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Fluid Temperature in Fractures

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ABSTRACT

Knowledge of the actual temperature of a fluid in a fracture created with hydraulic pressure has been non-existent. The significance of having this data lies in the advantages of being able to predict not only acid spending times and related retardation effects, but also the viscosities of fracturing fluids. Viscosity values enter into the "C" factors used in fracture area calculations. Thus, an estimated viscosity can greatly affect predicted fracture areas and subsequently expected production increases.

This work develops a method of calculating temperatures of injected fluids at a given distance from the well bore in a fracture, and suggests how this information may be used for better stimulation techniques.

INTRODUCTION

In the design of treatments for oil and gas wells no technique has been available to predict the temperature of the stimulation fluid as it moves outward in a fracture; yet the effect of temperature on acid spending times and on the viscosity of fracturing fluids is no mystery. Calculation procedures and chemical mixtures have been designed simply for original bottom-hole temperatures. It is known, however, that formation cooling takes place as a cool fluid is pumped down a well[1,2] and into the formation. By assuming that any chemical or physical reactions occur at original formation temperature a temperature estimate may be in error as much as 260°F, thereby affecting decisions as to the type of acid retarder needed, and estimates of fluid viscosity and density which are temperature dependent.

The evaluation of the transient temperature distribution of fracturing fluid during a fracturing operation is a complex heat transfer problem. Certain assumptions regarding the nature of fluid flow in the fracture, and the mechanisms of heat transfer in both the fracturing fluid and the formation are necessary for the solution. The most accurate analysis of the problem requires the use of transient numerical procedures which involve the simultaneous solutions of a number of linear differential equations which describe the heat flow in both the fluid and the formation. Because of the heterogeneous nature of reservoir rocks, an averaging of the thermodynamic properties of the rock is necessary, and such variables create error in the cumbersome and exacting solution memtioned above. Due to the cumbersome nature and limited versatility of transient numerical procedures and the uncertainity of fracture characteristics and formation properties, a versatile analytical solution was developed to estimate the fracturing fluid temperature distribution within the fracture.

DEVELOPMENT OF THEORY

Well stimulation problems which are concerned with high formation temperatures are related to deeper strata. Since evidence points to the fact that most deeper fractures are vertical, a vertical fracture was considered in this analysis. The only change in using a horizontal fracture would be in adapting the radial geometry to the equations developed.

The thermal conductivities of the fluid saturated rock and of the fracturing fluid are assumed to be constant. The work of Somerton[3] indicates the temperature ranges considered here are too small for significant alterations of thermal conductivity; however, rock conductivity must be measured under reservoir conditions. Walsh and Decker[4] studied the effect of pressure and fluid saturation on the thermal conductivity of rock, and reported that error in excess of 15 percent may be introduced when values are taken from laboratory samples. The opening of natural cracks, when a core is removed from overburden conditions, allows the entrance of air or the saturating liquid (both of which have lower conductivities than rock) and allows a barrier to the flow of heat to form.

The method of analysis selected for predicting the temperature distribution of the fracturing fluid with respect to both time and position within the fracture combines the transient closed form solution of the heat transfer within a semi-infinite slab (fractured formation) with a pseudo steady-state analysis of the heat transfer to the fluid in the fracture cavity. It was assumed for the mathematical model that the heat exchange between the formation elements in a direction parallel to the fluid flow in the fracture could be neglected. This means that each formation element or segment is considered to be thermally isolated from the adjoining segments. It was further assumed that the convective heat transfer coefficient in the flowing fluid is very high compared to the heat transfer characteristics of the formation rock. As a result, the fluid-formation interface temperature of each fluid element is equal to the bulk fluid temperature in contact with the element; or the heat transfer coefficient between the fluid and the rock is infinite.

In order to maintain realistic fracture mechanics a fluid leak-off rate was introduced, and for the example a fixed rate was used. However, the heat blockage effect of the leak-off fluid transpiring into the formation in a direction opposite to the heat flow was neglected. This would cause the fluid temperature predictions to be slightly high.

Figure 1 illustrates the fracture model assumed in this study. Figure 2 shows a fluid element within the fracture upon which an energy balance was made. In this model the fluid was considered to be transported through the fracture with heat transferred to it from the formation on either side. Heat transferred from the top and bottom surfaces of the fracture was considered to be negligible. As stated previously the model also accounts for fluid losses due to leakage even though heat blockage effects are neglected.

An energy balance on an elemental volume of the fracture fluid yields,

$$mcT + 2\,q\,(t)\,h\,dx = m_1\,cT + \left(m + \frac{dm}{dx}\,dx\right)\,c\,\left(T + \frac{dT}{dx}\,dx\right) \quad \ldots (1)$$

A mass balance on the fluid volume yields,

$$m = \left(m + \frac{dm}{dx}\,dx\right) + m_1$$

$$\text{or} \quad m_1 = -\frac{dm}{dx}\,dx \quad \ldots (2)$$

The energy balance expression can be reduced by neglecting the higher order terms, and with equation (2) gives,

$$mc\,\frac{dT}{dx} = 2\,hq(t) \quad \ldots (3)$$

The expression for the heat flux to the fluid flowing through the elemental fluid volume is complex and not readily reduced to an exact analytical expression. However, it can be approximated by the transient cooling of a semi-infinite slab which is exposed to a constant surface temperature[4]. This approximation becomes fairly accurate at a given point in the fracture after the first few minutes of pumping the fracture fluid. The heat flux at the formation fracture interface is given by,

$$q\,(t) = \sqrt{\frac{kc\rho}{\pi t}}\,(T_i - T) \quad \ldots (4)$$

This expression for heat flux is substituted into the temperature distribution equation and then the temperature variable is changed as follows:

$$\phi = T_i - T$$

and $$\frac{d\phi}{dx} = -\frac{dT}{dx}$$

It can be shown that

$$\frac{d\phi}{dx} = -\frac{2h}{m}\sqrt{\frac{k\rho}{\pi ct}}\,(\phi) \quad \text{. . (5)}$$

In this analysis it has been assumed that the mass flow into the fracture void is reduced by a constant leak-off rate. Thus, the fracturing fluid mass flow, m, in the fracture can be related to the distance, x, from the borehole by:

$$m = \frac{m_0}{L}(L - x) \quad \text{. .(6)}$$

Substituting this expression into equation (5) gives the following expression for the temperature distribution of the fluid within the fracture:

$$\frac{d\phi}{dx} = -\frac{2hL}{m_0}\sqrt{\frac{k\rho}{\pi c t}}\left[\frac{\phi}{L-x}\right] \quad \text{. .(7)}$$

This equation can be solved for the temperature distribution of the fracturing fluid within the fracture void at any given time after pumping is started. The solution is shown below after integration and substitution:

$$T = T_i - \left[T_i - T_0\right]\left[1 - \frac{x}{L}\right]^{\left[\frac{2hL}{m_0}\sqrt{\frac{k\rho}{\pi ct}}\right]} \quad \text{. . (8)}$$

This equation can be used to predict temperature of the fracturing fluid as a function of time and distance from the borehole.

The parametric curves shown in Figures 3 and 4 were generated from equation (8). These describe the fracture fluid temperature as a function of position within the fracture and pumping time. Well conditions which were used in equation (8) and illustrated in Figures 3 and 4 are as follows:

T_i, Fracture fluid temperature leaving the wellbore = 80°F
T_0, Original formation temperature = 200°F
L, Length of fracture = 100 ft.
h, Height of fracture = 5 ft.
m_0, Mass flow rate = 21,000 lbs./hr. (based on 10 barrels per minute pumping rate)
ρ, Density of rock = 167 lbs./ft.³
k, Thermal conductivity of fluid saturated rock = 1.5 Btu./ft. hr. °F
c, Specific heat of formation rock = 0.21 Btu./lb_m °F

Leak-off was introduced at 1% per ft. of fracture length.

Figure 3 indicates that the fluid temperature drops rapidly at points close to the wellbore, but at a given point 40 ft. from the well borehole temperature approaches 140°F only after 30 minutes of pumping. The temperature at a point 100 ft. out will not be affected by the fracturing operation. This is to be expected since leak-off has reduced the flow of fluid in the fracture to zero at this point.

Figure 4 shows that the fluid at 0.1 minute is still at 200°F 20 ft. out in the fracture, while after 30 minutes the temperature gradient for the 100 ft. fracture is approaching a linear realtionship with the 80° to 200° temperatures.

To demonstrate the advantages of this temperature prediction for the given well conditions a fracturing job with a gelled fluid might be considered first. Viscosity of a given gelled fluid at original formation temperature of 200° is 50 cp. After pumping 15 minutes the average temperature of all the fluid in the fracture would be 155°, for which average viscosity is 132 cp. C_{II} factors, or coefficients for viscosity controlled fluids, are 0.0075 for a 132 cp. fluid and 0.014 for a 50 cp. fluid. Fracture area calculations based on these coefficients show that an error of 60 percent is introduced merely by temperature inaccuracy. The larger area is always fractured by the cooler fluid. This comparison indicates that predicted fracture areas based on original bottom-hole temperatures are greatly conservative for deeper, or hotter wells.

The amount of sand necessary to fully pack a fracture is based on the width and area of the fracture one expects to create. It follows from a conservative calculation of fracture area that a smaller sand volume than is needed to pack a fracture will be pumped. The problem appears even more acute when one pictures a vertical fracture with an inadequate volume of sand in the bottom leaving a large part of the fracture to heal without a propping material in place.

The estimation of production increase after fracturing is a function of fracture length. Since length depends also on area calculations, P.I. would also be predicted at a lower figure when higher temperatures are used.

The reaction rates of regular acid at various temperatures are somewhat controversial as one might glean from published literature. However, any source will indicate a large increase in reaction rate with an increase of only 45°F. Any estimate of acid performance based on bottom-hole temperature is therefore likely to be in error. Retarders based on the higher temperature could, in many cases, be unnecessary.

The overriding fact concerning the statements above is that a calculated pad volume pumped ahead of a given treatment will cool the formation considerably, and a desired formation temperature can actually be accomplished. This will effectively control the temperature environment of any treating fluid, make it possible to more accurately design the treatments, and allow better predictions of results.

CONCLUSIONS

1. Temperature of a fluid moving through a fracture can be estimated at a given point and time using equation (8).
2. This information can result in better fracture area predictions, and in better acidizing design procedures.
3. Acid reaction rates can be slowed by cooling the formation face to a desired temperature with pad volumes.
4. Further work in this area should be done to include the heat of reaction of acid with carbonate rocks.
5. Further efforts should be directed toward improving the representation of the heat flux from the formation to the fluid.

NOMENCLATURE

m = Mass flow rate, lbs. /hr.

c = Specific heat of formation rock, Btu. / lb_m ^0F

q = Heat flux, Btu. /ft.^{2} hr.

h = Height of vertical fracture, ft.

x = Distance along fracture length L, ft.

T = Fluid temperature

t = Pumping time, in minutes

ρ = Density of rock, $lb_m/ft.^3$

k = Thermal conductivity of formation, Btu. /hr. ft. ^0F

L = Length of fracture, ft.

α = Thermal diffusivity, $\frac{k}{c\rho}$, ft.^{2}/hr.

ϕ = $(T_i - T)$

T_i = Initial formation temperature

T_0 = Fluid temperature at borehole-fracture intersection

m_l = Fracture fluid leak-off rate, lb_m/sec.

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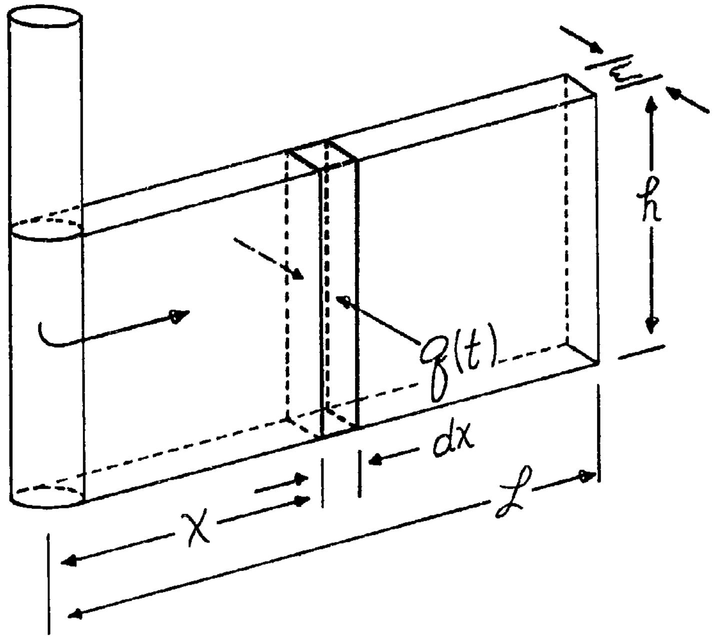
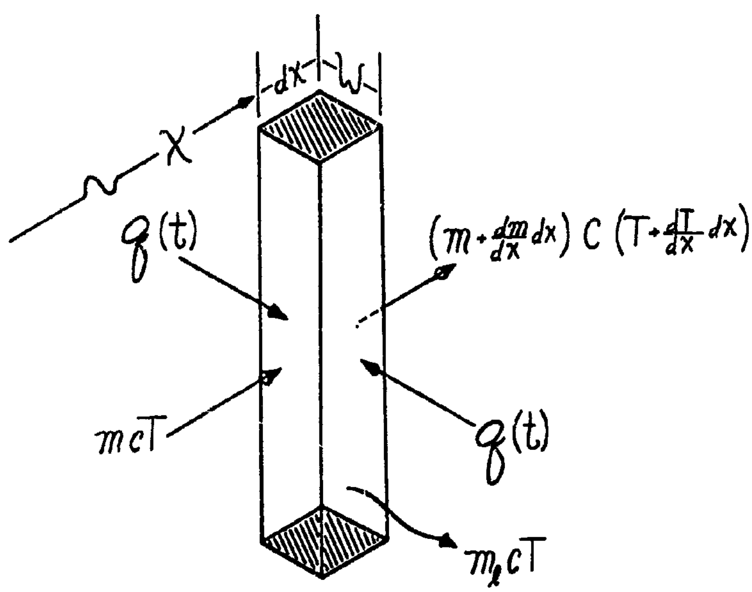


FIGURE I- FRACTURE MODEL



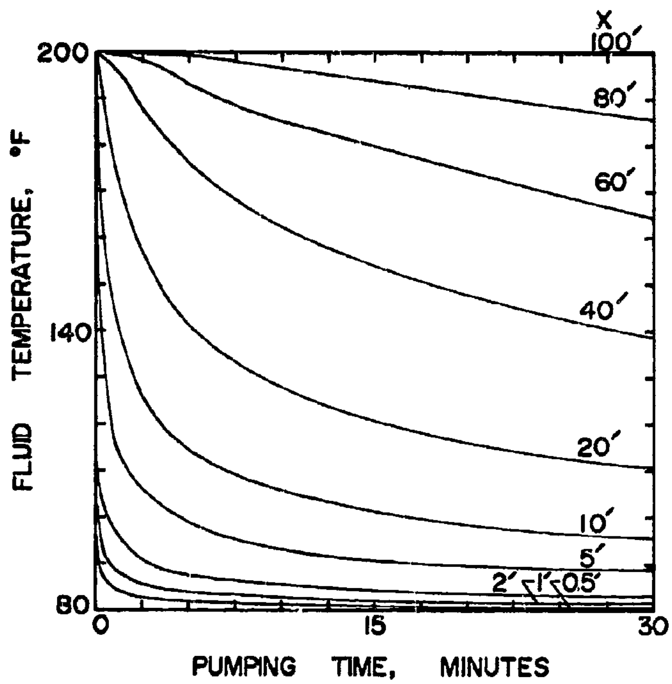


FIGURE 3 - FRACTURE FLUID TEMPERATURE HISTORY

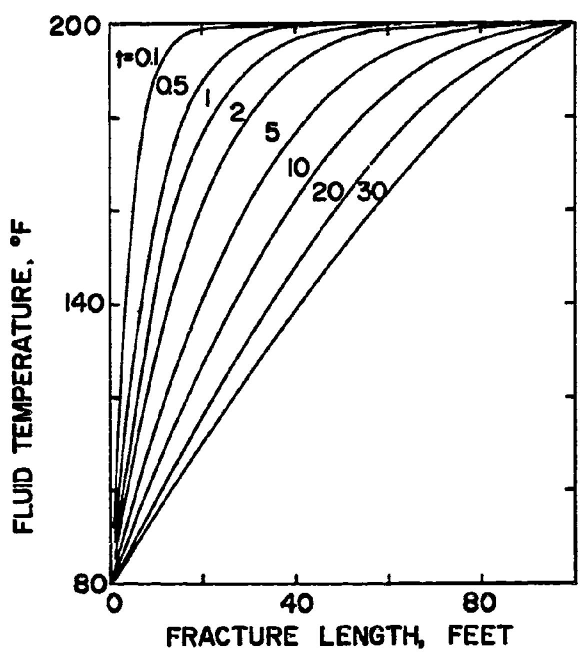


FIGURE 4 - TEMPERATURE DISTRIBUTION