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Numerical model for geothermal energy utilization from double pipe heat exchanger in abandoned oil wells

Zhongyue Lin[1], Kang Liu[1]*, Jing Liu[2], Dandan Geng[3], Kai Ren[4], Zhihong Zheng[5,6]

[1]*China National Administration of Coal Geology, Beijing 100038, P. R. China*
[2]*Schlumberger, Beijing 100015, P. R. China*
[3]*Daqing Oilfield Production Engineering Research Institute, Daqing Oilfield, CNPC, Daqing 163713, P. R. China*
[4]*DaZhou Administration of Emergency Management, Dazhou 635000, P. R. China*
[5]*Strategic Research Center of Oil and Gas Resources, NMR, Beijing 100034, P. R. China*
[6]*Department of Geology and Geography, West Virginia University, Morgantown 26506, USA*

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Abstract:
The number of abandonded wells are increasing in the late period of oilfield development. The utilization of these abandoned oil wells is promising and environment-friendly for geothermal development. In this study, a numerical model for geothermal heating is derived from a double pipe heat exchanger in abandoned oil wells. The main influencing factors of injection rate, injection time, and the types of filler in casing annulus on temperature profiles and outlet temperature have been considered in this model. The influences of injection rate on heat-mining rate are then discussed. Results show that the double pipe heat exchanger can gain higher temperature at the outlet when the casing annulus is filled by liquid other than dry cement under the given parameter combination. The outlet temperature decreases with the increase in injection rate and injection time. The temperature rapidly decreases in the first 40 days during the injection process. The balance between heat mining rate and outlet temperature is important for evaluating a double pipe heat exchanger in abandoned oil wells. This work may provide a useful tool for a field engineer to estimate the temperature of liquid in wellhead and evaluate the heat transfer efficiency for double pipe heat exchanger in abandoned oil wells.

1. Introduction

The number of abandonded wells continuously increases with the progress of oil field development. When an oil well is abondanded, its wellhead is traditionally sealed by a concrete. However exploring the oilfield geothermal energy in abandonded oilfield is becoming a trend. By using the geothermal resources in oilfields, it will be benefit to reduce the operation cost, and additionally to extend the economic life for aging fields (Wang et al., 2016, 2018). The geothermal extraction from abandoned oil wells have been investigated for several years (Erdlac et al., 2007; Bennett et al., 2012; Li and Sun, 2015).

The heat and mass transfer within the wellbore system (double pipe heat exchanger) is commonly used for the geothermal extraction of an abandoned well. During this process, liquid is injected through vertical annulus in wellbore, such as tubing-tubing annulus and tubing-casing annulus to extract heat from the surrounding formation. After the fluid reaches the bottom of the wellbore, the liquid flows upward through the tubing to the wellhead. Due to the temperature difference between the formation and the injected liquid, heat will flow through the wellbore. This heat transfer phenomenon changes the temperature and alter the characteristics of the injected liquid. The general schematic of a double pipe heat exchanger in an abandoned well is shown in Fig. 1. Heat transfer between wellbore and formation was investigated for several years. In early days, Ramey (1962) investigated the heat transfer between formation and wellbore by introducing the analytical solution for unsteady state heat transfer (Van E-

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*Corresponding author.
E-mail address: linyue_1982@163.com (Z. Lin); liukangluck@163.com (K. Liu); liujing0027@163.com (J. Liu); gengdandan@petrochina.com.cn (D. Geng); sdrenkai@foxmail.com (K. Ren); zhengzh@sinooilgas.org.cn (Z. Zheng).

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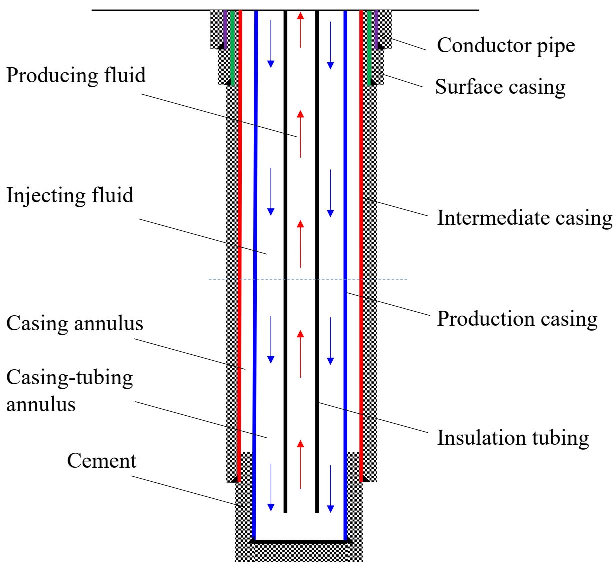


Fig. 1. Schematic of a double pipe heat exchanger in an abandoned well.

verdingen and Hurst, 1949). Eickmeier et al. (1970) utilized the numerical method to derive the temperature distribution in wellbore, considering tubing, casing, and cement circle. Hasan and Kabir introduced a series of semianalytical approximate solutions in wellbore temperature distribution investigation and investigated the influence of temperature on multiphase flow in wellbore (Hasan and Kabir, 1991, 1994a, 1994b; Hasan et al., 1998, 2003, 2005). Cheng et al. (2011) built the heat transfer model in steam injection wells, provided a novel analytical heat conduction time function based on this model considering the wellbore heat capacity, and compared the function with traditional Ramey's approximate and Chiu's empirical simplified solutions. Recently, Galvao et al. (2019) provided a coupled transient wellbore or reservoir temperature analytical model to investigate the temperature distribution for dawndown and build up tests at any gauge locations in wellbore. The liquid is considered a slightly compressible single-phase fluid. Chen et al. (2019) has summarized the typical heat conduction model and additionally calculated complex multi-field coupling process for enhanced geothermal systems.

The temperature profiles for a double pipe heat exchanger is commonly solved by numerical methods. Cui et al. (2017) introduced a new method for geothermal exploitation from hot dry rocks by recycling heat transmission fluid in a horizontal well and performed sensitivity studies to analyze the effects of various parameters on heat mining rate, including the injection rate, horizontal segment length, and thermal conductivity of the tubing. Nian and Cheng (2018) presented a comprehensive model that combined wellbore heat transfer, formation, and building energy transport, considering geothermal production, room temperature, and fluid production temperature. Sui et al. (2019) investigated the existing applications on geothermal energy extraction using abandoned petroleum wells. Subsequently, Sui provided a case study to investigate the influence of working fluids' properties, wellbore architecture, and operational parameters on geothermal energy production. Theoretically, the deep wells are more profitable than shallow wells. However, deep wells have more intermediate casings and casing annulus than shallow wells. The influence of casing-annulus on geothermal extracting process is considered in this model. Recently, Song et al. (2021) provided an integrated multi-objective optimization method to improve the performance of multilateral-well geothermal system, which is useful to improve geothermal production performance in field.

This work generally focuses on the heat transfer process for a double pipe heat exchanger in abandoned oil wells, and provides a numerical model and related solution for this heat transfer process. Based on this model, the influence of casing-annulus on geothermal exacting process is discussed, and additionally the influence of injection rate, injection time, and the types of filler in casing-annulus on temperature profiles and outlet temperature. This work may provide a useful tool for a field engineer to estimate the temperature of liquid in wellhead, and evaluate the heat transfer efficiency for double pipe heat exchanger in abandoned oil wells.

2. Heat transfer model for concentric double-tubing

2.1 Model description

Generally, there are two types of heat exchanger for geothermal resource extracting process. One is double pipe heat exchanger, the other is u-tube heat exchangers. The u-tube heat exchanger is commonly used for extracting heat from shallow subsurface, whereas the double pipe heat exchanger is more popular in abandond wells (Wang et al., 2018). Fig. 1 shows a typical double pipe heat exchanger in an abandonded well. The liquid is injected into the annulus between the casing and the tubing first, and then heated by the surrounding formation through wellbore. After the liquid reaches the bottom of the wellbore, it flows upward within the insulation tubing to the wellhead. The thermal energy within the liquid is utilized by equipment on surface, and then the temperature of working liquid is decreased. Finally, the working liquid is reinjected into the annulus between the casing and the tubing for circulation. Unlike shallow wellbore for u-tube heat exchanger, the depth of abandoned oil wells commonly reaches 2000-3000 m or even deeper. The borehole should be drilled and cemented several times to prevent pollution to the shallow subsurface, avoiding risks in drilling (shrinkage or collapse in borehole), and protecting target formation. Thus, several layers of tubes in a typical oil wellbore, such as the conductor pipe, surface casing, intermeditate casing, and production cansing, were observed (Fig. 1). The intermeditate casing may have more than one layer (taking single intermeditate casing for an example). Usually, conductor pipe and surface casing are cemented to the surface, but deeper strings, such as production casing, are not cemented all the way to the surface. Therefore, one or more casing annuli often exist between casings in abandoned wells. Takeing one casing annulus as an example, like Fig. 1. This annulus space may be filled with liquid, which contains rust inhibitor or cement (cemented to the surface). The filler in annulus influences the efficiency of double pipe heat exchanger. Thus, this factor should be considered in the heat transfer analysis of abandoned oil wells.

The heat transfer process in a double pipe heat exchanger is pretty complicated. The heat transfer among the formation, cement, and wellbore contains sevaral heat transfer form, including steady/unsteady state heat conduction, natural, and forced convention heat transfer. The heat transfer in formation, cement, and steel is a steady/unsteady state heat conduction. The heat transfer in casing annulus is a natural convention (annulus filled with water) or steady/unsteady state heat conduction (annulus filled with cement). The heat transfer in tubing-casing annulus and insulation tubing is forced convention. The overall temperature distribution is in an unsteady state, and the injecting time can influence the heat transfer process. Many other influencing factors, including injecting speed, flowing state, thermal conductivity of liquid, and the characteristic of filler in casing annulus, can influence the heat transfer process. Fig. 2 shows the cross section of double pipe heat exchanger (at the place with blue dashed line in Fig. 1), wherein Figs. 2(a) and 2(b) display the horizontal and vertical cross section. Majority of cross sections in abandoned oil wells are similar to those in like Fig. 2. Conductor pipe and surface casing are much shorter than intermediate and production casings. Thus, the wellbore was simplified as a three-layer tube (Fig. 2).

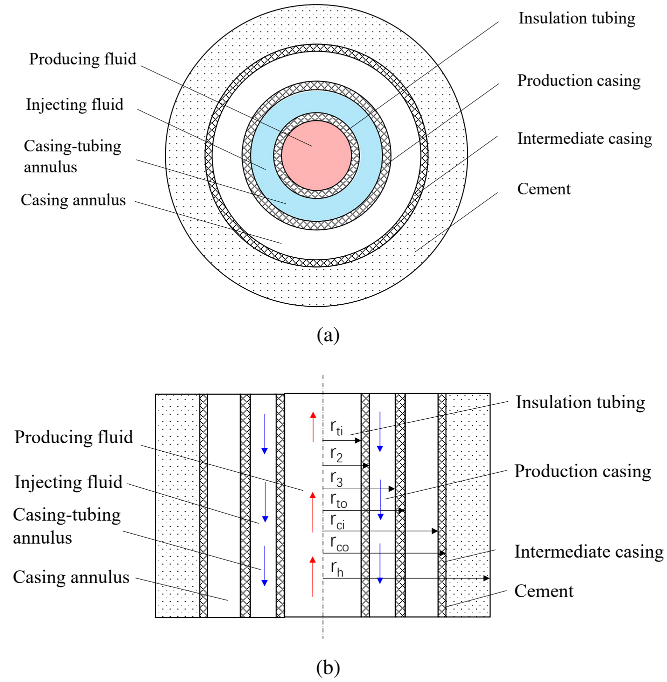


Fig. 2. Cross section of a double pipe heat exchanger.

2.2 General assumptions

Several simplifications are introduced to focus on the heat transfer process in liquid circulation:

1) The injection at the wellhead is in constant flow. Thus, the injecting speed will not change during the liquid circulation.
2) The physical characteristics of liquid along the well path vary. Thus, the wellbore is seperated into several units along the well path. In each unit, the physical characteristic of liquid is regarded as the average property.
3) The heat transfer formation is in an unsteady state.
4) The wellbore is vertical, and the wellbore structure is simplified as a three-layer concentric tube system (Fig. 2).

2.3 Governing equations for the heat transfer out of wellbore

For heat transfer between wellbore and formation, the heat diffusion equation is the basic equation to analysis the heat transfer problem. The heat equations can be described as follows (Carslaw and Jaeger, 1959; Hasan and Kabir, 1991):

$$\frac{1}{r}\frac{\partial}{\partial r}\left(r\frac{\partial T}{\partial r}\right)=\frac{(\rho c)_e}{\lambda_e}\frac{\partial T}{\partial \tau} \quad (\tau>0, r_h<r<\infty) \tag{1}$$

where r is the distance from the center of the tubing, T is the formation temperature, ρ is the mass density, c is the specific heat capacity, λ_e is the effective thermal conductivity, and τ is the injection time. r_h is the outside radius of the wellbore. Commonly, a is introduced as the thermal diffusivity of the formation, $a=\lambda_e/(\rho c)_e$. So Eq. (1) can be simplified as (Cheng et al., 2011):

$$\frac{1}{r}\frac{\partial}{\partial r}\left(r\frac{\partial T}{\partial r}\right)=\frac{1}{a}\frac{\partial T}{\partial \tau} \quad (\tau>0, r_h<r<\infty) \tag{2}$$

The initial boundery and outer boundery of Eq. (2) is the initial formation temperature at specific depth, which can be written as:

$$T=T_{ei}=T_0+nz \quad (r\to\infty \text{ or } \tau=0) \tag{3}$$

where T_{ei} is the initial formation temperature at depth z , T_0 is the temperature at surface, and n is geothermal gradient. The inner boundery can be written as:

$$\frac{d\Phi}{dz}=q_l=-2\pi\lambda\left(r\frac{\partial T}{\partial r}\right)\Big|_{r=r_h} \quad (r\to r_h) \tag{4}$$

where Φ is the general heat loss from side wall of wellbore, q_l is the heat flow between formation and side wall of wellbore perunitlength, and λ is the thermal conductivity. By using Laplace transform, the analytical solution of Eq. (1) can be expressed as:

$$\begin{aligned}T(r,\tau)=&T_{ei}+\frac{q_l}{\pi^2\lambda}\int_0^\infty\frac{1-\exp(-a\tau u/r_h^2)}{u^2}\times\\&\frac{Y_1(u)J_0(ur/r_h)-J_1(u)Y_0(ur/r_h)}{J_1^2(u)+Y_1^2(u)}du\end{aligned} \tag{5}$$

where Y_0, Y_1, J_0, and J_1 are special standard Bessel functions. At the inner boundary, Eq. (5) can be simplified as:

$$\begin{aligned}T_{rh}=&T_{ei}+\frac{q_l}{\pi^2\lambda}\int_0^\infty\frac{1-\exp(-a\tau u/r_h^2)}{u^2}\times\\&\frac{Y_1(u)J_0(u)-J_1(u)Y_0(u)}{J_1^2(u)+Y_1^2(u)}du\end{aligned} \tag{6}$$

Setting dimensionless temperature and time as:

$$T_D = -(T_{rh} - T_{ei}) \times \left(\frac{2\pi\lambda}{q_l}\right), \tau_D = \frac{a\tau}{r_h^2} \tag{7}$$

By combing Eqs. (6) and (7), the analytical solution can be derived. However, the expression of this accurate analytical solution is much too complicated, and it is difficult to use in field. A series of studies provided the simplified numerical solutions, or approximate solution. These solutions have been widely used in the past several decades. Ramey (1962) has provided approximate solution as:

$$T_D = \ln(2\sqrt{\tau_D}) - 0.2886 \tag{8}$$

Hasan and Kabir (1991) has provided their approximate solution as:

$$T_D = \begin{cases} 1.1281\sqrt{\tau_D}(1-0.3\sqrt{\tau_D}) & (\tau_D \le 1.5) \\ (0.4063+0.5\ln\tau_D)\left(1+\dfrac{0.6}{\tau_D}\right) & (\tau_D > 1.5) \end{cases} \tag{9}$$

Chiu and Thakur (1991) has provided their approximate solution as:

$$T_D = 0.982\ln(1+1.81\sqrt{\tau_D}) \tag{10}$$

These approximate solutions greatly simplified the calculation complexity in temperature distribution calculation.

2.4 Governing equations for total energy balance in wellbore

The heat transfer follows energy balance equation. In each unit of wellbore, the heat flowing into the unit is equal to the heat flowing out of the unit. That is:

$$\Phi_{in} = \Phi_{out} \tag{11}$$

where Φ_{in} is the sum of heat flowing into wellbore unit, and Φ_{out} is the sum of heat flowing out of the wellbore unit. If the temperature of wellbore is lower than formation, the heat will flow from formation into wellbore through side wall of wellbore. The sum of heat flowing into wellbore can be expressed as:

$$\begin{aligned}\Phi_{in} =& q_l\Delta z + \pi r_{ti}^2 v_{i\_in}\rho_i c_i T_{fi\_in} \\ &+ \pi\left(r_3^2 - r_2^2\right) v_{a\_in}\rho_a c_a T_{fa\_in}\end{aligned} \tag{12}$$

where Δz is the length of unit. v_{in} is the velocity of liquid flowing into unit (from the top for liquid in tubing-casing annulus and from the bottom for liquid in insulation tubing), which can be determined by injecting flux and cross section. T_f represents the average temperature of liquid. The subscript a and i represent liquid in tubing-casing annulus and insulation tubing, respectively. And the sum of heat flowing out of wellbore can be expressed as:

$$\Phi_{out} = \pi r_{ti}^2 v_{i\_out}\rho_i c_i T_{fi\_out} + \pi\left(r_3^2 - r_2^2\right) v_{a\_out}\rho_a c_a T_{fa\_out} \tag{13}$$

where v_{out} is the velocity of liquid flowing out of unit (from the bottom for liquid in annulus and from the top for liquid in insulation tubing). For liquid in tubing-casing, and the insulation tubing, the energy balance equation can be expressed as:

$$\Phi_{in} = \Phi_{in\_a} + \Phi_{in\_i} + q_l\Delta z = \Phi_{out} = \Phi_{out\_a} + \Phi_{out\_i} \tag{14}$$

where the heat flowing inside of each unit is:

$$\Phi_{in} = \Phi_{in\_a} + \Phi_{in\_i} + q_l\Delta z \tag{15}$$

$$\Phi_{in\_a} = \pi\left(r_3^2 - r_2^2\right) v_{a\_in}\rho_f c_f T_{fa\_in} + q_{l\_i\to a}\Delta z \tag{16}$$

$$\Phi_{in\_i} = \pi r_{ti}^2 v_{i\_in}\rho_f c_f T_{fi\_in} - q_{l\_i\to a}\Delta z \tag{17}$$

and the heat flowing outside of each unit is:

$$\Phi_{out} = \Phi_{out\_a} + \Phi_{out\_i} \tag{18}$$

$$\Phi_{out\_a} = \pi\left(r_3^2 - r_2^2\right) v_{a\_out}\rho_f c_f T_{fa\_out} \tag{19}$$

$$\Phi_{out\_i} = \pi r_{ti}^2 v_{i\_out}\rho_f c_f T_{fi\_out} \tag{20}$$

where $q_{l\_i\to a}$ is the heat transfer from insulation tubing to tubing-casing annulus per length of wellbore.

2.5 Governing equations for the heat transfer in wellbore

Generally, heat transfer in wellbore consists of heat conduction, natural heat convention and forced heat convention. Heat transfer equation can be expressed as:

$$q_l = 2\pi r_{to} U_{to}(T_h - T_{fa}) \tag{21}$$

$$q_{l\_i\to a} - q_l = 2\pi r_{to} U_{i\to a}(T_{fi} - T_{fa}) \tag{22}$$

where T_{fa} and T_{fi} are average temperature of liquid in tubing-casing annulus and insulation tubing in the selected unit in depth, respectively. And $T_{fa} = (T_{fa\_in} + T_{fa\_out})/2$, $T_{fi} = (T_{fi\_in} + T_{fi\_out})/2$. U_{to} is equivalent thermal conductivity from outer tubing to cement based on r_{to}, and $U_{i\to a}$ is equivalent thermal conductivity from fluid in insulation tubing to tubing-casing annulus based on r_{to}. As the thermal resistance in steel is pretty small. So it has been ignored this part in this manuscript. So the thermal resistance for Eqs. (21) and (22) are:

$$U_{to} = \frac{1}{\frac{1}{h_{f\_static}} + \frac{r_{to}}{\lambda_{cem}}\ln\frac{r_h}{r_{co}}} \tag{23}$$

$$U_{i\to a} = \frac{1}{\frac{r_{to}}{r_{ti}h_{f\_i}} + \frac{r_{to}}{r_2 h_{f\_a}}} \tag{24}$$

where h_{f_i} and h_{f_a} are force-convective heat transfer coefficient for liquid in inner tubing and tubing annulus, which can be determined by (Holman, 2009):

$$h_f = \frac{\lambda_f Nu}{d_e} \tag{25}$$

where d_e is characteristic length, λ_f is the thermal conductivity of liquid. Nu is Nusselt number, which can be expressed as (Holman, 2009):

$$Nu = \begin{cases} 4.36 & \text{(laminar flow)} \\ 0.023Re^{0.8}Pr^n & \text{(turbulent flow)} \end{cases} \tag{26}$$

where Pr is Prandtl number, Re is Reynolds number. n = 0.4 for temperature increasing and 0.3 for temperature decreasing. Reynolds number can be expressed as:

$$Re = \frac{\rho D v}{\mu} \tag{27}$$

where v is flowing velocity, μ is viscosity, and D is equivalent diameter.

The h_{f_static} is heat transfer coefficient for natural convection, which can be expressed as:

$$h_{f\_static} = \lambda_{f\_static}\left(r_{to}\ln\frac{r_{ci}}{r_{to}}\right)^{-1} \tag{28}$$

where λ_{f_static} is determined by empirical equation as (Holman, 2009):

$$\lambda_{f\_static} = \begin{cases} \lambda_a & (Ra \le 6000) \\ \left(2+0.5Ra^{1/4}\right)\lambda_a & (6000 < Ra < 10^6) \\ 0.046\lambda_a Ra^{1/3} & (10^6 < Ra \le 10^9) \end{cases} \tag{29}$$

where Ra is Rayleigh number, g is acceleration of gravity, a_v is coefficient of thermal expansion, c_p is specific heat for liquid, η is kinematic viscosity, and λ_a is thermal conductivity.

If the casing annulus is filled with cement, the heat transfer is steady/unsteady heat conduction, not natural convection, thus:

$$\lambda_{f\_static} = \lambda_{cem} \tag{30}$$

Additionally, the pressure drop for inner tubing can be expressed as:

$$\frac{dp}{dL} = \frac{8v\mu}{r_{ti}^2} \tag{31}$$

And the pressure drop for tubing annulus can be expressed as:

$$\frac{dp}{dL} = \frac{12v\mu}{(r_3-r_2)^2} \tag{32}$$

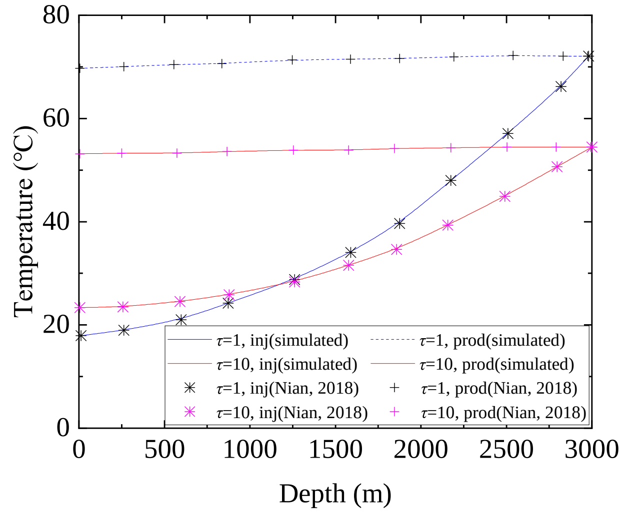


Fig. 4. Model verification by comparing the downhole temperature.

3. Numerical solutions

As explained previously, the wellbore is deperated into several units along with well path. In each unit, the heat transfer process can be calculated and saved. The detailed flow diagram for calculation is shown in Fig. 3. The calculation direction is from the wellhead to the well bottom.

4. Results and discussions

4.1 Model validation

Before the analysis and discussion, the model should be verified by previous studies. Fig. 4 shows the comparison of the solution of the derived model and Nian and Cheng (2018). The parameters of the wellbore and liquid injection process are equal. Result shows that the temperature profile in wellbore derived from our model is in compliance with the data from Nian and Cheng (2018), indicating that our model is reliable. Notice that in studies from Nian and Cheng (2018), the model is a circulating model, which includes two parts: the liquid heating in downhole and the liquid cooling in surface budings. The part for geothermal extraction in the formation is used. Nian and Cheng (2018) has considered a one layer of casing, that is, only one layer of cement sheath outside the production casing. The casing annulus in our model is filled by cement to follow the condition in Nian and Cheng's model.

4.2 Filler in casing annulus

Fig. 1 illustrates a typical oil well with several layers of casings. The casing annulus may be filled by gas, liquid (rust inhibitor), or cement (cemented to the surface) during production. For the geothermal extraction in abandoned wells, the casing annulus can be filled with dry cement or liquid. The thermal conductivity of cement and liquid vary, thereby influencing the temperature profile in the wellbore. Fig. 5 shows the temperature profile of injected liquid in tubing-casing-annulus and flowing back liquid in insulation tubing. Table 1 lists the basic parameters of the injection process.

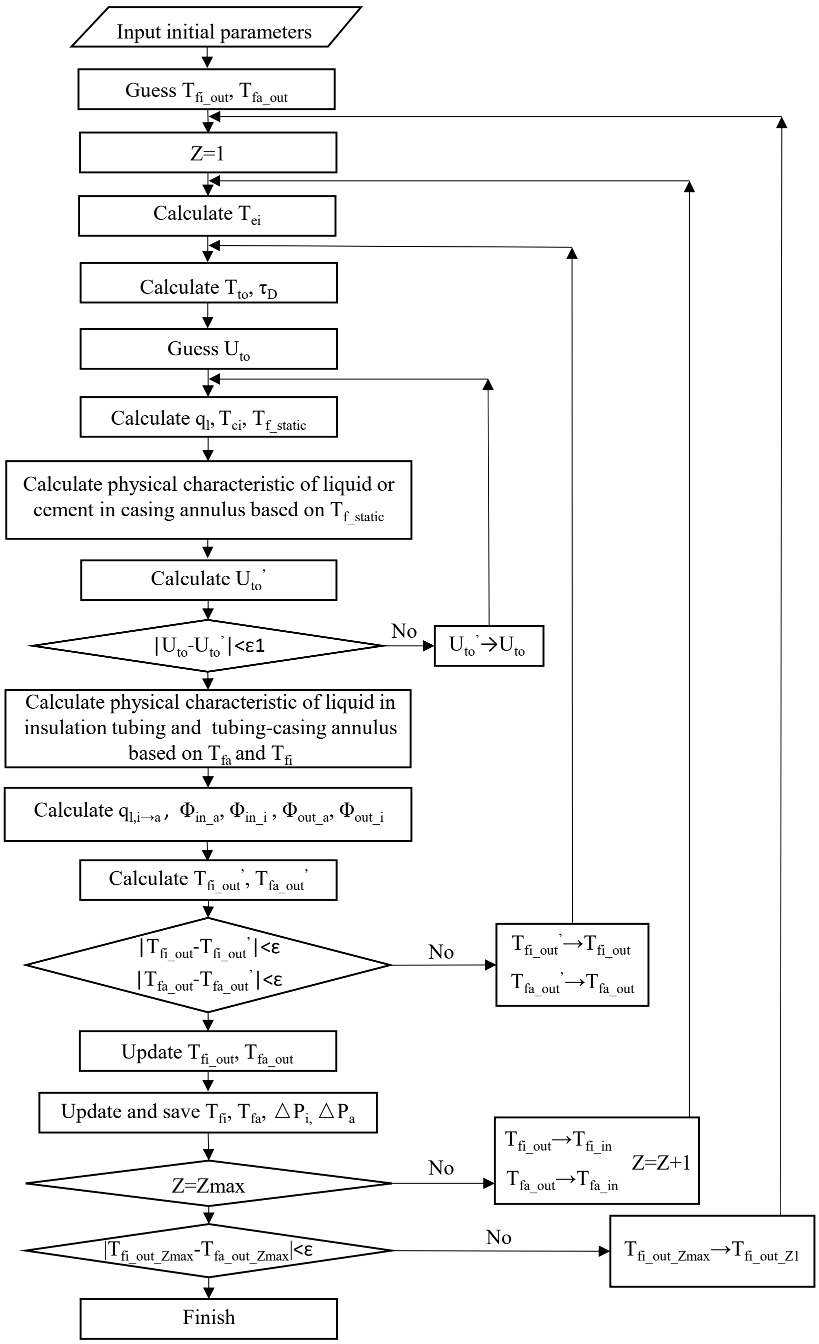


Fig. 3. Numerical solution process for the mathematical model.

Fig. 5 shows that the fluid temperature continuously increases during the injection process because of the geothermal exaction in the formation. The injected liquid follows upward through the insulation tubing after it reaches the bottom of the wellbore during the production process. Due to the heat loss and heat transfer process, the temperature of liquid is decreasing during the flowing-back process. And influenced by the action of the insulation tubing, the temperature drop is slight. Generally, for the whole wellbore, the temperature in insulation tubing is relatively stable. The temperature of injected liquid is set as 10 °C. When the casing annulus is filled with liquid, the temperature of the flowing back liquid at the wellhead will reach 52.4 °C. When the casing annulus is filled with dry cement, the temperature of flowing back liquid at the wellhead is only 44.4 °C. The liquid-filled casing annulus can gain higher temperature than cement-filled annulus at the wellhead, indicating that the annulus is better to be filled by liquid in double pipe heat exchanger with annulus. The equivalent thermal conductivity of liquid is higher than cement, thereby making the heat transfer more efficient in liquid-filled annulus. Under the given parameter combination, the equivalent thermal conductivity of liquid is approximately 0.6-0.7 W/(m·K) (which is changing in different temperature and *Ra*), whereas the thermal conductivity of cement in casing

Table 1. Basic parameters of the injection process.

Samples	Parameters	Values
a (m^2/s)	Diffusion coefficient of the formation	7.83×10^{-7}
c_f (J/(kg·°C))	Specific heat of working fluid	4200
c_a (J/(kg·°C))	Specific heat of casing annulus fluid	4200
dz (m)	Depth step	100
m (°C/m)	Geothermal gradient	0.033
Q_1 (m^3/d)	Injecting flux	200
r_{ti}(m)	Inside radius of the insulation tubing	0.031
r_2 (m)	Outside radius of the insulation tubing	0.04445
r_3 (m)	Inside radius of the production casing	0.06215
r_{to} (m)	Outside radius of the production casing	0.06985
r_{ci} (m)	Inside radius of the intermediate casing	0.11222
r_{co} (m)	Outside radius of the intermediate casing	0.12225
r_h (m)	Radius of cement-formation interface	0.14225
t_s (°C)	Temperature at surface	10
T_{inj1} (°C)	Temperature for working liquid at wellhead	10
Z (m)	Depth of well	2500
λ_e (W/(m·K))	Thermal conductivity of the formation	1.8
λ_{cem} (W/(m·K))	Thermal conductivity of the cement	0.933
λ_{ins} (W/(m·K))	Thermal conductivity of insulation in tubing	0.04
λ_{cem_a} (W/(m·K))	Thermal conductivity of the cement in casing annulus	0.35
ρ_1 (kg/m^3)	Density of working fluid	1000

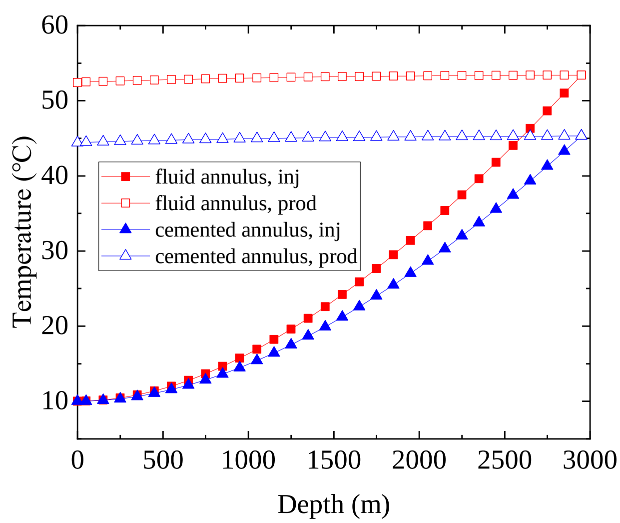


Fig. 5. Influence of filler in casing annulus on wellbore fluid temperature (τ = 1 d, Q_{inj} = 100 m^3/d).

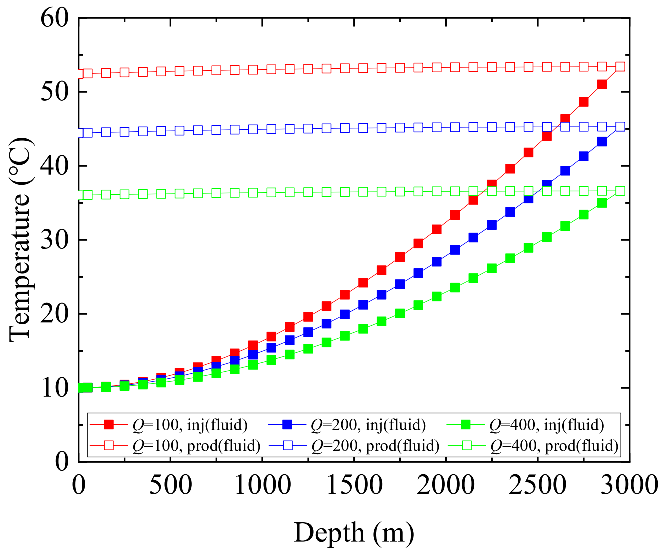
annulus is 0.35, which is smaller than annulus liquid. The cement in casing annulus is different from the cement sheath in the formation (out of outer casing). The cement in the formation contacts to the liquid directly. Thus, the thermal conductivity of the cement is larger, suggesting λ_{cem} = 0.933 according to Nian and Cheng (2018). The cement in casing annulus generally has no contact to the liquid in formation, which is much dryer than the cement in formation. Thus, the thermal conductivity of the cement in casing annulus with λ_{cem_a} is 0.35 based on Holman (2009). The following results are based on the given values listed above. If λ_{cem}, λ_{cem_a} and other parameters have other values, the results may change.

4.3 Injection rates and temperature profiles

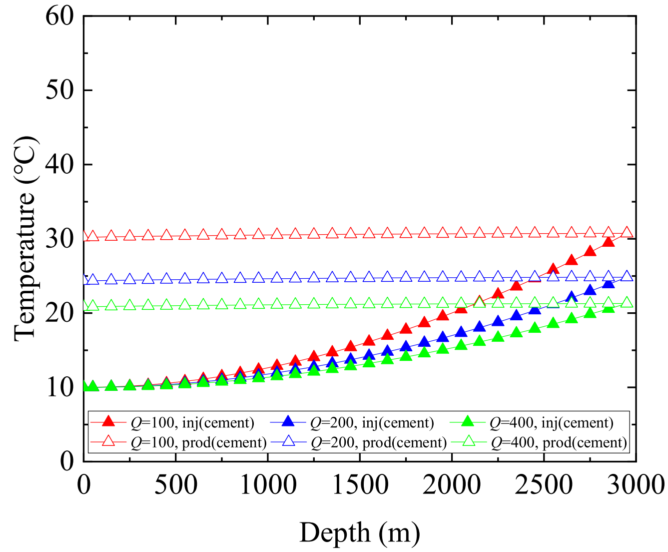
The injection rates influence the downhole temperature profiles. Fig. 6 shows the temperature profiles of liquid- and cement-filled casing annulus with injection rates of 100, 200, and 400 m^3/d. Figs. 6(a) and 6(b) show the occasions with liquid and cement casing annulus, respectively. On both occasions, the temperature of the liquid decreases with the increase in injection rate. The outlet temperature with liquid casing annulus is higher than that of the cement casing annulus. When the injection rate increases from 100 to 400 m^3/d, the outlet temperature decreases from 52.4 to 36.0 °C for the liquid-filled annulus heat exchanger and decreases from 30.2 to 20.8 °C for the cement-filled annulus heat exchanger. The temperature decrease in the insulation tube is quite small on all occasions.

4.4 Injection time and temperature profiles

The injection time also influences the downhole temperature profiles. Fig. 7 shows the temperature profiles for the liquid- and cement-filled casing annulus at injection times of τ = 1, 10, and 100 d. Figs. 7(a) and 7(b) present the liquid and cement casing annulus, respectively. Clearly, the injec-

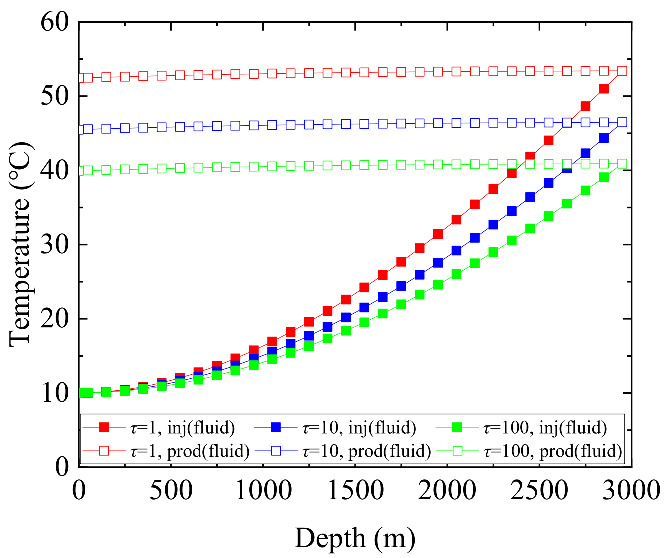


(a) liquid casing annulus

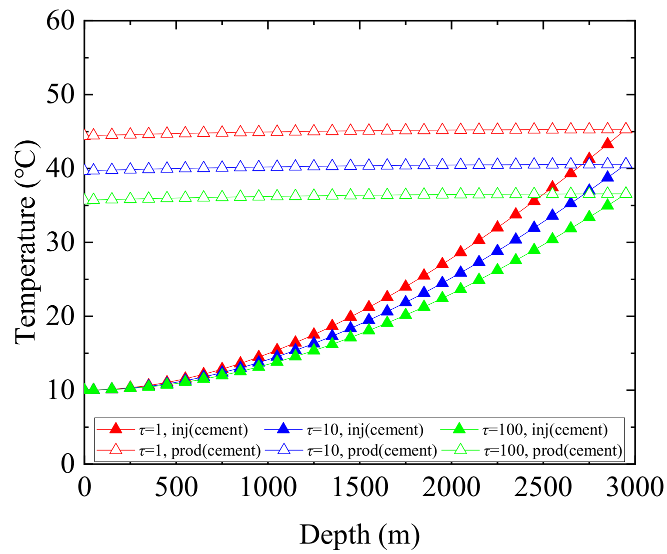


(b) cement casing annulus

Fig. 6. Influence of injection rates on downhole temperature profiles (τ = 1 d).



(a) liquid casing annulus



(b) cement casing annulus

Fig. 7. Influence of injection rates on downhole temperature profiles (Q_{inj} = 100 m^3/d).

tion time increases as the liquid temperature decreases. The decreasing rate of outlet temperature decreases as injection time increases. During the 100 days of injection process, the outlet temperature for fluid-filled annulus decreases from 52.4 to 39.9 °C, which is approximately 23.9% decrease in outlet temperature. Whereas the outlet temperature for cement-filled annulus decreases from 44.7 to 35.7 °C or approximately 20.1% decrease in outlet temperature because the temperature field in the formation is a time-dependent parameter. As the continuous liquid injected into the formation, the heat in the near-wall-region is exacted from the formation, and the temperature in the near-wall-region decreases. Thus, the heat flux between the formation and the wellbore decreases, thereby reducing the outlet temperature.

4.5 Injection rate and outlet temperature

Fig. 8 shows the effect of injection rate on the outlet temperature. The wellhead temperature is calculated under 1, 10, 40, 70, 100, and 150 d. In each time step, the wellhead temperature is calculated under the injection rates of 100, 200, and 400 m^3/d, respectively. The outlet temperature decreases with the increase in injection time and rate. The decrease rate of the outlet temperature decreases with the increase in injection time and rate. Under each injection rate, the outlet temperature decreases rapidly within 40 days and then gradually decrease in the following days. The outlet temperature in the fluid-filled

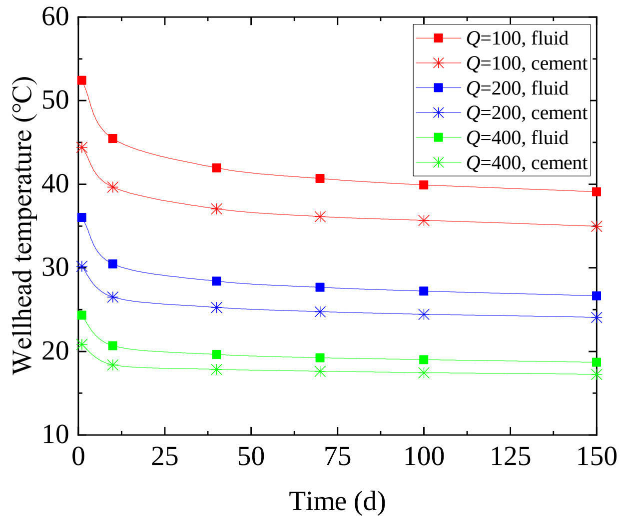


Fig. 8. Outlet temperature under different injection rates with time.

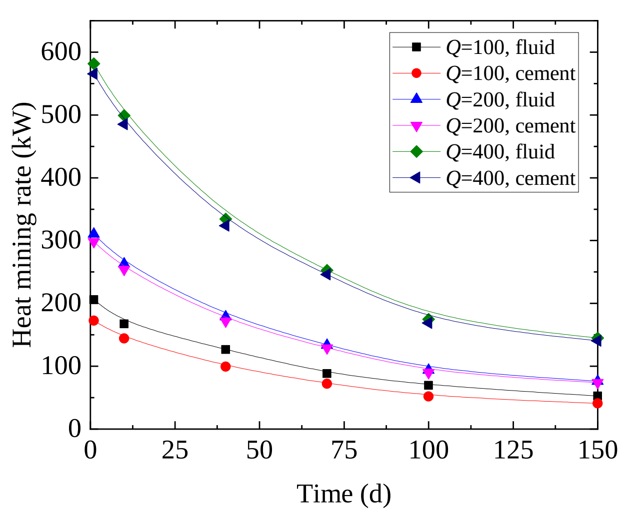


Fig. 9. Influence of injection time on heat flux under different injection rates.

annulus is higher than cement-filled annulus under the same injecting rate.

4.6 Injection rate and heat mining rate

Heat mining rate is an important parameter in evaluating the performance of the double pipe heat exchanger in abandoned oil well, indicating the general energy exacted from formation per unit time. The relationship between heat mining rate and injection time under different injection rate and annulus filler is shown in Fig. 9. Generally, the heat mining rate decreases as the injection time increases. Under the same injection rate, the heating mining rate in fluid-filled annulus well is slightly higher than that in cement-filled annulus well. As the injection rate increases from 100 to 400 m^3/d, the difference of heat mining rate between the two types of annulus decreases gradually. Generally, the heat mining rate in this case is about several hundred kW, which is not highly productive compared with the profitable wells in geothermal industry. The profitable wells are deeper than that in the case study or used as abandoned horizontal well for geothermal extraction.

5. Conclusions

This study focuses on the heat transfer process for a double pipe heat exchanger in abandoned oil wells, and provides a numerical model and related solutions for this heat transfer process. Based on this model, the influences of casing-annulus on geothermal exacting process are discussed, and more influencing factors are discussed, including the influence of injection rate, injection time, and the types of filler in casing-annulus on temperature profiles and outlet temperature.

Results show that the double pipe heat exchanger can gain higher temperature at outlet when the casing-annulus is filled by liquid other than dry cement. The utilization of insulation tubing is meaningful, which can greatly minimize the temperature drop in production process. The outlet temperature decreases with the increase in injection time, especially in the first 40 d. As the injection rate increases, the outlet temperature decreases during the injection process. Finally, increasing the injecting rate is helpful to enhance the heat mining rate, and the outlet temperature should also be considered to make the heat exchanger useful. This work may provide a useful tool for a field engineer to estimate the temperature of liquid in wellhead, and evaluate the heat transfer efficiency for double pipe heat exchanger in abandoned oil wells.

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Conflict of interest

The authors declare that they have no competing financial interests.

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