Managed Temperature Drilling: Real-Time Damage Monitoring of Insulated Drill Pipes and an Automatic Controller to Mitigate Effects of Subsequent Temperature Increase

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ABSTRACT

Drill pipe insulation is an effective method for downhole temperature management in high-temperature wells. Of late, the most popular pipe insulation method has been the application of a coating of low thermal conductivity to the inner wall of the drill pipe. When the coating is damaged, the insulation is also partially breached, leading to temperature management disruptions and higher downhole temperature.

Detection and prediction of coating damage is thus pivotal to successful downhole temperature management. There is currently no approach for the evaluation and detection of insulation coating damage. In this paper, we first propose a method to estimate drill pipe insulation integrity and then describe an automatic controller to account for the negative effects.

The insulation coating integrity evaluation workflow involves first using an advanced thermo-hydraulics model of the well to perform simulations of the planned drilling operations. From the simulation results, the relation between the bottom hole circulating temperature (BHCT) (and the surface temperature) and the drill pipe's average apparent thermal conductivity is established. We then use this relationship and compare it to the relationship between BHCT and surface temperature during actual drilling operations to determine damage (this is reflected as a change in the apparent thermal conductivity).

Next, to control the well's bottomhole temperature, a feedforward proportional, integral, derivative (PID) controller is used. In this study, the surface inlet temperature and the pump flow rate are used as the control inputs. Data from high-temperature land wells in the US using insulated drill pipes were used for the study. The effect of peeling and thinning of the insulation (the two prominent types of insulation damage) and its negative temperature effects were investigated.

This is the first study that demonstrates an approach to estimate the integrity of the drill pipe coating during actual drilling operation. In addition, a controller is suggested to automatically control /recommend flow rate and inlet temperature changes.

1. Introduction

When drilling geothermal wells, the high downhole temperature is a critical issue that lowers the life of the drilling tools, alters the fluid properties, and increases drilling risks and costs (van Oort et al., 2021). The development of high-temperature tools, drilling fluids, and cements have enabled drilling in extreme downhole conditions, but the increased cost from applying these advanced tools impair the profitability of many geothermal projects.

The fundamental premise behind managed temperature drilling (MTD) is to optimize the drilling plan and operation to maintain the downhole temperature within the working limit of the drilling tools and the drilling fluid. It aims to balance the capability of all components in the drilling system to optimize the drilling cost and performance in extreme downhole temperature conditions. By utilizing MTD, the drillable formation temperature of the drilling system can be expanded beyond the limits of each of the components in the drilling system.

One approach to keeping the downhole temperature within limits is to constrain the temperature increase of the drilling mud pumped into the drill pipe until it reaches the bottom of the hole. The mud traveling through the drill pipe is typically cooler than the mud in the annulus returning to the surface. The steel which is between the mud in the drill pipe (DP) and the annulus has a high thermal conductivity of 45 W/m/K. Under normal circumstances, the thermal energy flows from the annulus to the inside of the drill pipe, heating the mud, and in effect reducing the mud's ability to cool the bottomhole assembly. To suppress the heat transfer across the drill pipe, the drill pipe may be insulated. Among the MTD tools, insulated drill pipes are shown to be particularly effective, especially in deeper wells. Simulations show that drill pipe insulation is very effective for temperature management at depth, while the impact of surface mud cooling on the downhole temperature decreases in deeper wells (Khaled et al., 2023).

Tubing and pipeline insulation have been studied in the past with respect to heavy oil production and transportation (Lombard et al., 2008; Bell et al., 2021). To mobilize the heavy oil, hot steam is injected into the reservoir to heat the oil and thus decrease its viscosity. To keep the steam's high temperature and preserve the thermal energy carried by the steam, the steam is injected through insulated tubings. Once the heavy oil is produced and pumped into the transmission pipeline, pipeline insulation is used to suppress the heat dissipation from the oil to the environment to maintain the temperature and viscosity of the crude oil. In general, two types of insulation technology have been applied in the field, including insulation layers made of low-thermal-conductivity materials (Bell et al., 2021), and vacuum insulation (Singh et al., 2007).

Compared to production tubing and the transmission pipeline, DP works under more dynamic conditions. The alternating torques, the ever-changing axial load and the vibrations along with the impact forces challenge the robustness of the insulation structure. Furthermore, the thickness of the DP is strictly limited to allow more mud to flow through the DP and the annulus.

Between the two most popular DP insulation approaches, vacuum insulation is expensive and prone to damages by downhole impact and vibration, while the low-conductivity coating insulation

has a much lower installation cost and is less sensitive to impact and vibration. These advantages made insulative coating the prevailing DP insulation technology. However these insulations also fail, and there is as yet, no research on the real-time diagnosis and evaluation of the health of the DP insulation coating.

In this paper, we propose a method and procedure to diagnose the health of the insulation coating during drilling and introduce an automatic controller for downhole temperature maintenance in case of insulation failure. In the proposed method, a thermo-hydraulic model of the well is established and the relation between the circulating temperature and the coating health is first acquired. Then, using the measured surface and downhole temperature, the insulation health can be determined, and the remaining lifespan of the coating estimated. A PID controller is developed to maintain the downhole temperature when the insulation coating fails. The proposed procedure and the controller are demonstrated using simulated case studies.

2. Insulation Health Diagnosis

During drilling, the bottomhole circulating temperature (BHCT) and the surface temperature of the returning mud in the annulus are functions of formation properties, wellbore geometry, operational parameters, drillstring geometry, and drillstring properties including the DP apparent thermal conductivity. Assuming other parameters are unchanged, the BHCT and the surface temperature are functions of the DP apparent radial thermal conductivity k_{app}.

To get the relation between the mud circulating temperature and k_{app}, a thermo-hydraulic model of the well is established using the model developed by van Oort et al. (Fallah, 2021; Khaled et al., 2023; Wang et al., 2023). Based on the model, we assume the k_{app} and simulate the downhole temperature until steady state to get the BHCT. The BHCT at different assumed k_{app} is calculated and the BHCT-k_{app} curve is plotted (see Fig. 2). We will show in the case study that k_{app} is in fact a function of BHCT if the DP is sufficiently insulated.

The cross-section of the DP is a circular ring. Since the outer surface of the DP contacts the wellbore and suffers wear and impact, the insulation coating is on the inner surface to maximize the coating's life. Assuming the coating has a uniform thickness, the cross-section of the coating is also a circular ring. The k_{app} of the DP-coating system can be represented by (Bird et al., 2009)

$$k_{app} = \frac{\left(\ln\frac{r_{out}}{r_{in}}\right)_{DP+coating}}{2\pi L} \cdot \frac{1}{\frac{\left(\ln\frac{r_{out}}{r_{in}}\right)_{coating}}{2\pi L k_{coating}} + \frac{\left(\ln\frac{r_{out}}{r_{in}}\right)_{DP}}{2\pi L k_{DP}}} = \frac{\left(\ln\frac{r_{out}}{r_{in}}\right)_{DP+coating}}{\frac{\left(\ln\frac{r_{out}}{r_{in}}\right)_{coating}}{k_{coating}} + \frac{\left(\ln\frac{r_{out}}{r_{in}}\right)_{DP}}{k_{DP}}} \tag{1}$$

where r_{in} and r_{out} are the inner and outer radii of the corresponding layer, L is the unit length, k is the thermal conductivity, subscript $coating$ refers to the coating layer, and subscript DP refers to the steel part of the DP.

There are two typical damage modes for the coating: peeling, where part of the coating peels off the DP while the remaining coating keeps the thickness; thinning is when the coating is worn out uniformly. In this study, we assume that the coating damage is uniform along the drillstring, which means the coating health for each stand of DP is the same.

The DP insulation coating process is in its early stage of development and not all damage modes are properly documented. In this paper, we assume that there can be two damage modes: peeling or (and) thinning.

If peeling is the dominant coating damage mode, k_{app} is a function of the ratio of the remaining coating, α, and the thermal conductivity of the steel and the coating.

$$k_{app} = \alpha k_{steel} + (1 - \alpha)k_{perfect} \tag{2}$$

$$\alpha = \frac{k_{app} - k_{perfect}}{k_{steel} - k_{perfect}} \tag{3}$$

where $k_{perfect}$ is the apparent radial thermal conductivity when there is no coating damage, and k_{steel} is the thermal conductivity of steel/non-coated DP.

If thinning is the dominant coating damage mode, we can derive the relation between the remaining ratio of coating thickness, β.

Assuming the initial thickness of the coating is $t_{coating}$, the inner radius of the coating is

$$(r_{in})_{coating} = (r_{in})_{DP} - \beta t_{coating} \tag{4}$$

Substituting Eq. (4) into Eq. (1) and expanding the log terms, we get

$$k_{app} = \frac{\ln r_{out,DP} - \ln(r_{in,DP} - \beta t_{coating})}{\frac{\ln r_{in,DP} - \ln(r_{in,DP} - \beta t_{coating})}{k_{coating}} + \frac{\left(\ln \frac{r_{out}}{r_{in}}\right)_{DP}}{k_{DP}}} \tag{5}$$

Eq. (5) can be rearranged to obtain the below.

$$\left(\frac{k_{app}}{k_{coating}} - 1\right) \cdot \ln(r_{in,DP} - \beta t_{coating}) = \frac{k_{app}}{k_{coating}} \ln r_{in,DP} + \frac{k_{app}}{k_{DP}} \left(\ln \frac{r_{out}}{r_{in}}\right)_{DP} - \ln r_{out,DP} \tag{6}$$

$$\beta = \frac{1}{t_{coating}} \left(r_{in,DP} - \exp\left[\frac{1}{\frac{k_{app}}{k_{coating}} - 1} \cdot \left(\left(\frac{k_{app}}{k_{coating}} - \frac{k_{app}}{k_{DP}} \right) \ln r_{in,DP} + \left(\frac{k_{app}}{k_{DP}} - 1 \right) \ln r_{out,DP} \right) \right] \right) \tag{7}$$

In practice, the k_{app} of the DP-coating system can be plotted against the BHCT. The k_{app} can then be easily looked up from the curve using the measured BHCT. Eq. (3) and Eq. (7) can also be plotted for easy reference.

In summary, the apparent thermal conductivity k_{app} is first calculated via simulation. If the dominant coating damage mode is peeling, the remaining coating area ratio α can be calculated using Eq. (3); if the dominant coating damage mode is thinning, the remaining coating thickness ratio can be calculated using Eq. (7). By monitoring and extrapolating how α and β decrease during drilling, the remaining lifespan of the insulation coating may be estimated.

3. Case Study

For the case study we use a representative L-shape horizontal well in the Haynesville basin. The well trajectory is shown in Fig. 1. The well has a true vertical depth (TVD) of 12,000 ft and the formation temperature at that depth is 385ºF. A coating is painted on the inner surface of the 4.5" DP for insulation purpose.
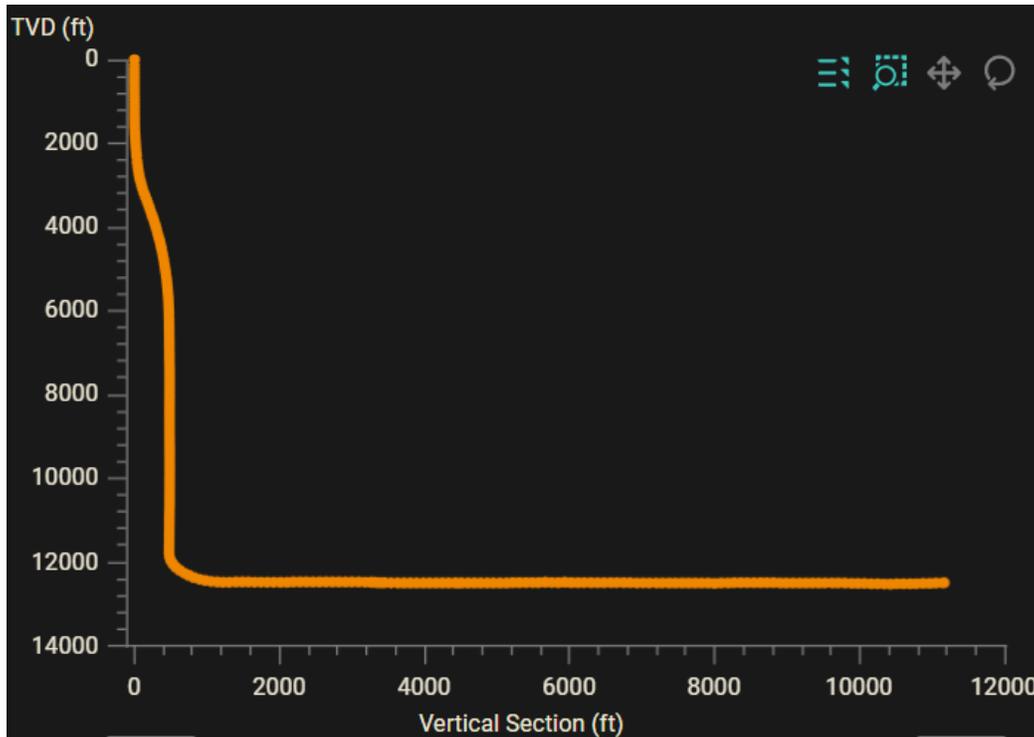

Figure 1: Case study well trajectory.

The well is modeled using the advanced hydraulics software developed by van Oort et al. (Fallah, 2021; Khaled et al., 2023; Wang et al., 2023). The DP is modeled as a uniform material of k_{app} which is calculated using Eq. 1.

Even with the mud cooler and the insulated DP, the downhole temperature became challenging for the downhole tools even before reaching the designed total depth. At measured depth (MD) 19,000 ft, which is in the middle of the lateral section, the BCHT for different k_{app} is modeled and simulated. The BHCT and mud temperature at the outlet are plotted in Fig. 2. According to Fig. 2, BHCT can be significantly decreased by as much as 100º F if k_{app} is sufficiently low. When the normalized k_{app} increases to about 30%, the BHCT is almost as high as that of using a non-insulated DP. In a field application, the BHCT can be measured and k_{app} can then be looked up using Fig. 2.
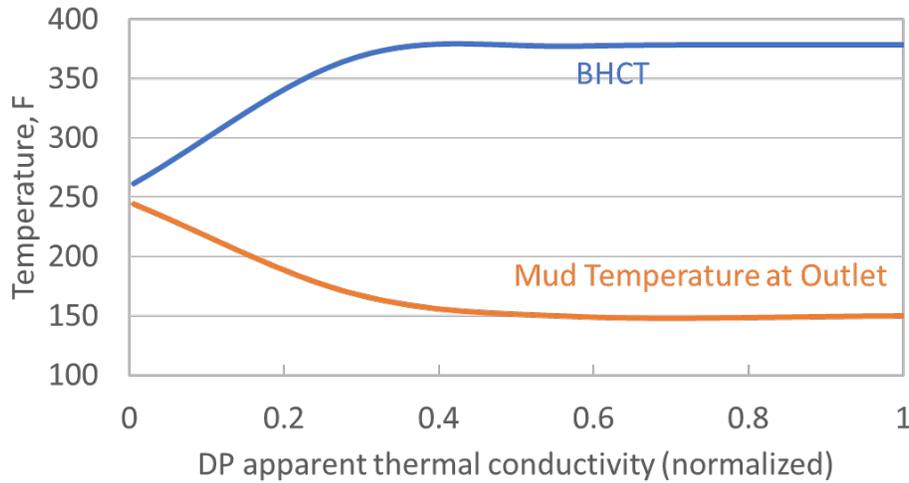
Figure 2: Relation between the mud temperature and the DP apparent thermal conductivity, k_{app}.

Fig. 3 shows the k_{app}-α curve calculated from Eq. 3. The k_{app} increases linearly as α drops. To achieve a normalized k_{app} of above 30%, the remaining coating area ratio required is $\alpha > 70\%$. Assuming peeling is the dominant damage mode of this DP, if the measured BHCT is 300 F, we look up Fig. 2 to get $k_{app} = 0.1$, and look up Fig. 3 to get $\alpha = 0.9$. By calculating α at different MD, the speed of coating damage can be calculated, and the remaining lifespan of the coating can be estimated.
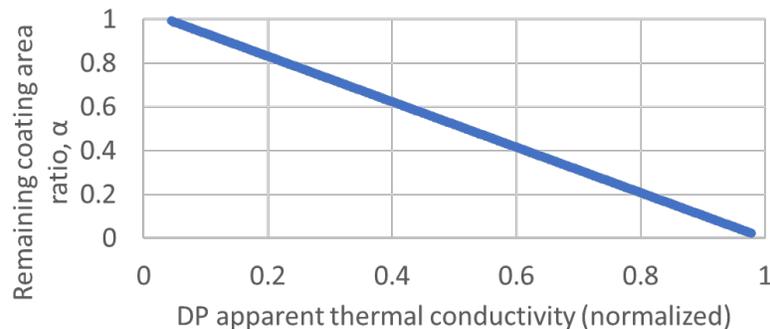

Figure 3: Relation between the remaining coating area ratio, α, and the DP apparent thermal conductivity, k_{app}.

Fig. 4 shows the k_{app}-β curve calculated using Eq. 6. Here, k_{app} grows nonlinearly as β drops. To achieve a normalized k_{app} of above 30%, the required remaining coating thickness ratio is 18% ($\beta > 18\%$). Assuming thinning is the dominant damage mode of this DP, if the measured BHCT is 300 F, we look up Fig. 2 to get $k_{app} = 0.1$, and then look up Fig. 4 to get $\beta = 0.7$. Here again, by calculating β at different MD, the speed of coating damage can be calculated, and the remaining lifespan of the coating can be estimated.
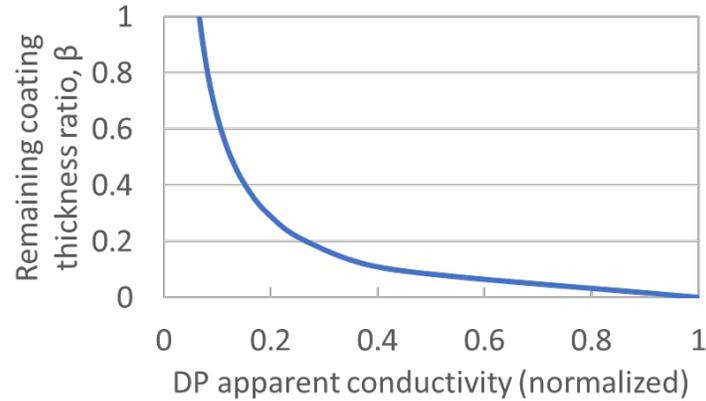
Figure 4: Relation between the remaining coating thickness ratio, β, and the DP apparent thermal conductivity, k_{app}.

The above method enables online diagnosis of the DP insulation coating without pull-out-of-hole. Based on the calculated coating damage speed and remaining coating lifespan, the driller can better plan the maintenance of the DP and decide when to switch to a new set of DPs. Figures 2-4 are based on the specific well data but can be used as a reference for general wells.

4. Automated Downhole Temperature Control System

If the insulation coating is damaged, the mud flowing through the DP receives excessive heat and may not sufficiently cool the bottom hole regions of the well. The BHCT is then increased and may lead to BHA components' accelerated aging or even sudden failure.

To mitigate the impact of the coating damage and maintain the BHCT, a feedforward PID controller is developed, as shown in Fig. 5. The controller controls the pump and the mud cooler. When the BHCT exceeds BHCT_{max}, the difference between BHCT_{max} and BCHT is calculated and fed into the PID controller to get the control signal u_{PID}. At the same time, a feedforward block calculates the feedforward control signal u_{ff}. The total control signal u_{tot} is a weighed sum of u_{PID} and u_{ff}. The plant can be either the pump or the mud cooler. A higher pump rate and a lower inlet mud temperature will, in most cases, restore the BHCT to within the limit of the downhole tools.
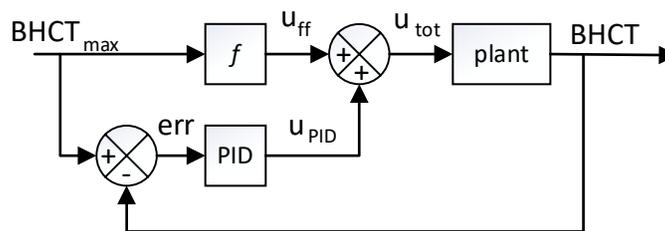

Figure 5: Feedforward PID controller.

This controller is demonstrated via a simulation based on the Utah FORGE dataset. The Utah FORGE 16A78-32 well at 5,900 ft is simulated using the model developed by van Oort et al. (Fallah, 2021; Khaled et al., 2023; Wang et al., 2023). The parameters of the well are listed in Tables 1-3. The insulation coating is assumed to be 0.02 inch thick with a thermal conductivity of 0.116 BTU/(h.ft.°F)

Table 1. Drilling fluid properties for Utah FORGE 16A78-32 well

Drilling Fluid Properties	
Fluid density (ppg)	8.9
Fluid plastic viscosity (lbf.s/100ft^2)	41771
Specific heat capacity (BTU/(lb.°F))	0.896
Thermal conductivity ((BTU.in)/(hr.ft^2.°F))	5.200

Table 2. Formation geothermal properties for Utah FORGE 16A78-32 well

Formation Geothermal Properties	
Formation surface temperature (°F)	67.85
Formation temperature gradient (°F/ft)	0.041
Rock density (ppg)	23.367
Formation specific heat capacity (BTU/(lb.°F))	0.222
Formation thermal conductivity ((BTU.in)/(hr.ft^2.°F)	16.016

Table 3. Wellbore configuration for Utah FORGE 16A78-32 well

Wellbore Configuration	
Wellbore depth (ft)	5900
Wellbore inclination (deg)	0

At the beginning of the simulation, the temperature in the well is at static equilibrium with the formation temperature. The pump is then turned on for 500 min to reach a steady state. Then, the DP apparent thermal conductivity k_{app} is increased from 4.585 BTU/(h.ft.°F) to 26.017 BTU/(h.ft.°F). The increase in k_{app} immediately increases the BHCT from 264°F to 290°F. The controller is then activated and the results for using the pump, and the mud cooler independently are shown in Figs. 6 and 7.

Fig. 6 shows the performance of the controller when only the pump rate, Q is changed. As the BHCT increases above the preset goal, the controller increases the mud pump rate from 400 gpm to 550 gpm. As a result, the BHCT decreases to below the preset limit of 290°F within a few minutes.

Fig. 7 shows the performance of the controller when controlling only the mud inlet temperature, T_{in}. As the BHCT increases above the preset goal, the controller forces the mud cooler to decrease the mud inlet temperature from 120°F to about 90°F.
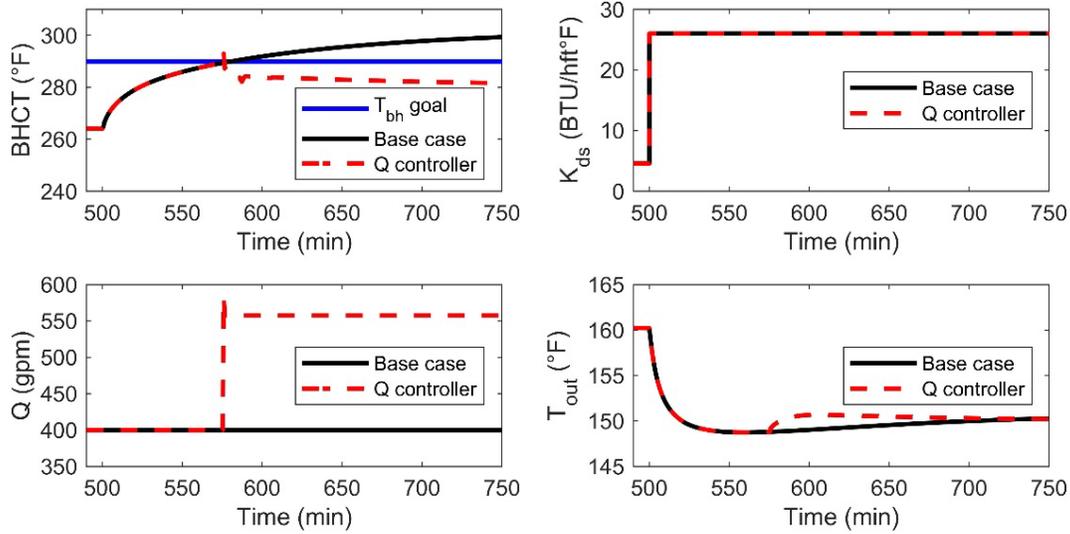
Figure 6: Performance of the controller when coating is damaged using only the pump.
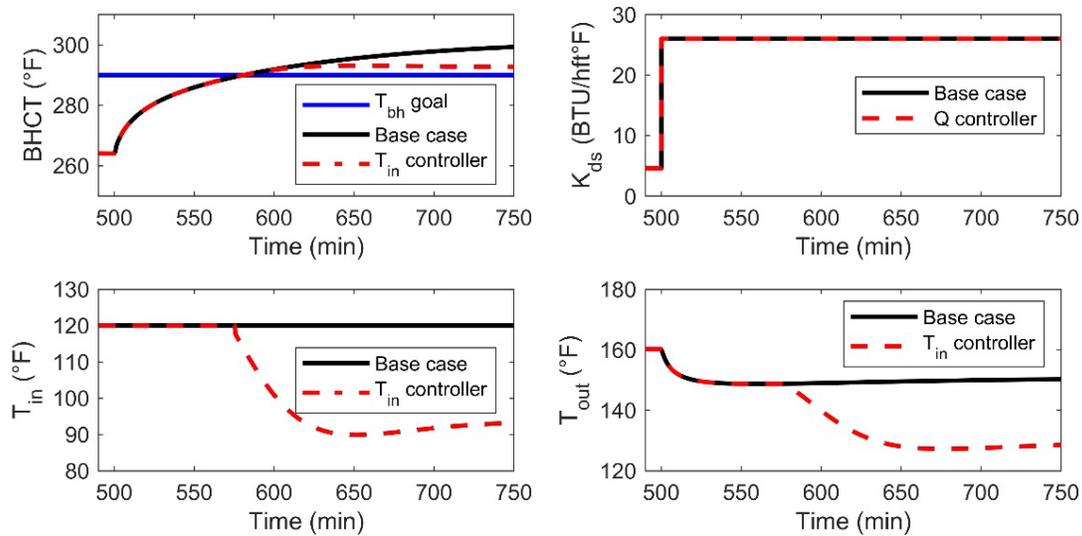

Figure 7: Performance of the controller when coating is damaged using only the mud cooler.

5. Conclusion

In this paper, we proposed a method and procedure to diagnose the insulation coating of insulated DP in real-time. To maintain the downhole temperature even when the coating is damaged, we developed a PID controller that uses the mud pump and the mud cooler to manage the downhole temperature.

(1) We used a validated thermo-hydraulic model to study the impact of apparent DP thermal conductivity on surface and downhole temperature.

(2) Assuming uniform coating damage along the drillstring, the relationship between apparent DP thermal conductivity and coating damage is derived.

(3) We proposed a method and procedure for online diagnosis of the health of DP insulation coating and showcased the method in a case study. If the dominant damage mode of the coating is peeling, the remaining coating area ratio can be determined. If the dominant damage mode of the coating is thinning, the remaining coating thickness ratio can be determined. The speed of coating damage can be calculated, and the remaining lifespan of the insulation coating can be estimated.

(4) A PID controller is developed to mitigate the impact on BHCT from sudden coating damage. The controller controls the mud pump and the mud cooler. The controller is demonstrated using a validated thermo-hydraulic model on the Utah FORGE dataset.

Glossary

k_{app}	-apparent thermal conductivity
$k_{coating}$	-insulation coating thermal conductivity
k_{steel}	-steel thermal conductivity
$k_{perfect}$	-apparent DP-coating system thermal conductivity when there is no coating damage
r_{out}	-outer radius
r_{in}	-inner radius
$t_{coating}$	-coating thickness
α	-ratio of the remaining coating if the dominant damage mode is peeling
β	-ratio of the remaining coating thickness if the dominant damage mode is thinning

Acknowledgement

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