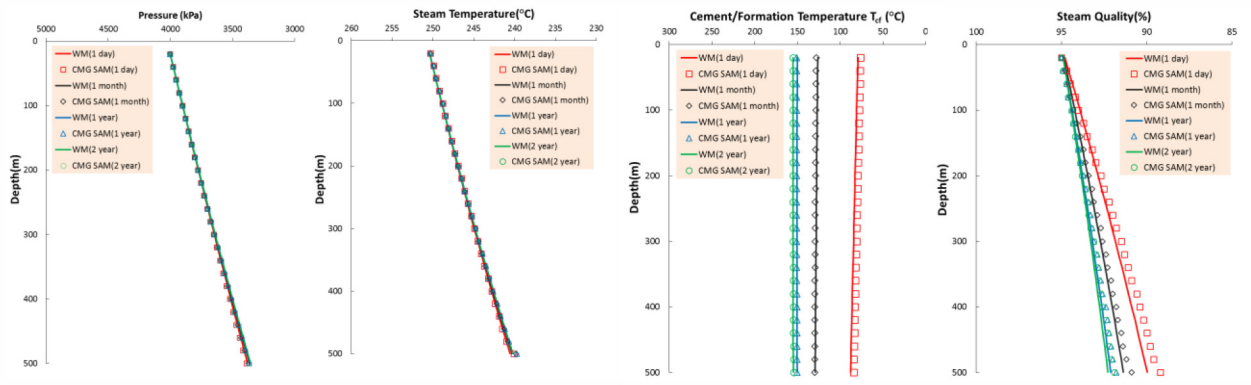

Figure 14—Results comparison between this study and CMG SAM for steam injection

In order to further validate the program WM in handling two-phase steam injection, a CMG FlexWell model with the same wellbore parameters is built (Fig. 15). The grid system in the CMG FlexWell model is set up along the wellbore to the surface. Fig. 16 shows that the results by this study (labeled as WM) match well with those of the FlexWell model especially when the duration of injection is long.

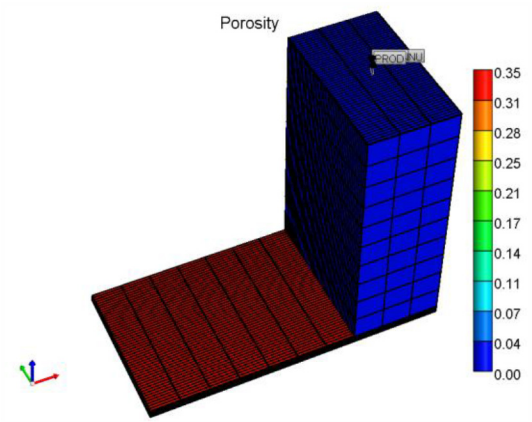

Figure 15—A CMG FlexWell model for validation of two-phase steam injection

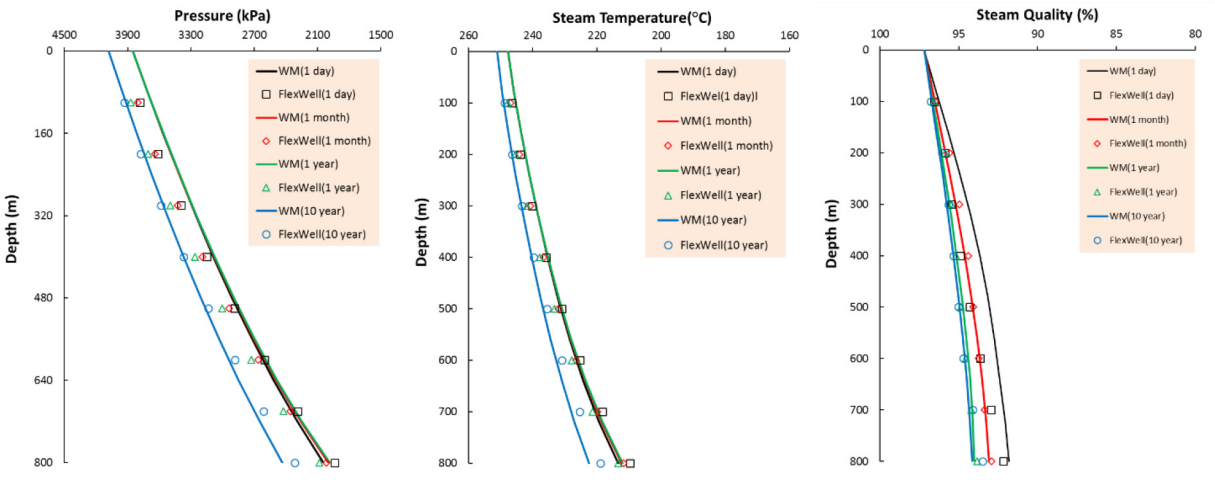

Figure 16—Results comparison between FlexWell and this study

Steam Injection in Double-Tubing Wellbore

The steam injection is also tested in a double-tubing wellbore case similar to a SAGD injector (Fig. 17). Most of the wellbore parameters are the same as the data listed in Table 3. It is assumed that the two tubings have the following specific parameters:

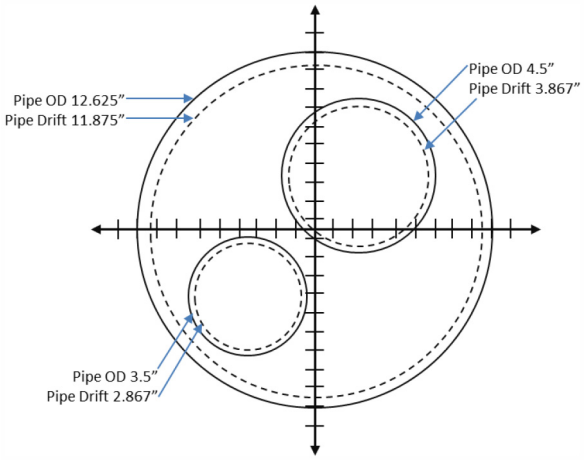

Figure 17—A typical double-tubing wellbore

Tubing 1: Pipe OD 3.5”, 260 m^3/day, Length 900 m
Tubing 2: Pipe OD 4.5”, 100 m^3/day, Length 900 m

Equations (14)-(16) are implemented in the program for calculating the natural heat transfer in the annulus. The heat transfer between the two tubings is computed by the same method. The results of a simulation run for ten years are shown in Fig. 18. When the injection steam parameters are slightly different, superheated steam phenomenon can also be observed after the injection time becomes long. For example, for the following configuration:

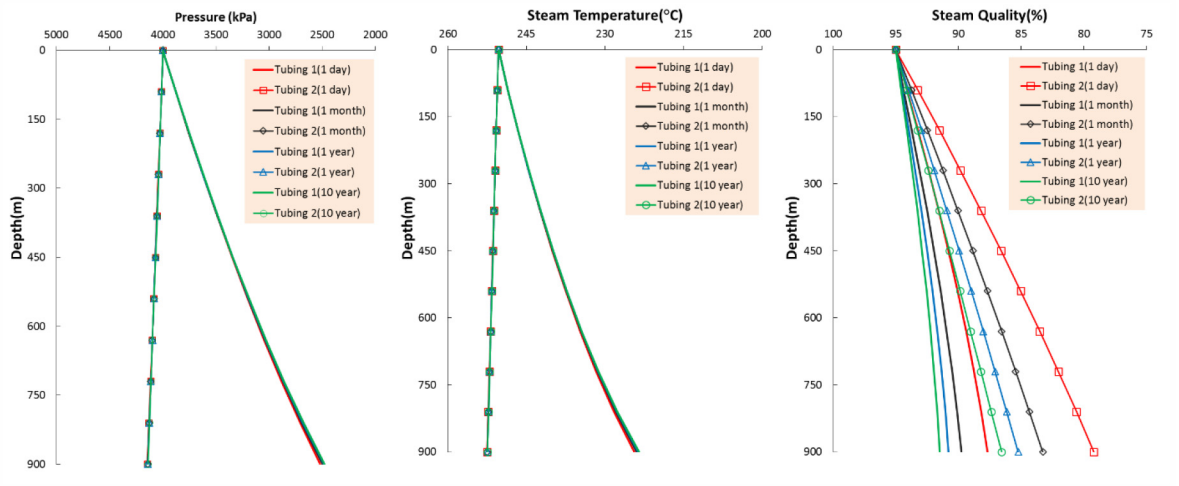

Figure 18—Simulation results of steam injection in a double-tubing wellbore

Tubing 1: 255m3/day, 3346.65 kPa, 240 °C, steam quality 0.99
Tubing 2: 100m3/day, 4000 kPa, 250.3 °C, steam quality 0.99

superheated steam can be observed in tuibing1 from depth 750m to 900m (Fig. 19).

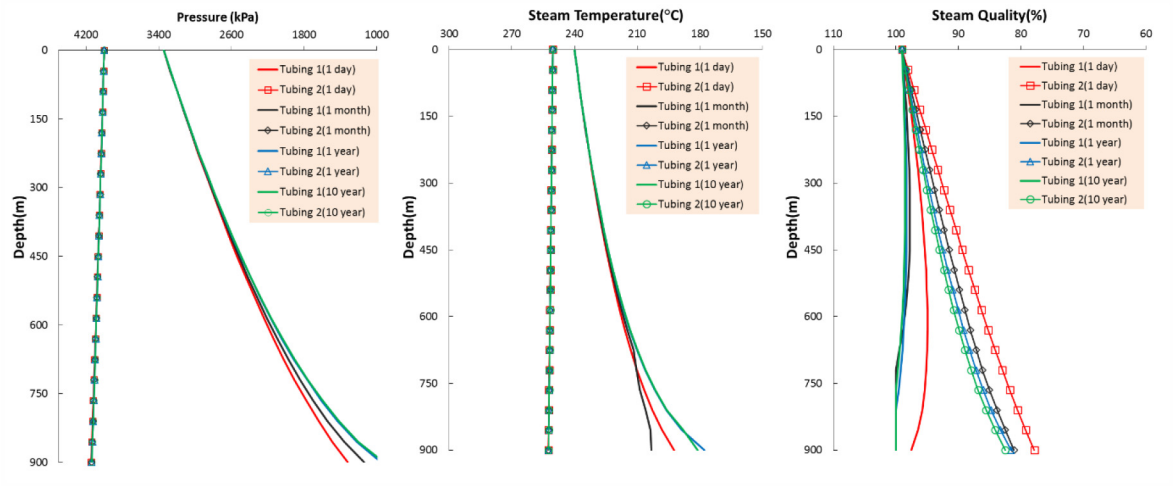

Figure 19—Simulation results of steam injection in a double-tubing wellbore with superheated steam phenomenon

Conclusions

In this paper, we described wellbore modeling including a flow model in tubing or annulus, wellbore heat loss calculation methods and a heat transfer model in surrounding formation. A standalone thermal wellbore simulator has been developed. This wellbore simulator can simulate single-phase injection and production, two-phase steam injection, and two-phase oil and water production. It uses a fully-implicit method to solve the flow equations in tubing or annulus and heat transfer in the surrounding formations.

CFD simulations using FLUENT have been conducted and a semi-numerical method has been proposed for improving heat loss calculation accuracy. The novelty of the semi-numerical method includes extending the 2D formation heat transfer simulation to include the casing wall and cement and adopting new correlations regressed based on FLUENT simulations. A correlation for handling heat transfer in double-tubing annulus was also derived.

A series of validations and tests have been performed for hot water injection, steam injection, and a double-tubing well. The validation work also shows that the improvement of the semi-numerical method for calculating heat loss can be significant.

Nomenclature

A = pipe cross-sectional area for fluid flow, ft^2
C_{pe} = formation heat capacity, Btu/(lbm °F)
d_{in} = pipe inside diameter, ft
f_{tp} = friction factor
g = gravitational acceleration constant, ft/sec^2
h_c = convective heat transfer coefficient of fluid inside annulus, Btu/(hr ft^2 °F)
h_f = convective heat transfer coefficient of fluid, Btu/(hr ft^2 °F)
h_p = enthalpy of phase p, Btu/lbm
h_r = radial heat transfer coefficient of fluid inside annulus, Btu/(hr ft^2 °F)
k_a = air thermal conductivity in the annulus, Btu/(hr ft °F)
k_{cas} = thermal conductivity of casing, Btu/(hr ft °F)
k_{cem} = thermal conductivity of cement, Btu/(hr ft °F)
k_e = thermal conductivity of formation, Btu/(hr ft °F)

k_{ins} = thermal conductivity of insulation, Btu/(hr ft °F)
k_r = formation thermal conductivity along the radial direction, Btu/(hr ft °F)
k_t = thermal conductivity of tubing, Btu/(hr ft °F)
k_z = formation thermal conductivity in the z direction, Btu/(hr ft °F)
m_h = unit thermal source/sink term, Btu/(ft^3 day)
N_u = Nusselt number
N_u' = modified Nusselt number for double-tubing annulus
p^w = wellbore pressure, psi
q = heat flux rate across the annulus, Btu/(hr ft)
Q_{loss} = heat loss rate to the surroundings, Btu/(hr ft)
R_a = Rayleigh number, dimensionless
r_{ci} = inside radius of casing, ft
r_{co} = outside radius of casing, ft
r_{cf} = cement/formation interface radius, ft
r_{ins} = radius of the outside tubing insulation, ft
r_{ti} = inside radius of tubing, ft
r_{to} = outside radius of tubing, ft
t = time, days
T_{ci} = casing internal temperature, °F
T_{co} = outside casing wall temperature, °F
T_{cf} = cement/formation interface temperature, °F
T_e = formation temperature, °F
T_f = fluid temperature inside tubing, °F
T_{to} = tubing external temperature, °F
p^w = wellbore pressure, psi
u_p = internal energy of phase p, Btu/lbm
U_{to} = overall heat transfer coefficient, Btu/(hr ft^2 °F)
V_m = average mixture velocity, ft/sec
V_p = velocity of phase p, ft/sec
V_{sp} = superficial velocity of phase p, ft/sec
V_{sw} = superficial velocity of water, ft/sec
x_{cp} = molar fraction of hydrocarbon component c in phase p
x_{wp} = molar fraction of water component in phase p
z = wellbore depth, ft
α = formation thermal diffusivity, ft^2/hr
α_p = in-situ volume fraction of phase p
δ = annulus aspect ratio ($\delta=r_{to}/r_{ci}$)
θ = local angle between well and the vertical direction, radian
ρ_e = formation density, lbm/ft^3
ρ_m = mixture density, lbm/ft^3
ρ_p = phase density, lbm/ft^3

Subscripts

c = hydrocarbon component (C1, C2,. . .)
p = phase (gas, oil, water)

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