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Simulating Cement Plug Temperature During Pull-out-of-hole

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ABSTRACT

Predicting wellbore and cement slurry temperatures is a basic demand for plug cementing job design. The calculations required are advanced. To meet the P&A industrial need, a numerical model suitable for well temperature prediction during mud displacement and pull out of the hole has been developed to meet the P&A industrial need. The model considers transient heat transfer between wellbore fluids, the work string, and the formation for all well depths during and after the job. This model is an upgrade from existing 2D models for wellbore temperature simulation with a stationary pipe string, often fixed at the well's total depth (TD).

This paper first explains the model in mathematical and numerical principles. Then the paper presents a series of case studies to investigate the influences of different parameters on the cement temperature. Those influencing factors include pipe diameter, fluid viscosity, well inclination, pulling velocity, and two types of operations (balanced plug and "pump and pull").

INTRODUCTION

Cement slurry temperature during cementing is one of the most concerning factors for the success of cement jobs. The downhole temperature, including wellbore wall and fluid temperature, is affected by many factors, such as wellbore geometry and structure, formation property, fluid property, pump rate, inlet temperature, and so forth. Temperature variation during a job (primary or plug job) must be predicted and used for slurry design.

Predicting the temperature of a wellbore with flows is challenging and requires advanced modeling. Numerical models were developed for mud circulating (drilling) and primary cement jobs decades ago (Raymond, 1969, Keller et al., 1973, Sump et al., 1973). Guillot et al. (1993) proposed a numerical simulator for calculating cementing temperature, which had been applied in cementing software. In modern days, computational fluid dynamics techniques are also used to simulate heat transfer problems in highly complex geometric and flow conditions. However, they are not well suited to industrial applications in well-cementing engineering. A comparison of cementing temperature simulations using the CFD technique and industry models can be found in Wang and Dai (2019).

The effects of various factors on the wellbore circulating temperature were discussed via a series of simulations in recent work by Liu (2021). It was pointed out that circulating with a thin fluid would cause a higher BHCT than a thicker fluid, and the influence of viscosity becomes less significant when viscosity is very high. On the other hand, although a large flow rate will generally lower BHCT if using a thick fluid, an increased flow rate helps to enhance convective heat exchange (thus increases wellbore temperature) for the first few bottom-ups because of the smaller Nusselt number. In addition, circulating within small pipes will result in lower BHCT compared to large pipes. These conclusions are made for circulating in a stationary pipe string; conclusions would be less straightforward if a complex well structure, multiple fluids, or moving pipe were considered.

While computer modeling of temperature for primary cementing scenario becomes an industry standard, where the casing string is stationary, application of those models on plug cementing, especially on the pull-out-of-hole process, is very limited. Modeling that process requires additional consideration of axial pipe movement, which influences the heat exchange between fluids, working string (casing, drill pipe, or coil tubing), and the formation. To address that effect, using a numerical model is the interest of the present paper. In this paper, we explain our model's mathematical method and numerical principles, then present case studies to investigate the influences of different parameters on cement temperature. Those influencing factors include pipe diameter, fluid viscosity, well inclination, and pulling velocity. We also compare results for two different plug cementing techniques: balanced plug and "pump and pull."

MODEL

The present model is developed from an existing 2D numerical model, which has been incorporated into several industrial programs serving various cementing and drilling engineering applications in the industry for roughly two decades. The original model considers fluid flow and heat transfer in the wellbore and the ambient formation but does not consider axial movement due to trip-in and trip-out of pipes. This model is discussed by Wang and Dai (2019) and Liu (2021). In the new model, an additional capability was developed to simulate the temperature change during the pull out of the hole (POOH) with or without pumping. This allows for the continuous simulation of entire plug jobs, from mud displacement to POOH, for wellbore temperature prediction.

The model assumes an axisymmetric wellbore structure and temperature distribution; thus, a 2D mesh is used to solve the discretized energy equations governing the heat transfer in fluid and solid materials. The calculation points are distributed along the measured depth and in the cross-section, i.e., inside the pipe, on the pipe, in the annulus, on the wellbore wall, and more points inside the formation. A uniform temperature is assumed in each finite volume (calculation cell), and energy conservation is enforced. The model is suitable for application to cementing jobs because it handles the flow of multiple fluids with different properties, as will always occur in a well during any cement job.

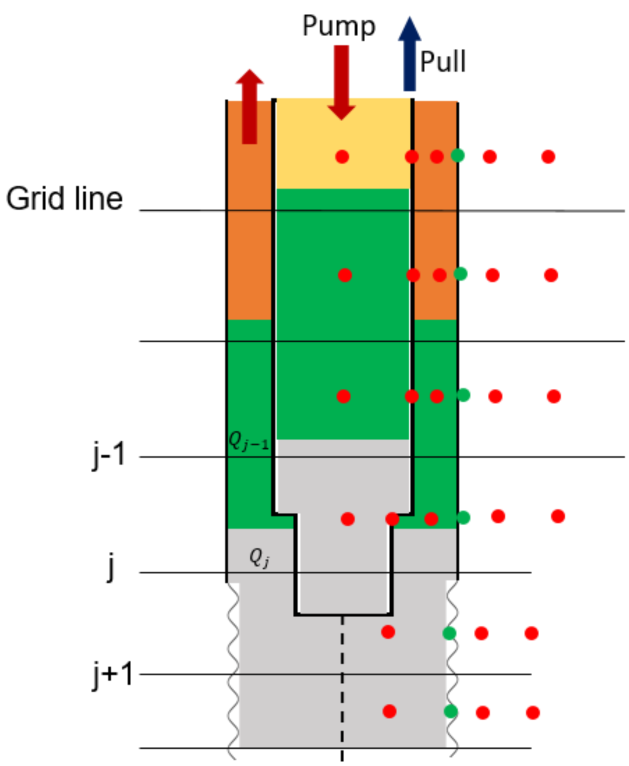


Figure 1: An illustration of wellbore structure with grid lines and calculation points shown for temperature modeling of pulling out of the hole. The red dots indicate the centers of the mesh cells used in the model. The green dots indicate the location of the borehole wall. Q's are flow rates found at the cell faces.

Mesh update. The grid points in the direction of measured depth are fixed when the pipe is pulled. However, the radial points are updated at each time step to adapt to pipe diameters when pulling the pipe. The volume of each cell is also updated to reflect the change of pipe ID/OD at all depths. This mesh design allows multiple diameters in a single cell, as seen in Figure 1.

Flow rate variation. In regular forward or reverse circulation, when the pipe depth is fixed (pipe velocity equals zero), the flow in the pipe or the annulus has a uniform rate along the measured depth because of mass conservation. In other words, the flow rate is the same as the pump rate (when U-tubing is not taking place). When pipe velocity is considered, flow rates become dependent on pipe velocity and depth because of pipe/hole size variation along the string. Flow rates must be found for each section of the wellbore flow rate according to the flow split at the bottom (balanced plug) or imposed pumping rate (pump and pull). The flow rate affects both streamwise energy transport and transverse convective heat transfer.

Convective heat transfer. The convective heat transfer coefficient is calculated by the following equations (Gnielinski, 1976; Santoyo, 2003; Incropera et al., 2007):

$$Nu = \frac{\left(\frac{f}{8}\right)(Re_D - 1000)Pr}{(1 + 12.7\left(\frac{f}{8}\right)^{\frac{1}{2}}\left(Pr^{\frac{2}{3}} - 1\right)}, \text{turbulent flow} \tag{1}$$

$$Nu = 4.36, \text{laminar flow} \tag{2}$$

Where Prandtl number $\mathrm{Pr} = \mu C_p/k$, Reynolds number $Re = \rho D v/\mu$, f is friction factor, μ is fluid viscosity measured at mean fluid temperature. When pipe velocity is non-zero, fluid velocity relative to the pipe is used to calculate the Reynolds number, effective viscosity, and Prandtle number. The pipe movement hence affects the heat exchange rate between fluid and wellbore.

Discretized energy equation. The energy equation inside the annulus with two different fluids in a control volume was expressed as Eq. (1):

$$\begin{aligned}\left[(\rho_1 V_1 C_1 + \rho_2 V_2 C_2)T_{a,j}\right]^{N+1} - \left[(\rho_1 V_1 C_1 + \rho_2 V_2 C_2)T_{a,j}\right]^{N} \\ = 2\pi r_{ID}(U_{ID}h_1 + U_{ID}h_2)\left(T_{a-1,j}^{N+1} - T_{a,j}^{N+1}\right) - 2\pi r_{OD}(U_{OD}h_1 + U_{OD}h_2)\left(T_{a,j}^{N+1} - T_{a+1,j}^{N+1}\right) + \rho_2 q_2 C_2 T_{a,u}^{N+1} \\ - \rho_1 q_1 C_1 T_{a,j}^{N+1} \quad (3)\end{aligned}$$

Where ρ is the fluid density, V is fluid volume, C is heat capacity, h is the length of the fluid in the cell, rID and rOD are the inner and outer radii of the annulus, U_{OD} and U_{ID} are overall heat transfer coefficients at the fluid-formation interface and drill pipe-annulus interface, respectively, and the terms q1 and q2 are volumetric flow rates. Note the subscript u represents the upstream cell, which can be j+1 or j-1 depending on the flow direction, and the subscripts 1 and 2 correspond to the fluids near the upstream and downstream faces in the cell, respectively. Superscripts N and N+1 are the time steps. Similarly, we can write the energy equation in the pipe as follows:

$$\begin{aligned}\left[(\rho_1 V_1 C_1 + \rho_2 V_2 C_2)T_{i,j}\right]^{N+1} - \left[(\rho_1 V_1 C_1 + \rho_2 V_2 C_2)T_{i,j}\right]^{N} \\ = 2\pi r_{ID}(U_{ID}h_1 + U_{ID}h_2)\left(-T_{i+1,j}^{N+1} + T_{i,j}^{N+1}\right) + \rho_2 q_2 C_2 T_{i,u}^{N+1} - \rho_1 q_1 C_1 T_{i,j}^{N+1} \quad (4)\end{aligned}$$

Where r_{ID} is the inner radius of the pipe, and U_{ID} is the heat transfer coefficient at the inner pipe interface. The equations are solved by a computer using Gauss-Seidel iterative method when initial temperature, inlet temperature, and undisturbed geothermal temperature are specified.

Hole section below the pipe end. As the pipe is pulled out of the hole, the pipe will evacuate the lower section of the well; thus, there is no fluid flow. However, the temperature will continue to evolve due to heat exchange between the stationary section of the fluid column and the formation. This is considered in the current model's calculations to predict the temperature recovery of the cement slurries.

RESULTS

A basic example

This simple, introductive case considers single fluid circulation in a vertical well, followed by a POOH operation. The string is at 9000 ft circulating for 223.9 minutes at 3 bpm. Then the pipe is slowly pulled out at 5 minutes per stand until it reaches 100 ft. The open hole diameter is 13.75 in. The pipe has a 5.5" in OD and 4.778" in ID. The surface temperature is 60 F, and BHST is 166 F. The case setup data of fluid and solid materials are listed in Table 1 and Table 2.

Table 1. Input data of fluid properties in the current simulation study

Fluid	Density (ppg)	Rheology	Thermal Conductivity (Btu/h.ft.F)	Specific heat (Btu/lb.F)	Inlet T (F)
Mud	10	BP, PV=29 cP, YP=21 lbf/100ft2	0.456	1	60

Table 2. Input data of solid properties in the current simulation study

Solid	Density (lb/ft3)	Thermal Conductivity (Btu/h.ft.F)	Specific heat (Btu/lb.F)
Casing	490.00	26.000	0.11
Cement	131.00	0.840	0.21
Rock	139.30	1.080	0.17

Profile

Figures 2-4 show the temperature profiles inside the pipe, in the annulus and the undisturbed formation temperature, at 3 moments: after displacement (before pulling), during pulling when pipe is at 5000 ft, and after pulling. After circulation, before POOH

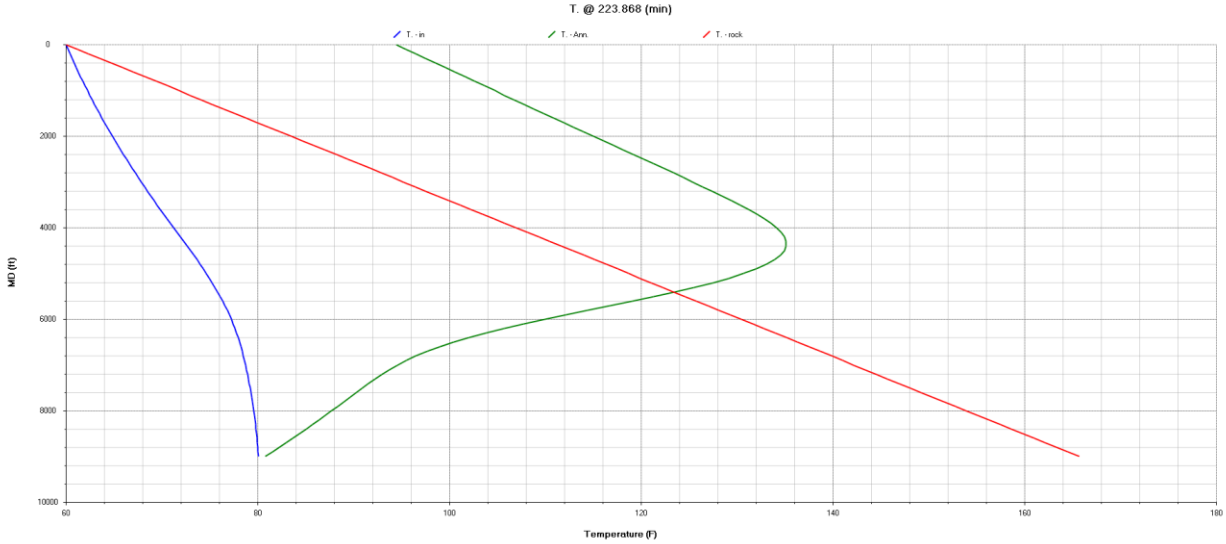


Figure 2: Temperature distribution after circulation. BHCT is approximately at 80 F.

After circulation, POOH to 5000 ft

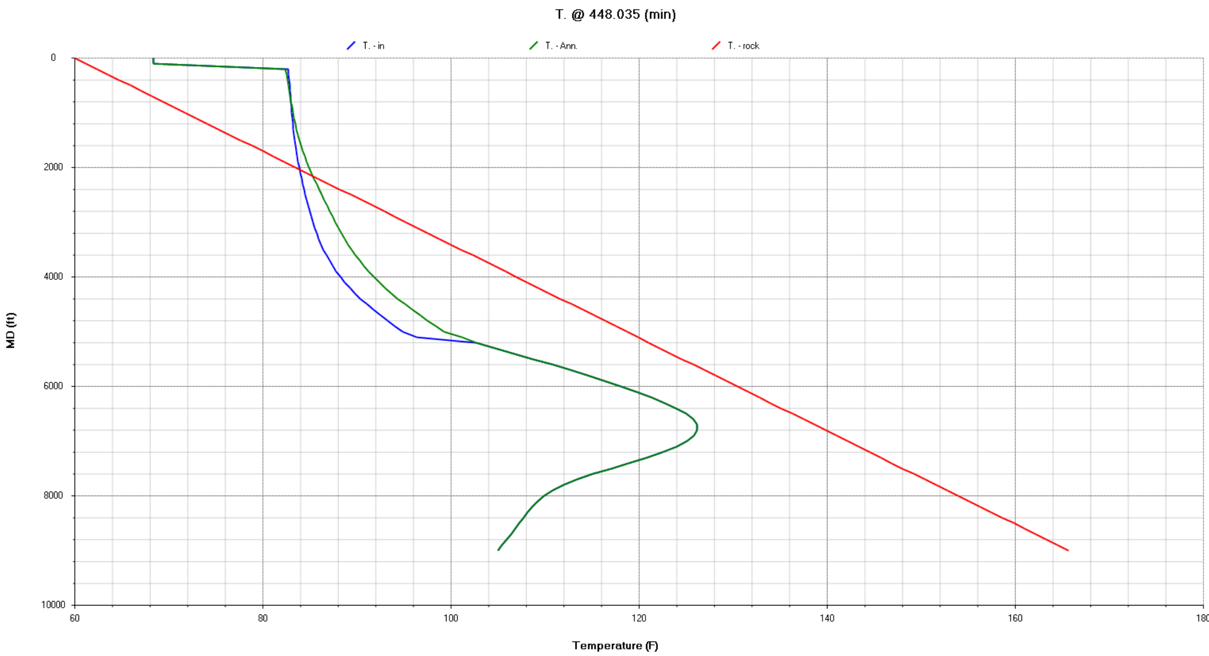


Figure 3: Temperature distribution when the pipe end is at 5000'. The fluid inside pipe at the pipe end runs out of the pipe and meets with the neighboring fluid dropped out of the annulus, and the mixed fluid is considered to reach a uniform temperature quickly (the time is ignored in the model). Therefore, for depths below the pipe bottom, T-in and T-annulus share the same line.

After POOH, pipe stationary at 1000 ft.

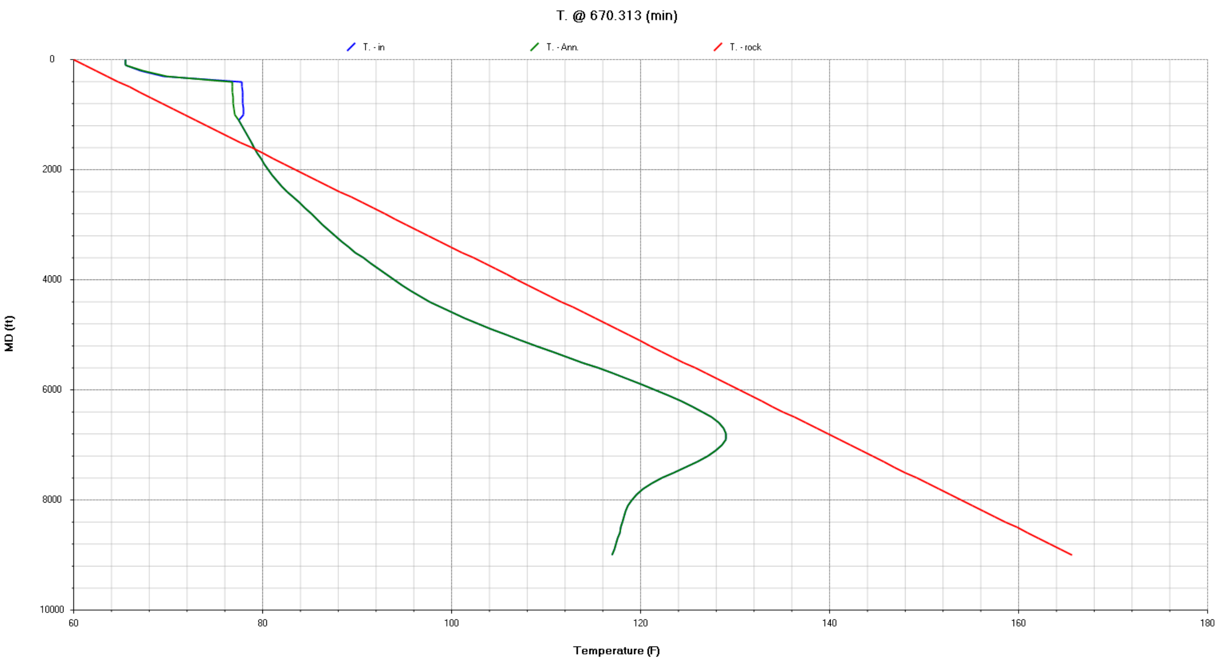


Figure 4: the fluid temperature at the end of POOH (pipe is at 1000 ft). Note the fluid below 8000 ft is noticeably recovered to a higher temperature if we compare it with the previous Figure.

History

The temperature evolution against elapsed time at certain depths is shown in Figure 5-7. At shallow depth (e.g., 2000 ft), the annulus temperature and in-pipe temperature change in opposite directions and eventually merge to the same temperature; at 5000 ft, the in-pipe temperature ramps up and then drops before merging with the annulus temperature. At the bottom, both annulus temperature and in-pipe temperature experience a continuous increase.

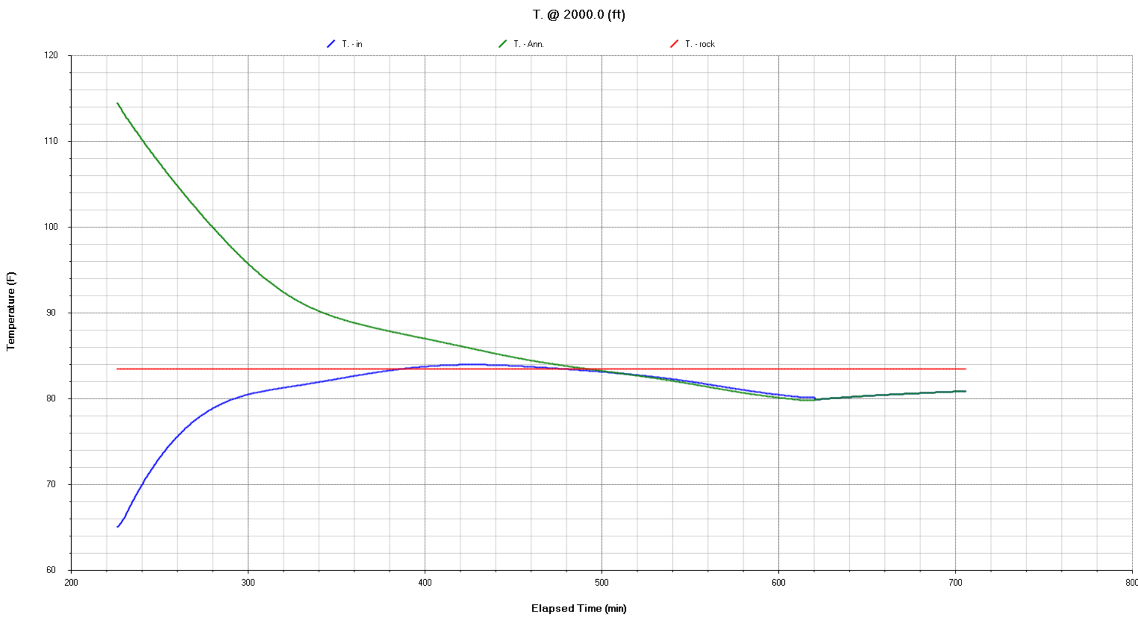


Figure 5: temperature history at 2000'. The T-in and T-ann merges to the same temperature at about 620 minutes, when the pipe end is pulled to the depth of 2000'.

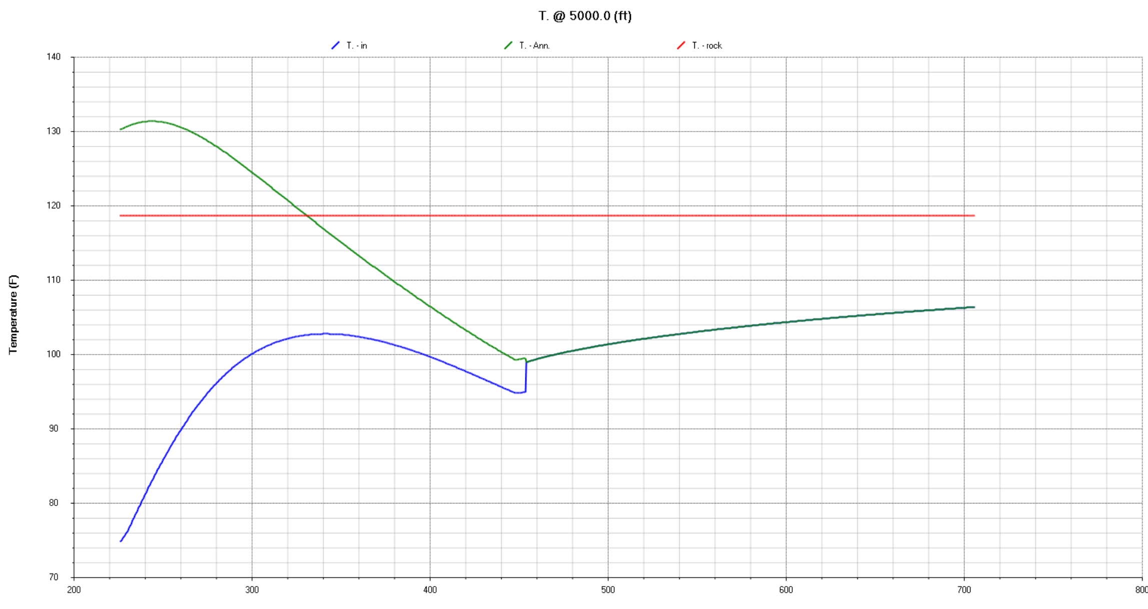


Figure 6: temperature history at 5000'. The T-in and T-ann merges to the same temperature at about 450 minutes, when the pipe end is pulled to the depth of 5000'.

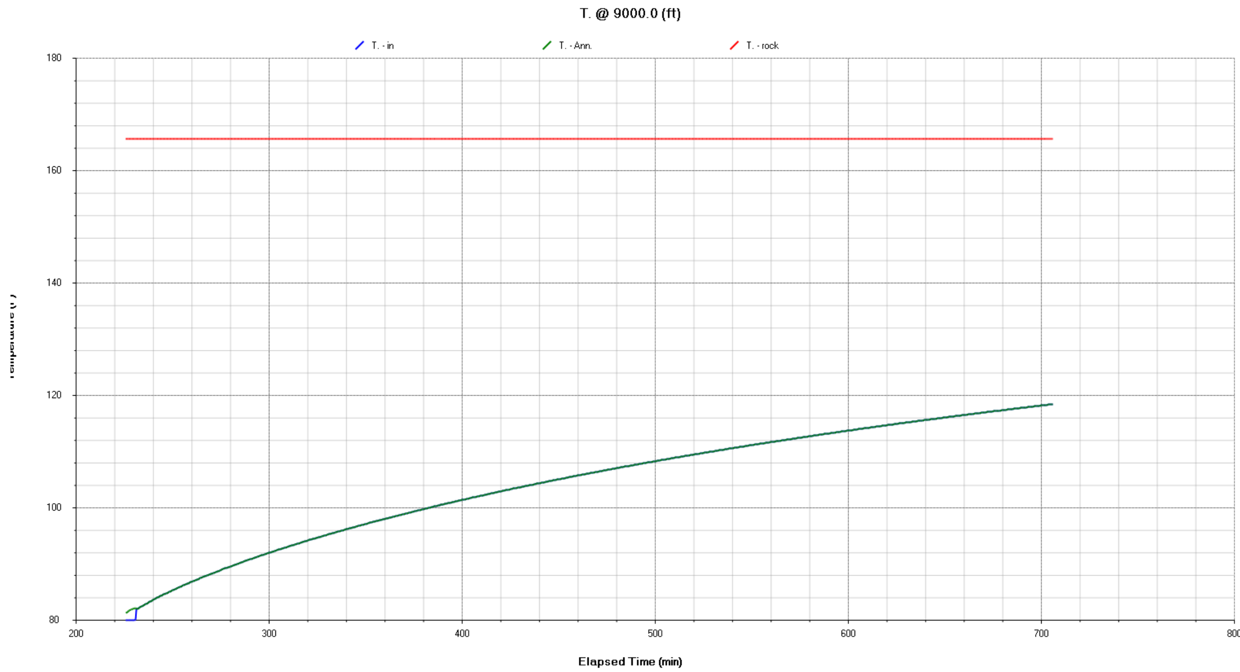


Figure 7: temperature history at the well bottom (9000') shows temperature recovery from 80F to approximately 120 F.

Balanced plug

When the balanced plug technique is used, the leading spacer, cement, trail spacer, and displacement fluids are pumped in sequence to the desired location, followed by a POOH process when the work string is slowly removed from the hole. Because the pulling speed is often slow, fluid levels inside the pipe and annulus are continuously adjusted under gravity to achieve hydrostatic equilibrium.

In this case study, we simulate a practical balanced plug job, including displacement and POOH operations. The fluid data are listed in Table 3.

Table 3. Fluid properties in balanced plug simulations.

	Fluid	Density (ppg)	Model	PV (cP)	YP (lbf/100ft2)	Conductivity (Btu/h-ft-F)	Heat capacity (Btu/lb-F)	Inlet T. (F)
1	mud	10.00	BP	29.0	21.0	0.456	1.00	80.0
2	spacer	11.00	BP	12.9	5.7	0.612	0.98	80.0
3	cement	11.50	BP	112.8	8.1	1.677	0.90	80.0
4	displacement	10.00	BP	29.0	21.0	0.456	1.00	80.0

The well is 9000 ft deep and 13.75" in borehole diameter. A 1000 ft plug is to be placed on the bottom. The basic case uses a 5.5" OD and 4.778" ID drill pipe to place the cement plug in a vertical well. To balance cement slurry and spacer, and make a 100 ft long spacer column, after POOH, 16 bbl spacer is pumped before cement, and 2.3 bbl spacer is pumped after cement. The volume of cement pumped is 183.7 bbl. Displacement time is 125.4 min, POOH is at 5 minutes per stand, so the time to pull the pipe to the top of the spacer is 61.1 min. Figure 8 shows the fluid schematics while pulling the pipe, where the spacer and cement levels in the annulus and pipe only slightly drop down, and air sections are created at the annular top and pipe top.

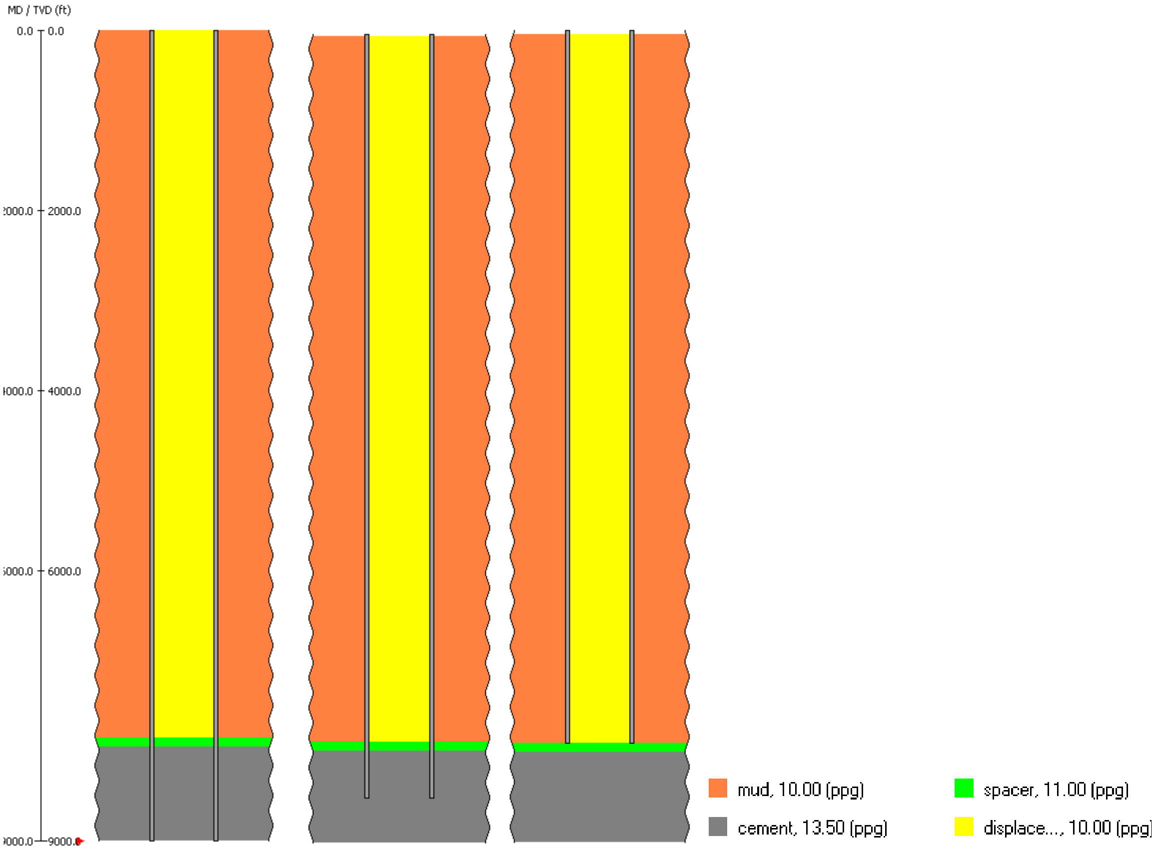


Figure 8: wellbore schematics with fluids during POOH. Left: the beginning of POOH (pipe end is at 9000 ft); middle: POOH when the pipe is pulled to 8500 ft; right: end of pull (pipe end at 8000 ft). [adjust the graph to align the top and bottom of the three wellbore schematics, and make the heights equal.]

Profile

After displacement, before POOH: The fluid temperature profiles inside the pipe and in the annulus after displacement are displayed in Figure 9 below. The temperature distribution against measured depth results from circulating for approximately 2 hours. The bottom is cooled to 97 F from 166 F at the beginning of pumping.

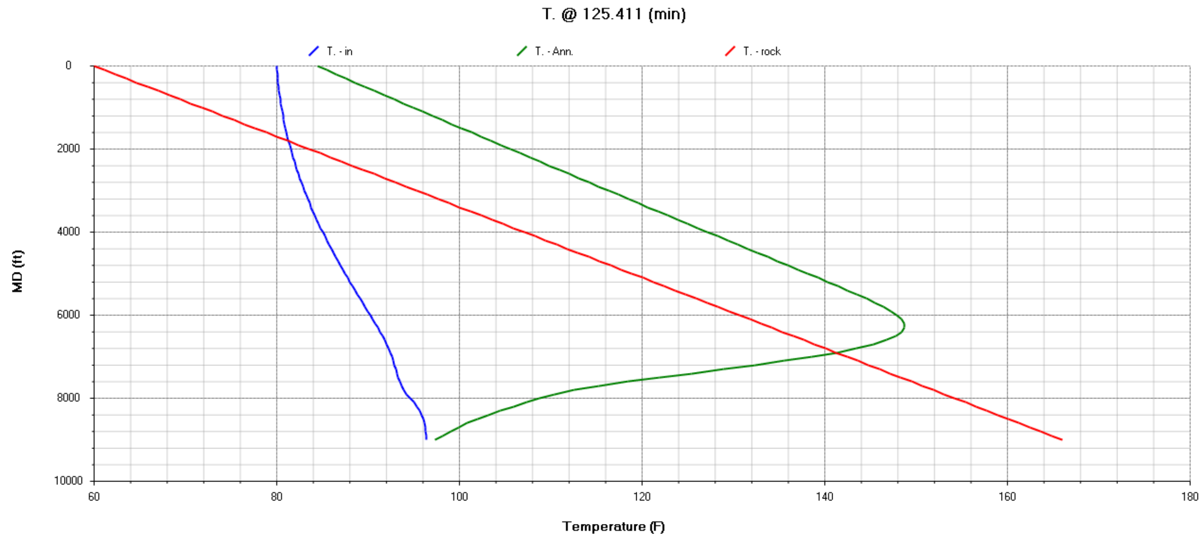


Figure 9: temperature profile after displacement. BHCT is at approximately 97F.

After POOH. After pulling the pipe to 8000 ft, the fluid temperature at the pipe bottom is approximately 132 F, and the bottom hole is recovered to 106 F (Figure 10). The difference between the annulus and in-pipe temperatures in depths above the pipe end is reduced. A big temperature slope in the lower section of the well is seen; in other words, the temperature of the slurry top is much higher than at the bottom after POOH.

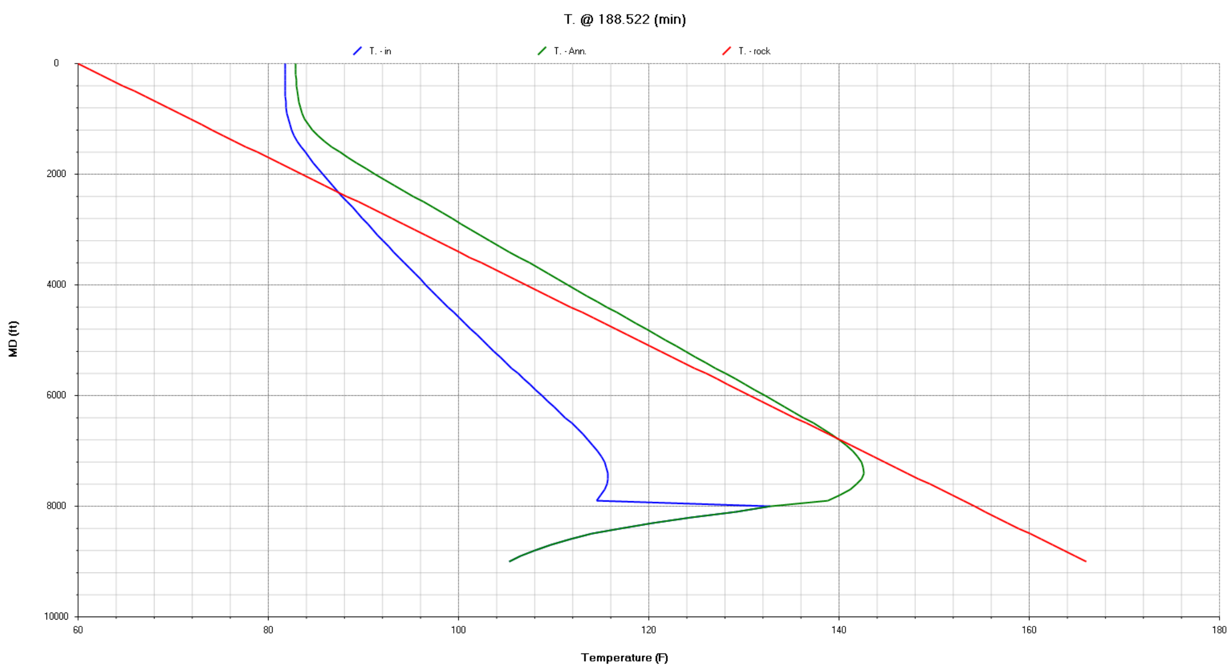


Figure 10: temperature profile after POOH (pipe end is at 8000').

History

The history of slurry temperatures during POOH is displayed in Figure 11. Both temperatures of the top in annulus and top in the pipe (corresponding to the first sack and last sack) rise by over 20 F while the bottom temperature increases by a smaller magnitude.

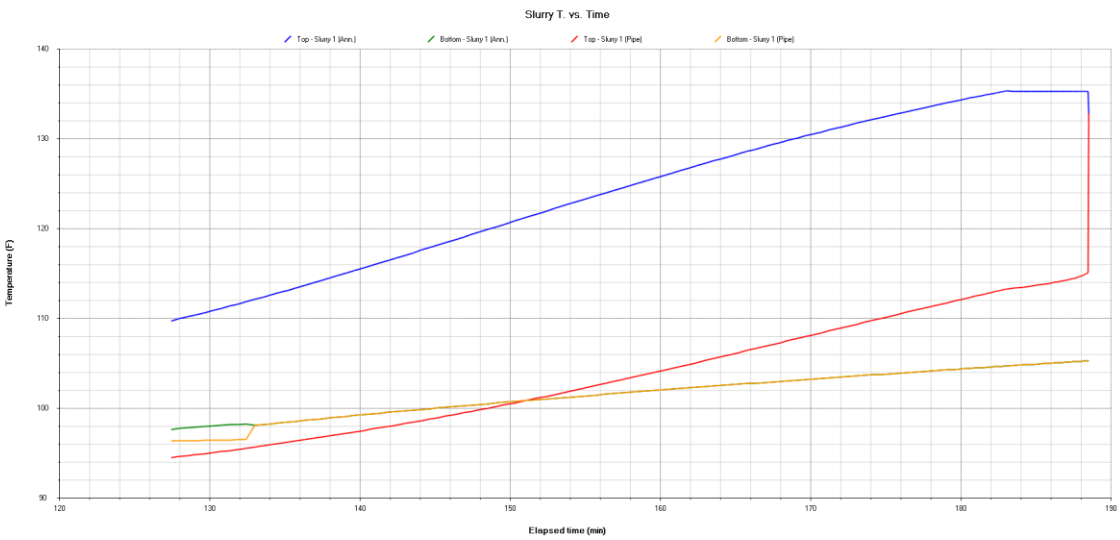


Figure 11: slurry temperature vs. time during POOH.

Pipe diameter

By varying the pipe diameters (OD and ID), a group of cases is simulated using the current model to investigate the impact of pipe sizes on the cement slurry temperatures. The smallest pipe is 2-in OD and 1.782-in ID, and the largest is 11.75-in OD and 11-in ID. The hole size is fixed for all cases. The pump rate during displacement is also fixed at 3 bpm. The simulated results are shown in Figure 12. The bottom temperature before pooh increases as the pipe size increases because the slow movement in a large pipe allows sufficient heat gain from the formation, thus a higher BHCT (also observed in Figure 13). The temperature differences between the top and bottom of the slurry before POOH (in annulus) and after POOH are getting smaller as the pipe sizes increase (also observed in Figure 14).

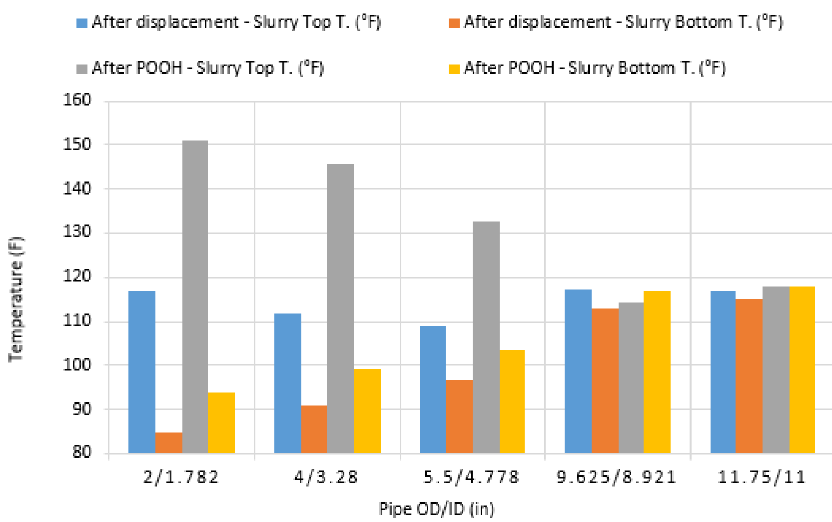


Figure 12: slurry temperature in a balanced plug job by various pipe sizes.

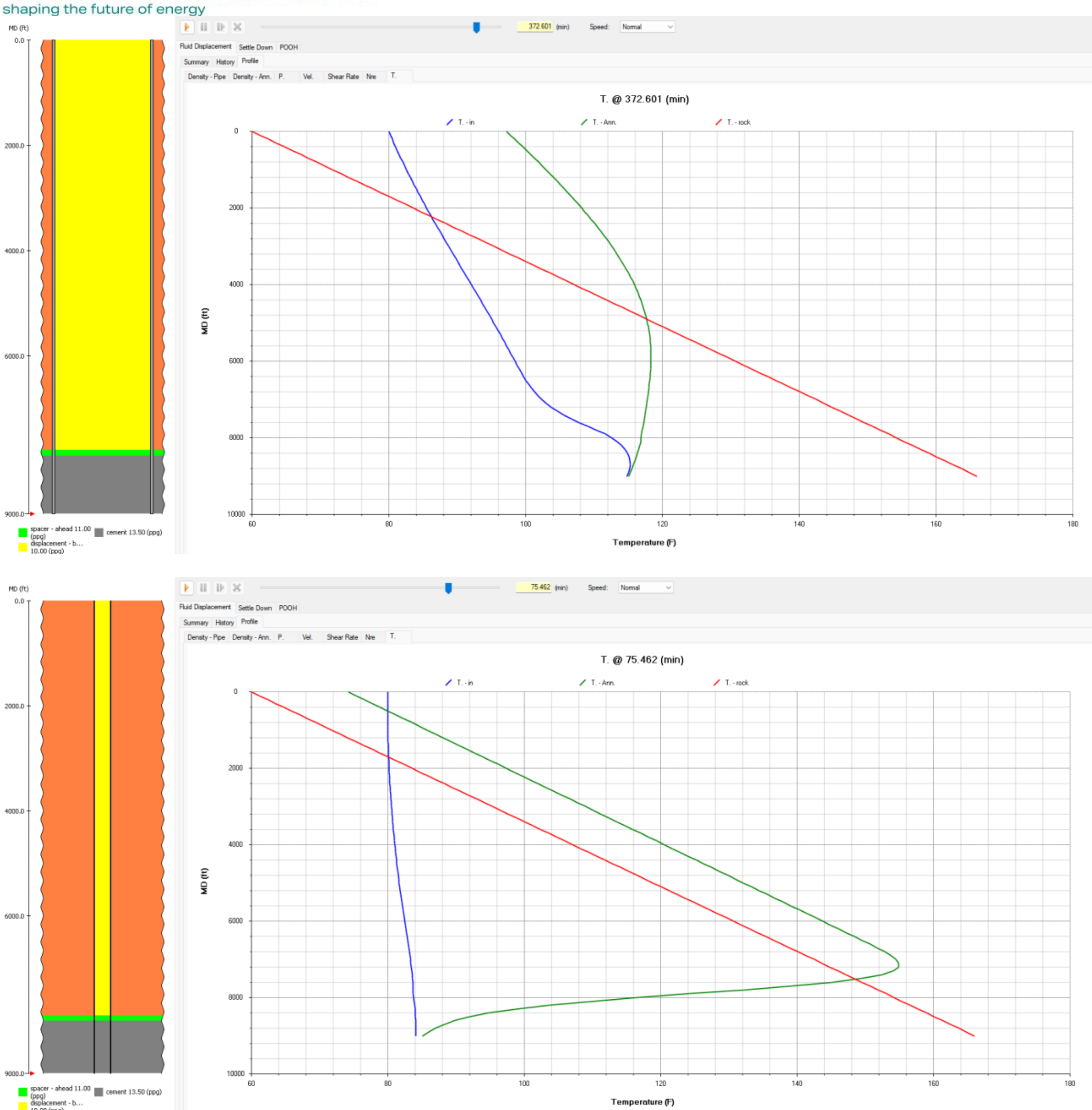


Figure 13: a comparison of temperature profiles after displacement between large and small pipes (top:11.75/11 in; bottom 2/1.782 in)

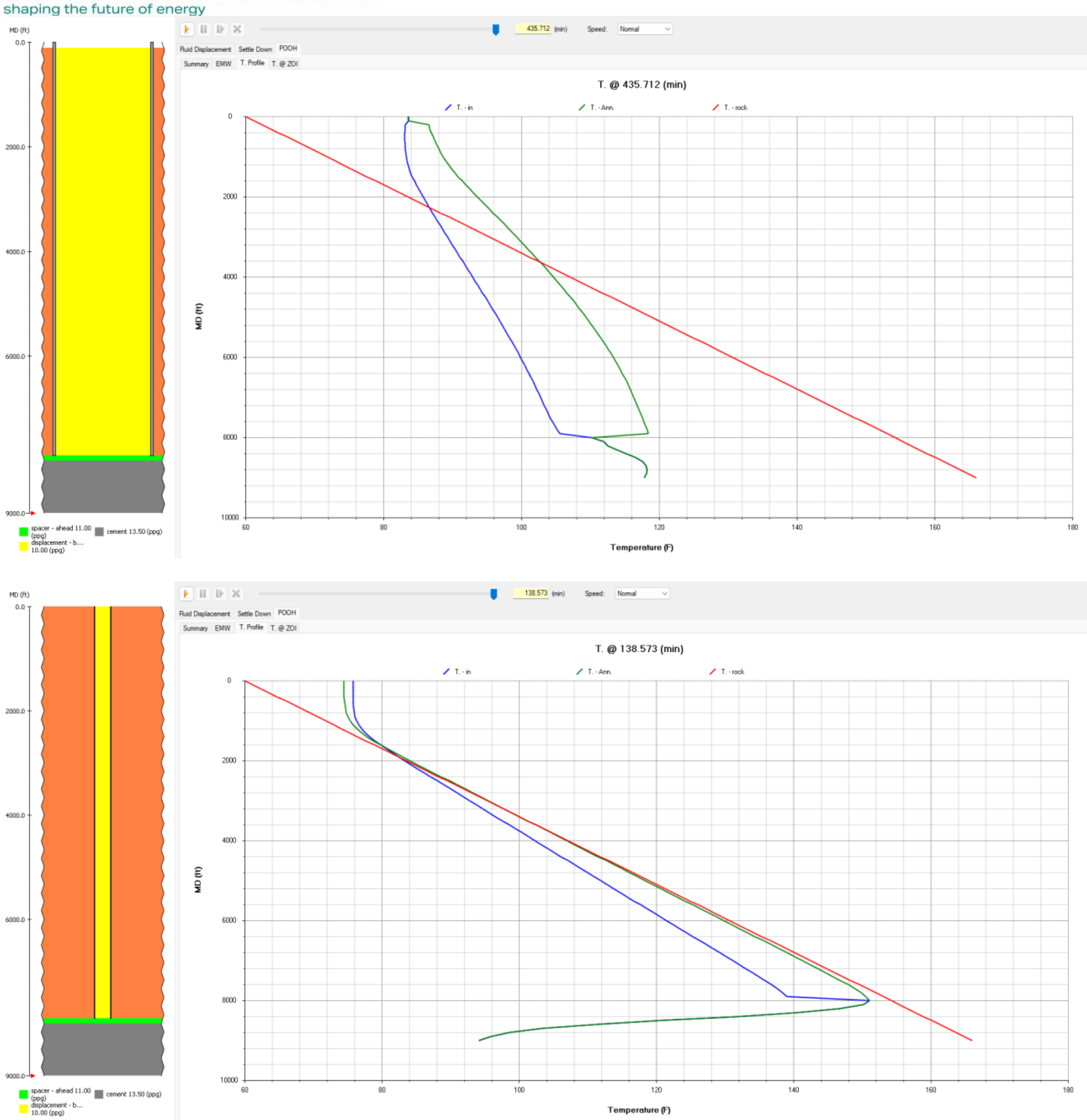
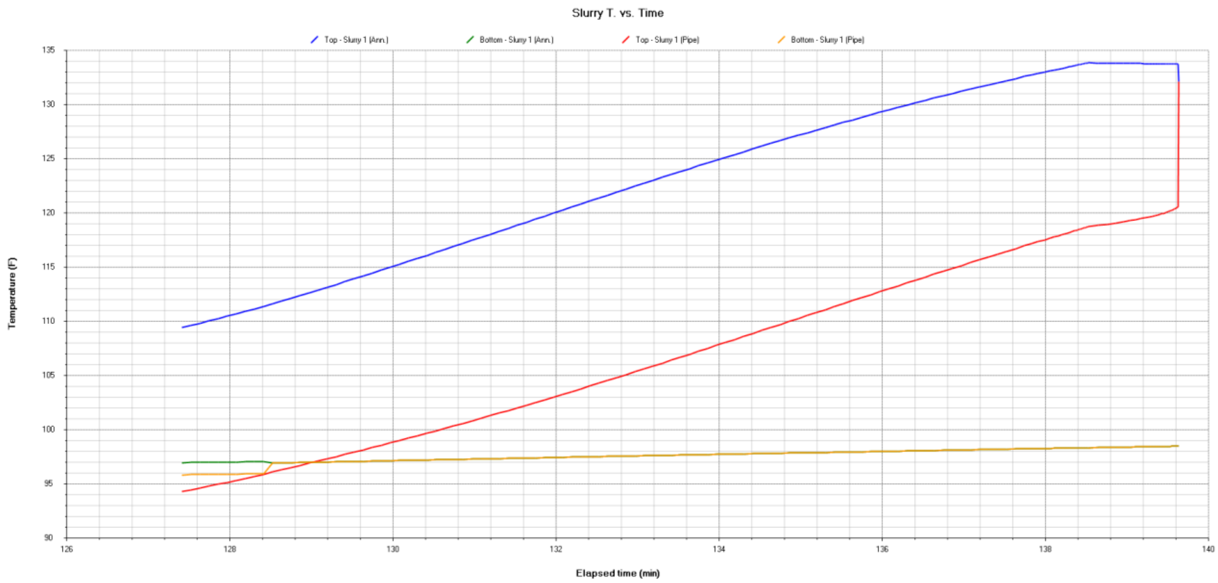


Figure 14: a comparison of temperature profiles after POOH between large and small pipes (top:11.75/11 in; bottom 2/1.782 in)

Pull velocity

The pulling speed during POOH in a balanced plug job is generally very low. A typical speed is 5 min/std. This gives sufficient time for the fluids to keep equilibrium during the process and allows cement temperature to rise significantly.



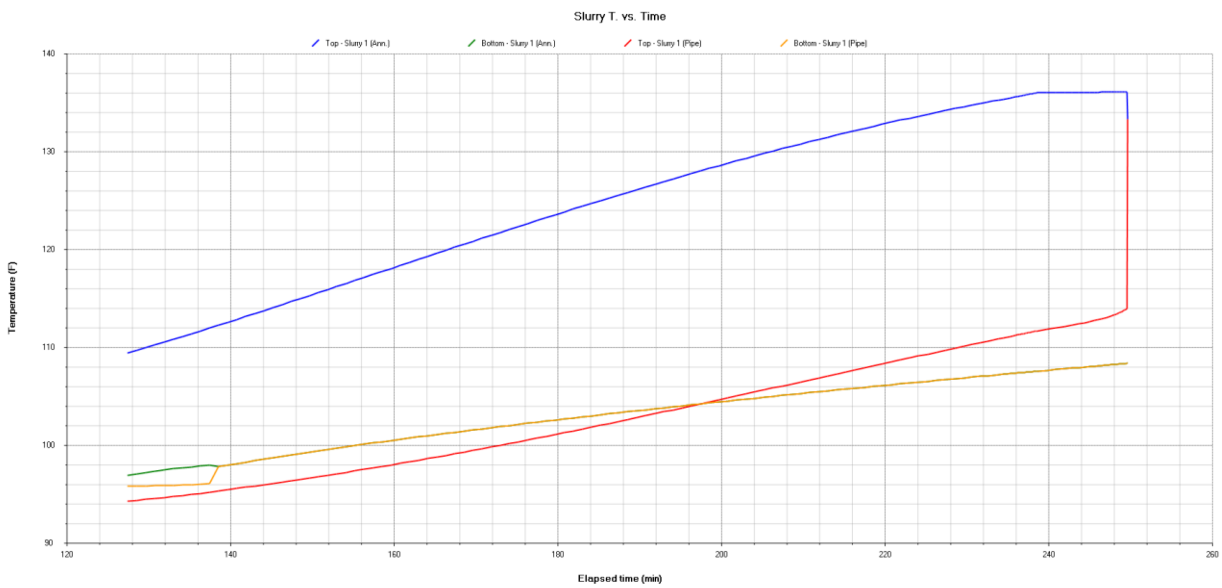


Figure 15: history of slurry temperature while pulling pipe at a speed of (a) 1 min/std; (b) 10 min/std.

As shown in Figure 15, when the pulling speed is low (b), the bottom temperature is recovered to a higher T at the end of pulling because a longer time is elapsed. However, the slurry top temperature of the two cases is close, despite significantly different periods. This is because the pipe velocity enhanced the convective heat exchange between the pipe and in-pipe fluid, pipe and annular fluid, and formation. Note a higher pipe velocity induces higher flows in the pipe and annulus.

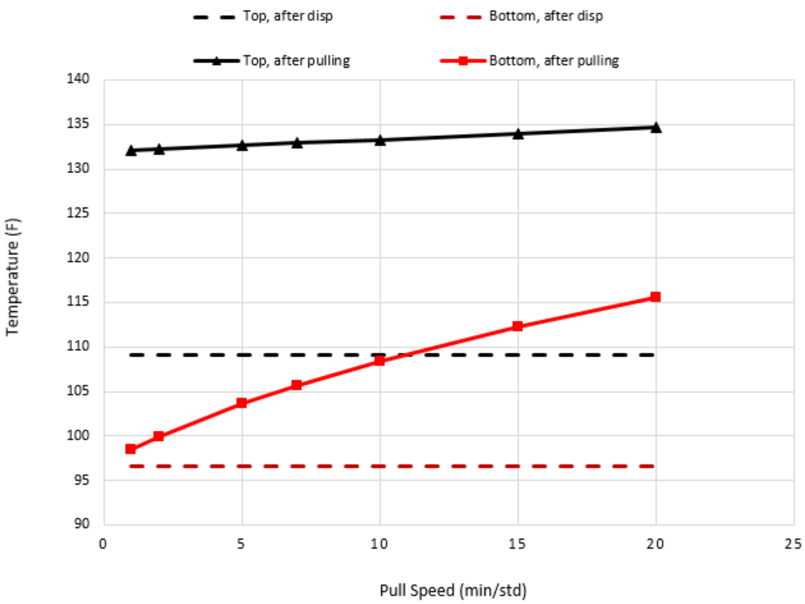


Figure 16: simulated slurry temperature after pulling out of the hole via different pulling speeds.

The slurry top temperature only slightly (and nearly linearly) increased as the pulling speed decreased from 1 min/std to 20 min/std, as seen in Figure 16. However, the slurry bottom temperature increased by approximately 20 F due to reduced speed (thus increased time for temperature recovery). Note the red line is not linear because this temperature recovery is not proportional to elapsed time.

Cement viscosity

We simulated a few cases to study the effect of the viscosity of the cement. In these cases, we only vary the PV and keep the YP of the slurry. Other fluids are not changed in rheological parameters and densities. Figure 17 presents the temperature results. It shows that viscosity changes in the cement do not significantly influence the slurry temperature if the plastic viscosity is relatively high (>70 cP, normally true for cement). The slurry top temperature after pulling is much lower when the cement has a low PV.

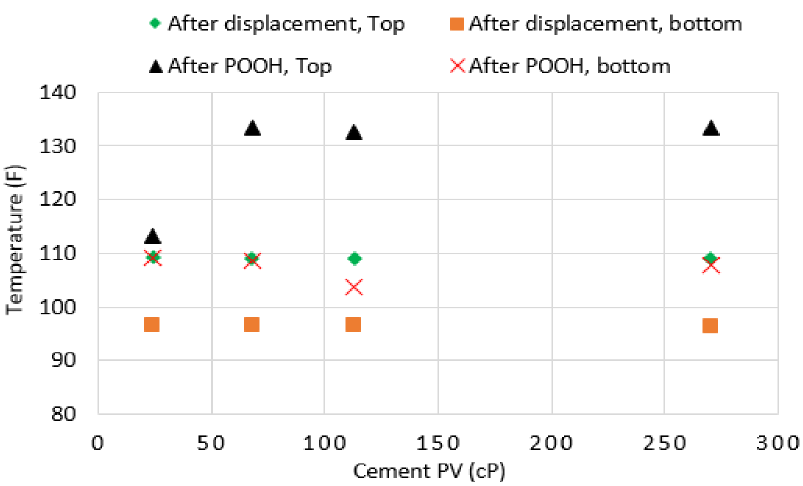


Figure 17: simulated slurry temperature influenced by cement's viscosity (PV). In all cases, YP is unchanged.

Viscosity of native fluid

We further studied the effect of viscosity of the native fluid by simulating a group of 5 combinations of PV and YP for the native fluid, from 1 cp and 1 lbf/100ft2 to 160 cp and 61 lb/100ft2. The results are compared in figure 18. The slurry temperatures are highest, over 140 F when the native fluid is very thin (1 cp). The temperature decreases dramatically when the native fluid gets thicker (except the top T after pulling), and that influence becomes negligible as the viscosity increases.

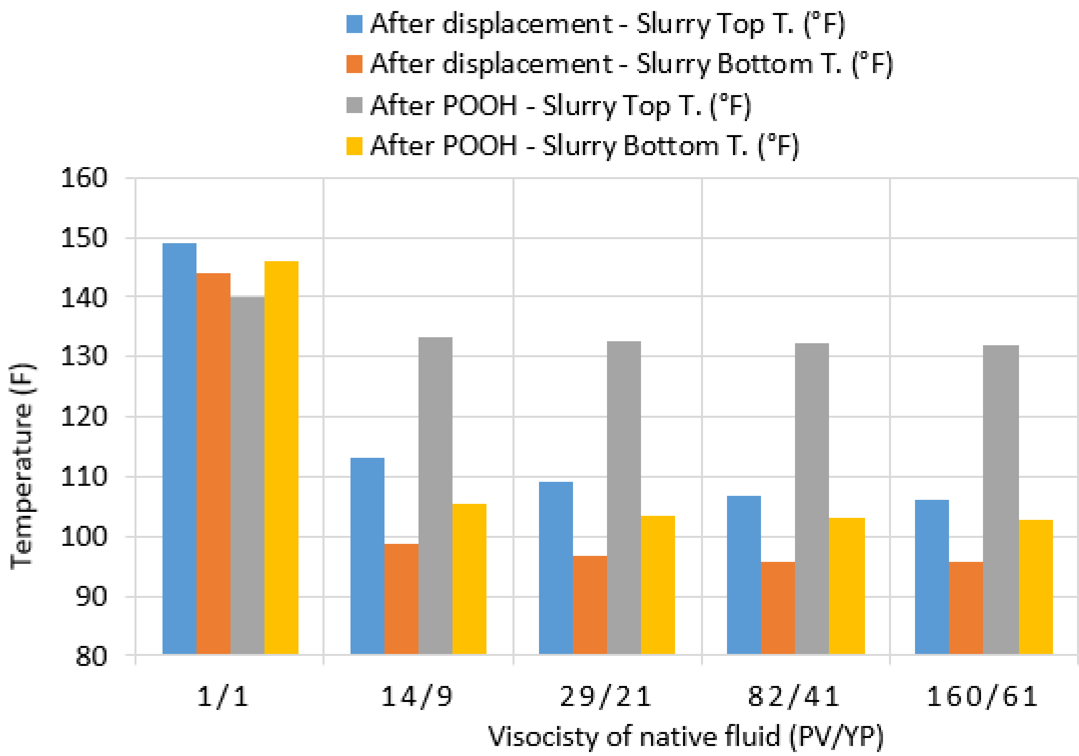


Figure 18: Effect of native fluid viscosity. The units are cP and lbf/100ft2 for PV and YP, respectively.

Balanced plug vs. pump and pull

In a pump and pull (PAP) job, the cementing crew pulls the pipe out of the hole and simultaneously pumps fluids into the well. Therefore a PAP job does not depend on gravity to spot the cement plug as the conventional balanced plug jobs do. The pump and pull technique alleviates much of the challenge of placing cement plugs in highly deviated and horizontal wells because it allows better control during the spotting of the plug. This technique also minimizes the possibility of stringing out the cement when pulling the stinger out. The PAP method can also be effectively used in vertical or normally deviated holes.

In this section, we simulate a typical type of PAP job, namely, "pump and pull after the cement is in place." In this method, a good amount of the cement slurry is displaced to the desired top of the plug with the stinger at the bottom depth of the cement. Pulling the string then begins at the same time pumping is started. First, we consider the vertical well and compare the balanced plug method with PAP method.

Vertical well

The setup is the same as in previous cases. Two pulling speeds are used, 18 ft/min and 45 ft/min, for both methods. The displacement fluid volume before pulling is smaller in the PAP method than in the balanced pug method because the displacement fluid will be further pumped during the pulling pipe. The temperature results, including top and bottom temperature before and after pulling, are shown in Table 4. The temperatures are generally slightly lower in PAP than in the balanced plug, except that the slurry top temperature after pulling is significantly lower in PAP by approximately 20 F. Increasing the pulling speed also slightly reduces the temperature after pulling in both methods.

Table 4 - A comparison of slurry temperature between a balanced plug and PAP in a vertical well.

	Balanced plug （18ft/min）	**Balanced plug （45ft/min）**	**PAP (18ft/min) Pumping: 0.53 bpm**	**PAP (45ft/min) Pumping: 1.32bpm**
After displacement - Slurry Top T. (°F)	109.1	109.1	107.3	107.3
After displacement - Slurry Bottom T. (°F)	96.6	96.6	94.7	94.7
After POOH - Slurry Top T. (°F)	132.6	132.3	109.7	107.2
After POOH - Slurry Bottom T. (°F)	103.6	99.9	101.9	98.0

Balanced plug (left); Pump and Pull (right).

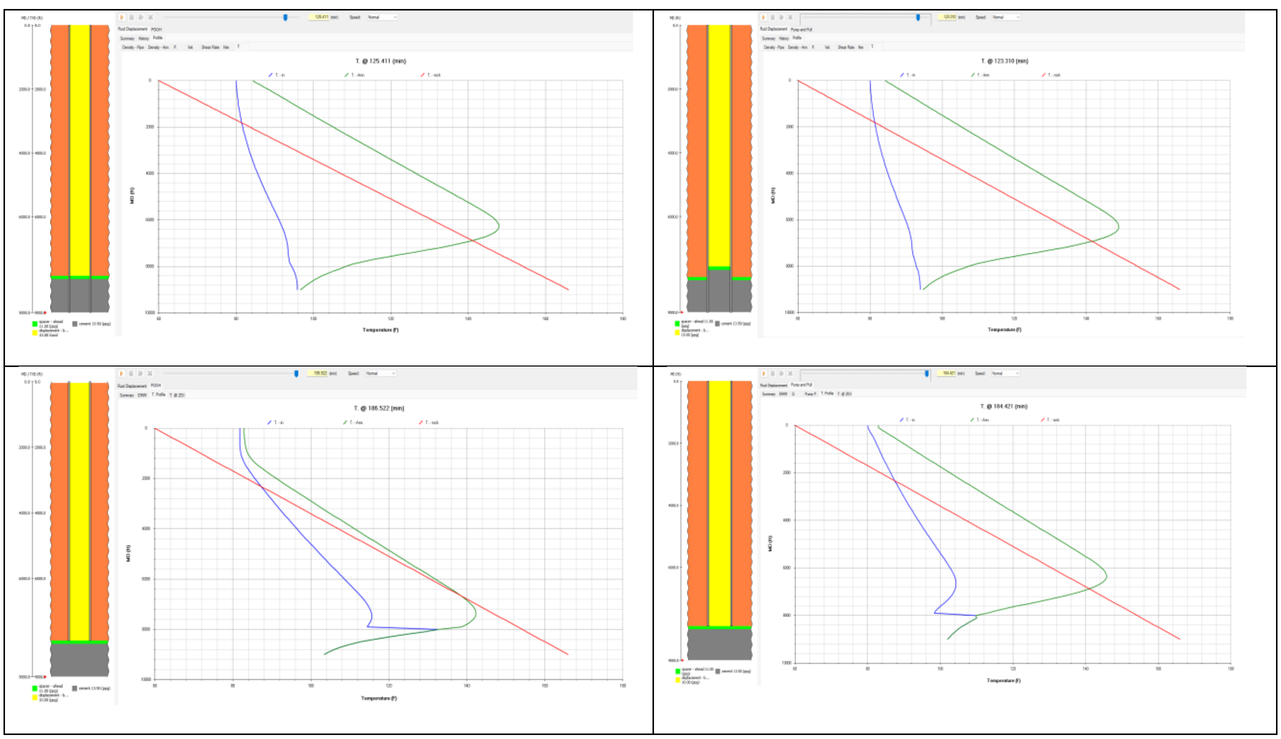


Figure 19: temperature profiles of the balanced plug (left column) vs. Pump and pull (right column) in the vertical well (at 18 ft/min). Top: after displacement; bottom: after pulling out.

The temperature profiles for both methods pulling at 18 ft/min, are shown in Figure 19. In PAP, the native fluid above the cement in the annulus has no movement relative to the borehole wall; the heat exchange between the formation and the annulus is thus greatly constrained (natural convection still exists), in contrast to a balanced plug. At the end of the pulling, the annulus temperature approached the rock temperature. The bottom of the slurry is not noticeably affected by the pulling operation and only experiences a similar temperature recovery. This is caused by the well bottom no longer being influenced by the pulling operation once the pipe end has lifted from the bottom.

Horizontal well

All previous cases are simulated within a vertical wellbore. We now consider an additional set of cases for a horizontal well with a similar set of parameters as those in the preceding section. The well starts at 4000 ft and the TVD at 5273ft (total MD is still 9000 ft). The BHST is 166 F, which is the same as the vertical well. The schematic in Figure 20 shows the wellbore trajectory by TVD vs. horizontal displacement.

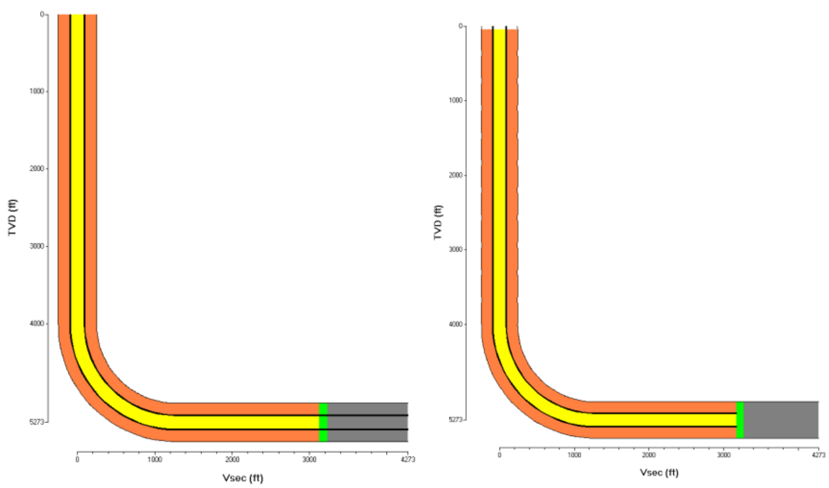


Figure 20: 2D schematics in a horizontal well showing the fluids after displacement (left) and after POOH (right) in the balanced plug.

The temperature results in the horizontal well are shown in Table 5. Similarly, after pulling, the PAP job has slightly lower temperatures except at the slurry top. The horizontal well generally has a higher temperature when compared with the vertical well, which is because the entire cement column is located in a horizontal section, all influenced by the same geothermal temperature of BHST.

Table 5 - A comparison of slurry temperature between a balanced plug and PAP in a horizontal well.

	Balanced plug （**18ft/min**）	Balanced plug （**45ft/min**）	**PAP (18ft/min) Pumping: 0.53 bpm**	**PAP (45ft/min) Pumping: 1.32bpm**
After displacement - Slurry Top T. (°F)	123.3	123.3	122.3	122.3
After displacement - Slurry Bottom T. (°F)	103.6	103.6	102.5	102.5
After POOH - Slurry Top T. (°F)	148.1	147.8	123.4	121.0
After POOH - Slurry Bottom T. (°F)	110.2	106.7	109.2	105.6

The temperature profiles in horizontal wells using both methods pulling at 18 ft/min, are shown in Figure 21. Affected by the geothermal temperature, the annulus temperature in the horizontal well shows a wider depth range of the hot zone, in contrast to the sharp V shape seen in the vertical well. Again, limited heat exchange between fluid and wellbore in PAP resulted in a large temperature difference between annulus temperature and in-pipe temperature after pulling; it also led to a smaller temperature difference between the top and bottom of the plug than the balanced plug because the temperature recovery at the slurry top is restricted.

Balanced plug (left); Pump and Pull (right).

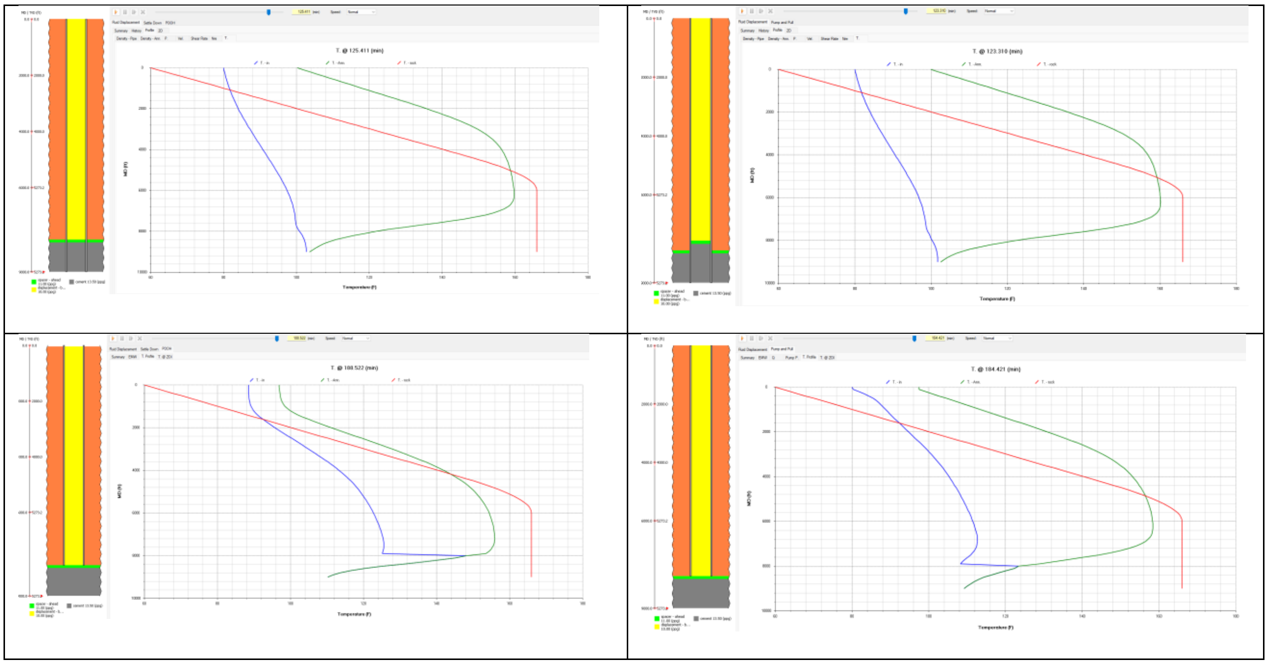


Figure 21: temperature profiles of the balanced plug (left column) vs. Pump and pull (right column) in a horizontal well (at 18 ft/min). Top: after displacement; bottom: after pulling out.

CONCLUSION

This paper presented a new numerical model suitable for temperature prediction for plug cementing, including a balanced plug and pump and pull. A series of numerical simulations are performed to study the slurry temperature variation in plug jobs. The simulation study based on the proposed model leads to the following conclusions:

1. The temperature difference between the top and bottom of the plug, both before and after pulling the pipe, reduces as the pipe size increases.
2. Slurry temperature decreases dramatically when a thin native fluid gets thicker (except at the top slurry after pulling), and the influence of viscosity becomes small as the viscosity further increases.
3. Changing cement viscosity does not significantly influence the slurry temperature if the viscosity is relatively high. The slurry top temperature after pulling is much lower if the cement has a low PV.
4. The slurry top temperature after pulling only slightly (and nearly linearly) increases as the pulling speed decreases from 1 min/std to 20 min/std. However, the slurry bottom temperature largely increases (about 20 F in our example).
5. Temperature is slightly lower in PAP than in a balanced plug job if pulling at a similar speed, except at the plug top, where PAP has a significantly lower temperature, by approximately 20 F in our example. Increasing the pulling speed also slightly reduces the temperature after pulling in both methods. Conclusions apply to both vertical and horizontal wells.

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