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A semi-analytical solution to the transient temperature behavior along the vertical wellbore after well shut-in

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ABSTRACT

Temperature measured from a permanent downhole gauge in a well after the well shut-in provides a unique perspective for surveillance and production management. For example, in deepwater environment, production engineer needs to know the temperature of a shut-in well before it is being restarted since different temperature profiles along the wellbore may need very different restarting strategies for flow assurance purpose. A number from the "rule-of-thumb" or running complicated numerical simulation is either not reliable or impractical.

This paper presents a semi-analytical model to estimate the temperature transient behavior after the well shut-in. The temperature at a point along the wellbore, which is useful for production management and flow assurance, is solved and the solution can be easily implemented for calculating temperature history. The temperature profile solution for locations along the wellbore is also presented in the paper. Furthermore, matching the calculated temperature with the measured temperature at the same location will yield the well local heat transmissibility coefficient. The applications of the solution to this model are multiple folders and a deepwater field example is provided to demonstrate some applications and valid the results.

1. Introduction

Understanding transient temperature behavior is critical to managing reservoir production, especially in deepwater environments where the temperature may change significantly from the reservoir to the sea floor. Therefore, an operator needs to manage flow assurance and production chemistry problems continuously, especially during transient production and well shut-in times. For example, depending on the duration of a shut-in, one may need to decide whether to inject hydrate inhibitors for flow assurance purpose. Waxing is another problem related to transient temperature behavior as paraffin deposition would occur when the wellbore temperature is below the wax appearance temperature. Currently, a common practice of estimating transient wellbore temperature from well shut-in is either based on complicated numerical modeling (Izgec et al., 2007), or using a "rule-of-thumb" estimation. Decisions based on the rule-of-thumb estimation can be too conservative or opposite. On the other hand, it is impractical to run a complex transient simulation to make a decision so frequently. This situation requires an engineer to understand the temperature transient behavior along a wellbore and heat transmissibility coefficient of the wellbore, and make an informed decision quickly. A typical deepwater well diagram with heat transfer is shown in Fig. 1. The problem to solve is when the well is shut-in at a Surface Control Subsurface Safety Valve (SCSSV), how the temperature will behave along the wellbore so that the temperature of interest would not fall into the range of flow assurance concerns. Therefore, quickly determining the temperature at a given depth is very critical for production management.

The heat transmissibility coefficient represents the net thermal resistance of the flowing fluids, tubing, casing annulus, casing wall, and cementing to the flow of heat (Willhite, 1967) and it is usually difficult to directly determine it through measurement. Oh et al. (2014) designed a laboratory scaled experiment to measure the steady-state heat transfer and then calculated the heat transmissibility coefficient for subsea buried pipelines. However, as a variety of heat insulation materials are usually used in different forms to prevent heat loss, this makes the determination of heat transmissibility more complex and time consuming (Guo et al., 2006). Additionally, the heat transmissibility coefficient may be time dependent for given materials (Zolotukhin, 1979; Izgec et al., 2007). Furthermore, complex drilling and cementing work make the traditional determination of the well heat transmissibility coefficient uncertain. Additional complexity in

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Nomenclature

Normal

A_{inj} = fluid injection parameter $[L]$ (m)
A = fluid production parameter $[L]$ (m)
b = surface geothermal temperature $[T]$ $(°C)$
c_{pf} = specific heat capacity of phase j, and $j=w, o, r$ for water, oil and rock $[L^2T^{-1}t^{-2}]$ $(J/(°C\ kg))$
E_i = exponential integral function, dimensionless
f = temperature distribution at the moment of well shut-in $[T]$ $(°C)$
f_D = dimensionless temperature distribution at the moment of well shut-in, dimensionless
$f(t_{Dc})$ = dimensionless time function, dimensionless
$G(t_{Dc})$ = modified dimensionless producing time, dimensionless
G_g = geothermal gradient $[TL^{-1}]$ $(°C/m)$
h = depth $[L]$ (m)
Δh = depth difference $[L]$ (m)
h_G = temperature and pressure gauge location $[L]$ (m)
h_{SCSSV} = surface control subsurface safety valve location $[L]$ (m)
h_p = perforation location $[L]$ (m)
$I_0(x)$ = zeroth order modified Bessel function of the first kind
$I_{0e}(x)$ = zeroth order exponentially scaled modified Bessel function of the first kind
K = formation thermal conductivity $[MLt^{-3}T^{-1}]$ $(W/(m\ °C))$
$K_0(x)$ = zeroth order modified Bessel function of the second kind, dimensionless
$\dot{q}$ = heat flux rate $[ML^2t^{-3}]$ (W)
q = steady-state production rate $[L^3t^{-1}]$ (m^3/day)
r = radius $[L]$ (m)
r' = variable of integration $[L]$ (m)
r_w = wellbore radius $[L]$ (m)
r_D = dimensionless radius, dimensionless
r_{ti} = inside tubing radius $[L]$ (m)
r_{to} = outside tubing radius $[L]$ (m)
r_{ci} = inside casing radius $[L]$ (m)
r_{co} = outside casing radius $[L]$ (m)
s = Laplace transform variable, dimensionless
t = time $[t]$ (s)
t_s = shut-in time $[t]$ (s)
t_c = producing time $[t]$ (s)
t_D = dimensionless time, dimensionless
t_{Ds} = dimensionless shut-in time, dimensionless
t_{Dc} = dimensionless producing time, dimensionless
t_D^* = modified dimensionless shut-in time, dimensionless
T = temperature $[T]$ $(°C)$
T_d = temperature at the wellbore $[T]$ $(°C)$
T_f = fluid temperature $[T]$ $(°C)$
T_{fh} = fluid temperature at chemical injection mandrel $[T]$ $(°C)$
T_{fG} = fluid temperature at gauge $[T]$ $(°C)$
T_{fp} = fluid temperature at perforation $[T]$ $(°C)$
T_{fss} = pseudo-steady state producing fluid temperature $[T]$ $(°C)$
T_∞ = geothermal temperature $[T]$ $(°C)$
T_o = initial shut-in fluid temperature $[T]$ $(°C)$
T_D = dimensionless temperature, dimensionless
U_T = overall heat transmissibility coefficient $[Mt^{-3}T^{-1}]$ $(W/(ms^2\ °C))$
Δz = vertical segment thickness $[L]$ (m)

Greek

α = formation thermal diffusivity $[L^2t^{-1}]$ (m^2/s)
β = time related constant, dimensionless
γ = Euler's constant, dimensionless
δ = heat conduction parameter $[t^{-1}]$ $(1/s)$
ρ_f = fluid density $[ML^{-3}]$ (kg/m^3)
τ = dimensionless radial integration factor, dimensionless

the heat transfer models along the wellbore and determinations of heat transmissibility coefficient, such as the temperature and friction for coil tubing operation, have been discussed in literature (Livescu and Wang, 2014; Hasan and Kabir, 2002). This paper presents a practical way to determine the heat transmissibility coefficient using downhole temperature gauge data with a semi-analytical model.

A downhole temperature gauge provides important data for reservoir characterization and well surveillance. Even though temperature is not a driving force for fluid flow, it is still one of the most important factors for fluids properties and mobility (Wu et al., 2014). Duru and Horne (2010) found that the temperature in the reservoir was dependent on the pressure and the flow rate, and matching the measured temperature could be used to obtain fluid and reservoir properties. Shah (2004) proposed an algorithm to determine fluid levels quantitatively for a production well after shut-in using temperature data. Ribeiro and Horne (2013) combined temperature transient analysis with pressure transient analysis to improve the characterization of hydraulic fractured wells and found that temperature analysis has the potential to reduce uncertainty related in fracture length and reservoir permeability. Wu et al. (2014) examined measured downhole temperature variation caused by the Joule–Thomson effect and presented an analytical relationship between the temperature data and production index. This paper demonstrates that the temperature data from the downhole gauge can be used to calculate the temperature profile and determine heat transmissibility coefficient after the well has been shut in.

Much research has been done in the area of determining the temperature along the wellbore for different well statuses. The classic study by Ramey (1962) gave a solution for wellbore temperature prediction for steady-state fluid injection/production problems, which has been widely used in temperature production logging. This solution's accuracy was improved by researchers in the early production period (Hagoort, 2004; Kutasov, 1989). Guo et al. (2006) presented three models for predicting temperature profiles in thermal-insulated flow conduits for different flow regimes, but did not cover the well shut-in situation. Hasan et al. (2005) gave a model for computing the bottom hole temperature for given well head temperature in the wellbore during both drawdown and buildup tests for gas wells, but this model cannot be used to calculate the temperature changes in the matrix. Furthermore, Spindler (2011) found that Hassan's approximate solution is not smooth along the boundary and solved the model explicitly without any approximations. In numerical modeling effort, Chen and Novotny (2003) presented a finite difference model to predict wellbore and formation transient temperature behavior, especially for deviated and multiple temperature gradients wells. Bahonar et al. (2011) developed both isothermal and nonisothermal simulators, which can be used for calculating both heat transfer from tubing to the surrounding medium and heat effects on the pressure-