

Simulation Study on Controlling Mud Coolers to Mitigate Fluid Loss in Drilling Geothermal Wells

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Abstract

The objective of this project is to study how mud coolers impact wellbore instability, especially fluid losses, while drilling geothermal wells. A thorough geomechanics analysis was conducted to study how near wellbore and far field stresses change under geothermal drilling operations. A heat transfer model was developed to estimate temperature profiles inside the drill-pipe and in the annulus while drilling geothermal wells. A computational simulator, which incorporates this heat transfer model along the drill-string and near wellbore stresses, was developed to study lost circulation. This simulator is capable of studying how mud coolers change near wellbore stresses which lead to potential lost circulation. A case study was performed to prove the reliability of the developed simulator. The results obtained from the simulator reveal that if mud coolers are used to maintain the surface circulating temperature of about 185 °F, the fluid temperatures along the drill-pipe while circulating are less than 300 °F which can help downhole sensors to work properly. However, the model also predicts a temperature difference between the bottomhole fluid temperature and the bottomhole reservoir temperature of about 230 °F. This large temperature change causes a very high thermal stress of 3,219-psi and therefore the formation is now completely under tension. Total losses will occur under these drilling operations. The findings from this study recommend that companies should be careful when using mud coolers while drilling geothermal wells. In this case study, the author suggests that companies should explore alternatives on downhole sensors which can withstand higher temperature instead of using mud coolers to drill wells in this area.

Introduction and Literature Review

Drilling geothermal wells is substantially more challenging than drilling conventional oil and gas wells as a result of high temperatures and very hard formation rocks (William et al. 2008). According to Lowry et al. (2017) and Dumas et al. (2013), drilling costs can be as high as 70% of the overall cost to drill a geothermal well. The main reasons for this high drilling cost are non-productive time and low rate of penetration due to drilling problems such as lost circulation and severe wellbore stability issues.

Carson (1982) and Dunn et al. (1987) suggested that lost circulation was the most common issue when drilling and cementing geothermal wells due to their naturally highly-

fractured formations. The second most common issue was the poor bonding between cement and formation rocks. The papers also stated that lost circulation, in most cases, was the root cause of other drilling problems such as sloughing, caving, washout, wellbore collapse, poor cement job, stuck pipe, and overall wellbore integrity problems. In many cases, complications from lost circulation caused geothermal wells to be plugged and abandoned which led to the failure of many geothermal projects. A thorough study of lost circulation in geothermal wells was conducted by Saleh, et al. (2020) and determined that out of 4,500 lost circulation zones, 65% had total losses, meaning that there was no drilling fluid returning to the surface. This study also revealed that cement was a primary material used to treat the total loss and Lost Circulation Material (LCM) was used as the secondary material. The problem when using cement as a treatment method for lost circulation is how it will permanently damage long intervals of formations.

In recent years, many studies have focused on investigating different LCMs to mitigate lost circulation while drilling geothermal wells. Very few papers investigate how geomechanical rock properties and downhole thermal effects cause lost circulation. Alpkiray et al. (2022) presented a work that studies temperature effects on wellbore stability and fluid losses while drilling geothermal wells. This paper will focus on how controlling mud coolers impacts downhole rock stresses and downhole fluid losses while drilling geothermal wells.

Kirsch (1898) was the first one who derived a set of two equations for calculating stresses on the radial and tangential directions around a vertical hole in a cylindrical coordinates. These two equations were applied for a vertical wellbore of a radius R by Zoback (2007) as follows

$$\sigma_{rr} = \frac{1}{2} (\sigma_{Hmax} + \sigma_{Hmin} - 2P_p) \left(1 - \frac{R^2}{r^2}\right) + \frac{1}{2} (\sigma_{Hmax} - \sigma_{Hmin}) \left(1 - \frac{4R^2}{r^2}\right) + \frac{3R^4}{r^4} \cos 2\theta + \Delta P \frac{R^2}{r^2} \quad (1)$$

$$\sigma_{\theta\theta} = \frac{1}{2}(\sigma_{Hmax} + \sigma_{Hmin} - 2P_p) \left(1 + \frac{R^2}{r^2}\right) - \frac{1}{2}(\sigma_{Hmax} - \sigma_{Hmin}) \left(1 + \frac{3R^4}{r^4}\right) \cos 2\theta - \Delta P \frac{R^2}{r^2} - \frac{\alpha_t E \Delta T}{1 - \nu} \quad (2)$$

At the wellbore, $r = R$ then Eqs (1) and (2) becomes

$$\sigma_{rr} = \Delta P \quad (3)$$

$$\sigma_{\theta\theta} = (\sigma_{Hmax} + \sigma_{Hmin}) - 2(\sigma_{Hmax} - \sigma_{Hmin}) \cos 2\theta - \Delta P - 2P_p - \frac{\alpha_t E \Delta T}{1 - \nu} \quad (4)$$

where σ_{rr} , $\sigma_{\theta\theta}$, are the effective radial and tangential stresses.

The tangential stress is also called the hoop stress; σ_{Hmax} and σ_{Hmin} are the two maximum and minimum horizontal stresses; P_p is the pore pressure; R and r are the radius of the wellbore and the radius of a point away from the wellbore; θ is the azimuth of σ_{Hmax} ; and $\Delta P = P_m - P_p$ is the differential pressure between the mud pressure and the pore pressure.

The last term in Eq. (2) is called thermal stress caused by the difference between bottomhole mud temperature and bottomhole formation temperature. α_t ($1/^\circ\text{C}$) is the thermal expansion coefficient; E (Mpa) is the static Young's modulus; and ν is the Poisson's ratio.

$$\sigma_T = \frac{\alpha_t E \Delta T}{1 - \nu} \quad (5)$$

The magnitude of the hoop stress depends on the angle θ . At the angle where the horizontal stress is maximum, the hoop stress is minimum. Under downhole conditions, rocks normally exhibits compression. When $\Delta P = P_m - P_p$ or the thermal stress terms are high enough, rocks can be under tension leading to unexpected partial or total losses. This happens when drilling with equivalent circulating density is higher than the minimum horizontal stress. To reduce the $\Delta P = P_m - P_p$, one must reduce mud weight, control pump rate, build better mud cake, and/or control fluid rheology.

Due to the high geothermal temperature gradient in geothermal wells, downhole circulating mud temperature can be as high as 300 – 400 $^\circ\text{F}$. This high circulating temperature will cause damages on downhole tools and sensors. To avoid this problem, companies use mud coolers at the surface to keep the downhole fluid temperature low when drilling geothermal wells. However, the use of surface mud coolers causes higher downhole temperature differences between the mud and the formation. This causes a sudden rise in the thermal stress described by Eq. (5) causing the hoop stress value to reduce. How to control the surface circulating fluid temperature using mud coolers is not well understood.

Saedi et al., (2018) modified the original model developed by Kabir et al. (1996) to predict temperature profiles inside a tubing/drill-pipe and inside an annulus. The two equations for estimating temperature profile for drill-pipe and for the annulus are presented as follows:

$$T_{dp} = \gamma e^{\xi_1 Z} + \delta e^{\xi_2 Z} + g_G Z - B g_G + T_{es} \quad (6)$$

$$T_{an} = (1 + \xi_1 B) \gamma e^{\xi_1 Z} + (1 + \xi_2 B) \delta e^{\xi_2 Z} + g_G Z + T_{es} \quad (7)$$

where g_G is the geothermal gradient in $^\circ\text{F}/\text{ft}$; Z is for vertical depth in ft; ξ_1, ξ_2 depend on thermal properties; γ, δ depends on the boundary conditions.

According to Saedi et al., (2018), these constants can be calculated as follows:

$$\gamma = \frac{(T_{dpi} + B g_G - T_{es}) \xi_2 e^{\xi_2 Z} + g_G}{\xi_2 e^{\xi_2 Z} - \xi_1 e^{\xi_1 Z}} \quad (8)$$

$$\delta = T_{dpi} + B g_G - T_{es} - \gamma \quad (9)$$

where T_{dpi} is the drillpipe temperature at the

surface. Details of calculating other parameters can be found in the Appendix A.

The main objective of this project is to develop a computational model and a computer software using Python to study lost circulation caused by excessive thermal stress increase when using a mud cooler.

Computational Model and Software Development

Near wellbore losses for vertical wells occur when $\sigma_{rr} = \Delta P = P_m - P_p$ is higher than the hoop stress, $\sigma_{\theta\theta}$. The ΔP depends on the mud pressure and the pore pressure. The Hoop stress depends on the maximum and minimum horizontal stresses, the azimuth angle, the mud and pore pressures, and the thermal stress. For a specific type of rock at a given well depth, these stresses and pore pressures are constants and do not depend on the operating conditions. However, the thermal stress is strongly dependent on operating conditions such as pump rate and surface temperature. The ΔT in the thermal stress term can be estimated using the Saedi et al., (2018) model. Details of the model can be summarized and shown in Fig. 1.

Python coding language, which is an open-source language, was chosen to execute the numerical solution. The software was developed in such a way that it can support the sensitivity analysis automatically. The software uses the surface drill-pipe temperature to perform the drill-pipe temperature calculation described in Fig. 1 for every 100-ft segment until it reaches to the bottom of the well. The software will then calculate the annular temperature for every 100-ft segment in a similar manner as described in Fig. 1. until it reaches to the surface.

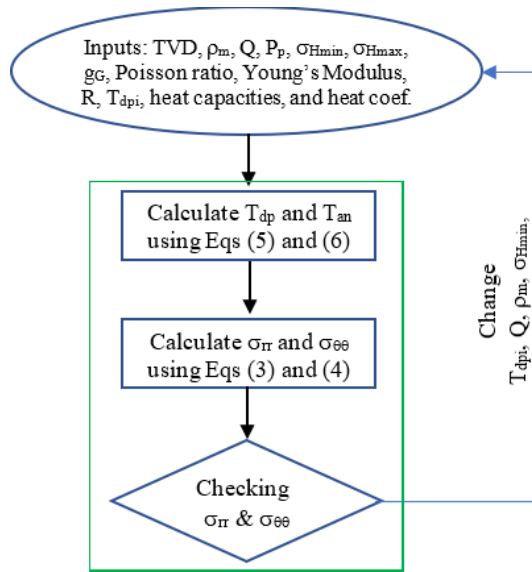


Figure 1: Flow chart of the computational model

Simulation Results

Simulation Inputs

The results of this study are obtained using data from a geothermal field in California, USA. This geothermal field covers a total area of about 11,000 acres and has about 120 wells including producers and injectors. The field was originally designed to produce roughly 20 MWe and enough to supply power for 250,000 homes. The well G in this area was considered in this study. The well penetrated into the hot reservoir at a depth of 10,000-ft. The temperature profile of the well G is shown in Fig. 2. When drilling this well, severe losses occurred from 793-ft to 6,500-ft. LCMs did not work and so 36 cement plugs were pumped to stop the lost circulation. A total of about 1.5 million dollars were spent for lost circulation treatments alone. Detailed inputs of the simulations are presented in Table 1.

Table 1: Inputs for the simulations

Input name	Abbreviation	Value	Unit
True vertical depth	TVD, ft	10,000	ft
Wellbore radius	r_w	6.125	in
Drill-pipe OD	OD_dp	5.5	in
Pore pressure gradient	P_p	0.43	psi/ft
Frac. Pressure gradient	P_f	0.74	psi/ft
Geothermal gradient	g_G	0.04	$^{\circ}\text{F}/\text{ft}$
Mud density	ρ_m	10.5	ppg
Max horizontal stress	σ_{Hmax}	7612.5	psi
Min horizontal stress	σ_{Hmin}	7030	psi
PoissonRatio	ν	0.25	
Young's modulus	E	2,755,000	psi
Thermal expansion coef.	α_t	0.0000085	$1/^{\circ}\text{C}$
Formation thermal Cond.	k_e	1.4	Btu/(hr-ft-F)
Formation spec. heat	C_f	0.2	Btu/(lbm-ft)
Heat capacity of fluid	c_f	0.75	Btu/(lbm-ft)
Surface temperature	T_s	85	$^{\circ}\text{F}$

The testing temperature and pressure of this well is shown in Fig. 2. The current temperature of the reservoir at 10,000-ft is about 485 $^{\circ}\text{F}$.

Simulation Results Without Using Mud Coolers

Using the developed software with the inputs shown in Table 1, the geothermal temperature profile, the drill-pipe temperature profile and the annular temperature profile are shown in Fig. 3.

These results are obtained with a circulation rate of 108-GPM and without mud coolers. In other words, the high surface temperature of about 265 $^{\circ}\text{F}$ is totally due to the heat transfer from the formation to the fluid at the TD of the reservoir. Depending on circulation rates, the bottomhole temperature will vary accordingly. The effect of the bottomhole temperature and the temperature difference between the reservoir temperature and the bottomhole temperature on the circulation rate is shown in Fig. 4.

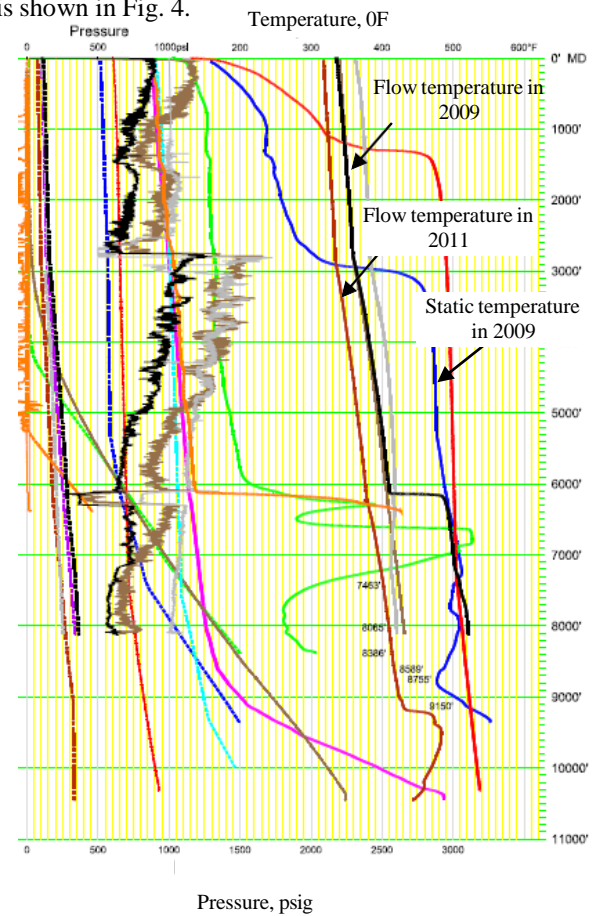


Figure 2: Testing fluid temperatures of the well

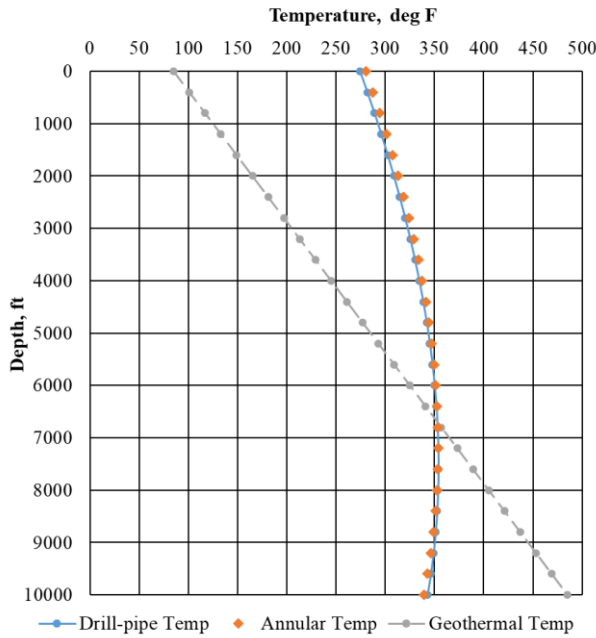


Figure 3: Prediction of geothermal, drill-pipe and annular temperature profiles

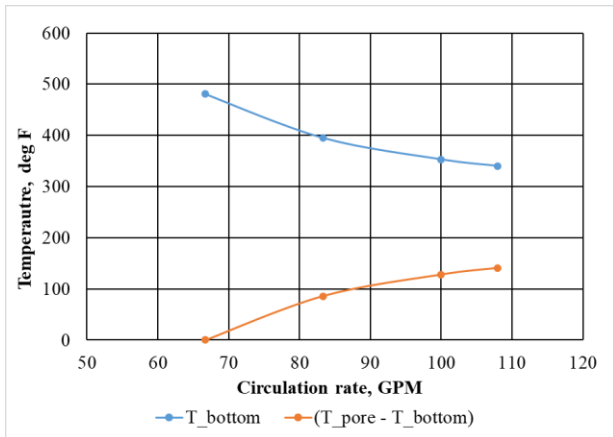


Figure 4: Effect of bottomhole temperature and ΔT on circulation rate

As expected, the results clearly show that, as circulation rate increases, the bottomhole temperature decreases. This leads to the difference between the reservoir temperature and the bottomhole temperature increasing. This is because when circulation rate is higher, the heat exchange occurs in a shorter period of time and hence circulating fluid temperature at the bottom is reducing.

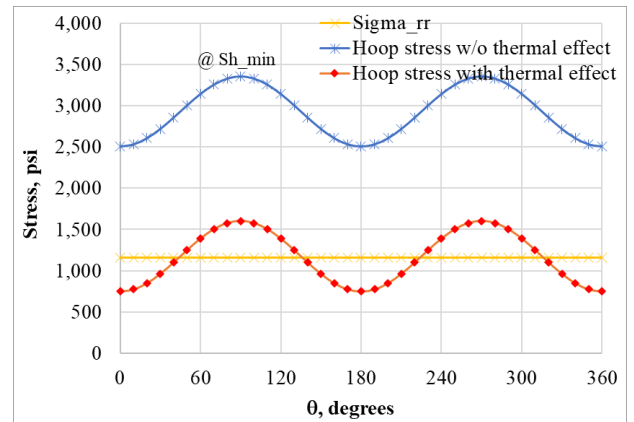


Figure 5: Stresses at the wellbore – Without using mud coolers with and without the effect of thermal stress

The hoop stress with and without the effect of the thermal stress and the effective radial stress obtained from the software are shown in Fig. 5. When θ angle changes from 0 – 360 degrees, the effective radial stress remains unchanged; the hoop stress reaches maximum values at 90 and 270 degrees. At the angles of 90 and 270 degrees, the minimum horizontal stress is present. The case of no thermal stress is considered, which the results show that even with a very high overbalance (effective radial stress, $\sigma_{rr} = P_m - P_p$) of 1,160-psi, the σ_{rr} is still less than the minimum value of the hoop stress of about 2,500-psi. Therefore, lost circulation is not expected to happen. This could be very misleading because in reality, the difference in the reservoir temperature and the circulating bottomhole fluid temperature of about 140 °F will induce a thermal stress calculated using Eq. (5) of about 1,756-psi. This will cause the hoop stress values at the θ angles of 0 and 180 degrees to be about 751-psi which is less than the effective radial stress of 1,160-psi. This was the root cause of lost circulation when drilling this well.

Fig. 6 show the hoop stress at a function of the radius. The radius changes from 1.0 (at the wellbore) to 2.0 (two times larger than the wellbore radius). These hoop stress values are plotted for the the θ angle of either 0 or 180 degrees as shown in Fig. 5. The results also reveal how the thermal stress effects the hoop stress. It is obvious that when thermal stress is considered, the hoop stress at the wellbore is less than the effective radial stress and hence lost circulation will occur. The drilling fluid is invading the formation, losses will get more severe as the reservoir temperature away from the wellbore is higher than that of at the wellbore.

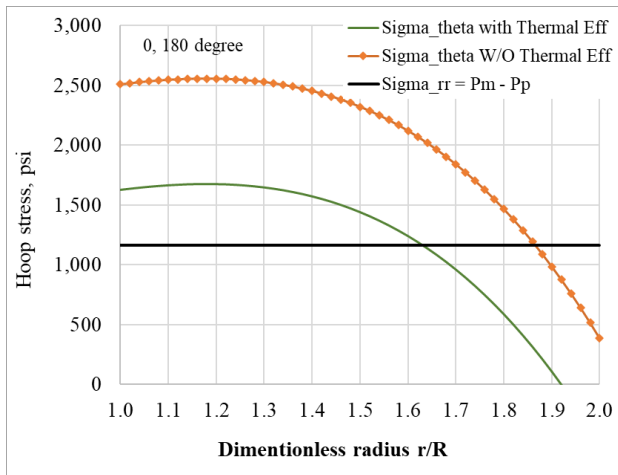


Figure 6: Effects of thermal stress on the hoop stress

Simulation Results with Using Mud Coolers

It is obvious that drilling without using mud coolers might cause some damages on downhole equipment and sensors due to high bottomhole temperature. Most of downhole sensors are not reliable when temperatures are higher than 300 °F (150 °C) (Ginley, 2019). Drilling wells in this considered geothermal area might have downhole temperatures of about 340 °F and surface temperatures of 275 °F and hence there will be a high risk of damaging downhole sensors. Therefore, mud coolers are highly recommended when drilling wells in this area. The key question is, “what surface circulating temperature should be maintained?” If the surface circulating temperature is kept too low, the bottomhole temperature is also low, causing the difference between reservoir temperature and the bottomhole temperature to be too high. This will cause the formation to become more tensile and potentially cause lost circulation.

In this study, we simulate the surface circulating temperature of about 185 °F with a circulating rate of about 160 GPM. Under these operating conditions, the temperature along the wellbore is less than 300 °F as shown in Fig. 7 which guarantees downhole equipment and sensors work properly. The difference between reservoir temperature and downhole temperature, ΔT , in this case is 230 °F. With this high ΔT , the thermal stress is 3,219-psi which causes the formation to become tensile as shown in Fig. 8. If drilling under these conditions, the reservoir will experience downhole hydraulic fracturing and total loss will be observed. Therefore, companies should explore alternatives on downhole sensors which can withstand higher temperature instead of using mud coolers to drill these wells.

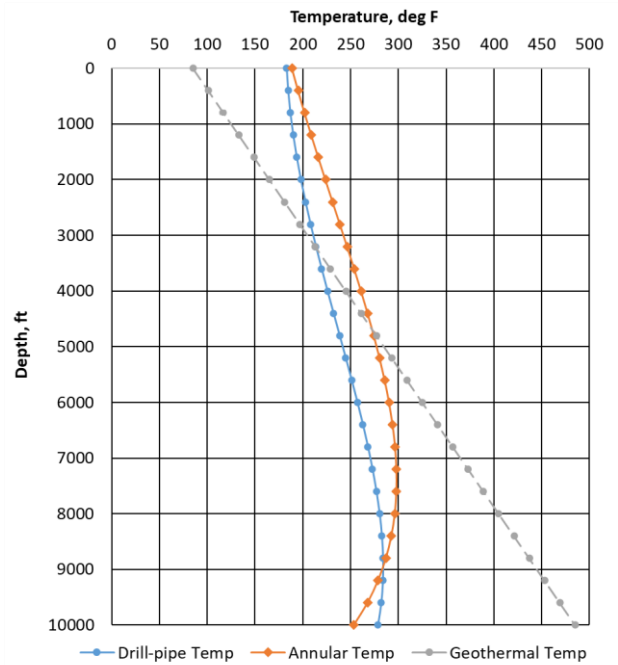


Figure 7: Drill-pipe and annular temperature profiles Using mud coolers – Circulating rate of 160 GPM and surface circulating temperature of 185 °F

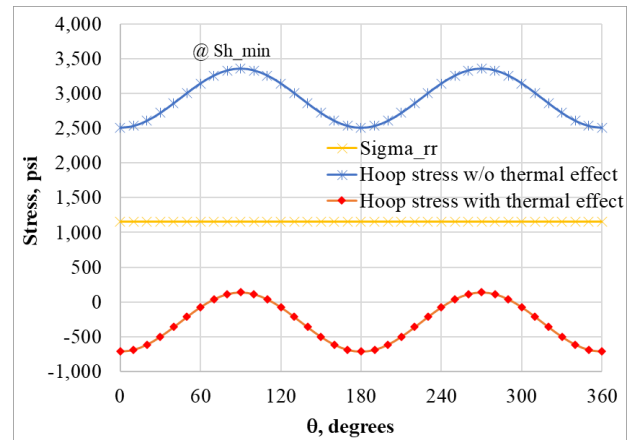


Figure 8: Stresses at the wellbore – With using mud coolers with and without the effect of thermal stress

Concluding Remarks

This study successfully incorporated the geomechanics model and the heat transfer model while drilling geothermal wells into a computational model to predict the circulating bottomhole fluid temperature and potential lost circulation. A software written using Python coding language was developed as a tool to predict the potential fluid losses while drilling. The developed computational model and software can be used to study what surface circulating temperatures should be controlled to prevent damages on downhole tools, and sensors and to mitigate lost circulation. A few case studies were

conducted for wells in a geothermal field in California, USA. The main findings can be summarized as follows:

- The developed computational model and software work properly to estimate drill-pipe and annular temperature profiles along the wellbore. The software also helps to estimate the wellbore hoop stress and the effective radial stress, which are used to determine lost circulation while drilling, with and without thermal stress effect.
- If mud coolers and the thermal stress effect are not considered, the model predicts the minimum wellbore hoop stress of about 2,500-psi which is higher than the effective radial stress of 1,160-psi and hence no lost circulation is expected. However, if mud coolers are not used but the thermal stress effect is considered then the model predicts a minimum wellbore hoop stress of about 751-psi which is less than the effective radial stress. This was the root cause of the lost circulation when this geothermal well was drilled.
- If mud coolers is used to maintain the surface circulating temperature of about 185 °F, the fluid temperatures while circulating are less than 300 °F which can help downhole sensors to work properly. However, the model predicts a temperature difference between the bottomhole fluid temperature and the bottomhole reservoir temperature of about 230 °F. This large differential temperature causes a very high thermal stress of 3,219-psi, calculated using Eq. (5), and therefore the formation is now completely under tension. Total losses will occur under these drilling operations.

Acknowledgments

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Nomenclature

A	= parameter defined by Eq. (A2)
B	= parameter defined by Eq. (A1)
C_{fl}	= heat capacity of fluid, Btu/lbm-°F
C_e	= heat capacity of formation, Btu/lbm-°F
gG	= geothermal gradient, °F/ft
r_w	= wellbore radius, ft
r_t	= radius of drill-pipe, ft
t	= Circulation time, hr
T_{an}	= Circulating annular temperature of fluid, °F
T_{dp}	= Circulating drill-pipe temperature of fluid, °F
t_D	= dimensionless circulation time
T_D	= dimensionless temperature
Te_i	= initial earth temperature, °F
Te_s	= surface temperature, °F
U_b	= Overall heat transfer coeff across annulus
U_a	= Overall heat transfer coeff across drill-pipe
w	= mass flow rate, lb/hr

z	= true well depth, ft
α^*	= heat diffusivity of formation, ft ² /hr
ξ_1	= constant defined by Eq. (A3)
ξ_2	= constant defined by Eq. (A4)
ρ_e	= formation density, lb/ft ³

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Appendix A

To completely calculate the drill-pipe and annular temperature profiles as described in Eq. (6) and Eq. (7), the following equations are needed:

$$B = \frac{wC_{ft}}{2\pi r_t U_t} \quad (A1)$$

$$A = \frac{wC_{ft}}{2\pi} \left[\frac{k_e + r_e U_a T_D}{r_e U_a k_e} \right] \quad (A2)$$

$$\xi = \frac{1 + \sqrt{1 + \frac{4A}{B}}}{2A} \quad (A3)$$

$$\xi = \frac{1 - \sqrt{1 + \frac{4A}{B}}}{2A} \quad (\text{A4})$$

$$T_D = 1.1281\sqrt{T_D}(1 - 0.3\sqrt{T_D}) \quad (\text{A5})$$

$$t_D = \frac{\alpha^* t}{r_w^2} \quad (\text{A6})$$

$$\alpha^* = \frac{k_e}{c_e \rho_e} \quad (\text{A7})$$